Volume 8 • Special Issue on Natural Gas • January–August 2013

Energy Security Insights

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Foreword

The one segment of the energy supply industry which has changed drastically in the last few years is the natural gas supply industry. Not only have natural gas reserves expanded substantially in different parts of the world, but the situation in North America in particular has changed far beyond anybody's expectations. As a result, the USA, for instance, has the potential for becoming an exporter of natural gas in the very near future. The prices of gas in that country have already reached a level which is almost one quarter of the price that existed just a few years ago. Undoubtedly, this situation is not likely to continue very long, because at existing prices demand for gas will grow very rapidly which would lead to price increases on a large scale.

In India too the prospects for increase in natural gas reserves are very bright, but, unfortunately, there have been delays in decision making and some lack of coordination between various government agencies and the corporate sector. The prospects for shale gas in India are not all that bright, TERI, in fact, has brought out a policy brief earlier this year (included in this volume), titled "*Look before you leap*", highlighting some of the problems associated with large-scale shale gas production in India which needs to be taken into account before arriving at a comprehensive policy, which respects environmental and other aspects related to the production of shale gas.

One interpretation of the advent of shale gas and an increase in the supply of conventional gas is that this fuel provides a very useful bridge for moving from solid and liquid fossil fuels, namely coal and oil, to renewable sources of energy, which would require time before they become comprehensively competitive with conventional fossil fuel sources. The reality is that research and development in the field of renewable energy technologies has been quite low with respect to the potential that they hold and the substantial benefits that they provide in reducing the emissions of greenhouse gases (GHGs). The use of renewable sources of energy also carries with it substantial co-benefits, such as enhanced opportunities for energy access, particularly for those who receive no electricity supply today and who are really not part of the electricity grid worldwide. A total of 1.3 billion people lack access to electricity, and renewable energy technologies provide an extremely attractive option for them to be able to get clean, durable, and widely available energy supply from renewable sources. Renewable energy also ensures health benefits, because even a kerosene lamp, which is used on a large scale by those who have no access to electricity to meet their lighting needs, produces harmful pollutants, which has serious effects on the health, particularly of women and children, who generally get much greater exposure to such pollutants than adult males.

This issue of '*Energy Security Insights*' provides an overview of various characteristics of the natural gas market in different parts of the world, including India. With increase in the supply of natural gas, there would certainly be an enhancement of security of supply of energy overall. There would also be some shifts in the geo-politics of energy supply, particularly with some regions of the world, such as the USA, which has always been a major importer of hydrocarbon fuels, actually becoming self-sufficient with increase in natural gas production as well as concurrent increases in oil production. From the energy security perspective, it would be very useful for a country like India to monitor natural gas developments in different parts of the world, so that we could take decisions and exercise choices that would not only enhance the security of energy supply, but also provide benefits of a fuel that is significantly cleaner in its environmental impacts than petroleum and coal. This issue of '*Energy Security Insights*' not only provides information on global natural gas developments but also a basis for debate and discussion on this subject and laying a foundation for monitoring future developments in the field.

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Status Note: Natural Gas Sector

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Changing Global Scenario

The discovery and successful production of shale gas is set to alter the natural gas sector, globally. After the successful production of shale gas in the United States of America, several other countries are also looking into their domestic potential, and technical feasibility of exploring the resource. With the possibility of rising production from different parts of the world, questions on waste management, environmental impact, and impact on land and water resources need to be studied in detail. New, environmentally less harmful techniques are also being explored. The impacts of rising availability and use of natural gas will be far reaching; and will be felt on prices, international price determination mechanisms, geopolitical landscape, and will consequently also impact the development and use of other fuels.

Table 1 gives an estimate of natural gas resources, both conventional and unconventional, across the world.

Natural Gas Sector in India

Decreasing Supply of Natural Gas

Natural Gas production in India has gone from almost zero in the 1950s to 87 million standard cubic metres per day (mscmd) in the current year. The total gas production in India was about 40.680 billion cubic metres (bcm) in 2012–13.

In 2013, total gas production fell by 14% in India. While production from ONGC and OIL has been consistent, the steep fall in RIL-BP-Niko's KG-DWN-98/3 block (also known as KG-D6) — from 61.8 mscmd about three years ago to 14 mscmd now — has led to this decrease.

Rising Imports

The rising demand for natural gas in India coupled with a decline in its domestic production has led to an increase in India's dependence on LNG imports. India became the world's sixth largest liquefied natural gas importer in 2011, with 5.3% of global imports (EIA, 2013). Imported LNG is typically more than twice as expensive as domestically produced natural gas, because it is not subject to the government setting prices through the Administered Price Mechanism.

Infrastructure

The rising imports also make it imperative to establish new terminals. Subsequently, in addition to the existing Dahej, Hazira, Dabhol, newly commissioned Kochi and the upcoming Ennore

Table 1 Remaining* technically recoverable natural gas resources by type and region, end of 2012 (tcm)

Regions	Conventional	Unconventional				Total
		Tight Gas	Shale Gas	Coalbed Methane	Sub-total	
East Europe/Eurasia	143	11	15	20	46	190
Middle East	124	9	4	-	13	137
Asia-Pacific	44	21	53	21	95	138
OECD Americas	46	11	48	7	66	112
Africa	52	10	39	0	49	101
Latin America	32	15	40	-	55	86
OECD Europe	26	4	13	2	19	46
World	467	81	212	50	343	810

* Remaining resources refers to comprise known as reserves, reserves growth, and undiscovered resources.
Source: IEA, 2013

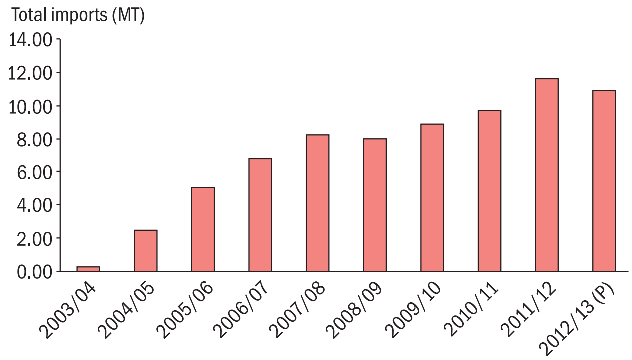

Figure 1 Imports of Natural Gas in India over the last 10 years.
Note: MT – Million Tonnes; Reliance LNG Import Data is not included; P - Provisional
Source: PPAC, 2013

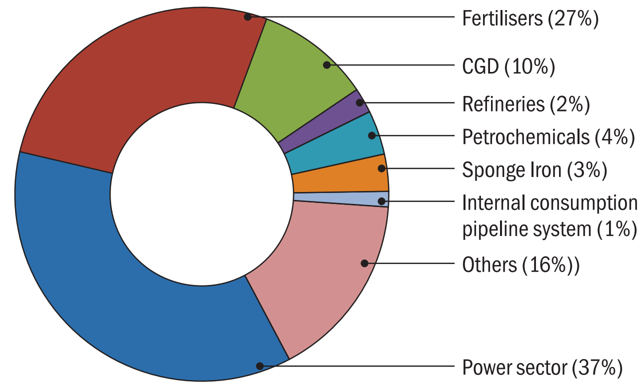

Figure 2 Consumption of natural gas by various sectors (Apr '12 – Mar '13)
Source: Indian Petro < http://indianpetro.com/articleView.do?articleID=115827; http://www.indianpetro.com/articleView.do?articleID=96994&pgNo=0> (July 6th, 2013)

terminals, three additional terminals have been planned at Mangalore, Kakinada, and Gangavaram.

The country has a total of 11,000 km of Natural Gas pipelines at present. According to the Minister of Petroleum and Natural Gas, the country is in the process of laying 12,650 km of additional pipelines (Press Information Bureau, 2013). The shortage of supply of natural gas exacerbated by delay in commissioning of plants has also led to the very low use of most of the domestic pipelines.

Natural Gas Consumption

The sale of domestically produced gas is regulated by the Gas Utilization Policy introduced by the government in 2008 after the KG-D6 block operated by RIL–Niko commenced production. The government had identified key priority sectors – fertilizer plants, gas-based power plants, and city gas distribution networks. About 45 mscmd of the gas produced in the KG-D6 block was allocated to these sectors; the remaining gas could be sold to other non-priority sectors. This list was later expanded to include steel plants, refineries, petrochemical plants, LPG, and captive power plants. However, due to fall in production from KG-D6 block the government has reduced allocation to non-core sector while maintaining the allocation for core sectors.

