HEINRICH BÖLL STIFTUNG
INDIA

To Frac or Not to Frac
Shale Gas in India - Prospects and Risks

A Study by **Chandra Bhushan**

Heinrich Böll Foundation

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The author

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p. 43: Vikas Choudhary, CSE, Delhi

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Published by Heinrich Böll Foundation, India, April 2016

Design & Print: Satyam Grafix, New Delhi
Copyediting: Ambika Aravindd

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Foreword

Energy policy in India poses enormous challenges. India has a huge unmet energy demand, and by far the lowest per capita energy consumption among the BRICS group of major emerging economies. With a rapidly growing economy and a still increasing population, India's energy production and consumption will need to increase several times in the next decades in order to meet human development needs. The challenge for India is how to meet this energy demand equitably, affordably and sustainably.

The Indian government under Prime Minister Narendra Modi is committed to scale up industrial growth through initiatives such as 'Make in India' and its support for start-up companies. At the same time, the government is committed to implement ambitious plans to reduce India's dependence on fossil fuels, a major source of emissions leading to global warming.

These two objectives could be conflicting. While, currently, coal still constitutes the major portion in the primary energy mix, India has committed in the December 2015 Paris COP Agreement to massively increase the share of renewables. Obviously, it is difficult to scale up renewable energy in the absence of upgraded grid technology and accommodating policy frameworks. Work has started to overcome the challenges, but there are some who argue for the need of a 'transition fuel' that can give crucial support in the intermediary period before renewables become dominant – a temporary fossil solution with a smaller carbon footprint than coal. Some people regard natural gas as such a 'transition' option; others fundamentally dispute the very viability of any 'transition' fossil option. At any rate, gas production saw major expansion over the last decade by the use of technologies extracting unconventional sources, which have become known under the term 'fracking' and 'shale gas'.

Shale gas development took place on a large scale especially in the U.S. In fact, before the recent emergency of a low energy price trend that is unlikely to last for long, shale gas was about to reverse the role of the U.S. as the world's largest energy importer. However, the technological and commercial success story of shale gas has come with major ecological problems and risks, especially as regards the use and pollution of water. Popular protests against fracking have become widespread in the U.S. and Europe.

In order to provide for a better understanding of the possibilities and risks involved in shale gas development, the India office of the Heinrich Böll Foundation commissioned this study. It analyses experiences with the technology, especially in the U.S., provides an overview about shale gas potentials in India, and points to environmental and social impacts and risks that the adoption of a shale gas strategy by a developing country such as India would imply. The study ends on a very clear note of warning. The Foundation wishes to thank the author, Chandra Bhushan, for the extensive research work undertaken and his sober and careful analysis.

Delhi, April 2016

Dr. Axel Harneit-Sievers, Director

Heinrich Böll Foundation, New Delhi

Introduction

World over, there has been a growing interest in natural gas the as it is the cleanest burning fossil fuel and has the lowest carbon intensity for producing electricity. Countries are, therefore, using more and more natural gas, making it the fastest growing fossil fuel.

The global consumption of natural gas increased by about 30% between 2003 and 2013 and it is projected that the contribution of natural gas to the global energy mix will increase from 21.5% in 2010 to 24% in 2035. The International Energy Agency (IEA) has even predicted a golden age for natural gas in which the global gas demand rises by more than 50% between 2010 and 2035 and natural gas overtakes coal to become the second-largest primary energy source after oil.

The IEA's golden age for natural gas is based on the assumption of unlocking world's vast resources of unconventional gas – shale gas, tight gas, and coalbed methane. This is exactly what has happened in the United States (US) in the last six years. Advances in technology of extracting oil and gas from shale formations have led to a huge increase in the production of shale gas and oil in the US. Gas prices are at record lows and the US is now on the verge of becoming self-sufficient in natural gas.

But the US is not the only country with shale gas resources; there are large reserves of shale gas in countries like China, Australia, Algeria, Canada, and Mexico. Some of these countries are likely to start producing shale gas from 2020. The world is, therefore, entering the age of unconventional natural gas – colloquially termed as 'shale gas revolution'.

In India

Natural gas is a scarce commodity in India. The gap between demand and supply of natural gas is about 40%. Additionally, India imports about 30% of its natural gas consumption as Liquefied Natural Gas (LNG) at a very high price. The short supply and high prices of natural gas have led to significant negative environmental and social impacts.

1. India is not able to provide natural gas for cooking to a large proportion of its population. Only about 65% of the urban households and 12% of the rural households use LPG as a main source of cooking energy. This has led to an increase in premature deaths and diseases as a result of the indoor air pollution caused by traditional fuels such as firewood and biomass.

2. India is not able to supply natural gas to the urban transport sector. Thirteen of the world's top 20 polluted cities are in India. Gas can play a major role in reducing urban air pollution.
3. Adequate supply of gas to the power plants can reduce coal consumption in India significantly, thereby reducing both local pollution and carbon emissions. Presently, the gas power plants in India operate at less than 40% capacity.

India, therefore, is looking for an affordable and secure supply of natural gas. It is planning to bring gas from Turkmenistan through TAPI (Turkmenistan–Afghanistan–Pakistan–India) Pipeline. It is looking to import LNG from gulf countries as well as from the US. It is also looking to explore and exploit shale gas.

The present shale gas resource in India is not very high. It is about 100 Trillion Cubic Feet (TCF), which is sufficient to meet India's gas demand at the current level for about 25 years. Also, the shale gas basins in India are not as prolific as those in the US. Shale gas extraction therefore will be difficult and more expensive in India compared to the US. Nevertheless, considering the desperate natural gas situation in the country, the government is looking to unlock this resource.

In 2013, the Government of India finalized its policy for the exploration and exploitation of shale gas. The present policy has adopted a cautionary approach and has allowed only national oil companies (NOCs) to carry out exploration and exploitation of shale gas and oil-private companies are not allowed. So far the development of shale gas in India is limited to drilling of few exploratory wells. However, this could change very quickly. There is a fear that large-scale development of shale gas could impact the environment and the lives and the livelihoods of communities.

Back to the US

Shale gas development in the US has been quite controversial. Though the production of shale gas has increased manifold, many states like New York, Maryland, Vermont, and North Carolina have put moratorium on shale gas development due to its perceived negative environmental consequences. The development of shale gas has been associated with increased water exploitation and pollution, increase in emissions of toxic air pollutants, and land degradation. In addition, large-scale use of cheap shale gas is likely to reduce investments in renewable

energy and energy efficiency measures, thereby contributing to climate change. Research also points to the fact that high emissions of methane from shale gas development make shale gas as good or as bad as coal in terms of greenhouse gas emissions.

The study tour

It was in the background of India coming out with its shale gas policy and heated debate in the US that I decided to get a firsthand experience of the shale gas revolution in the US.

I started my two-week shale gas tour in which I visited a state that is considered a pioneer in shale gas development (Pennsylvania) and a state that has put a moratorium on shale drilling (New York). I visited shale gas sites in the forests as well as some densely populated counties of Pennsylvania. I also visited a new and an old coal mine (I visited Centralia where underground coal fire is taking place for decades) to make some visual comparison between shale gas and coal.

I met people from all walks of life. I met representatives of companies like Halliburton and Chesapeake Energy Corp. and also attended a big meeting of Marcellus Shale Coalition, the biggest coalition of shale gas companies in the US. I met representatives of NGOs, Academia, and Think tanks and visited the Cornell University to meet researchers working on shale gas issues. Lastly, I met representatives of state and federal governments including Department of Environment, Pennsylvania and the US Environment Protection Agency.

The objective of my visit was simple: I wanted to understand what has gone right or wrong in the US so that we in India do not repeat the same mistakes.

I have come back with a picture that is not very simple. It is a nuanced picture of tradeoff between local imperatives and global environmental challenges.

1. Shale gas is like any fossil fuel. It is not a “bridge fuel” between coal and renewable energy. On climate, the world needs to take action in the next 20 to 30 years and methane is hugely damaging to climate over a 20-year period. Large-scale methane emissions from well to burner will be highly detrimental to the fight against climate change. Reducing coal and adding gas, as is being planned in the US, is not a solution for climate change. Developed countries like the US need to reduce both. Large-scale and continued use of shale gas would be hugely detrimental to the global efforts towards fighting climate change.
2. However, shale gas development has taken off in the US and would soon takeoff in countries like China and Australia. Shale gas is a reality; we can slow its growth, but can’t stop it. What we can certainly do is to reduce its environmental impacts including reduction in methane emissions by setting stringent performance standards. Also, the global community must come together and set goals for renewable energy and energy efficiency so that we do not lose focus on climate change. If we don’t do this, cheap shale gas will paralyze the growth of the renewable energy and energy efficiency sector for decades.
3. Shale gas development has far lower impacts on the local environment compared to coal mines, including impacts on water. Having studied the environmental and social fallouts of coal mining in India, I would prefer shale gas to coal any day.
4. However, with higher population density, lower water resources, and higher proportion of arable and forest land, the impacts of fracking on the ecosystems, people, and communities in India would be higher than what I saw in the US. India, therefore, would need more stringent environmental norms and practices if it wants to exploit shale gas safely and manage its environmental fallouts.
5. I could take a moral high ground and say that India should not go for shale gas exploitation. However, considering the scarcity of natural gas and the benefits it can provide to vast sections of the population including health of women and improved air quality in cities, this would be a hypocritical position especially in light of the large-scale shale gas use in the US and potentially in China, Australia, and other countries. I therefore believe that India should go ahead, but cautiously, with shale gas exploration and exploitation. However, before that, it should do the following.

a. We should be clear why we want to develop the shale gas sector. India should develop the shale gas sector to meet its essential gas demand in the short to medium term and not to meet its climate goals; shale is not a solution for climate change. This is important to internalize in policy circles, as we need to exclude shale gas as part of climate solution.

b. Undertake detailed investigation of basins to understand issues like water requirements, quality and quantity of flow back and other wastewater generation, characteristics of wastes and air emissions, etc. This information should be out in the public domain for taking a democratic decision regarding the future course of action.

c. If India decides to go for shale gas, then it should put in place the following environmental and social safeguards without any compromise.

   - The existing environmental rules and regulations on natural gas development in India are not suitable for shale gas. India, therefore, should come out with new stringent rules and regulations covering the entire life cycle of shale gas development. This should include requirements for a detailed environmental impact assessment before starting exploitation, stringent water use and pollution control standards, standards for air pollution (including methane emissions control), and safe disposal of wastes, etc.
   - India should also put in place a "no-go" policy for shale gas development. Shale gas development should not be allowed, for instance, in areas of high ecological value, important watershed or areas with water stress, etc. New York state has put a moratorium on fracking simply because, people in New York City got worried because their watershed is 130 km away and they have protected that water for a long time.
   - India will also have to put in place a highly advanced waste management infrastructure to deal with toxic wastes generated from shale gas wells. The current waste management techniques won't work.
   - Lastly, consent of the community, regular consultation with them, and information disclosure is very important; so is sharing benefits with them. The benefit of shale gas development must flow to the affected communities.

Section 1

Shale gas

2013 was a record year for natural gas production in the US. For the first time in its history, the gross natural gas production in the US crossed 30 trillion cubic feet (TCF)[1]. The country, which traditionally relied on imports to meet its natural gas requirements, is now on the verge of becoming self sufficient and is touted to become an exporter of natural gas by 2020. Gas prices in the US are at record lows reflecting strong production growth and record high gas inventories[2]. About 40% of gas production comes from a source which was barely thought to be a commercially viable source just a decade back. This source is now popularly known as shale and the gas produced from these rock formations is called as shale gas.

Shale gas is a part of an unconventional gas resource base that has traditionally been considered difficult or costly to produce (See Box: Unconventional gases). These resources were known for decades but it is only due to recent technological developments, mainly horizontal drilling and hydraulic fracturing, that they are now being recognized as an important source of energy for the world.

Presently, shale gas is a North American phenomenon; most of the shale gas in 2013 was produced in the US and Canada. Outside North America, the largest contribution to shale gas production came from China –mere 7.1 billion cubic feet or about 0.2% of China's total production of natural gas. However, in light of the North American experience and with evidence of a large and widely dispersed resource base, there has been a surge of interest in shale gas from countries around the world (See Box: Why so much interest in shale gas?).

Unconventional gases

Unconventional gases are gases produced from sources other than conventional oil and gas reservoirs. Different categories of unconventional gas include the following.

- Shale gas is natural gas contained within a commonly occurring rock classified as shale. Shale formations are characterized by low permeability, with more limited ability of gas to flow through the rock than is the case with a conventional reservoir. These formations are often rich in organic matter and, unlike most hydrocarbon reservoirs, are typically the original source of the gas.Thus, shale gas is gas that has remained trapped in, or close to, its source rock.
- Coal bed methane is natural gas contained in coalbeds. It is now typically produced from non-mineable coal seams. For stimulating larger flow of gas, technology such as hydraulic fracturing,is also employed in case of coal bed methane.
- Tight gas is a general term for natural gas found in low permeability gas reservoirs that cannot produce economically without the use of technologies like hydraulic fracturing to stimulate flow of the gas towards the well. Tight gas is often a poorly defined category with no clear boundary between tight and conventional, nor between tight gas and shale gas.