Natural Gas Pricing

The Indian natural gas sector is evolving and is still at a nascent stage of development. Multiple gas prices exist in India.

- APM gas price where the government fixes the price of APM gas.
- Non-APM gas price which is determined as per the provisions of Production Sharing Contract (PSC).
- The price of imported LNG under term contracts governed by the Sale Purchase Agreements between the LNG seller and buyer.
- Spot cargoes are purchased on mutually agreeable commercial terms as per market conditions.

The following table shows the price variation in India.

Table 2 Natural gas pricing

Source	Price (US $ per MBtu)	Average supply during 2011–12 (mmscmd)
NOCs' APM Gas	$2.52 - $ 5.25/mBtu	50.7
NOCs' Non-APM Gas	$4.2/ mBtu	7.45
PMT#	$ 4.2 - $ 5.73/ mBtu	11.03
Niko-Hazira	$ 2.673 - $ 5.346/mcf	0.48
Ravva Satellite	$ 4.3/ mBtu	0.97
RIL-KG-D6	$ 4.2/ mBtu	42.32
Long Term R-LNG*	$ 6.97 - $ 9.06/ mBtu	25.51
LNG (Spot)*	$12.52 - $17.44/ mBtu	14.11

\# Purchase price of Panna-Mukta Gas is $ 5.73/ mBtu & of Mid Tapti is $5.57/ mBtu.
* R-LNG/ Spot prices are ex terminal prices, exclusive of regasification charges
Note: mBtu - Million British Thermal Units ; mcf - Thousand Cubic Feet
Source: Rangarajan, et al. 2012

Rangarajan Committee

An Expert Committee was appointed under the Chairmanship of Dr C Rangarajan to examine the pricing mechanism for natural gas in India in 2012. In its report to the Government, the committee has reviewed various gas pricing mechanisms existing nationally and internationally and has recommended a possible mechanism for pricing till the time a 'gas-on-gas competition' becomes feasible.[1] It recommends a uniform gas pricing mechanism, at an arm's length basis. It suggests determining prices as an average of average of volume-weighted average at well-head (on net-back basis) for gas imports and volume-weighted average of US Henry Hub, UK National Balancing Point and the netback price at the sources of supply for Japan.

In June 2013, the Cabinet Committee on Economic Affairs gave its approval to implement the pricing mechanism recommended by the Rangarajan Committee. This will come into effect in 2014 and will remain in force for five years.

Unconventional Gas

Coalbed methane

33 CBM blocks, located in the states of Jharkhand, West Bengal, Chhattisgarh, Madhya Pradesh, Maharashtra, Rajasthan, Gujarat, Andhra Pradesh, Tamil Nadu, and Odisha and Assam, have been awarded to national oil companies and private companies for exploration and production of CBM in the country.

While the total prognosticated CBM resources for these awarded 33 CBM blocks, is about 63.85 tcf, of which, so far only 9.12 tcf reserves have been established as Gas-in-Place (GIP). Commercial CBM production has started from one block—Raniganj (South) since 14 July 2007, which contributes about 0.28 mmscmd of CBM production. Seven more blocks are expected to start commercial production in near future. The total CBM production is expected to be around 4 mmscmd by end of the 12th Five-Year Plan i.e., 2016–17.

Natural Gas Hydrates

A National Gas Hydrates Programme (NGHP) was introduced in India in 1997. Reconnaissance surveys carried out by DGH have found Gas Hydrates to be present in the Krishna-Godavari basin, Mahanadi basin of the Bay of Bengal, and the Andaman Islands and collected a number of gas hydrate cores from 21 sites and 39 holes. The total prognosticated gas resource from the gas hydrates in the country is placed at 1,894 TCM.

Shale gas in India

A draft Shale Gas policy has been introduced in the country and is currently under review at the Government.[2] Various exercises have been carried out to estimate the extent of shale reserves in the country. However, there is a wide variance in the estimates by different agencies ranging from 45 TCF (Six sub basins studied by CMPDI) to 2,100 tcf (upper limit given by M/s Schlumberger). However, none of the studies have covered all the basins in the country (Lok Sabha, 2013).

The Government has granted permission to ONGC for an R&D project in Gondwana Basin in the existing two CBM Blocks for exploration of Shale Gas.

There is a need to exert caution before approving shale gas exploration in India due to several environmental and social risks associated with it (the extent of land and water requirement; possible water table contamination and surface water contamination during horizontal drilling and hydraulic fracturing amongst others).

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[1] The Report of the committee can be found at <http://eac.gov.in/reports/rep_psc0201.pdf>
[2] For more details, please refer to TERI Energy Data Directory and Yearbook 2012/13.

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Issues of Pricing and Regulation in the Domestic Natural Gas Sector

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The subject of pricing of natural gas has become contentious in recent times. The stakes are in thousands of crores for the exploration and production (E&P) companies and contractors concerned. The price has a large impact on major user sectors, viz., fertilizers, power, steel, refineries, petrochemicals, LPG, city gas, etc. The economy wide impact of the price causes the administrative Ministry (of Petroleum and Natural Gas) to take the support of an empowered group of ministers and/or the Cabinet Committee on Economic Affairs (CCEA) for decision making.

Nature of Gas Price Increase

The CCEA approved, on 26 June 2013, the Natural Gas Pricing Guidelines 2013, which are based on the recommendations in the report of the Committee, constituted by the Prime Minister in May 2012, to review the Production Sharing Contract Mechanism in the petroleum industry (GoI, 2012). The Committee was chaired by Dr Rangarajan, Chairman, Economic Advisory Council to the Prime Minister.

These guidelines will apply to all domestically produced gas (except those fixed contractually for a certain period of time, or with specific formulae) for five years starting from 1 April 2014 (CCEA, 2013). This start date provides continuity as the present price for KG-D6 gas is valid upto 31 March 2014.

Though several weeks have passed since the approval, the guidelines are still not available on the petroleum ministry's website; only a 'Ready Reckoner' is available (MoPNG, 2013). A press report about a briefing held by the government on 28 June 2013 stated that the price for domestic gas producers in 2014 — if all these factors remain the same — would be around \$8.4/mmbtu (Mishra, 2013). This number is considered in the following discussion.

The Ready Reckoner

The Ready Reckoner states: "The underlying principle is that Indian producers should get a similar price what the gas producers elsewhere are getting." However, instead of looking for producer prices, the formula looks at *selling* prices at gas trading hubs, and *import* prices of Japan and India, with deductions to estimate net backs to producers. Clearly, these include costs and profit margins of various intermediaries that are difficult to accurately estimate. The derived numbers will become a subject of debate. The Ready Reckoner states that the formula yields a price of \$6.83/mmbtu for April–June 2013, but no working has been attached to understand the data used.

It is not clear why a common price is proposed for all domestic gas producers — it is well known that the costs of producing gas vary from well to well, field to field; for example, offshore production costs more than onshore production, deep wells are more expensive than shallow wells, and so on. This proposal will provide handsome profits to some producers, and less to others; it would be more appropriate to have different producer prices depending on the particular circumstances. Pakistan follows such a policy (Pakistan Oil and Gas Regulatory Authority, 2012).

The Ready Reckoner states: "The present price of \$4.2/mmbtu has not been found to be feasible." However, no reasons have been provided, despite the fact that the present price had been approved by another group of ministers, about six years ago (MoPNG, 2007).

The Ready Reckoner further states:

> Every \$1/mmbtu increase in the gas price would result in an additional burden of approximately 1 billion US\$. However, half of it, i.e., around 500 million US\$ will

come back to the Government in the form of royalty, profit petroleum, taxes and dividend… [which if required] can take care of the additional subsidy burden of fertilizer and LPG.

Here too, no calculations are provided. Prima facie, government's receipts do not add up to half the price increase in the initial years:

- Royalty is 5% of the well head value of gas for first seven years after commencing commercial production, rising to 10% thereafter;
- Taxes will be a small percentage of revenues, as they are 30% on profits after deducting tax exemptions;
- Dividends are post tax payouts from profits, which the government will receive only to the extent of its stake in the producing entity;
- Profit Petroleum is what remains after Cost Petroleum is subtracted from revenues. The government's share in it rises in steps according to the level of the Investment Multiple (IM): 10% for IM below 1.5; 16% for IM between 1.5 and 2; 28% for IM between 2 and 2.5; and 85% for IM above 2.5. Thus, in later years, there may be large inflows to the government, but until they materialize, the subsidy burden will need to be financed from other sources.