Source: Golden Rules for a Golden Age of Gas, World Energy Outlook Special Report on Unconventional Gas, International Energy Agency, 2012

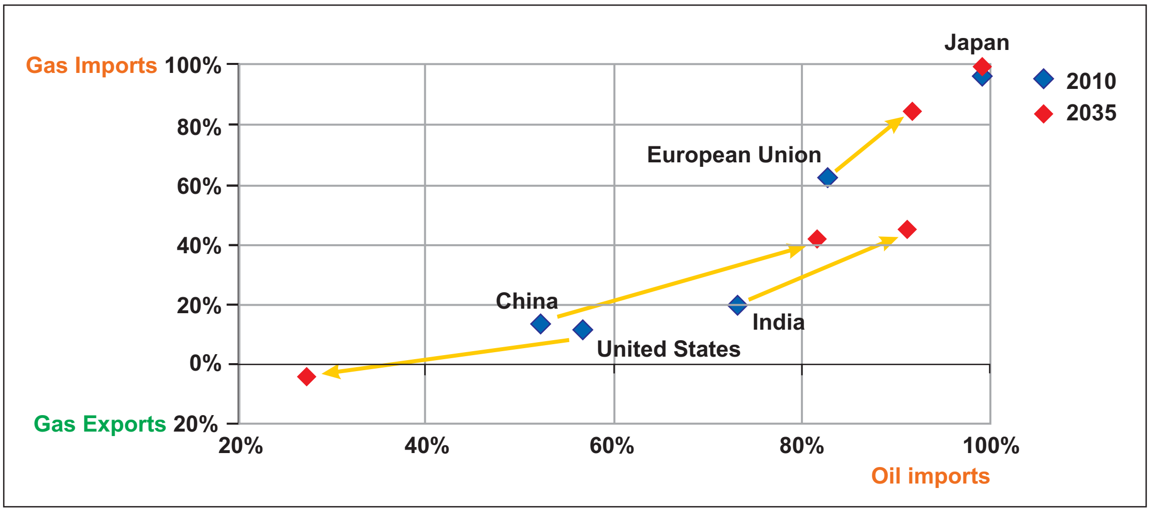
Why so much interest in shale gas?

The global energy mix, in the absence of strong climate policy, is likely to remain highly dependent on fossil fuel. According to IEA, even in 2035, about 75% of the energy demand will be met by fossil fuels. IEA, however, also predicts that the share of coal and oil will reduce and that of gas will increase in the next 20 years due to many factors including local pollution imperatives and greenhouse gas reduction targets. The global demand for gas can increase by 40% by 2035 compared to the 2010 levels.

The increase in gas demand will make many large countries increasingly import dependent. China's dependence on imported gas is likely to increase to 40% by 2035; India's to 45%, and that of the EU by more than 80%.

Interestingly, much of the shale resource exists in countries with limited endowments of conventional oil and gas supplies such as South Africa, Jordan, and Chile; in countries like the US and China that are currently net gas importers and face increasing import dependency; and in countries where conventional hydrocarbon resources have largely been depleted, such as Europe. The exploitation of shale gas is therefore likely to reduce prices and import dependencies of countries for natural gas.

Figure 1: Dependence on imported gas



Source: World Energy Outlook, 2012, IEA

1.1 How much shale gas and where?

There are varying estimates on the resource base of the unconventional gas, as these gases have not been explored extensively in all parts of the world. The IEA estimates that the remaining technically recoverable resources of unconventional gas worldwide are similar to the size of remaining conventional gas resources[3].

Advanced Resources International, Inc. (ARI) did the most comprehensive assessment of shale gas for the U.S. Energy Information Administration (EIA), under which the shale gas and shale oil resource in 26 regions, containing 41 individual countries were estimated. The EIA/ARI assessment established a total risked shale gas[4] in-place of 35,782 TCF, including the US. Of this total, approximately 7,795 TCF is considered the risked, technically recoverable shale gas resource[5].

Two-thirds of the assessed, technically recoverable shale gas resource is concentrated in six countries: US, China, Argentina, Algeria, Canada, and Mexico. The top 10 countries account for over 80% of the currently assessed, technically recoverable shale gas resources of the world[6].

Figure 2: Assessed Shale Gas and Shale Oil Basins of the World

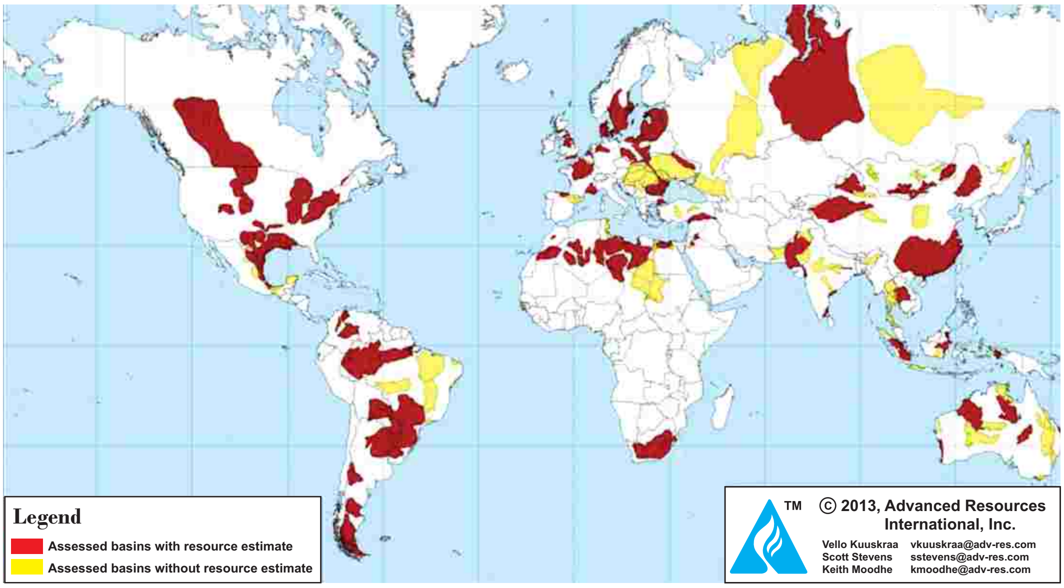


Table 1: Technically Recoverable Shale Gas Resources (TCF)

US	1,161
China	1,115
Argentina	802
Algeria	707
Canada	573
Mexico	545
Australia	437
South Africa	390
Russia	285
Brazil	245
Others	1,535
TOTAL	**7,795**

Source: EIA/ARI World Shale Gas and Shale Oil Resource Assessment, June 2013

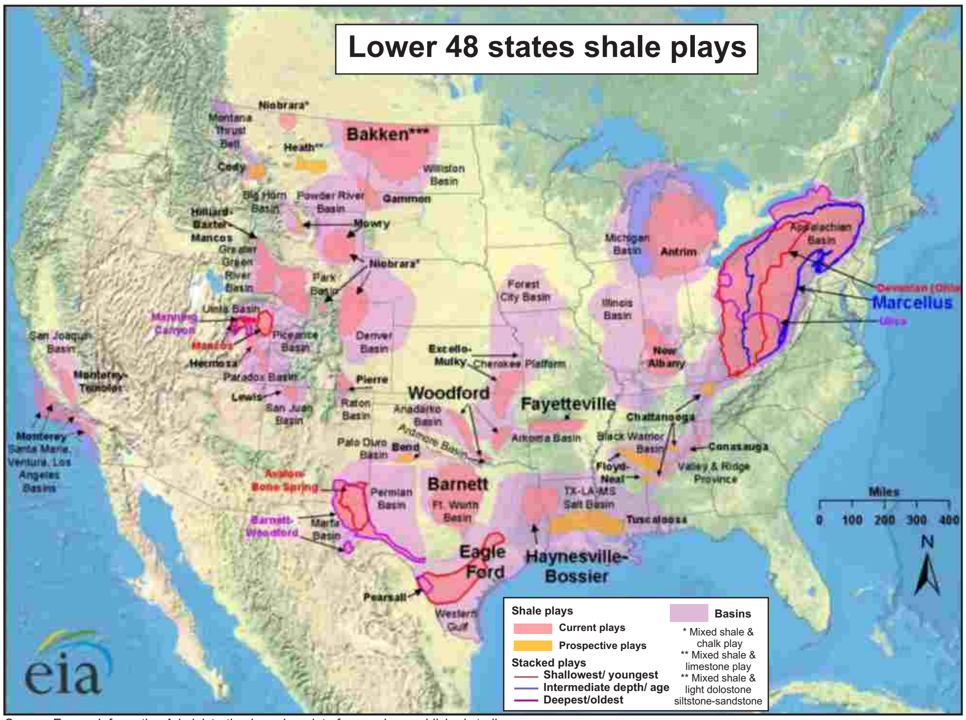
1.1.1. United States

The US has one of the largest Recoverable Shale Gas Resources (1161 TCF) and is the largest producer of shale gas in the world. In recent years, US shale gas production has grown rapidly from 2.0 TCF in 2007 to 11.9 TCF in 2013.

Shale gas deposits (also called as plays) are widely distributed across the Northeast, Gulf Coast, Mid-Continent, Southwest, Rocky Mountain, and West Coast Regions[7].

- The Northeast region includes shale gas plays located in the Appalachian, Illinois and Michigan Basins. The Appalachian Basin includes the Marcellus, Devonian Big Sandy, Devonian Low Thermal Maturity, and the Devonian Greater Siltstone shale plays. New Albany is situated in the Illinois Basin while the Antrim shale play is in the Michigan Basin.
- The Gulf Coast region includes the Haynesville, Eagle Ford, and the Floyd-Neal/Conasauga shale gas and shale oil plays. The Haynesville shale play is located in the Texas and Louisiana basin, Eagle Ford is located in the Texas Maverick Basin and Floyd-Neal/Conasauga is in the Black Warrior Basin.
- The Mid-Continent region includes shale gas plays located in the Arkoma, Ardmore and Anadarko Basins such as the Fayetteville, Woodford, and Cana Woodford shale plays.
- The Southwest region includes shale gas and shale oil plays located in the Fort Worth and Permian Basins. These basins include the Barnett, Barnett-Woodford and the Avalon and Bone Springs shale plays.
- The Rocky Mountain region includes shale gas plays in the Greater Green River, San Juan, Uinta, and Williston Basins. These basins include the Hilliard-Baxter- Mancos, Lewis, Mancos, and the Bakken shale plays.

Figure 3: United States Shale Gas Basins and Plays



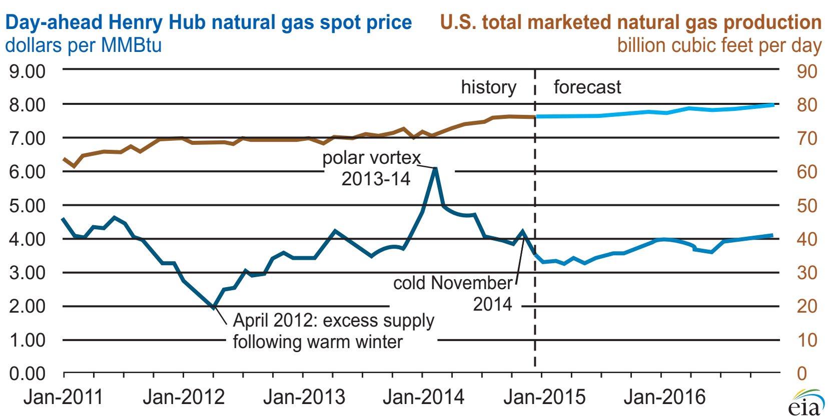
Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2010

- The West Coast region includes shale oil plays in the San Joaquin and Los Angeles Basins. The basins incorporate the Monterey/Santos shale oil play.

Technological advancements in the horizontal drilling and hydraulic fracturing methodologies have made production of shale gas economically feasible, thereby, reducing the cost of production. Although, the average cost of production depends on a number of factors that vary from region to region, it tends to be within the range of $2 to $3 per thousand cubic feet of gas. This comes to about half to one-third of the cost of production for new conventional gas wells in the US. The natural gas prices are at record low and likely to remain so in the near future.

The shale gas revolution has contributed to the growth of the US economy by increasing competitiveness of industries dependent on natural gas, increasing employment opportunities as well as providing revenue to the government. It is estimated that most of the jobs created in recent times in the US has happened in the shale oil and gas sector[8].

Figure 4: Natural gas prices in the United States

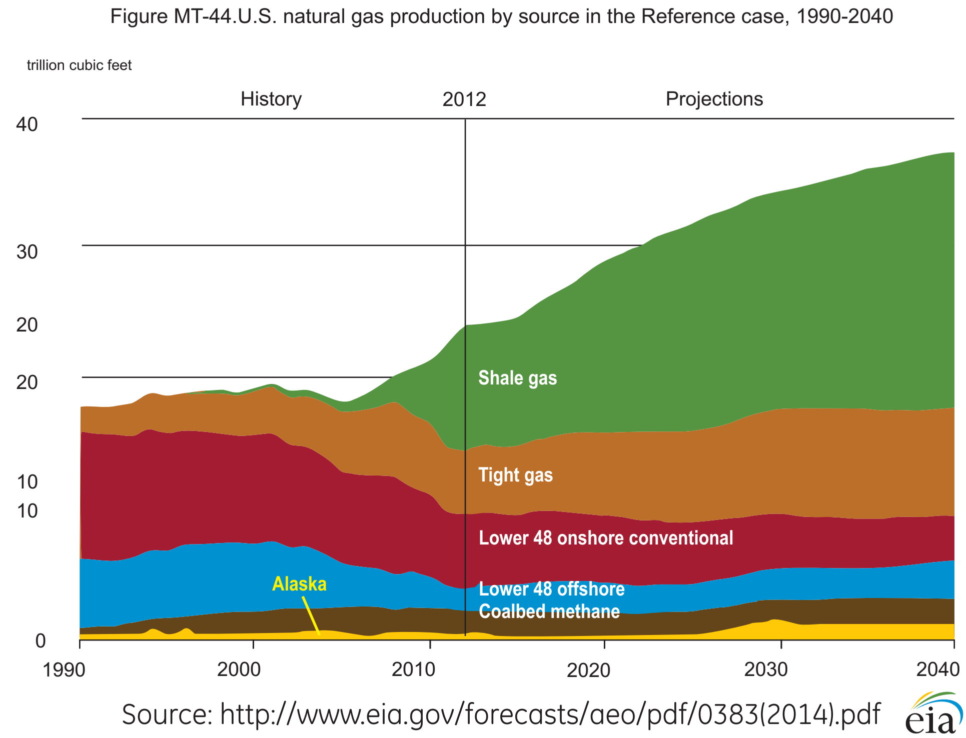


Source: U.S. Energy Information Administration, Short-Term Energy Outlook, January 2015

Future Projections

Shale gas production is set to more than double in the US by 2040. The share of shale gas in the total US natural gas production increases from 40% in 2013 to 53% in 2040. With production growing more rapidly than demand and use, the US will become an exporter of natural gas by 2020.