The CCEA expects that providing global pricing for gas "will help incentivize investment in the Indian upstream sector" (GoI, 2012). However, even though global pricing has been allowed for crude oil since 2002, Ms Mahalingam observes that it has not led to "a single global oil major participating in our upstream exploration efforts" (Mahalingam, 2013). This implies that issues other than price are holding back investment; these must be identified and addressed.

Impact of Gas Price Increase on the Fertilizer Sector

Every Dollar increase in gas price will raise the cost of producing urea by $25/MT; about 18 million tonnes is presently produced from natural gas (Jena, 2013). The proposed gas price increase of $4.2/mmbtu will raise the national cost of producing urea by $ 1.89 billion, or ₹12,285 crores (at ₹65/$).

The present sale price of urea to farmers has been fixed by the government at ₹5,360/MT (Fertilizer Association of India, 2012), even though the actual cost of production at prevailing gas prices is more than twice as much. Urea producers receive the difference as a subsidy from the government. If the increase in cost due to the higher gas price is to be passed on to the farmers, then the urea price will have to be almost doubled. As this is not politically feasible in an election year, the entire burden will have to be borne by the government, in the form of additional subsidy.

This is easier said than done. Even though the government had made a provision of ₹65,974 crores toward fertilizer subsidy in 2012–13 (Revised Estimates) (*The Hindu Business Line*, 2013), the arrears due to the fertilizer companies as on 31 March 2013 were ₹31,500 crores (CMIE, 2013). An important reason was that about ₹22,200 crores from the budget had to be used to pay the arrears for the previous year 2011–12. This results in large delays in disbursal of subsidy, which seriously affects the cash flow of manufacturers. The situation has become so difficult that the Fertiliser Association of India has been constrained to file a case in the Delhi High Court against the Department of Fertilisers in July 2013 seeking interest for non-payment of subsidy in the stipulated time of 45 days after the fertilizer was sold (CCEA, 2013).

If the Government is unable to pay the present level of subsidy in time, there is ground for reasonable doubt for its ability to bear the additional burden. The Budget for 2013-14 is ₹65,971 crores; after paying off arrears of 2012-13, the amount left is just ₹ 34,471 crores. Since gas prices are denominated in US dollar terms, the depreciation of the rupee in recent months (which may perhaps continue in coming months) will add significantly to the subsidy burden in 2013-14. In this scenario, the additional burden of about ₹12,285 crores due to doubling of gas price from 2014-15 will not be easy to handle.

Under these circumstances, investors will seriously doubt the viability of any new investments in gas-based capacity.

Fertilizer production and consumption will be affected, which will dent agricultural output. Food Security will be reduced, at a time when ironically a special regulation is being brought in.

Impact of Gas Price Increase on the Power Sector

There is about 16,000 MW capacity stranded for want of gas supply (CCEA, 2013). Another 8,700 MW of new gas-based generation capacity is stranded, with no gas available for commissioning the plants (*The Economic Times*, 2013). The Association of Power Producers fears that these units will become Non Performing Assets (NPAs); a total of approximately ₹100,000 crores is stuck, including new-capacity investments worth ₹36,000 crores (*The Hindu Business Line*, 2013).

Clearly, the non-availability of gas will turn away new investors from the power sector for a considerable period of time. Even if there are large gas discoveries, the chances are that new investors will seek strong guarantees of supply continuity before taking a single effective step.

The Association of Power Producers had estimated in January 2013 that the annual cost for the
30 mmscmd of domestic gas that the Power sector receives will rise by about ₹7,200 crores if gas price increases to $ 8/mmbtu (Infraline Database, 2013). This impact now appears to be about ₹9,400 crores, after updating the data for exchange rate (~ ₹65 now from ~ ₹55/$ prevailing then) and announced price of $8.4/mmbtu in place of $8/mmbtu. This cost will flow into all sectors of the economy, raising costs of all products and services across the board, and making downstream units less viable and non-competitive. It will hurt economic growth, and spur inflation.

The variable cost of generating power will rise so much that gas-based power plants will move further down the Merit Order Dispatch ranking, which will adversely affect their offtake. Since gas contracts are typically on Take or Pay basis, such gas-based power plants will face a serious problem of being able to utilize their capacities in aprofitable manner. Loan defaults are a real possibility.

Naturally, the Ministry of Power had requested for status quo on gas price (MoPNG, 2013).

Impact on Fiscal Deficit

According to the CMIE, the cumulative gross fiscal deficit by end of July 2013 was ₹3.4 lakh crores, which is 62.8% of the amount budgeted for the fiscal year 2013–14, and much higher than the level of 51.5% in the same quarter of the preceding year (CMIE, 2013).

In a press briefing, the Finance Minister, P Chidambaram, indicated that the CCEA decision has only determined the price that gas producers will get, and that the government will address the concerns raised by the power and fertilizer ministries. Perhaps, these sectors may pay a lower gas price; also, the MRP of urea may be increased.

If the government decides to bear the entire burden on the fertilizer and power sectors, the amount will be about ₹12,285 plus 9,400 crores, i.e., ₹22,085 crores. This will add about 4% to the Gross Fiscal Deficit; it will be less to the extent that the burden is transferred to customers.

Thus, the increase in gas price will also have a significant negative impact on national finances.

Need for Price Revision

Considering these negative repercussions, a moot point is whether the price increase is at all required. Unfortunately, the report of the committee (GoI, 2012) suffers from some serious lacunae.

The committee was set up by the Ministry of Petroleum and Natural Gas (MoPNG) in order “to look into the design of future Production Sharing Contracts (PSCs) in hydrocarbon exploration, so as to enhance production of oil and gas and the Government’s share....” The fifth term of reference was to examine “structure and elements of the guidelines for determining the basis or formula for the price of domestically produced gas, and for monitoring actual price fixation” (MoPNG, 2012).

The fundamental disconnect arises from the fact that the mandate did not require the committee to consider the impact or acceptability of the proposed price to end users. The report is silent on the views of the power and fertilizer sectors, or the impact on them, even though Chapter 19 of the report mentions that 67% of gas demand in the Twelfth Five-Year Plan will be from these major sectors, and that this demand is ‘Price-Elastic’ (GoI, 2012, pp. 79).

Another serious lacuna is that the report has not justified the need to change the present price. This is crucial, because several events show that the present price must be adequately profitable for the KG-D6 contractors.

- In 2003, RIL/Niko submitted a bid in NTPC's tender for supply of 12 mmscmd of KG-D6 gas for 17 years under International Competitive Bidding procedures. RIL/Niko offered a gas price of $2.34/mmbtu at the wellhead, which being the lowest, was accepted by NTPC. The parties may well have gone ahead to sign the contract had not other events intervened. Since this price was proposed by the contractors themselves, they must have been certain that they would earn adequate profits from it, after recovering all their investment costs.
- However, four years later, the contractors proposed, on their own, another formula, which after a limited bidding process, and examination by Government of India, was accepted, after minor modification, by an empowered group of ministers to culminate it at a higher price of $4.2/mmbtu. It stretches credulity to imagine that the contractors — one of whom is a highly successful business group — proposed a formula that gave them a loss-making price.
- Gas sales commenced in April 2009. In August 2011, a large multinational and global leader in the oil and gas business, namely BP, paid $7.2 billion to acquire a "30% stake in 21 oil and gas production sharing contracts (PSCs) that Reliance operates in India, including the producing KG-D6 block" (RIL and BP, 2011). As other blocks are at an exploration stage, we may safely assume that the bulk of this amount was paid for KG-D6. For purposes of valuing the block, the gas price would have been definitely taken at $4.2/ mmbtu until 31 March 2014, and probably even beyond that, since it was not possible then to predict the price thereafter. There is a distinct possibility that $4.2 was considered adequate for the entire life of the KG D6 block, since BP's average realization for natural gas globally was $3.97 in 2010, which was the relevant year at the time of taking the decision (BP, 2012, pp. 65). Further, it should be safe to assume that this large company, with global gas operations, did not pay large sums of money to buy into an asset selling gas at a loss, especially when they were burdened with the large compensation claims arising out of the Makondo blowout in the Gulf of Mexico!

All this establishes without doubt that the present price is adequate.

The reduced earnings from the block are due to the reduced output, for which selling price is not to blame. The people of India should not be asked to compensate the contractors for the production problems of KG-D6.