Figure 5: Shale gas production projections for the United States



Source: http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf

1.1.2. China

China has one of the largest technically recoverable shale gas deposits, estimated to be 1,115 TCF. It has shale gas mainly in the marine and lacustrine deposited rock shales of the Sichuan, Tarim, Junggar, and Songliao basins. Additionally, risked technically recoverable shale gas deposits are found in smaller, structurally more complex Yangtze platform, Jianghan, and Subei basins[9].

According to the current industry view, the geological conditions in China are considerably less favorable than in North America. Many Chinese shale basins are tectonically complex with various faults – some seismically active – which does not support shale development. Similar issues have weakened China's coal bed methane production in past. It is for these reasons that only 20% of the shale gas resources are assumed to be accessible[10].

Presently, China is among the only three countries along with the US and Canada to produce commercial quantities of shale gas. In 2013, China produced about 7 billion cubic feet (BCF) of shale gas, which is about 0.2% of China's total production of natural gas.

In December 2011, shale gas was approved by the China State Council as a new type of natural resource to be managed separately from conventional gas. In March 2012, the National Development and Reform Commission (NDRC) announced the shale gas Development plan (2011–15) which set a target of producing 250 BCF shale gas in 2015. In its recently released comprehensive Energy Development Strategy Action Plan (2014–20), China has set a target of producing 1.0 TCF of unconventional gas to meet 10% of its total energy demand from natural gas[11]. Presently, China imports 30% of its natural gas requirements and shale gas is considered to reduce China's dependence on imported gas besides coal.

Shale gas industry in China is in its nascent stage, but developing rapidly. Various companies like BP, Sinopec, Chevron, Statoil, Conco Phillips, Total, and others have entered China for Shale gas development.

Recently, Shell and CNPC were given the 3,500 km^2 Fushun-Yongchuan block, which is located in the southern Sichuan. The Fushun-Yongchuan is China's first foreign-invested production sharing contract for shale gas. Shell has signed an initial agreement with petro China for jointly exploring shale gas at the Fushun block, southern Sichuan basin. By April 2012, the company had already drilled five deep exploration wells: one vertical data well, two vertical frac wells, and two horizontal frac wells. Shell and Hess have also signed agreements to conduct joint study with PetroChina'sTurpan-Hami unit to explore shale oil in the Santanghu basin.

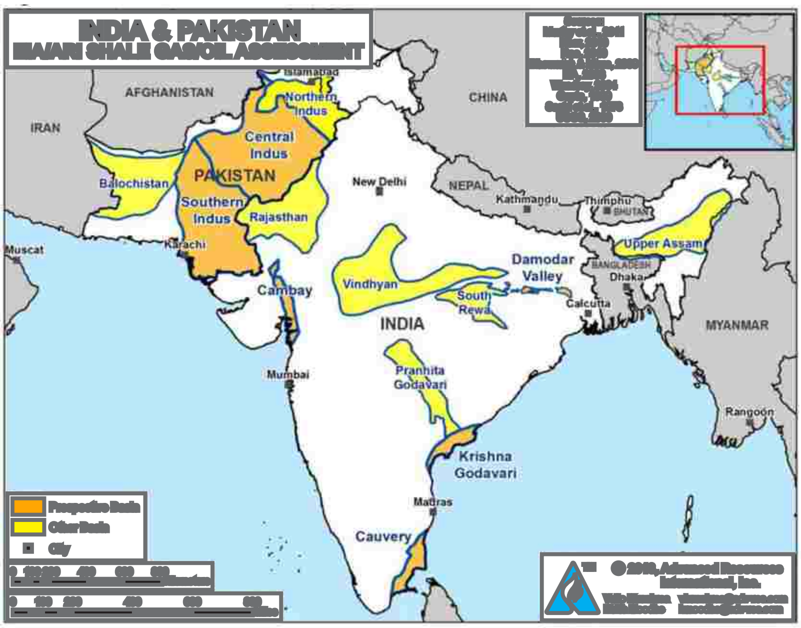
Conco Phillips recently was allocated two shale exploration blocks in the southern Sichuan basin. Chevron is also conducting a joint study with Sinopec in the Yangtze platform, just south of the Sichuan basin. Chevron started seismic acquisition in the block in July 2011 and started its first well there during first half of 2012. BP, ENI, Conco Phillips, Statoil, Exxon Mobil, and TOTAL have also initiated activities in leasing shale gas blocks in the Sichuan or Yangtze platform. New field Exploration and EOG Resources, North America shale gas operators have also started evaluations in the basin in the past few years.

1.1.3. India

It is projected that India possesses shale deposits across Gujarat, Jharkhand, West Bengal, Andhra Pradesh, Tamil Nadu, Assam, Rajasthan, and a few other areas. But only six basins have been identified where extractions is possible. They are Cambay (in Gujarat), Assam-Arakan (in the North-East), Gondawana (in central India), Krishna-Godavari onshore (in Andhra Pradesh), Kaveri onshore, and The Indo- Gangetic Plain. However, there are no credible estimates of the reserves available in these basins.

EIA/ARI assessed four priority basins: Cambay, Krishna-Godavari, Cauvery, and Damodar Valley. It also screened other basins in India, such as the Upper Assam, Vindhyan, Pranhita-Godavari, Rajasthan, and South Rewa. However, in these basins the shale was thermally tooimmature or the data for conducting a rigorous resource

Figure 6: Shale Gas and Shale Oil Basins of India



assessment were not available.Overall, EIA/ARI estimates a total of 584 TCF of risked shale gas in-place for India. The risked, technically recoverable shale gas resourceis estimated at 96 TCF.

Studies by the United States Geological Survey(USGS), however, indicate lower resources than those projected by EIA/ARI. For example, for the Krishna-Godavari shale gas basin, USGS reports a mean estimate of 4.1 TCF, compared with the EIA/ARI estimate of 27 TCFof technically recoverable shale gas resource[12].

Government policy on shale gas

The Government of India had put out in 2012, a draft policy for the exploration and exploitation of shale gas. The salient features of the draft policy draft were as follows.

- International competitive bidding for the blocks
- Fiscal regime based on royalty and production linked payments, similar to the regime adopted for Coal Bed Methane operations. Shale gas to pay ad-valorem royalty at the prevailing rate of natural gas to the state governments. Production-linked payment on ad-valorem basis to be made to the central government on different production slabs, which will be biddable items. Cost recovery will not be admissible.
- The contract duration to be of 32 years and be divided into two phases. Phase I, for a period of seven years, will be for exploration, appraisal, evaluation of the prospect, and feasibility. Phase II will be the development and production phase for the remaining duration of 25 years. There will be freedom to market shale gas within India on an arm's length basis within the framework of the government policies in marketing and pricing of the gas.

The draft policy also addressed some of the issues related to environment protection, but not adequately. For instance, the draft policy proposed making multiple casing programme (at least two casings) mandatory requirement across all sub-surface fresh water aquifers. It further suggested that there should be a mandatory rainwater harvesting provision in the exploration area, which minimizes the extent to which water will be required. It states, "as far as possible", river, rain or non-potable groundwater only should be utilized for fracking - and reuse/recycling of water should be the preferred method for water management.

In 2013, the shale gas policy was finalized and issued. The final policy has adopted a cautionary approach and has allowed only national oil companies (NOCs) to carry out exploration and exploitation of shale gas and oil from on land blocks that were allotted to them on a nomination basis before the advent of the New Exploration Licensing Policy in 1999, under which exploration blocks are offered on a bidding basis.

Companies will be permitted three assessment phases, each with a maximum period of three years. Royalties and taxes would be the same as for conventional gas production in a particular area.In the second phase, state-owned companies and industry will be allowed by the government to explore shale gas.

Recent developments in India

India is at the beginning of the exploration stage in the shale gas. Recently, ONGC drilled and completed India's first shale gas well, RNSG-1, inthe Raniganj sub-basin of the Damodar Valley in West Bengal. The well was drilled to a depth of 2,000 meters and reportedly hadgas shows at the base of the Permian-age Barren Measure Shale. ONGC plans to drill two additional wells in the Karanpura sub-basin of Damodar basin. Two vertical wells (Well D-Aand D-B) were previously tested in the Cambay Basin and had modest shale gas and oil production from the Cambay Black Shale[13].

In order to gain expertise in this upcoming industry, Indian companies are partnering with the US companies as well as investing in the US shale gas plays.

- ONGC signed an agreement with ConocoPhillips in March 2012, for partnering in the exploration and development of shale gas resources in India and other regions. In the first phase of the agreement, both the companies have plans to explore Cambay, Damodar, Kaveri, and KG basins.

- Oil India Limited (OIL) has hired Schlumberger and is conducting a feasibility study of shale gas potential in the Rajasthan and Assam-Arakan basins.
- Reliance Industries Limited (RIL) has signed three upstream joint ventures (Pioneer Natural Resource, Chevron and Carrizo Oil & Gas) and a midstream JV (Pioneer) for carrying out operations in the US. RIL has invested a total of US$4.09 billion in shale gas assets.
- GAIL signed an agreement with Carrizo Oil & Gas and acquired a 20% stake in the latter's Eagle Ford acreage for US$95 million. GAIL also signed an agreement with Cheniere Energy for 20years for the supply of 3.5 million tonnes per year of LNG.

Shale gas in Pakistan

Estimates done by EIA/ARI indicate that Pakistan has relatively higher shale gas and oil potential than India. The two shale formations, Sembar and Ranikot in Lower Indus area, studied by EIA/ARI puts risked shale gas in-place for Pakistan as 586 TCF and risked, technically recoverable shale gas resource at 105 TCF; both slightly higher than India. The shale oil potential in Pakistan is even much higher. The risked shale oil in-place is 87 billion barrels in India and 227 billion barrels in Pakistan. The risked, technically recoverable shale oil resource is estimated at 3.8 billion barrels for India and 9.1 billion barrels for Pakistan.

Table: Shale gas and oil potential

	Risked Gas In-Place (TCF)	Technically Recoverable gas (TCF)	Risked Oil In-Place (Billion bbl)	Technically Recoverable Oil (Billion bbl)
India	584	96	87	3.8
Pakistan	586	105	227	9.1

Source: EIA/ARI World Shale Gas and Shale Oil Resource Assessment, June 2013

Section 2

Social and environmental impacts

Major concerns are being raised around the world regarding shale gas development. Countries like France and Germany[14] have banned fracking and so have many states and local governments in the US, the largest producer of shale gas in the world. In the US, New York, Maryland, Vermont, and North Carolina have put moratorium on shale gas development. Longmont, Colorado, recently became the first city in the state to pass a ban on hydraulic fracturing[15]. So why are governments and communities opposing shale gas development?

The main reason is that shale gas has significantly higher environmental impacts than the conventional natural gas, thereby affecting the well-being of the local communities. The other reason is that large-scale use of shale gas likely to be hugely detrimental to the fight against climate change.

The reason for the potentially larger environmental impact of shale gas operations is the nature of the resource itself. Shale gas is less concentrated than conventional deposits. They are difficult to extract because they are trapped in low permeability rock that impedes their flow. Since the resources are more diffuse and difficult to produce, the scale of operations required for a given volume of shale gas output is much larger than for conventional gas. This means that drilling and production activities are more invasive, involving a generally larger environmental footprint.

Shale gas development is highly land intensive. Whereas onshore conventional fields might require less than one well per ten square km^2, unconventional fields might need more than one wellper km^2, significantly intensifying the impact of drilling and completion activities on the environment and local residents[16]. In addition to the smaller recoverable hydrocarbon content per unit of land, unconventional developments tend to extend across much larger geographic areas, thereby affecting larger population. The Marcellus Shale in the US covers more than 250,000 km^2, which is about ten times larger than the Hugoton Natural Gas Area in Kansas – the country's largest conventional gas producing zone.

A typical well pad with multiple shale gas wells in the US

Shale gas development is also highly water intensive. While hydraulic fracturing is already used on occasions to stimulate conventional reservoirs, shale gas developments almost always require the use of this technique in order to generate adequate flow rates into the well. The associated use and release of water gives rise to a number of environmental concerns, including depletion of freshwater resources and possible contamination of surface water and aquifers.

The environmental and health effects of shale gas development occur during its entire production life cycle-from exploration till well plugging and site restoration.

2.1. Shale gas production life cycle

Shale gas life cycle begins with site preparation and ends with well abandonment and site restoration.