Issues with the Formula Proposed by the Rangarajan Committee

The Rangarajan Committee has not provided an illustrative example for the complex formula devised by them. It requires taking a simple average of two components: one being the weighted average price in USA, Europe, and Japan, and other being India's import price. Considering that India's LNG imports are just 2% of the quantity of gas consumed in the overseas markets selected, it is not appropriate to give equal weightage to these components. A fully weighted average formula would be more appropriate.

Japan should not be included in the formula. Since it has no energy resources, it has built its economy on the basis of expensive energy, and is proficient in making high value added products. Its situation is quite different from India.

As regards LNG, the report asserts: "It may be assumed that each gas exporting country also faces competition…" (GoI, 2012, pp. 115, para 24.2.3). However, facts do not support this assumption. Global demand for LNG is far more than the supply; at the end of 2011, global regasification capacity with buyers was 608 mil tpa, which is more than double the global liquefaction capacity with sellers at 278 mil tpa (International Gas Union, 2011). Regarding 2012, BP's annual report mentions, "tight global LNG market" due to "strong demand and high spot prices in Asia, driven by Japan's need for LNG to replace lost nuclear power…." Its forecast for 2013 mentions, "limited increases in LNG supplies and continuation of the uncertainty surrounding nuclear power generation in Japan..." LNG is a sellers' market, and the pricing initiative is with LNG suppliers, not buyers (BP, 2012).

Alternative Price Formulations

This debate underscores the dire need for transferring the pricing function to a regulator, as has been done for electricity. Regulators will bring out discussion papers that enable all opinions to be expressed, and can then take a decision, that will have better acceptability. The powers of the Petroleum and Natural Gas Regulatory Board should be suitably amended.

As this process will take its own time, two simple alternatives are proposed for pricing. The existing price formula has been accepted by contractors, the government, and customers. It has two restrictive conditions whose removal should help contractors:

- Gas price may be revised every month, based on previous month's crude price, instead of annual revision; and
- Actual crude price may be used, by removing the ceiling of $60/barrel.

The formula for calculating gas price will become $2.5 + CP ^ 0.15, where CP is average Brent crude oil price for previous month.

Customers will find this acceptable, as the gas price will work out to $4.55/mmbtu at a Brent price of $120/barrel. Every change of $10 in crude price changes the gas price by 2–3 cents.

Alternative 2:

The formula proposed by the present committee may be adjusted slightly by applying a single weighted average that excludes Japan and includes India. The formula becomes: "Weighted average of USA (Henry Hub), Europe (NBP) and Netback for India LNG imports".

By providing weightage to India in proportion to its volume, the "tail will not wag the dog". This yields a price of $4.56/mmbtu.

As both methods yield very similar prices, either may be found acceptable across the board.

Table 1 Committee formula adjusted for proportionate weightage to India

Region	Qty BCM	Rate $/mmbtu	Data Source
USA	752	2.72	US Energy Information Agency
Europe	266	9.35	Quantity from International Energy Agency, price based on Bloomberg
India	19	10.24	Petroleum Planning and Analysis Cell, MoPNG website
Total	1,036		
Weighted average		4.56	

Downstream Investor Requirements

Downstream investments are far more capital intensive than upstream investments.

Table 2 Downstream investments compared with upstream

	Investment estimate	Gas Quantity	Ratio ₹ crs / mmscmd
Urea plant - 1 mil tpa	₹6,000 crores	2 mmscmd	3,000
Power plant -1,000 MW	₹ 4,000 crores	4 mmscmd	1,000
Oil and Gas Production KG D6	₹ 40,000 crores	80 mmscmd + Oil	Less than 500

The economic life of new urea and power plants is in the range of 10–30 years. Payback periods are in the range of 6–8 years. Any further investment in urea/power plants requires credible assurances on long-term gas supply arrangement, and a transparent price formula that will enable the plant to be competitive for at least 10 years. A good example is the fertilizer plant Omifco, set up in Oman by IFFCO and Kribhco; the Government of Oman had assured gas supplies for 20 years, and fixed the gas price over the entire period with a defined escalation formula.

This is quite different from the present policy of limiting the period of gas allocation and price determination for only five years. The next supply policies must take a longer time horizon.

Fertilizer companies also have to factor in the possibility that, during the next few years, the subsidy system will be dismantled, and gas price will not be a pass through for government to pick up the bill.

Non-supply Dents Investor Confidence

Non-supply of gas is the biggest business risk for urea and power plants, as gas is their one and only raw material.

Companies in the fertilizer sector have prepared elaborate plans for setting up 8–10 urea plants in India, but all have deferred their plans. Many however have determined that it may be better to invest overseas in countries that have abundant gas. Some have already invested, while others are at various stages of doing so.

In the power sector, capacities of 8,000 MW having no gas linkage are in dire straits. Of the remaining 17,500 MW, units with major dependency on KG-D6 have been stopped since early 2013. Investment of about ₹90,000 crores is affected; all lenders and investors are deeply concerned about the security of their funds.

Future investment in major gas consuming sectors will be muted: "Once bitten, twice shy". In sum, there is demand destruction due to supply concerns.

Investors will come back to these sectors only if gas suppliers provide guarantees of arranging alternate supplies, so as to ensure supply continuity for 10–20 years. Present gas sales agreements place stringent Take or Pay penalties on buyers; but the Liquidated Damages penalty on Sellers for failing to supply gas are weak. Also, the Sellers can escape liability for non-supply by claiming deficiency in gas reservoirs.

In order to deal with these issues, it is important that the technical capabilities of the government arm regulating upstream contractors, is strengthened greatly. Ideally, these functions should be with an independent regulator having the authority to levy penalties on contractors not extracting petroleum "in the overall interest of India" (MoPNG, 2009).

Disclosure Requirements

Major gas consumers are keen to have an understanding of the status of gas fields, such as the reserves status, production profile, and any information that is relevant for understanding the risk of business continuity. Gas suppliers should even today, out of enlightened self-interest, take the initiative to brief their principal customers on such matters. For example, there is no clarity on how much longer the supplies of APM gas will last, and at what rate.

Transparency builds trust, without which future gas sales contracts will be difficult. Uncertainty over firm gas sales will also hurt investment in E&P.

Government and regulators should facilitate this process by mandating much higher standards of disclosure requirements for oil and gas companies, in line with the practices followed in countries with large petroleum reserves such as USA, Canada, and Australia.

Conclusion

The entire debate on gas pricing will help the evolution of the regulations involving a vital part of the energy economy. A more inclusive approach to determining pricing, and transparency regarding petroleum operations will help to bridge the wide gap that exists today between producers and customers. Government needs to play a role that recognizes the importance of customers in the proper development of the producing sector.

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Issues of International Long-term Gas Contracts in the Context of Evolving International Gas Markets*

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Introduction

Traditionally, the Liquefied Natural Gas (LNG) business has been based on long-term contractually rigid agreements, where the buyer and seller have made sale and purchase commitments to each other and are bound by the contract to abide by them, regardless of the prevalent market conditions. The largest buyers in the LNG market have been North East Asian countries such as Japan and Korea, who in 2012 accounted for about 53% of the total LNG imports globally. It is important to mention that the first few commercial LNG projects which started in the 1960s were in Europe (Atlantic Basin) with Algeria exporting LNG to France and the United Kingdom (UK) and Libya exporting to Italy and Spain. So, the Atlantic Basin was the birth place of LNG, but later on, the Pacific Basin took the lead in the LNG trade with Japan and South Korea accounting for majority of the trade.

Atlantic Basin vs Pacific Basin

The market fundamentals and structure in the Atlantic and Pacific Basins varied greatly. In the Atlantic Basin, there were two main gas producing and consuming regions — North America and Europe. However, countries in North America (the US) and Europe were not solely dependent on LNG supplies, as they had access to piped gas from domestic sources and the rest was imported from other countries via transnational pipelines. For the US, before the shale gas revolution made it a gas surplus country, gas used to be imported from Canada and Mexico, while in Europe countries such as Norway, Russia, and other states of the Former Soviet Union were the gas suppliers. Initially, in Europe, apart from the UK, the price of LNG was based on competing liquid fuels, but today the European market also has gas hub pricing points, such as the Zeebrugge, in addition to other gas hubs which are fast developing across the continent. Europe is a mature market for gas, but LNG is still being priced versus liquid fuels, even though the gas market is well developed and gas has a high and stable share of the energy market. There is room for gas to gas competition in Europe, but as in the USA and the UK, this will take time to develop. Therefore, North America and Europe were not markets where LNG was substituting liquid fuels as in Japan and Korea in the Pacific Basin (explained below), but complementing piped gas supplies.