1. **Civil/Site preparation:** Firstly, access routes are built and site is prepared by clearing and leveling the surface. This is followed by construction and installation of well pads and preparing the site for the drilling activities. During these activities land and vegetation is damaged and surface water bodies can also be polluted due to increased sedimentation. The impacts are significantly higher if shale gas development takes place in forest areas.

   Based on the geological characteristics of the formation and climatic conditions, operators may (1) excavate a lined pit or impoundment to store freshwater, drilling fluids, or drill cuttings-rock cuttings generated during drilling; (2) use tanks to store materials; or (3) build temporary pipelines to transport materials to and from an off-site location and permanent pipelines to transport gas to processing plants. Construction of pipelines has major impacts on habitat fragmentation in forest areas.

2. **Drilling:** The drilling phase is the most visible and disruptive. Operators drill a hole (referred to as the wellbore) into the earth through a combination of vertical and horizontal drilling techniques.

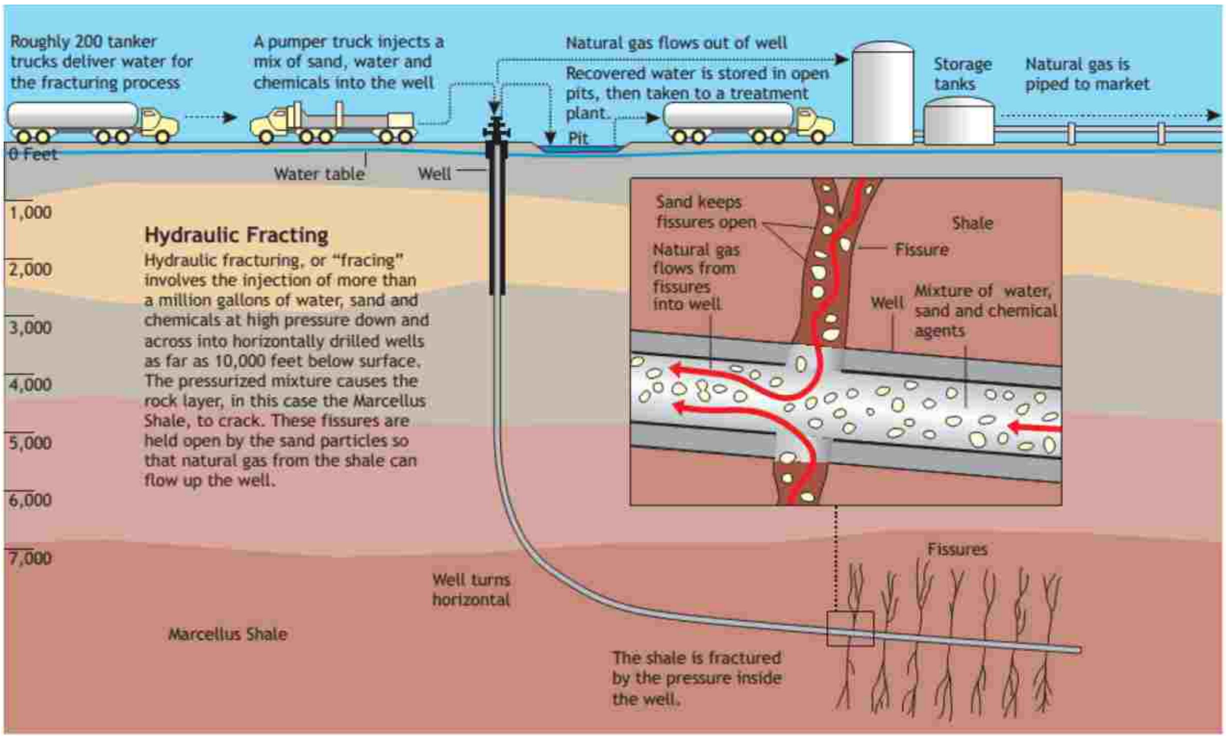
- In the drilling process, the drill string and bit are removed from the wellbore so that casing and cement may be inserted.
- As drilling progresses with depth, casings that are of a smaller diameter than the hole created by the drill bit are inserted into the wellbore and bonded in place with cement, sealing the wellbore from the surrounding formation.
- Drilling mud (a lubricant also known as drilling fluid and consists of consists of a base fluid, such as water or oil, mixed with salts and solid particles) is pumped through the wellbore at different densities to balance the pressure inside the wellbore and bring rock particles and other matter cut from the formation back to the rig.
- After vertical drilling is complete, horizontal drilling is conducted. Instruments guide drilling operators to the “kickoff point”-the point that drilling starts to turn at a slight angle and continues turning until it nears the shale formation and extends horizontally. Horizontal stretches of the well typically range from 2,000 to 6,000 feet long but can be as long as 12,000 feet.
- At the completion of drilling, the drilling mud may be recycled for use at another drilling operation or disposed of safely. Mud has to be carefully monitored for leaks and spills. Mud is stored either in mobile containers or in open pits which are dug into the ground and lined with impermeable material.
- Rock cuttings recovered from the mud during the drilling process amount to between 100 and 500 tonnes per well, depending on the depth. These, too, need to be disposed of in an environmentally acceptable fashion.
- Throughout the drilling process, operators may vent or flare some natural gas.

3. **Hydraulic fracturing:** In this process water mixed with other chemicals is pumped into the ground to create cracks (also referred to as fissures or fractures) to release the gas into wells.

- Before fracturing a series of tests are conducted to ensure that the well, wellhead equipment, and fracturing equipment can safely withstand the high pressures associated with the fracturing process.
- A perforating tool is inserted into the casing and used to create holes in the casing and cement. Through these holes, fracturing fluid—that is injected under high pressures—flow into the shale formations.
- The water, chemicals, and proppant used in fracturing fluid are typically stored on-site in separate tanks and blended just before they are injected into the well.
- The operator pumps the fracturing fluid into the wellbore at pressures high enough to force the fluid through the perforations into the surrounding formation expanding existing fractures and creating new ones in the process.
- After the fractures are created, the operator reduces the pressure.
- The proppant stays in the formation to hold open the fractures and allow the release of oil and gas.
- Given the length of horizontal wells, hydraulic fracturing is often conducted in stages, where each stage focuses on a limited linear section and may be repeated numerous times. This multi-stage fracturing technique has played a key role in unlocking production of shale gas in the US. A standard single-stage hydraulic fracturing may pump down several hundred cubic meters of water together with proppant and a mixture of various chemical additives. In shale gas wells, a multi-stage fracturing would commonly involve between ten and twenty stages, multiplying the volumes of water and solids by 10 or 20, and hence the total amount of water use might reach from a few thousand to up to twenty thousand cubic meters of water per well and volumes of proppant of the order of 1000 to 4000 tonnes per well. The repeated stresses on the well from multiple high-pressure procedures increase the premium on good well design and construction to ensure that gas bearing formations are completely isolated from other strata penetrated by the well.

4. **Flowback:** Some of the fracturing fluid that was injected into the well will return to the surface

Figure 7: The shale gas life cycle



Source: US Energy Information Administration, World Shale Gas Resources, 2011: the report was prepared by Advanced Resources International.

(commonly referred to as flowback) along with water that occurs naturally in the oil- or gas-bearing formation. The flowback is brought to the surface, collected, treated and reused or disposed. Along with flowback some amount of natural gas is also released. They are either vented or flared. Venting and/or flaring of the gas at this stage are the main reasons why shale gas can give rise to higher greenhouse-gas emissions than conventional production. The best practice during this period is to use a so-called "green completion" or "reduced emissions completion", whereby the hydrocarbons are separated from the fracturing fluid (and then sold) and the residual flow-back fluid is collected for processing and recycling or disposal. But this is not a common practice.

5. **Production:** The volume of flowback ejected reduces steadily and is replaced by natural gas production. The natural gas is captured, stored and transported away for processing. The moisture coming out with natural gas – called produced water – is highly contaminated and has be collected and treated.

   The life of a shale gas well is estimated to be significantly lower than conventional gas wells. Shale gas wells typically exhibit a burst of initial production and then a steep decline, followed by a long period of relatively low production. Output typically declines by between 50% and 75% in the first year of production, and most recoverable gas is usually extracted after just a few years[17].

6. **Well plugging and abandonment:** At the end of their economic life, wells need to be safely abandoned, facilities dismantled and land returned to its natural state or put to new appropriate productive use. Long-term prevention of leaks to aquifers or to the surface is particularly important. For this the integrity of the casing has to be secured and well plugged before abandoning the site.

2.2. Environmental Impacts

The key environmental impacts of shale gas development includes water stress and water pollution, land disturbance and contamination and air pollution.

2.2.1. Water and water pollution

Water use

Shale gas production requires large volumes of water and can put stress on the water resources in local areas. Compared to conventional gas, shale gas requires 2000–10,000 times more water. A single shale well may require few thousands to 20,000 m^3 of water[18]. In areas with limited water resources, huge extraction of water for shale gas can lead to serious environmental and social effects. It can deplete groundwater resources, dry up surface water bodies, affect biodiversity and harm the local ecosystem. It can also reduce the availability of water for local communities and increase conflict over water.

Water use is the most important issue for a country like India where many parts of the country (including shale gas basins like Cambay, Cauvery, and Damodar) regularly face freshwater scarcity[19]. Freshwater availability in India is now less than 1000 me/capita/year, bordering scarcity. Shale gas development in India can, therefore, be constrained by water availability.

China's shale gas development is already facing this problem. For example, the Tarim Basin in the Xinjiang Uyghur Autonomous Region holds some of the country's largest shale gas deposits, but also suffers from severe water scarcity. The development of China's shale gas industry has to date focused on the Sichuan basin, in part because water is much more abundant in this region[20].

Water contamination

Fracking can pollute both groundwater and surface waterways such as rivers, lakes and streams. Fracking pollution can enter waters at several points in the process—including leaks and spills of fracking fluid and wastes, well blowouts, the escape of methane and other contaminants from the well

Freshwater Storage Pond at a Shale Gas Site in Pennsylvania

bore into groundwater, and the long-term migration of contaminants underground.

In the US, leaks and spills of chemicals and wastes from fracking sites have been widely reported[21]. More than 1,000 complaints of drinking water contamination related to fracking have been documented in the US[22]. The US Environmental Protection Agency (EPA) is currently investigating the impact of fracking on water quality and on public health, following a number of complaints and lawsuits.

Research in the US is now increasingly linking shale gas development with groundwater contamination. A study by researchers at Duke University found that the proximity of drinking water wells to fracking wells increases the risk of contamination of residential wells with methane in Pennsylvania. The researchers pointed to faulty well casing as a likely source[23]. Data from gas wells in Pennsylvania from 2000 to 2012 show that a shale gas well is six times more likely to have problems with structural integrity than a conventional well. A 6.2% well failure due to "defective, insufficient or improperly installed" cement or casing was reported from shale gas sites[24]. According to Tony Ingraffea of Stanford University, failure of casing and cement is inherent; it can be minimised but cannot be eliminated. As per Tony's studies, in Northeast Pennsylvania, 9% failures happen in first few years. Projections are that 40% will fail over next 10 years and all in 30 years[25].

Recently, Pennsylvania has confirmed more than 239 cases of water-well contamination from oil and gas activities. According to Scott Perry, Department of Environment Protection (DEP), Pennsylvania, most contamination is because of the leakages in the temporary waste pits. Also, above Marcellus there are many shallow gas layers. If cement casing is poorly done, methane from these shallow layers gets into underground water and contaminates wells. In 24 cases, however, the Pennsylvania DEP concluded that there had been a "failure to prevent migrations to fresh groundwater".

A recent study of contamination in drinking water wells in the Barnett Shale area of North Texas found arsenic, selenium, and strontium at elevated levels in drinking water wells close to fracking sites. The researchers conclude that fracking has increased pollution in drinking water supplies by freeing naturally available chemicals to move into groundwater at higher concentrations or through leaks from faulty well construction[26].

Waste water treatment and disposal

The treatment and safe disposal of wastewater is a major challenge for the shale gas industry. Anywhere between 10%–50% of the fracturing fluid is returned as flowback. The moisture coming out with the gas – produced water – also needs be separated and treated. These effluents contain chemicals used in the hydraulic fracturing process(see Box: Chemical composition of frack fluid). Effluents are also contaminated with metals, minerals, and hydrocarbons leached from the reservoir rock. High level of salinity is quite common and, in some reservoirs, radioactive minerals are also released. In Marcellus wells in Pennsylvania, the flowback water can have TDS as high as 2,50,000 mg/l and COD of 20,000 mg/l[27].

Flow-back returns (like wastewater from drilling) require secure storage on site and specialized treatment and disposal. Before 2011, Pennsylvania allowed operators to discharge flowback through publicly owned sewage treatment plants into rivers. In 2011, it was revealed that millions of litres of irradiated wastewater loaded with toxic chemicals were being dumped into Pennsylvania's rivers and streams. The practice was stopped and drillers were asked to dispose waste using different treatment systems (see Box: Disposal standard and practices in Pennsylvania).

Wastewater management from shale gas facilities could be a major challenge in a country like India where infrastructure is lacking to treat such polluted wastewater from individual wells. Similarly, compliance and enforcement will be difficult considering the lack of capacity in the pollution control boards.