At the start of the LNG trade in Asia Pacific, Japan and South Korea's most important LNG suppliers were the South East Asian countries like Indonesia and Malaysia. The suppliers, being developing countries, had little appetite to take risks in huge energy export projects and needed guarantees to secure their investments in the LNG supply projects. At the same time, Japan and South Korea being energy resource starved countries and having to import all their energy requirements, prized energy supply security above all else and were willing to pay a premium for that supply security. As the downstream markets of the LNG buying utilities in Japan and Korea were captive markets with limited or no competition, they were able to know with absolute certainty, apart from unpredictable changes in weather, unexpected economic and/or other natural events (earthquakes, tsunamis, etc.), the domestic energy demand they would have to meet yearly. Since Japan and Korea were using LNG as a substitute for oil imports, LNG prices were linked to crude oil prices as both countries initially did not have any gas market or domestic gas reference price.

Risk-sharing Structure in the LNG Business

The risk-sharing relationship between the buyers and the sellers of LNG meant that the buyer would take the 'volume risk' and the seller would take the 'price risk'.

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* This paper has been authored Mr R K Garg. Research on the article was done by Mr Vikramaditya Kaul.

This meant that the LNG supplier in the long-term LNG sale–purchase contract agreed to a variable pricing formula, which in the case of Asia Pacific was generally indexed to oil (Japanese Customs Cleared Crude Cocktail being a common benchmark used). The LNG exporter would have to deal with the risk of change in the price of crude oil and the subsequent impact it would have on its cash flows.

The buyers, on the other hand, would take the volume risk, which meant that they had to off-take a certain amount of LNG every year, with only some marginal off-take flexibility being provided in the LNG contract, so that the buyer could make some adjustments annually to the contracted off-take level in response to demand fluctuations in its domestic market. If the buyer, after allowing for flexibility, was not able to off-take the minimum required volume—which would be a significant percentage of the annually contracted off-take volumes—then the buyer would be subject to Take or Pay provision of the LNG sales contract, where the buyer in spite of not taking certain quantities of LNG, would have to pay the seller for those volumes.

Development of LNG Trade

Generally in LNG trade, the course of LNG shipments was predictable and fixed, with tankers plying on routes determined by complex and rigid long-term contracts as mentioned previously. From a select few players at the start of the LNG trade, by 2012 there were 18 LNG exporting countries with 89 LNG trains with a combined capacity of 282 MMPTA (Million Metric Tonnes Per Annum), while there were 26 LNG importing countries with 93 Regas Terminals totalling 668 MMTPA capacity. Short term and spot volumes accounted for 25% of the total volume of LNG trade, up from about 5% in the year 2000. The Asia Pacific region is dominant in the LNG trade accounting for 70% of the global LNG Trade. Currently, there are 378 LNG vessels engaged in the LNG trade. For the development of the short-term trade in LNG, un-contracted vessels which are not tied to long-term contracts are essential, as they will be available for spot and short-term contract. Short-term contractual trade is expected to grow further in the long run and is expected to play a bigger role in the LNG trade alongside long-term and high volume LNG sale contracts.

Structural Change in LNG Markets and Impact on LNG Contracts

Apart from the development in the short-term in LNG trade, there are two major changes in the international gas market place that have impacted the LNG business and will eventually have an impact on LNG contracting practices.

LNG Pricing: Gas vs Oil Linkage

Developments in the US Shale gas industry have revolutionized the gas sector in the US with far reaching effects on the LNG trade internationally. Due to the shale gas revolution in the US, the country has turned from a potentially large LNG importer into a large exporter in the near future. The US LNG export projects are pricing their LNG off the Henry Hub gas price. For the first time in the history of LNG trade, such large volumes of LNG will be priced off a gas hub and this has far reaching consequences for pricing as a whole for internationally traded LNG. As the Henry Hub gas prices currently are in the mid-USD 3/mmbtu range, this is currently making LNG exports from the US to Far East countries such as Japan and Korea, cost competitive with the rest of the LNG exporting countries, as the others exporters want LNG price to be linked to crude oil like Brent or JCC, which are above $100/bbl. This gas hub linkage of LNG prices is making US LNG exports cheaper and more attractive and is leading to demands by various LNG buyers, specially, Japan since its nuclear crisis. Due to this sellers are starting to consider basing LNG prices off gas hubs.

For the Pacific Basin, where India is located, this marks a major change in LNG pricing formulas in LNG sale and purchase contracts. Traditionally, LNG contracts have been linked to some form of crude oil like Japanese Crude Cocktail in LNG sales contracts in the Asia Pacific Basin. Gas hub-based LNG pricing will mark a paradigm shift from the traditional oil-linked pricing formula and will reduce LNG imports costs for the buyers.

India is also attempting to source LNG from the US, as it feels that having a portfolio of LNG supply with both crude oil and gas hub pricing will enable it to have a balanced-cost effective LNG supply portfolio.

Flexible LNG and Destination Clause

The development of flexible LNG originated from the Atlantic Basin in 2003. Traditionally, LNG contracts between buyers and sellers in the Atlantic Basin, like the Asia Pacific Basin, were subject to rigid destination clauses, which meant that the buyers and sellers could not divert the contracted LNG volumes to higher paying markets or divert the surplus LNG, which was not absorbed by the original customer in its domestic market, to other gas deficit markets. The reason for this was to prevent arbitrage with long-term contract volumes and also to guarantee the seller that term volumes sold in one market would not compete with volumes sold in another market. But, in the year 2003, the 2nd European Gas Directive of the European Commission, banned destination clauses for piped gas as well as for LNG, because the Commission considered destination clauses preventing diversion to be an anti-competitive market-segmentation practice being carried out by LNG exporters. Due to this ruling, new LNG contracts have been drafted that increased contractual flexibility and this has led to increased flexibility from producers in the Atlantic Basin such as Nigeria, Equatorial Guinea, and Egypt. Also, a number of sellers have started to self-contract cargoes, selling directly in the downstream market, thus reducing off-take risk. This increase in destination flexibility has led to an increasing amount of LNG that is exported towards the higher priced Asia Pacific Basin.

This flexibility came into play when Japan faced a major power crisis due to the March 2011 earthquake and resulting tsunami. The March 2011 Japan earthquake led to a complete shutdown of nuclear power capacity in Japan and subsequently in an effort to replace lost nuclear power capacity, Japan imported record levels of LNG, by opting for upward flexibility in its term contracts, executing short-term deals for LNG supply and buying additional quantities from the spot market. The heavy demand from Japan caused spot market prices to rise to record levels reaching parity with oil prices. This energy crisis in Japan created important commercial opportunities for flexible LNG. A good part of this LNG was available from flexible LNG coming out of the European market and LNG from projects conceived initially for the USA market from Qatar. In 2012, Asia accounted for 70% of short-term global imports, with Japan and South Korea accounting for 33% and 16%, respectively.

Additionally, the business model that US LNG exports from the Atlantic Basin have adopted is a Free on Board (FoB) sales contract, with no destination clause, meaning that whichever market the LNG goes to from the US load port, is upto the buyer and the seller has no say in it. In the long run, as US exports start to enter the market, this will add to the development of the spot market and the availability of flexible LNG volumes.

However, this contractual development in destination flexibility in the Atlantic Basin has not had a significant influence in contracting practices in the Asia Pacific Basin. In the Asian market, destination clauses are still seen as a means to provide security for buyers and sellers in term of having assured supplies and an assured demand. But, the increased amount of flexible LNG from the Atlantic Basin, due to the relaxing of the destination clause is putting traditional contracting practices in the Asia Pacific Basin under considerable pressure and is forcing a rethink of the established risk-sharing model mentioned.

In this new more flexible market, India will continue to source additional supplies on a short-term basis as it has being doing, to supplement its long-term contracts and to meet demand which long-term import volumes cannot meet. India is a hugely gas deficit market and in this type of domestic gas market scenario, India will always be an importer of LNG. Thus, if there is additional flexibility in supply in the market, the objective will always be to keep scouting the market for the most cost-competitive deals it can get.

Conclusion

As new supplies enter the market from the US and Canada, Australia, and East Africa and gas hub LNG pricing makes its debut in LNG business in a few years, coupled with an increase in flexibility in supply contracts, India will face a market situation where there will be a wide variety of sourcing options. Petronet LNG, a pioneer in the LNG business in India, with its vast experience in long- and short-term LNG sourcing, will leverage this experience to procure the most cost-competitive LNG to meet the gas needs of the nation.