Table2: Characteristics of flowback from Marcellus wells

Parameter	Range	Median	Units
Total alkalinity	48.8-327	138	mg/L*
Hardness as $CaCO_3$	5,100-55,000	17,700	mg/L
Total suspended Solids	10.8-3,220	99	mg/L
Turbidity	2.3-1,540	80	NTU†
Chloride	26,400-148,000	41,850	mg/L
Total dissolved solids	38,500-238,000	67,300	mg/L
Specific conductance	79,500-470,000	167,300	umhos/cm‡
Total kjeldahl nitrigen	38-204	86.1	mg/L
Ammonia nitrogen	29.4-199	71.2	mg/L
Biochemical oxygen demand	37.1-1,950	144	mg/L
Chemical oxygen demand	195-17,700	4,870	mg/L
Total organic carbon	3.7-388	62.8	mg/L
Dissolved organic carbon	30.7-501	114	mg/L
Bromide	185-1,190	445	mg/L

Adapted from data of Hayes, T. 2009, Sampling and analysis of water streams associated with the development of Marcellus shale gas. Final report to Marcellus Shale Coalition. Gas Technology Institute, Des Plaines, IL

* milligrams per liter

† nephlometric turbidity units

‡ micro mhos per centimeter

Chemical composition of frack fluid

Fracking fluid consists of water mixed with chemicals. The oil and gas industry estimates that 99%of fracking fluid is water and the other 1.0% is a mix of chemicals. To frack a well in southwest Pennsylvania, Range Resources, one of the big players in the shale gas business, reported using[28] :

- 14,400 m^3 of water
- 2150 tonnes of sand
- 5000 litres of hydrochloric acid
- 6500 litres of a friction reducer
- 8400 litres of antimicrobial agent
- 1500 litres of scale inhibitor (which includes ethylene glycol, a teratogen).

In the US, there is a major concern regarding the composition and toxicity of various chemicals used. Part of the reason is that regulations do not require companies to disclose all information about the kind of chemicals they are using (see section: Regulating shale gas). However, published reports indicate that these chemicals routinely include toxic substances.

According to a 2011 congressional report, the frac fluids contained 29 chemicals that are (1) known or possible human carcinogens, (2) regulated under the Safe Drinking Water Act for their risks to human health, or (3) listed as hazardous air pollutants under the Clean Air Act. Highly toxic BTEX compounds – benzene, toluene, xylene, and ethylbenzene – are used in many hydraulic fracturing products[29].

In general, various chemicals used are as follows[30] .

- Acids—hydrochloric acid or acetic acid is used in the pre-fracturing stage for cleaning the perforations and initiating fissure in the near-wellbore rock.
- Sodium chloride (salt)—delays breakdown of the gel polymer chains.
- Polyacrylamide and other friction reducers—Decrease turbulence in fluid flow decreasing pipe friction, thus allowing the pumps to pump at a higher rate without having greater pressure on the surface.
- Ethylene glycol—prevents formation of scale deposits in the pipe.
- Borate salts—used for maintaining fluid viscosity during the temperature increase.
- Sodium and potassium carbonates—used for maintaining effectiveness of cross linkers.
- Glutaraldehyde—used as disinfectant of the water (bacteria elimination).
- Guar gum and other water-soluble gelling agents—increases viscosity of the fracturing fluid to deliver more efficiently the proppantinto the formation.
- Citric acid—used for corrosion prevention.
- Isopropanol—increases the viscosity of the fracture fluid.

The most common chemical used for hydraulic fracturing in the United States in 2005–09 was methanol, while some other most widely used chemicals were isopropyl alcohol, 2-butoxyethanol, and ethylene glycol[31].

2.2.2. Air pollution

Shale gas development results in air pollution from the well bore as well as from vehicles, drilling rig engines, pump engines, and compressors. The main sources of toxic air pollutants are from gas venting and flaring, emissions and leakages from compressor stations and evaporation of various chemicals and wastes.

People who live close to drilling sites can be exposed to high levels of a variety of air pollutants including particulate matters, NOx, VOCs such as benzene, xylene, and toluene etc. In some of the high-density fracking sites in the US, the air pollution levels have been found to be very high.

In Texas, monitoring by the Texas Department of Environmental Quality detected levels of benzene-a known carcinogen-in the air that were high enough to cause immediate human health concern at two sites in the Barnett Shale region, and at levels that pose long-term health concern at an additional 19 sites[32]. Air monitoring in Arkansas has also found elevated levels of VOCs-some of which are also hazardous air pollutants-at the perimeter of hydraulic fracturing sites[33].

Fracking is a significant source of air pollution in areas experiencing large amounts of drilling. A 2009 study in five Dallas-Fort Worth-area counties experiencing heavy Barnett Shale drilling activity found that oil and gas production was a larger source of smog-forming emissions than cars and trucks[34].

Considering the increasing significance of air pollution from the shale gas site, USEPA has in December 2014came out with final regulations to control VOC emissions from the oil and gas sector[35]. The EPA's New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants directs shale gas companies to install green completion equipment's and capture VOCs and methane from flowback as well as reduce fugitive emissions from tanks, storage sites, and compressor stations. These rules will come under force from 2015 onwards.

"The action taken today is expected to yield nearly a 95% reduction in smog-forming volatile organic compounds emitted from more than 13,000 hydraulically fractured gas wells each year," said EPA Office of Air and Radiation Assistant Administrator Gina McCarthy[36].

Under the rule, operations are required to use "reduced emissions" or "green well completion" equipment to capture gas and condensate that comes up with hydraulic fracturing flowback, preventing their release into the air and making the valuable hydrocarbons available to the producer for sale.

During a transition period that ends 1 January, 2015, they will have the option to flare instead. The transition period is a change from the rule the agency proposed last July and acknowledges the industry's concern that there is not yet enough equipment for 13,000 completions per year and that training workers in the use of the equipment will take time.

Even flaring reduces volatile organic compound, or VOC, emissions by 95%, but green completions are preferred for multiple reasons. They provide the same reduction in VOCs as flaring. But while flaring allows the emission of smog-forming nitrogen oxides, green completions do not.

The oil and gas industry is responsible for about 40% of US emissions of methane, a powerful greenhouse gas. Although the targets of the rule are VOCs and hazardous air pollutants, methane is captured through this technology as well.

2.2.3. Earthquakes and vibration

A number of incidences of seismic activity linked to fracking have been recorded, including minor earthquakes and tremors. Because it creates cracks in rocks deep beneath the surface, hydraulic fracturing always generates small seismic events. Most of these events are not detected at the surface, but larger seismic events can be generated when the well or the fractures happen to intersect, and reactivate, an existing fault[37].

USGS scientists have linked increase in the number of magnitude 3 and greater earthquakes in the midcontinent of the United States with disposal of wastewater from shale gas in deep injection wells. Beginning in 2001, the average number of earthquakes occurring per year of magnitude 3 or greater increased significantly, culminating in a six-fold increase in 2011 over 20th century levels[38]. One hypothesis is that the wastewater is thought to lubricate fault lines, causing them to slip.

In April and May 2011, Cuadrilla Resources, the company carrying out fracking at Preese Hall, Lancashire, suspended exploration following two earthquakes with magnitudes of 1.5 and 2.3. An independent scientific report commissioned by the British government confirmed that “the earthquake activity was caused by direct fluid injection” during the fracking process and conceded that it was not possible “to categorically reject the possibility of further quakes"[39].

Seismic activities not only create anxiety in communities, they also can potentially affect well integrity by damaging casing and cementing. These can lead to leakages and groundwater contamination. In densely populated countries like India, seismicity associated with shale gas can be a major constraint for the development of this sector.

2.3 Climate impacts

Supporters of Shale gas have termed it as "transition fuel" and"green" source of fuel[40]. President Obama has termed it as a "bridge" to a clean energy future[41]. According to shale gas industry, burning gas in power stations, releases roughly half the carbon emissions of coal, making shale gas a more environmentally friendly option than coal. However, recent evidence suggests that the climate impacts of the life cycle emissions from shale gas could be significantly higher than estimated earlier. The most worrisome part is that large use of shale gas is likely to reduce investments in renewable energy and energy efficiency, thereby compromising the fight against climate change.

In most modeling studies, large-scale use of natural gas is not associated with any significant reduction in greenhouse gas emissions by 2050. In a major study published in Nature in which five state-of-the-art integrated assessment models of energy–economy–climate systems were simulated, an abundant gas scenario (additional natural gas consumption of up to +170% by 2050) led to much smaller impact on CO_2 emissions (from –2% to +11%), and a majority of the models reported a small increase in climate forcing (from –0.3% to +7%) associated with the increased use of abundant gas[42].

According to IEA, a high unconventional gas scenario (called Golden rule scenario in which natural gas constitutes 25% of the global energy supply and unconventional gas production triples by 2035) does not lead to any significant reduction in energy-related Co_2 emissions[43]. IEA also concludes "greater reliance on natural gas alone cannot realise the international goal of limiting the long-term increase in the global mean temperature to two degrees Celsius above pre-industrial levels. Achieving this climate target will require a much more substantial shift in global energy use".

2.3.1 GHG emissions

Shale gas has higher GHG emissions than conventional gas because it requires more wells and more hydraulic fracturing per cubic metre of gas produced. This means more energy consumption and more venting and flaring of methane and associated gases. However, a major debate has arisen on the climate performance of shale gas vis-à-vis coal. In the US, shale gas is being promoted as a substitute to coal. The central point of this controversy is how much methane is emitted during the entire life cycle of the shale gas and what is the global warming potential (GWP) of methane.

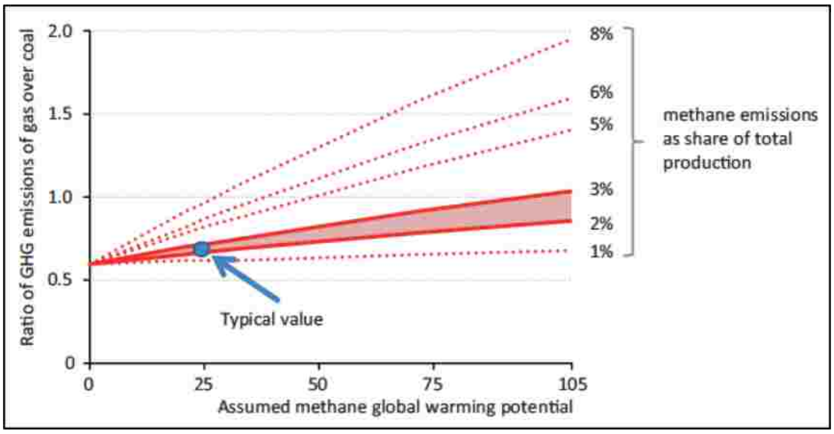
Methane is a more potent greenhouse gas than CO_2, but has a lower half-life than CO_2. The Global Warming Potential (GWP) of methane, compared to CO_2, averaged over 100 years is 25. Averaged over 20 years, the GWP of methane rises to 72[44]. Recent studies, however, peg the 20 years GWP of methane as 105[45]. As the GWP of methane is high, any significant release of methane during the life cycle of shale gas increases the climate footprint of shale gas development significantly.

It is estimated that at a GWP of 105, if three per cent of shale gas production is emitted from well-to-burner, then shale gas losses all its GHG emissions advantage over coal.

Traditionally, methane emissions from shale gas as been considered to be small. New studies however are increasingly finding evidence of large emissions of methane from drilling sites. Methane is also released through leaks, in processing, and during transportation.

Studies have suggested that 3.6% to 7.9% of the total gas output of a shale gas well is lost through fugitive methane emissions. This would mean that

Figure 8: Climate change impacts of shale gas vs. coal



Source: Golden Rules for a Golden Age of Gas, World Energy Outlook Special Report on Unconventional Gas, International Energy Agency, 2012

"compared to coal, the footprint of shale gas is at least 20% greater and perhaps more than twice as great on the 20-year horizon"[46].

In February 2012, monitoring of air samples from a natural gas field near Denver by the National Oceanic and Atmospheric Administration and the University of Colorado, Boulder, found that about four per cent of the gas was lost to the atmosphere[47]. According to the US National Academy of Sciences: "Given limited current evidence, it is likely that leakage at individual natural gas well sites is high enough, when combined with leakage from downstream operations, to make the total leakage exceed the 3.2% threshold beyond which gas becomes at least comparably worse for the climate than coal for at least some period of time "[48].

In the US, companies are not mandated to monitor fugitive methane emissions by law. Recently, however, few states have started asking operators to monitor methane emissions from the site. DEP, Pennsylvania has asked companies to start monitoring methane leaks and give a report to DEP in February 2015.

2.3.2 Impacts on renewable energy and energy efficiency

A key area of concern is the impact of the large-scale use of cheap shale gas on renewable energy and energy efficiency investments. Though the supporters of the shale gas claim that shale gas is the "bridge fuel" between coal and the renewable energy, many experts believe that shale gas will stymie the growth of the renewable energy sector for decades[49].

A major study published by the Stanford's Energy Modeling Forum, which convened 50 experts and 14 different modeling teams from industry, academia, and government to look at how the surge in natural-gas production could transform the US economy, found that a boom in shale gas would not lead to any significant reduction in GHG emissions from the US. Most experts in the Stanford study expect natural gas to displace not only coal, but also nuclear, and renewable energy between now and 2035[50]. A low natural gas price in the US is also likely to reduce investments in energy efficiency[51].

The upsurge of cheap shale gas in the US has even made the IEA nervous. Fatih Birol, chief economist of the IEA has gone on record and said: "If gas prices come down, that would put a lot of pressure on governments to review their existing renewable energy support policies. We may see many renewable energy projects put on the shelf." Birol said the world must continue to invest in renewables, energy efficiency and carbon capture and storage, in order to stave off climate change. If the world fails to invest in renewables, a new generation of gas-fired power stations would have a lifetime of at least 25 years, effectively "locking in" billion of tonnes of carbon emissions a year[52].