Shale Gas Prompts Regulatory Changes in Europe

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A contentious unconventional natural resource that is being developed today is shale gas; other subcategories of unconventional natural gas include tight gas and coalbed methane. Practically, shale gas is natural gas extracted from shales, a type of organic-rich sedimentary rock formed from deposits of mud, silt, clay, and organic matter. On account of their low permeability, shales allow significant quantities of natural gas to be trapped within their pores. In order to release and extract shale gas from the shale formations two innovative technological techniques are being used — directional/horizontal drilling and high volume hydraulic fracturing. The first technique —Directional/horizontal drilling, involves the drilling of wells at depths usually greater than 2 km, whereby the horizontal leg of the well follows the contour of a given geological formation for up to 3 km or more. The second technique of hydraulic fracturing or fracking involves the high-pressure injection of the fracturing fluids — a mixture of water (98–99.5%), a proppant (such as sand, bauxite or ceramic beads), and chemicals (0.5–2%) into the shale formation to break the shale rock and connect the pores that trap the natural gas. While these technologies are being commercially deployed in the US, the European experience has been more limited and concerns are being raised as to what are the environmental impacts of such technologies.

Until recently shale gas was not even on the European Union's (EU's) table. According to a report released by the United States (US) Energy Information Administration (2013), the EU holds promising gas reserves, approximately 470 trillion cubic feet of unproved wet shale gas technically recoverable resources (TRR), whereas Russia has reserves of 287 trillion cubic feet of TRR, China 1,115 trillion cubic feet of TRR, the USA 567, and Canada 573.

From a strict legal and regulatory standpoint, a study conducted by the European Commission (2012) concluded:

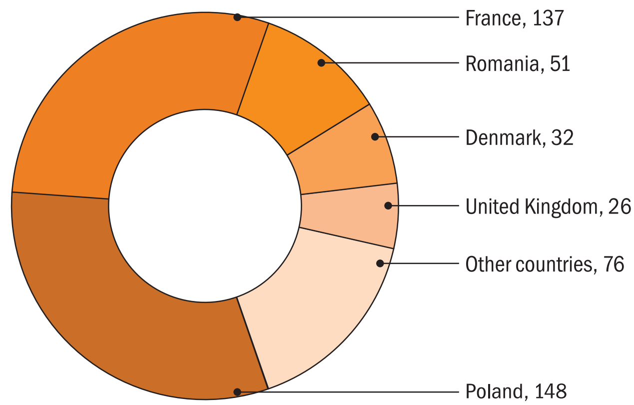

Figure 1 Unproved wet shale gas TRR in Europe
Note: Figures in trillion cubic feet

> [U]nconventional hydrocarbon projects involving the combined use of advanced technological processes such as horizontal drilling and high volume hydraulic fracturing, notably shale gas exploration and exploitation activities are covered by EU environmental legislation from the planning until the cessation.

Shale gas exploration and exploitation falls under Directive 85/337/EC on the assessment of the effects of certain public and private projects on the environment (EIA Directive). If an installation produces more than 500,000 m^3/day then it will automatically fall under the Annex I list of activities subjected to a mandatory environmental impact assessment. Considering the fact that unconventional gas wells produce somewhere between 115,000 to 250,000 m^3/day, and taking into account the European Parliament (2012) Resolution on the environmental impacts of shale gas and shale oil extraction activities, the European Parliament's Environment Committee voted on 11 July 2013 in favour of a proposal imposing a mandatory EIA for all shale gas drilling activities in the European Union.

Other important European pieces of environmental legislation applicable to shale gas are: Directive 2006/21/EC on the management of waste from extractive industries; Directive 2000/60/EC establishing a framework for community action in the field of water policy; Regulation 1907/2006/EC concerning the Registration, Evaluation, Authorization and Restriction of Chemicals (REACH), establishing a European Chemicals Agency, amending Directive 1999/45/EC and repealing Council Regulation (EEC) No. 793/93 and Commission Regulation (EC) No 1488/94 as well as Council Directive 76/769/EEC and Commission Directives 91/155/EEC, 93/67/EEC, 93/105/EC and 2000/21/EC; Directive 98/8/EC concerning the placing of biocidal products on the market; Directive 96/82/EC on the control of major-accident hazards involving dangerous substances, amending and subsequently repealing Council Directive 96/82/EC; Directive 92/43/EC on the conservation of natural habitats and of wild fauna and flora; and Directive 2004/35/EC on environmental liability with regard to the prevention and remedying of environmental damage.

A mandatory EIA should increase awareness among local communities and authorities, increase the preparedness among environmental agencies and local authorities, and offer local communities an opportunity to be consulted early in the process.

Furthermore, the Habitats Directive foresees a specific authorization regime for projects likely to affect the breeding sites or resting places of protected species and requires a prior study of the impacts, including cumulative ones, of a foreseen shale gas project, if the project could affect in a significant manner Natura 2000 sites (Council Directive 92/43/EEC of 21 May 1992 on the conservation of natural habitats and of wild fauna and flora, Article 6).

The legislative debate on shale gas development dates back to 2012 when the European Parliament rejected calls for a moratorium on shale gas extraction across the Union, but stated that caution must be exercised and robust regulation should be in force. However, a few European countries have decided to introduce a moratorium on shale gas and hydraulic fracturing. These are France, Bulgaria, and until recently Romania (the Romanian Government lifted the moratorium on shale gas and hydraulic fracturing in May 2013).

Shale gas opponents have called for stringent rules on chemicals used in the fracturing process, as well as expressing widespread concern on matters including well integrity, waste management, air quality, and methane emissions. The European Commission is scheduled to publish its proposals for a risk-management framework for unconventional hydrocarbon activities by the end of 2013. However, the general public attitude in countries such as France, Sweden, and Germany towards shale gas projects appears to be dominated by concerns about the environmental impact of the shale gas activities.

At the EU level, the legal basis for prospecting, exploring, and extracting hydrocarbons is governed by Directive 94/22/EC on the conditions for granting and using authorizations for the prospection, exploration, and production of hydrocarbons. This directive outlines the general principles on which the national regimes should be based. However, the decision of opening national reserves to exploitations remains a sovereign matter.

France

France was originally viewed as one of the most promising countries in Europe for shale gas development but has maintained a moratorium since 2011, imposed on hydraulic fracturing for shale gas due to concerns about its potential adverse environmental impacts. In September 2012, President Francois Hollande announced a continued ban on hydraulic fracturing in France and called for the revocation of seven outstanding permit applications for hydraulic fracturing operations. The debate will most likely continue given the existing financial interests in the future of shale gas exploration in France, particularly the difference of opinion between the ministries of environment and industry.

Germany

Since Germany relies on gas imports from Russia and Norway, its dependence will most likely increase due to the early closure of nuclear power stations and declining conventional gas reserves. It must be noted that 2013 marked an all-time low in gas reserves for Germany, a country that consumes about 81 billion cubic metres of natural gas per year, of which 86.2% is imported. Shale gas exploitation could be important for German energy independence. However, the

German Federal Government is rather reticent and postponed any federal legislation on hydraulic fracturing until after the Federal Election on 22 September 2013. In anticipation of any legislative proposal, the German Ministry for Environment issued a study on the impact of hydraulic fracturing on water and the environment. The study did not propose a ban on hydraulic fracturing but recommended the exclusion of water protection zones from shale gas operations, mandatory EIAs for drill sites and full disclosure of fracturing fluids.

Poland

Poland has embraced a positive attitude towards shale gas activities. Economic and geostrategic reasons motivate its preference towards shale gas, since successfully exploiting their resources could free Poland from its dependence for energy supplies. Additionally, the country has the potential to become the largest gas producer in Europe.

In order to prospect, explore or to produce hydrocarbons, an exploration or production concession is required. This concession is an administrative decision prepared and drafted by the Department for Geology and Geological Concessions and issued by the Ministry of Environment. The governmental apparatus does not have a specialized authority dealing with authorizing/permitting shale gas exploration, prospecting and production. The following authorities have competence in this field:

- Ministry of Environment, with the support of the Department for Geology and Geological Concessions (DGGC) has the competence to grant authorizations for exploration, prospection, and production. The DGGC plays an important role in conducting the procedure and presenting the authorization drafts to the Minister for Environment for approval. The monitoring of the use of authorizations also falls under the competence of this department, together with the prerogative of evaluating whether an environmental decision is required.
- The State Mining Authority (SMA) is responsible for approving the operational plan. For this type of approval, the concerned local authorities need to give their opinion. This authority also supervises geological and mining operations.

Now Poland's shale gas business is facing a serious challenge after the EU's highest court ruled that Warsaw violated European law by allowing licences to be issued for the exploration and extraction of hydrocarbons, without fully open tenders. The European Court of Justice ruling, issued on 27 June 2013 affects around 100 shale gas exploration licences issued by Warsaw to firms which were accompanied by production permits that had not been put out to tender, in breach of the EU's Hydrocarbon Directive. The ruling could have grave consequences for Poland, with the country's current policy aimed at protecting exploration licence holders' interests by issuing subsequent production licences without tenders. Moreover, the Polish government is now exposed to litigation and potential compensation claims.

This decision may be only the first sign that Europe is not ready to deploy shale gas exploitation and in the rush towards the new golden gas, legislators may overlook essential regulatory aspects.

The United Kingdom

The United Kingdom (UK) has an estimated unproved wet shale gas technically recoverable reserve of 26 trillion cubic feet, and recently the Prime Minister has indicated that he supports shale gas development *(Daily Telegraph*, 2013). The UK has shown a positive reaction to shale gas development, probably because its North Sea reserves are in decline and it has to import approximately one-third of its total natural gas consumption.

Commercial extraction has not started in the UK but the Department of Energy and Climate Change (DECC) previously awarded 334 onshore licenses for petroleum and gas exploration. However, hydraulic fracturing had been suspended in the UK for about 18 months, after two seismic tremors were detected near the country's only fracking operations in Lancashire. Nevertheless, on 13 December 2012 the UK government allowed the resumption of exploration for shale gas in the UK, subject to new controls being introduced to mitigate the risk of seismic activity.

A new report prepared and published by the British Geological Survey (2013) states that the Bowland Basin is likely to contain double the quantity of shale gas technically recoverable than initially estimated.

The UK appears to be quite serious about exploiting shale gas as it announced a package of reforms that will stimulate investment, facilitating shale gas exploration and development. The UK tax regime will be the 'most generous for shale in the world' stated George Osborne, the Chancellor of the Exchequer. The Chancellor announced tax allowances to be introduced, reducing the effective rate of tax on shale gas production to 30%, rather than the 62% paid on most oil and gas production in the UK. Nevertheless, energy companies are expected to provide benefits to the local community of at least £100,000 per well site where fracking occurs and 1% of any production revenue.

The UK Environment Agency issued a commitment at the end of June to streamline the environmental permitting regime for shale gas, with a single point of contact for the industry, new draft technical guidance for consultation, and a three-step ambitious reduction in the time to issue a permit from 13 weeks in September to 1–2 weeks by February 2014.

On 19 July 2013, the Department for Communities and Local Government issued a new planning guidance for onshore oil and gas development, including shale gas and coal bed methane. Environmental Impact Assessments (EIAs) are also covered by the guidance which states that EIAs will only be required if 'the project is likely to have significant environmental effects'. These guidelines, along with the Environment Agency's plan to streamline and simplify the environmental permitting process for shale gas development further indicates the government's push to develop the shale gas industry in the UK. Nevertheless, the permitting process for shale gas exploration in the UK remains complex and difficult but the guidelines provide increased clarity as to how the system is intended to work. How well the regulatory system will work remains to be seen.

Romania

Romania has unproven wet shale gas technically recoverable resources of 51 trillion cubic feet, the third largest deposit in Europe. In May 2012, the government temporarily suspended permits for shale gas exploration while waiting for the results of the EU's environmental studies on this energy source. In March 2013, Prime Minister Victor Ponta announced that the moratorium on shale gas exploration in Romania had been lifted. Romania's positive attitude towards shale gas is justified by the potential impact of shale gas on energy security, as Romania depends on imports to cover approximately 20% of all of its overall energy needs, according to data from the World Bank. According to a US Energy Information Agency study, the shale gas resources might be enough to cover domestic demand for 100 years. Aside from job creation, the investment could also bring $600 million over the next 15 years.

However some local communities are deeply concerned about the risks posed by hydraulic fracturing on the environment, quality of drinking water, and increased seismic activity. The National Agency for Mineral Resources (NAMR) launched a campaign to increase public awareness and public debate on shale gas.

The Romanian legislation concerning oil and gas resources does not stipulate any specific rules regarding unconventional resources. In the absence of any specific disposition, the general rules for petroleum development will apply. Consequently, the NAMR does not issue licences for exploration/exploitation but signs a concession agreement to cover three steps — exploration, development, and exploitation. After signing such an agreement with NAMR, the operator then has to notify the competent authority for environmental protection about their intention to explore. Exploration activities could last upto five years.

A document released by the Ministry for Environment and Climate Change states that environmental impact assessment procedures for shale gas have not been identified yet and no EIA has been carried out yet, nor have any regulations concerning this matter been elaborated upon. The NAMR has identified approximately 70 acts and regulations (including Government's decisions and ministerial orders) applicable to shale gas developments. In absence of a clear strategy and cooperation between responsible authorities, it seems that the Romanian executive might get lost in the legislative maze unless they decide to develop a more effective and efficient framework for shale gas developments before granting any other concessions.

Analysing the most recent regulatory developments in the European Union, with respect to shale gas developments, revealed a strong dichotomy between those emphasizing environmental risks and public concerns versus those advocating for the economic benefits of shale gas. It has become clear that there is no simple solution for the existing debate and ultimately it is a matter of national sovereignty to allow shale gas operations within the jurisdiction. However, governments which are anxious to become important players on the energy market might overlook a few important steps in the regulatory process. There are important aspects that should not be curtailed: environmental impacts need to be properly assessed and considered; local communities need to be consulted as public acceptance is essential; a clear and effective regulatory system needs to be in place in order to avoid bureaucratic ambiguity and create a stable and attractive investment climate.

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Shale Gas in India: Look Before You Leap*

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Introduction

Natural gas forms 9% of the total commercial energy mix in India, but demand far exceeds supply, as shown in Figure 1. Part of the demand in 2012–13 was made up by the import of Liquefied Natural Gas (LNG) to the extent of 18 bcm. Several power plants, which were in operation, or ready for commissioning, or in an advanced state of construction, representing about 10,000 MW of generation capacity, were, however, idle for want of gas.

The exploration and production of shale gas in the United States (US) has been a game changer, making the country self-sufficient in natural gas over the last few years. This has created considerable excitement globally, particularly in Europe. India is also looking at exploring shale gas domestically to fill in the supply–demand gap. But, will, what works for the US also work for Europe and India? This policy brief explores this question in the context of India. It explains the nature of shale gas, the technology for its extraction from underground sources, and its potential for India. It also highlights overseas acquisitions of this resource by Indian companies even before it is sourced domestically, and then examines the viability of the technology in India. One of the key determinants of the viability of this technology is the availability of large quantities of clean water. This policy brief raises a red flag on this complementary input for exploiting shale gas resources in India, given that India is a water-stressed country, and is fast approaching water scarcity conditions.

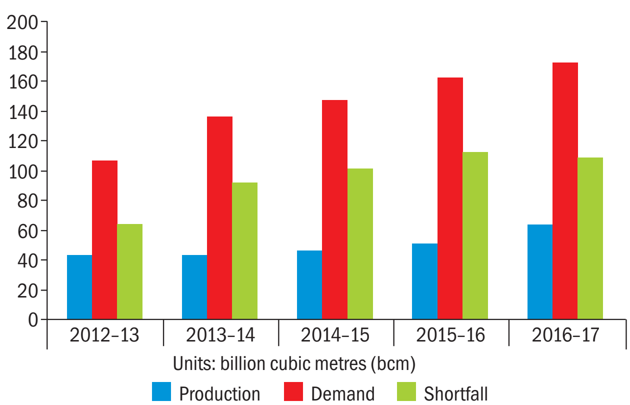

Figure 1 India's estimated natural gas production versus demand
Note: Shortfall as percentage of demand varies from 60–69%
Source: MoPNG, 2011

Box 1: Shale Gas

Natural gas (mainly methane) is generally classified under two heads: (a) conventional gas, and (b) unconventional gas. Most of the natural gas that is produced globally comes under the category of conventional gas where, after drilling in a sedimentary basin that is rich in gas, the gas migrates through porous rocks into reservoirs and flows freely to the surface where it is collected, treated, and then piped to various users. Shale gas on the other hand is located in rocks of very low permeability and does not easily flow. Therefore, the technique for recovery of shale gas is quite different from that of conventional gas.