Section 3

Regulating Shale Gas Development

It is said that the environmental and social impacts of an industry is related to the strictness or the leniency of the regulatory regime. The US experience of shale gas development supports this axiom. Shale gas in the US is largely regulated under the state laws and the law varies widely from states to states. A review of the regulations in different states, therefore, is very important to understand the kind regulations that need to be put in place to reduce the environmental footprints of the shale gas developments in a country like India.

3.1 Federal regulations on shale gas in the US

Regulation of shale gas exploration and production generally comes under the jurisdiction of the states barring some federal laws that control aspects of production and exploration such as the Safe Drinking Water Act (SDWA), Clean Water Act (CWA), Clean Air Act (CAA), and Resource Conservation and Recovery Act (RCRA). While the oil and gas industry maintains that existing shale gas development regulations imposed by the states are adequate, major environmental groups in the US are pressing for further federal regulation due to emerging concerns about water usage and possible contamination among other environmental risks.

Federal exemptions for shale gas

Oil and Gas (O&G) sector is the US has many exemptions under the federal laws. For instance, hazardous wastes from O&G sector are not considered as hazardous under the federal laws. To plug this loophole, states have enacted their own legislations to manage hazardous wastes from O&G sector.

In the US the federal government regulates the underground injection control programme for disposal wells. But fracking has been excluded from the definition of disposal wells, except if they use diesel for fracking, under the 2005 Energy Policy Act. This has been termed as Halliburton loophole because ex-vice president Dick Cheney who used to head Halliburton at one time pushed this exemption. So, presently no federal permit is required to drill and frack shale O&G wells.

3.2 State Regulations

Different states have varying shale gas regulations across the US. Regulations are imposed on a multitude of aspects of shale gas development such as site selection, spacing of wells, drilling of wells, hydraulic fracturing, wastewater storage and disposal, underground injection of chemicals, disposal of excess gas, production taxes and accident reporting impositions.

1. Permitting

Every state has some or other permitting requirement for drilling a well. The permitting requirements in most states require submission of a detailed permit application that includes information about resource consumption and pollution potential. In New York State, however, a case-by-case preparation of Environment Impact Statement (EIS) is required.

Under the Pennsylvania Oil and Gas Act, an oil and gas company must obtain a permit from the Pennsylvania Department of Environmental

Protection (DEP) before drilling a well[53]. DEP is authorized to charge a fee for the submission of a permit application. DEP has to issue a permit within 45 days from the date of submission unless cause exists to extend this time period for an additional 15 days. DEP can impose necessary conditions in the granting of a permit and can deny the requested permit for one of the following five reasons.

- The well site is in violation of the Act or the issuance of a permit would violate the Act or another environmental law;
- The application is incomplete;
- The owner or operator of a coal mine has objected to the well location, and those objections remain unresolved;
- The well has not been bonded satisfactorily; or
- The applicant has wells that are currently in continuing violation of the Act or another applicable law for which the DEP is responsible.

2. Site selection and preparation

Regulations in many states restrict where wells can be sited. Most states have well spacing requirements that limit the number of wells in an area, and most also have some form of setback rules limiting the proximity of wells to buildings or features.

The regulation for minimum distance between wells varies from 100 to 3,750 feet. Similarly, setback rules prohibit drilling of wells from 100 to 1000 feet from buildings. In high density, or urbanized areas, for example in Ohio and Colorado, the setbacks are larger than low population density states.

Some states have put stringent setback regulation for public water supply and water bodies. For instance in Pennsylvania, shale wells cannot be drilled within 500 horizontal feet of any existing water well without written consent of the owner of the water well. The minimum distance between natural gas wells and public water supplies is fixed at1000 feet. Similarly, wells also cannot be located within 300 horizontal feet of any body of water and wetland larger than one acre[54]. A well operator can obtain a variance or waiver from these distance requirements upon the satisfaction of certain criteria and with the imposition of appropriate conditions to protect people, property, and waters. When deciding whether to grant a well permit, DEP is required to consider the impact of the well on a variety of public resources, including natural and historical sites.

Some states have also put regulation on predrilling water well testing. These tests establish the baseline water quality for an area prior to drilling activity. If groundwater is later found to be contaminated, predrilling test results are important evidence for determining whether contamination is related to drilling activity.

Pennsylvania has a unique approach. The state does not formally require predrilling testing. However, under state law, if tests are not done before development, operators are barred from claiming in future legal action that any alleged groundwater contamination was preexisting. In effect, this is a burden-shifting rule. Although plaintiffs retain the burden of proof that some contamination exists, such contamination within 2,500 feet of wells and within one year of drilling is presumed to be attributable to the operator defendant unless rebutted with predrilling testing evidence[55].

In Pennsylvania, within 9 months of completion of drilling, a company has to restore the site – remove wastewater, wastes, cover pits, take everything to waste disposal sites, remove machinery not used for production etc.

3. Well drilling

The primary methods of maintaining well integrity are adequate casing and cementing of the wellbore. Poor casing and cementing can provide a potential conduit for groundwater contamination. Both are heavily regulated by almost all states with shale gas development.

Casing is steel pipe of varying diameter that separates the wellbore from surrounding rock. Casing can be divided into four general types, in decreasing order of diameter. Conductor casing is set at the surface in many cases, including in conditions where surface soils may cave during drilling. Surface casing is then set, followed by intermediate and production casing, each set within the preceding, larger-diameter casing. This creates a series of concentric cylinders the casing string. Cement is circulated within the gap between each layer of casing.

States have varying level of stringency in regulations on the depth to which well casing must extend and be cemented. Most states require casing to be set and cemented to minimum depth – varying from 30 to 120 feet - below the base of layers or zones containing freshwater. The American Petroleum Institute (API) best practice says, "at a minimum, it is recommended that surface casing be set at least 100 ft. below the deepest underground source of drinking water encountered while drilling the well"[56].

Cement types and cement circulations are also heavily regulated by the states. New York's proposed legislation specifically mandates that cement would have to conform to API Specification 10A and would have to contain a gas-block additive.

Different states have different requirements for cement circulation. Most states require surface casing, the outermost layer of casing, to be cemented all the way to the surface. However, cementing requirements for intermediate and production casing are much more heterogeneous. Some states require intermediate and production casings to be cemented to the surface.

Several states have requirements for pressure testing prior to fracking. Under this, the well must be pressure tested to show that the cement and casing can stand the maximum pressures that will be placed on them by fracking.

In Pennsylvania, as a companion to the casing and cementing plan, operators are required to maintain a cement job log that documents the actual procedures and specifications of the cementing operation.

4. Hydraulic Fracturing

Regulations on water withdrawals and disclosure of the composition of fracturing fluids are the most common regulations that the states have put for hydraulic fracturing.

Majority of states require permits for surface and groundwater withdrawal. Many states also require registration and reporting of water withdrawal.

A Shale gas well drilling site in rural Pennsylvania

Pennsylvania requires a water management plan covering the full lifecycle of the water used in shale gas production, including the location and amount of the withdrawal and an analysis of the impact of the withdrawal on the body of water from which it came. Pennsylvania also operates ecosystem models that provide the basis for rejecting applications for water withdrawals that would put stress on ecosystems.

4.1 Fracking fluids disclosure

The federal Safe Drinking Water Act (SDWA) authorizes states to regulate underground fluid injection, under EPA guidance. Among other requirements, application of the SDWA to fracturing fluids would have required "inspection, monitoring, record keeping, and reporting" by state regulators. In practice, this probably would have required the disclosure of fracturing fluid composition. In 2005, however, Congress amended the SDWA to exclude fracturing fluids other than diesel fuel. Fracturing fluid disclosure has since become a controversial issue, with environmental groups calling for states to require disclosure independent of federal law.

The federal government, however, is trying to overcome the limitations of the 2005 amendments and regulate disclosure of these chemicals. The US Department of the Interior also issued draft rules requiring fracturing fluid disclosure for wells drilled on federal lands. The EPA has indicated that it will require disclosure under the Toxic Substances Control Act.

Many states require some form of fracking fluids disclosure. Most rely on a web-enabled database, FracFocus, which was developed with US Department of Energy funding. The level of details to be disclosed, however, varies significantly.

Not all states require disclosure of all chemicals used. Some state rules have exemptions for trade secrets. Some states also require disclosure of additive volume and concentration. Pennsylvania requires the disclosure of the percentage by volume of each additive in the fracking fluid.

Shale gas companies are required to disclose information on quantity and source of water used for fracking wells in Pennsylvania

Very few states regulate fracturing fluids beyond mere disclosure. Wyoming, for example, requires prior approval for use of benzene, toluene, ethylbenzene, and xylene (BTEX) compounds.

5. Fluids and wastewater storage

Storage and disposal is required for flowback fluids and fluids coming out from the formations. The maximum volume of these fluids comes out during and immediately after the fracking process. But wastewater is generally produced from the formation on an ongoing basis (though in much smaller volumes) and must be removed from gas before it can be transported and sold.

Fluid storage needs vary over the course of the shale gas development process. Fracturing fluids must be stored before use, and the post fracturing wastewater, including flowback fluids and produced fluids, must also be stored before disposal. For these purposes different types of pits are tanks are used.

Different states put different requirements for the design of tanks and pits for different types of fluids and wastes. Some states even require a specific permit application for fluid storage. All states, however, regulate open-pit storage in some way or other including giving specifications for liner thickness and freeboard. Freeboard is important for preventing overflow of fluids, particularly during and after intense rain.

In general, highly polluted wastewater is required to be kept in stored in sealed tanks whereas drilling fluids, muds, and cuttings are allowed to be kept in lined open pits with freeboard. API best practice stipulates, "completion brines and other potential pollutants should be kept in lined pits, steel pits, or storage tanks"[57].

6. Wastewater disposal

All states allow and regulate various disposal methods for wastewater. States have also set discharge standards for disposal of treated effluents into surface water bodies.

Recycling of wastewater for future fracking is permitted by all states. Most states also allow underground injection as disposal option, but regulate the practice in some way. Few states allow underground injection but have recently issued limited or local moratoria because of increased seismic activity linked to shale gas fluid disposal.

Disposal of wastewater at treatment facilities is the second most common form of wastewater disposal allowed. But different states allow different methods for the disposal of treated wastes. Some allow treated wastes to be discharged into surface water, some allow evaporation pits, some allow wastewater to be used for "land treatments" such as ice and dust control or road stabilization, though some of these states require advance approval and/or apply restrictive conditions to the practice.

Disposal standard and practices in Pennsylvania

DEP, Pennsylvania issued a new regulation in 2010 to manage high TDS wastewater discharges from the shale wells. Under the new regulations, new and expanded facilities that accept oil and gas wastewater for treatment must meet strict discharge limits of 500 mg/l for TDS, 250 mg/l for chlorides, 10 mg/l for barium and 10 mg/l for strontium on a monthly average.

The new standards also strictly regulate the transportation of wastewater to a commercial or centralized facility. These include requirements for transportation, accident prevention and contingency planning emergencies, wastes from accidents and spills, recordkeeping and reporting, and appropriate signage on vehicles. Waste haulers are required to take permits and are subject to the requirements of the DEP Waste Transportation and Safety Program.In Pennsylvania, almost all techniques are used to dispose wastewater from frack wells.

a. Treatment at Publicly Owned Sewage Treatment Facility

Traditional treatment at publicly owned sewage treatment (POST) plants offers only dilution of TDS, rather than removal, and the end result is the discharge of salty water into surface waters. It is inexpensive and often fairly convenient. In the very early phase of development of the Marcellus field in 2007 and 2008, dilution was a fairly common disposal method. But due to mounting water quality concerns, DEP stopped the practice of disposal through POST plants in 2011.

b. Existing Dedicated Treatment Facilities

In Pennsylvania there are dedicated brine treatment facilities, but they offer only dilution of TDS, rather than removal, and discharge salty water to surface water. For many years, these facilities have accepted and treated wastewater from the oil and gas industry, but the increased volumes and loads from Marcellus drilling mean that new facilities are needed to meet the gas industry's wastewater treatment needs. Some of the old plants are exempted from the new standards. However, should one of these facilities decide to expand, the new treatment standards would apply to the expanded load.

c. New Dedicated Treatment Facilities

Currently, there are 25 newly proposed dedicated treatment facilities (conventional brine plants) planning to treat natural gas wastewater so that it can be discharged to surface water. The equipment is designed to remove salts, metals, and oils. These facilities must meet the new TDS regulations.

d. Reuse With or Without Pretreatment

Flowback is now being increasing reused, either with or without some level of treatment, to fracture additional wells. In Marcellus shale, the average recovery of hydraulic fracture fluids injected is estimated to be about 13.5%. Approximately 60% of this is reused and 40% is disposed of using different treatment and disposal methods.

Relatively clean initial flowback water (which returns to the land surface within a few days of fracking) are blended without treatment with fresh water at the well pad and reused. The water is reused a number of times in fracking until it contains approximately 50,000–100,000 mg/L TDS, at which point it is treated.

e. Advanced Facilities

Advanced facilities with technologies like evaporation and crystallization of salts are being constructed to treat highly contaminated wastewater. This kind of advanced treatment option offer the advantages that the effluent meets new state standards and that the treated water is directly reusable in fracking other wells. Its big disadvantages include production of a large solid waste residue (salts) and high costs. In these facilities solid waste disposal is a major challenge. Because these are highly concentrated wastes, they also contain radioactive wastes and hence have to be disposed to a radioactive waste disposal site.

f. Deep injection/disposal wells

Deep injection wells are a form of waste disposal that pumps untreated wastewater down through very deep wells and out into rocks bounded above by an impermeable rock layer(s). The U.S. Environmental Protection Agency (EPA) is responsible for permitting these wells in Pennsylvania.

Pennsylvania currently has about seven such brine disposal wells. Although Pennsylvania may eventually have additional deep injection wells for Marcellus wastewater, they are not expected to be sufficient. Lately, companies have started sending effluents to West Virginia and Ohio for deep well injection.

Wastewater that is not reused, recycled, or disposed of on-site must be transported elsewhere for disposal, sometimes in pipelines but usually by truck. Most states regulate this wastewater transportation and/or require it to be tracked and recorded.

7. Excess Gas Disposal

Excess gas is produced before and during production. They can either be vented, flared or stored for reuse. These gases if vented may result in emissions of VOCs or other pollutants. Both venting and flaring also result in GHG emissions—venting of natural gas releases methane, a potent GHG, whereas flaring emits carbon dioxide. Because of these risks and effects, venting and flaring practices are frequently regulated by states.

Venting is banned by only few states. The remaining allows venting, but regulate it. Some states have specific restrictions, such as the number of days on which venting may occur, the amount of gas that may be vented, or the development phases during which gas may be vented. Venting may be allowed during well cleanup, testing, or emergencies, but otherwise banned.

Flaring is allowed by all states but most states do regulate the practice in some way. Some restrict the amount of gas that may be flared, the location of flares, or the development phases during which gas may be flared.

Pennsylvania has aspirational or discretionary standards. These require operators to minimize gas waste or avoid harm to public health but do not create any enforceable requirement.

API suggests that all gas resources of value that cannot be captured and sold should be flared and recommends that flares be restricted to a safe location and oriented downwind considering the prevailing wind direction at the site.

8. Solid waste disposal

States regulate disposal of drilling fluids, mud and cuttings. They either allow disposal in lined pits at the site or at off-site disposal facilities. Where these come into contact with sources of contamination (e.g. synthetic drilling muds, oils and chemical additives), these are to be shipped off-site for disposal. However, water based mud are allowed to be reused. Drilling mud are also allowed for well plugging.

9. Regulations during production

Active wells may generate produced water, which must be disposed of properly. Produced water practices are generally regulated under the same provisions as other wastewater. Similarly, venting and flaring are regulated during production. Wells may be refracked to increase production, and operators must follow the same state rules as for initial frack jobs. There regulatory requirements for accidents reporting as well as reporting of the well performance.

In Pennsylvania, well operators must file with DEP an annual report listing specified production information. These reports are kept confidential for five years.

10. Plugging and Abandonment

When a well is no longer producing, it must be permanently plugged and abandoned. Wells are also taken out of production and, "temporarily abandoned." Most states have detailed plugging and abandonment procedures to ensure that the well does not become a conduit for contamination through migration of fluids and gases.

Most states regulate the duration over which a well is allowed to sit idle. Beyond this time period, operators have a choice: they can restart production at the well, temporarily abandon it (if allowed by the state), convert it to a waste disposal well (contingent on state rules), or permanently plug and abandon it. The range of idle time is anywhere from 1 month to 25 years. Many states allow well idle times to be extended by regulators if operators apply to do so and meet certain conditions.

Many states allow operators to temporarily abandon wells, ranging from 3 months to 5 years,allowing them to remain idle but—in most cases—requiring operators to take various measures to reduce the risk of damage to or contamination of the well. For example, Colorado requires temporarily abandoned wells to have the wellbore isolated from the surface with a cement retainer or other barrier.

A well is plugged by setting mechanical or cement plugs in the wellbore at specific intervals to prevent fluid flow. Most State regulations typically permit the placement of the following materials within the wellbore: cement, drilling mud, gels, mechanical plugs, and other non-porous materials such as clays. In recognition of its strength and low permeability, cement typically is used to create a seal between formations or to seal off the surface of the wellbore.

In Pennsylvania, when a well operator abandons a well, the operator must plug the well to prevent any upward flow of materials. The operator must provide DEP with notice of plugging to afford DEP the opportunity to be present when the well is plugged. If an operator abandons a well without plugging it, DEP is authorized to enter the site, plug the well, and sell any remaining equipment to recover the cost of plugging. The operator is liable for any unrecovered costs.

To ensure that operators don't abandon the well, well operators must file a bond with DEP for the well and well site. The bond must be payable to the Pennsylvania state and be conditioned upon the operator "faithfully perform[ing] all of the drilling, water supply replacement, restoration, and plugging requirements" of the Act. The bond amount per well is determined by the Environmental Quality Board in an amount to reflect the anticipated cost of plugging a well. An operator who does not comply with the various provisions of the Act is subject to forfeiture of the bond funds into the Well Plugging Restricted Revenue Account. However, presently the bond amount for closure is just $10,000, whereas the costs can be at least $ 100,000. Experts believe that such lower bond amount will not be deterrence for operators to abandon the wells without proper closure.

11. Severance Tax

Most states levy severance taxes on gas production. States generally use one of two methods to calculate the tax-either a percentage of the market value of the gas extracted or a fixed dollar amount per quantity extracted.

In Montana, the tax rate is 0.5% for the first 18 months of a well's operation and 9% thereafter. Indiana charges a fixed rate (3 cents/Mcf) when gas is sold below $3/Mcf, and a percentage rate (1%) when it is sold for higher prices.

Pennsylvania imposes "impact fee" on every well drilling for gas in the Marcellus Shale formation. The levy changes from year to year based on natural gas prices and the Consumer Price Index, but in 2013, gas companies paid $50,000 for each new well they drilled.

Pennsylvania collected impact fee worth $224 million in 2013. Sixty percent of the impact fee revenue stays at the local level, going to counties and municipalities hosting wells. The rest goes to various state agencies involved in regulating drilling and to the Marcellus Legacy Fund– which gets spread out around the state for environmental and infrastructure projects.

3.3 Regulations in India

India has no specific regulations for shale gas. However, specific environmental regulations exit for the conventional Oil and Gas Wells.

1. Permits

Offshore and onshore oil and gas exploration, development and production require prior environmental clearance from the union ministry of environment, forests and climate change (MoEF&CC). These projects need to prepared an Environment Impact Assessment (EIA) report based on a terms of reference given by MoEF&CC.

These projects also need to obtain consent to establish and consent to operate from the state pollution control boards (SPCB) under the Water and Air Act. They also need to taken authorization to dispose hazardous wastes under the Hazardous waste rules.

2. Pollution regulations

a. Standards for liquid effluent

I). Onshore facilities - marine disposal

Ph	5.5–9.0
Oil & grease	10mg/l
Suspended solids	100mg
(3 days at 270 c)	30mg/l

BOD onshore discharge of effluents, in addition to the standards prescribed above, proper marine outfall has to be provided to achieve the individual pollutant concentration level in sea water below their toxicity limits as given below, within a distance of 50 meters from the discharge point, in order to protect the marine life:

Parameter	Toxicity limit (mg/l)
Chromium	0.1
Copper	0.05
Cyanide	0.005
Fluoride	1.5
Lead	0.05
Mercury	0.01
Nickel	0.1
Zinc	0.1

ii). Onshore facilities – land disposal

Oil and gas drilling and processing facilities, situated on land and away from saline water sink, can opt for disposal of treated water by reinjection in abandoned well, which is allowed only below a depth of 1000 meters from the ground level. In case of re-injection in abandoned well the effluent have to comply only with respect to suspended solids and oil and grease 100 mg/l and 10 mg/l, respectively.

For onshore disposal in surface water bodies, the permissible limits are given below:

Parameter	Discharge standards (not to exceed)
pH	5.5–9.0
Temperature	40^{0}c
Suspended solids	100mg/l
Zinc	2 mg/l
Bod	30 mg/l
Cod	100 mg/l
Chlorides	600 mg/l
Sulphates	1000 mg/l
TDS	2100 mg/l
%sodium	60 mg/l
Oil and grease	10 mg/l
Phenolics	1.2 mg/l
Cyanides	0.2 mg/l
Fluorides	1.5 mg/l
Sulphides	2.0 mg/l
Chromium (cr^{+6})	0.1 mg/l
Chromium (total)	1.0 mg/l
Copper	0.2 mg/l
Lead	0.1 mg/l
Mercury	0.01 mg/l
Nickel	3.0 mg/l

Source: Pollution control acts, Rules & Notifications issued under Central Pollution Control Board, June 2010

iii). Offshore facilities

For offshore discharge of effluents, the oil content of the treated effluent without dilution shall not exceed 40 mg/l for 95% of the observation and shall never exceed 100 mg/l.

b. Standards for air emissions and flaring

- DG sets at drill site as well as production station shall confirm with the norm notified under the environmental protection act ,1986
- Venting of gas is not allowed. All gaseous emissions are to be flared.
- All flaring shall be done by elevated flares except where there is any effect on crop production in adjoining areas due to the flaring in such cases one can adopt ground flaring.

c. Guidelines for the disposal of solid waste, drill cutting and drilling fluids

I). Onshore installation

- Drill cuttings (DC) originating from onshore or locations close to shore line and separated from water base mud (WBM) should be properly washed and unusable drilling fluids (DF) such as WBM, oil base mud (OBM), synthetic base mud(SBM) should be disposed off in a well-designed pit lined with impervious liner located off site or on site. The disposal pit should be provided additionally with leachate collection system.

- Use of diesel base mud is prohibited. Only WBM should be used for onshore drilling operations.
- In case of any problem due to geological formation for drilling, low toxicity OBM having aromatic content<1% should be used. If the operator wants to use any such OBM/SBM it should intimate it to MoEF&CC and SPCB.
- The chemical additives used for preparation of DF should have low toxicity of 96 hr. LC50 value>30,000 mg/l as per mysid toxicity or toxicity test conducted on locally available sensitive sea species. The chemicals used should be biodegradable.
- DC separated from OBM after washing should have oil content at <10gm/kg for disposal into disposal pit.
- The waste pit after it is filled up shall be covered with impervious liner, over which, a thick layer of native soil with proper top slope should be provided.
- Drilling wastewater including DC wash water should be collected in disposal pit and evaporated or treated and should comply with the notified standards for onshore disposal.
- Barite used in preparation of DF shall not contain Hg > 1mg/kg and Cd > 3mg/kg
- Total material acquired for preparation of drill site must be restored after completion of drilling operation leaving no waste material at the site. SPCB should be informed about restoration work.

ii). Offshore installation

- Use of diesel base mud is prohibited. Only WBM is permitted for offshore drilling. If the operator intends to use low toxicity OBM or SBM to mitigate specific hole problems in the formation, it should be intimated to MoEF/SPCB. The low toxicity OBM should have aromatic content<1%.
- The toxicity of chemical additives used in the DF (WBM or obmor SBM) should be biodegradable (mainly organic constituents) and should have toxicity of 96 hr.LC50 value>30,000 mg/l as per mysidtoxicity or toxicity test conducted on locally available sensitive sea species.
- Hexavalent chromium compound should not be used in DF. Alternative chemical in place of chrome lignosulphonate should be used in DF. In case chrome compound is used, the DF/DC should not be disposed offshore.
- Bulk discharge of DF in offshore is prohibited except in emergency situations.
- WBM/OBM/SBM should be recycled to a maximum extent. Unusable portion of OBM should not be discharged into sea and shall be brought to on-shore for treatment and disposal in an impervious waste disposal pit.
- Thoroughly washed DC separated from WBM/SBM& unusable portion of WBM/SBM having toxicity of 96 hr. LC50>30,000mg/l shall be discharged off shore into the sea intermittently, at an average rate of 50bbl/hr./well from a platform so as to have proper dilution & dispersion without any adverse impact on marine environment.
- Drill cutting of any composition should not be discharged in sensitive areas notified by the MoEF.
- In case of specific hole problem, use of OBM will be restricted with zero discharge of DC. Zero discharge of DC would include re-injection of the DC into a suitable formation or to bring to shore a proper disposal. In such a case, use of OBM for re-injection should be recorded and made available to the regulatory agencies. Such low toxic OBM having aromatic content<1% should be made available at the installation.
- In case, DC is associated with high oil content from hydrocarbon bearing formation, then disposal of DC should not have oil content>10 gm/kg.

- The DC wash water should be treated to confirm limits notified under EPA, before disposal into sea. The treated effluent should be monitored regularly.
- Discharge of DC from the installation located within 5km away from shore should ensure that there is no adverse impact on marine eco-system and on the shore. If, adverse impact is observed, then the industries have to bring the DC on-shore for disposal in an impervious waste disposal pit.
- If any, environmental friendly technology emerges for substitution of DF and disposal technology, it may be brought to the notice of MoEF and regulatory agencies. If the operator desires to adopt such environmental friendly technology a prior approval from MoEF&CC is required.
- Barite used in preparation of DF shall not contain Hg>1mg/kg and Cd>3mg/kg.
- Oil drilling operators are required to record daily discharge of DC &DF to offshore and also to monitor daily the effluent quality, and submit the compliance report once in every six-month to MoEF&CC.

3.4 Is Indian regulation of conventional oil and gas sector suitable for shale gas?

A comparison of the environment regulations for the conventional oil and gas wells in India with shale gas regulation of Pennsylvania, throws up a mixed result. On one hand, there are major shortcomings in the Indian regulations; on the other hand, some of the provisions in the Indian regulations are more elaborate and strict, but poorly implemented.

Though India has a stricter permitting procedure in terms of requiring an EIA study and prior environment clearance, Pennsylvania does not require an EIA study. The problem with the stricter permitting procedure in India is that it is very poorly implemented.

Instead of asking every well pad to undertake EIA, Pennsylvania has much more specific permitting requirements covering most aspects of shale gas development. The permitting requirements in Penn state include siting regulations, water withdrawal permit, permit for wastewater and solid waste transportation and disposal, financial bond for well plugging and site restoration.

Indian regulations also lack regulation for well design, casing and cementing which are most important to avoid groundwater contamination and accidents.

India has elaborate provisions for disposal of solid waste, drill cutting and drilling fluids, including restrictions on kind of chemicals to be used during drilling.

The biggest drawback in Indian regulation is that it has no provision for regulating water withdrawal and its wastewater standards are too general. The air emissions and venting regulations are also too general. These standards will have to be revised for shale gas. For instance, the TDS standard in India is 2100 mg/l compared to 500 mg/l in Pennsylvania.

India will have to enact regulations for well plugging and site restoration as well as come up financial surety mechanism to ensure the same. Similarly, India should also levy a form severance tax or resource tax and share it with the local communities and authorities.

All in all, major changes in the legislations will be required before shale gas operations should be allowed in the country.

Section 4

Discussion and conclusion

The rapid development of the shale gas in the US took most by surprise. Most environment regulators, including USEPA, were not prepared to deal with the scale and pace of development in the sector. Local communities didn't know much about the impacts of the sector and environmental groups were uncertain and some even supported shale gas development. However, politicians from the local to federal level, including the President of the United States enthusiastically supported the sector. In fact, the ex-secretary of state Hillary Clinton went across the world selling the idea of shale gas[58]. All this happened because everyone benefitted economically - at least in the short-term. Landowners made money by leasing land for drilling, government departments got more taxes and levies, people got jobs and lower gas bills and companies dependent on gas made more profits. Today, however, there are question marks on the sustainability of this economic windfall. With lower oil prices, expert opinion is divided on the future prospects for the shale gas industry.

Damage has already been done

Mainstream environmental groups in the US started with supporting shale gas as a "bridge fuel" to a cleaner energy future-the next best domestic alternative to coal as an electricity source while alternatives like wind and solar scaled up. They believed that it is cleaner than coal and less damaging to climate.

The relations between gas industry and NGOs were so cosy that Sierra club, the oldest environment group in the US actually took \$26 million between 2007 and 2010 from the gas industry, mostly from Aubrey McClendon, CEO of Chesapeake Energy—one of the biggest gas drilling companies in the US and a firm heavily involved in fracking—to help fund the Club's Beyond Coal campaign.

But the things have changed lately. Most big NGOs are now against fracking. The most important reason is that their members who give them annual fees are against fracking due to its local environmental impacts.For the grassroots members of these groups-especially in parts of the country where fracking was already underway-the risk of local pollution and potential threats to water supplies isn't worth the national and global climate benefits of greater gas consumption.

A prominent NGOs leader, who didn't want to be quoted, said that the damage has already been done. What the likes of Carl Pope did in early 2000 to support gas means that this industry is now entrenched and difficult to dislodge. Interestingly after all controversy Sierra club has started a beyond gas campaign to oppose fracking, oppose exports of LNG and to push for much more stricter standards for power plants so that gas can also be restricted in power plants. Sierra club's website now says that shale gas is "dirty, dangerous, and run amok ".

4.1. Sustainability of shale gas

Shale is a distributed resource and not a point resource like conventional oil and gas or coal. It is very difficult to estimate reserve and resources in distributed resources. In conventional oil and gas if the boundary of the deposit can be established, the reserves can be reasonably estimated. In shale even when the boundary of the deposit is known, establishing reserves is very difficult simply because there is huge diversity both vertically and horizontally. So, a lot more exploratory wells have to be drilled to get rough idea about the deposits and the reserves.

Most experts believe that the estimates put out by the U.S. Shale industry is speculative. In 70%–80% wells they drill, they are finding far less gas than was estimated. Also, they are not sure what they are going to get from the wells. Some wells in Pennsylvania are only giving CO_2 and water and some wells are giving everything: methane, butane, propane and even crude oil.

The problem is compounded by the fact that the technology is still not fully established. Where to drill, how many wells to drill, where to go horizontally, how far to go, at what angle, everything is trial and error. But over the past 10 years the recovery has increased because the industry is learning and refining the drilling design.

As of now, most US companies are not profitable. The prices are down. Companies want to export to increase prices but big consumers and even the conservatives are opposed to it. They want local use and hence low prices. Shale gas companies in the US are surviving of junk bonds and investments from overseas. They have leased lots of land and are showing value of gas underground as an asset. They are then selling share of their companies to companies in China, India and Japan. They are surviving on these investments. They are using part of this money to buy more acreage and the cycle continues. However, lower crude oil prices in the last one-year has started to bust this speculative cycle.

Impact of the falling oil prices

In the last 8–9 months, crude oil prices have fallen substantially since reaching a peak of around $110/barrel in July 2014. The current prices are hovering around $60-65/barrel and according to IEA's World Energy Outlook 2014 this could cut investment in US shale oil by 10 percent in 2015. Many analysts believe that the current lower oil prices are an attempt by OPEC to squeeze the booming US shale oil sector-which has higher production costs than OPEC nations. But will lower prices affect Shale gas development as well? Many believe, it already is.

The first to be impacted by lower oil prices will be the associated gas production. Associated gas is gas produced along with shale oil. As shale oil investments and production will dip, so will associated gas. Associated gas accounted for about 18 percent of total U.S. gas production in 2013[59].

Shale gas sector will get hit because of the fall in prices of natural gas liquids (NGLs). NGLs are produced along with shale gas and are used as a substitute for oil in petrochemical industries. In the US, companies in 2014 made more money from NGLs than from dry gas. As crude oil prices fall, so will that of NGLs. A lower gas price along with low NGLs price will make many shale gas wells unviable.

The plans of the US shale gas companies to export Liquefied Natural Gas (LNG) and prop up gas prices in the US will have difficulty in materializing. A sustained lower oil prices makes U.S. exports of LNG, which are based on the arbitrage between low prices in the U.S. and much higher prices overseas (especially in Asia), unviable.

The last but the most important factor is the impact of lower oil prices on the new investments in the sector. The industry's weak balance sheet is a major vulnerability for the sector. Most shale firms invest more in drilling than they earn, making up the difference by raising money from the market through bonds and other investment tools. Companies associated with oil & gas sector now account for close to 20% of all high-yield (junk) bonds of the US. In 2013 more than a quarter of all shale investment was done by firms with dodgy balance sheets (defined as debt of more than three times gross operating profits)[60]. A slump in oil prices will dry up this debt market and many companies may go bust. All this will lead to significant reduction in new investments in the sector.

But many in the oil and gas sector believe that this drop in oil prices is good for the sector. It will weed out bad players and bad practices. It will spur innovation and cost cutting measures and make the sector more competitive.But overall, the drop in oil prices has brought realism back to the sector.

4.2. What should India do?

India has huge gas deficit. Gas power plants worth 10,000 MW capacities are idle due to gas shortages. The average utilization rate of gas-fired plants was 40% in 2012/13[61]. Shortage of gas is also impacting the fertilizer industry and the transport sector. The shortage of gas and its high price means that it is difficult for the government to supply natural gas as a cooking fuel to a large majority of households. Only about 65% of the urban households and 12% of the rural households use LPG as a main source of cooking energy[62]. This has huge health implications for women as indoor air pollution emitted from traditional fuels such as firewood and biomass cooking stoves contain toxic pollutants and can cause many respiratory and pulmonary diseases[63].

India will face a shortfall of more than 110 billion cubic meters (bcm) of natural gas by fiscal 2015/16, up from more than 60 bcm in 2012-13 and 90 bcm in 2013/14, according to the petroleum ministry. Part of the demand in 2012/13 was met by 18 bcm of LNG imports. The short-term outlook for gas looks grim in the absence of sufficient domestic gas supplies[64]. The question before India is whether to keep importing expensive LNG from the likes of Qatar or to invest in domestic production of gas including shale gas. The answer is easy. India would prefer producing domestic gas than depending on expensive LNG. That is the reason why the government has come out with a shale gas policy and allowed government-owned companies to start exploration. The challenge is: can it be done safely?

Shale gas is a "feast and famine" resource. The gas production is very high initially – one to two years – and then there is very little production. So companies must keep drilling to keep up the production. It is estimated that the US must drill 15,000 to 20,000 wells each year to meet its gas demands. This could mean drilling and fracking a million wells till 2050. The environmental impact of such intensive and extensive drilling is truly enormous.

In a country like India with high population density, low water resources, higher proportion of arable and forestland, the impacts of fracking on the ecosystems, people and communities would be difficult to manage. This is the view of the Indian industry as well. ONC Chairman and Managing Director Sudir Vasudeva, while highlighting the potential for shale gas in the Damodar Basin, said in May 2014 that land use for drilling operations may face severe resistance from local residents, while securing the huge water resources required for

Pipelines to supply large quantities of water for fracking in forests of Pennsylvania shale gas operations posed a great challenge[65].

Apart from the environmental issues, India will also need huge investments and foreign expertise to explore, establish the sustainability and develop the shale gas reserves. The US had an advantage of an existing very good service sector for oil and gas industry that was used for the shale gas development; something that India doesn't have.

India has not invested much in shale gas development so far. We should learn from the success and failures of the US and approach shale gas development sensibly. The key learning's are:

1. Not a bridge energy source

India should be clear why it wants to develop shale gas sector. It should develop shale gas sector to meet its gas demand and not to meet its climate goals; shale is not a solution for climate change.

The assertion that gas is a bridge between coal and renewables is not true. The fact is shale formations are not only producing gas they are also producing oil. There are wells that are producing only gas, only oil or oil and gas both. There are no boundaries. If a company hydrofracs, it is not going to stop at gas. It will take out oil as well. So it is a hydrocarbon economy like any other in the past.

On climate the world needs to take action in next 20–30 years and methane is hugely damaging to climate over 20 years period. Large-scale methane emissions from well to burner will be highly detrimental to the fight against climate change. Reducing coal and adding gas is not a solution for climate change. The world needs to reduce both.

2. Plan before permitting

Information beforehand on resources – land, forest, wildlife, water, people, infrastructure etc. – is key for good development of shale gas. Most problems are because of poor resources assessment and mapping.

- Undertake regional resource and environmental assessment of the shale plays before starting exploration and drilling.
- Developing common infrastructure like pipelines and processing plants can reduce the impacts significantly. Presently in the US, impacts are exacerbated by the fact that different companies are having separate pipelines, roads, water sources etc. Better coordinator between companies is very important.
- Design and layout of pipeline infrastructure is very important. Transportation of gas through pipelines in predefined direction (preferably along the existing roads), instead of multiple directions, can reduce impacts significantly.

Energy poverty is chronic in India. Eighty per cent of households still use polluting biomass for cooking

- Well pad should not be put near ecologically sensitive areas. Also, instead of multiple pads, one pad can be used to drill many more wells than what is being done today. This will reduce land footprint significantly.

3. Be extra careful on water

Fracking will not only deplete water source, it can irreversibly contaminate it. Fracking, therefore, should not be allowed in important watersheds. New York state has put a moratorium on fracking simply because, people in New York City got worried because their watershed is 130 km away and they have protected that water for a long time. Fracking threated this precious resource.

4. Regulations, monitoring and enforcement is key

Some of the states in the US have enacted reasonably strong environmental regulations for the shale gas industry. Still, they are finding that there are major gaps to be filled. Handling of toxic wastes is a big gap. These wastes from some of the shale plays contain radioactive materials that normal hazardous waste sites are not accepting. Similarly, closing down well and reclamation of well pad area is another gap. Most states demand relatively small financial bond for the closure which is not going to be a sufficient deterrence for compliance. Regulation of well construction and casing is still a concern and so is reducing fugitive emissions. Lastly, monitoring, compliance and enforcement, including detection and classification of violations is a major challenge. The lessons are:

1. Have regulation and sufficient regulatory capacity in place before the industry takes off
2. Enact strict regulations because the sector has nasty pollution issues -- wastewater, VOC and methane emissions and toxic wastes etc.
3. Permitting procedure must have a detailed evaluation of water availability, toxic waste and wastewater disposal.
4. Have national level regulation. State by state regulation in the U.S. has created major problems.
5. Have very strict rules on well drilling and set a very high bar on who can drill. Training and licensing of drilling operators is important.
6. Setup clear systems for disclosure of data by well operators.
7. Have a very strong information management system to evaluate all sort of information and transmit it to stakeholders. The information system should be electronically enabled. Regulators should be e-enabled as well. They should be provided with mobile and GPS-enabled devices for inspection and monitoring.
8. As the sector is new, training of regulators is must. Also, develop standard operating procedure for monitoring, compliance and enforcement.
9. Classify violations properly and impose fines accordingly.
10. Set system for the monitoring of the transportation of wastes. In the US, truckers have been found to dump wastes on the roads and vacant land.

5. Consult communities and share benefits

Consent of the community, regular consultation with them and information disclosure is very important; so is sharing benefits with them. Landowners in the US can get $1000–4000/acre as lease rent for giving right to drill. They also get some percentage of the value gas production.

6. Others issues

- In the US, there is hoarding of shale gas acreage by companies. Companies are sitting on leases and not producing. Experts believe that there is a need to set a time frame for development of wells. If they can't develop it must be sold back to the government (and not to some other company to avoid speculation).
- Exploration cost is very high compared to than the conventional oil and gas. It is also risky. Government should therefore develop shale gas in a way that the risk money is private and not public.

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