Drilling and Recovery of Shale Gas

Figure 2 shows the various underground geographical features for recovery of conventional and unconventional gases. Conventional gas can occur by itself or in association with oil. These are shown on the left and right side of the Figure, respectively. Coalbed methane (CBM), which is extracted from coal beds, is also an unconventional gas and, in terms of depth, occurs much closer to the land surface than other similar gases. However, shale rock is sometimes found 3,000 metres below the surface. Therefore, after deep vertical drilling, there are techniques to

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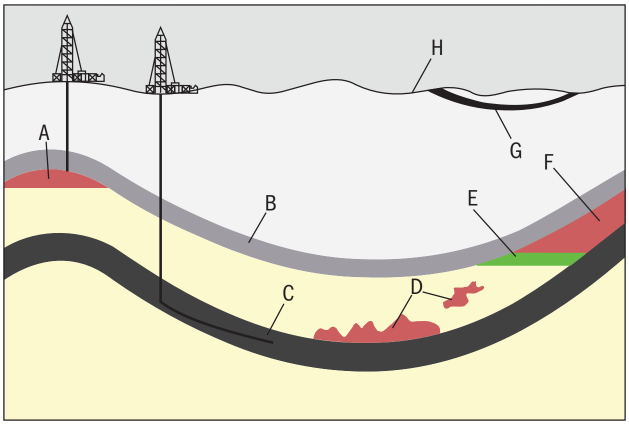

A- Conventional non-associated gas
B- Seal
C- Gas-rich shale
D- Tight sand gas
E- Oil
F- Conventional associated gas
G- Coalbed methane
H- Land surface
Source: US Energy Information Administration (2011): www.eia.gov

Figure 2 Shale Gas Extraction
Source: Eucers strategy paper: Strategic perspectives of unconventional gas, Vol. 1, 1 May 2011

drill horizontally for considerable distances in various directions to extract the gas-rich shale. A mixture of water, chemicals, and sand is then injected into the well at very high pressures (8,000 psi) to create a number of fissures in the rock to release the gas. The process of using water for breaking up the rock is known as "hydro-fracturing" or "fracking". The chemicals help in water and gas flow and tiny particles of sand enter the fissures to keep them open and allow the gas to flow to the surface. This injection has to be done several times over the life of the well. The number of wells to be drilled for shale gas far exceeds the number of wells required in the case of conventional gas and the land area required is a minimum of 80 to 160 acres.

Shale Gas in the US

There are 34 states in the US, which have vast deposits of rocks rich in shale gas. Production of the gas has added about 20% to domestic gas availability and over 20,000 wells have been drilled. From being an importer of LNG, the country is now self-sufficient and there are plans to export gas from the very terminals that were built for imports.

Estimates of fresh water usage for fracking in the US vary from 2.8 to 3.8 million gallons per well to an average of 4.5 million gallons in the Marcellus field and up to 13.0 million gallons in the Eagle Ford field. These figures need to be multiplied by the number of times fracking has to be done to a well and the number of wells at each location.

Around 80% of the mixture remains underground and the remaining 20% rises to the surface, where it is not always disposed of safely. Environmentalists claim that many different chemical products, some of which are toxic, are injected, along with several million gallons of fresh water, into each of the wells. They further claim that leakage of the toxic chemicals has contaminated aquifers, which are the sources of drinking water. There are also claims that methane can leak through the casing of the well and get released into the atmosphere. These claims are vehemently disputed by the oil and gas companies.

The Environmental Protection Agency (EPA) was charged by the US Congress in 2010 to investigate the potential impacts of fracking on drinking water and groundwater across the country. There has been a considerable delay in releasing its report, which is now due in 2014.

India's Participation in the Shale Gas Industry in the US

Reliance Industries Ltd (RIL) has made big investments (US$ 3.5 billion) in the Marcellus and Eagle Ford shales through joint ventures with Chevron, Carrizo, and Pioneer. Marcellus has been described as the largest discovered unconventional gas field in the US and one of the largest worldwide, with estimated net recoverable resources of 318 trillion cubic feet (tcf). In comparison, the resources in RIL's own D6 fields in the KG Basin were estimated to hold around 3.4 tcf in November 2012, dropping from 10.3 tcf in December 2006. According to RIL's Annual Report for 2012–13, the break-even cost of shale gas production in the US is as low as US$3.50–4.00 per Million British Thermal Units (MMBtu). RIL's revenues from the shale gas business more than doubled to US$ 545 million in 2012 compared to 2011. RIL views its investment as a profitable proposition and not necessarily at gaining technology and experience to explore for shale gas in India. Oil India Limited (OIL), Indian Oil Corporation (IOC), and GAIL India Limited have also made investments in shale gas production in the US.

The other interesting contribution to shale gas development in the US is the export of *guar gum* from India, which helps in improving the viscosity and flow of water in the fracking process. The gum is extracted from *guar ki phalli*, grown mainly by farmers in arid lands in Rajasthan and Haryana. Earlier, *guar gum* was used mainly as an additive in ice creams and sauces, but with the serendipitous discovery of its use in shale gas extraction, its production has risen enormously, earning almost US$5 billion during the period from April 2012 to January 2013.

Shale gas in Europe

Europe has not had the same success in exploiting shale gas as the US for several reasons. In the US, resources under the land belong to the land owner who is happy to allow drilling and get paid by the gas companies, whereas in Europe — as also in India — these resources belong to the government. Also, important tax benefits are given to companies in the US to drill and produce shale gas. In Europe, the geology of shale rock is different from that of the US and it is more likely to be found in places that are more densely populated. The NIMBY effect ("Not in My Back Yard") is much more prevalent in Europe than in the US. The possible contamination of water supply is a serious concern of European governments. France, Bulgaria, Luxembourg, the Czech Republic, and the Netherlands have either banned or put a moratorium on shale gas exploration. However, in the UK, a ban, imposed earlier due to suspected seismic activity, has been lifted. The Tyndale Centre for Climate Change has estimated that around 3,000 wells will need to be drilled in the UK to contribute 10% of annual consumption.

Proposed shale gas exploration policy in India

There is an obvious interest in exploring for shale gas domestically, given the enormous success in the US. The Ministry of Petroleum and Natural Gas (MoPNG) has identified six basins as potentially shale gas bearing. These are Cambay, Assam-Arakan, Gondwana, Krishna-Godavari, Kaveri, and the Indo-Gangetic plain. A map derived from different sources is shown in Figure 3.

In a study conducted by the United States Geological Survey (USGS), recoverable resources of 6.1 tcf have been estimated in 3 out of 26 sedimentary basins. The Government of India had also put out in 2012, a draft policy for the exploration and exploitation of shale gas, inviting suggestions from the general public, stakeholders, environmentalists, etc. Salient features of the policy draft are given in Box 2.

As we write this brief, this policy is being considered by a group of ministers. The draft policy has identified some of the water issues in the exploitation of shale gas and these are reproduced verbatim hereunder:

- Optimal exploitation of shale gas/oil requires Horizontal and Multilateral wells and Multistage Hydraulic fracturing treatments of stimulate oil and gas production from shale.
- This may require large volume of water ~3–4 million gallons per well (11,000 to 15,000 cubic metres of water required for drilling/hydro fracturing depending upon the well type and shale characteristics).
- The water after hydraulic fracturing is flowed back to the surface and may have high content of Total Dissolved Solids (TDS) and other contaminants (typically contains proppant (sand), chemical residue occur in many geologic formation, mainly in shale). Therefore, the treatment of this water before discharge to surface/subsurface water needs to be in line with the Central/State Ground Water Authority regulations.

Box 2: Salient Features of the Proposed Shale Gas Policy

- The identified blocks will be advertised for international competitive bidding. Participation of the state will not be mandatory.
- All areas, which are already allotted and where operations have entered the development/production phase shall be excluded from the area to be offered for shale gas exploration.
- If an offer for shale gas overlaps or falls within an existing oil and gas/CBM block, right of first refusal will be offered to the existing contractor to match the offer of the selected bidder.
- Fiscal regime proposed for exploration to be based on royalty and production linked payments, similar to the regime adopted for CBM operations. Ad valorem royalty at the prevailing rate for natural gas would be applicable and accrue to the state governments. Production-linked payment on ad valorem basis will be made to the central government on different production slabs, which will be biddable items. Cost recovery will not be admissible.
- The contract duration will be of 32 years and will be divided into two phases. Phase I will be for a period of 7 years and 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.

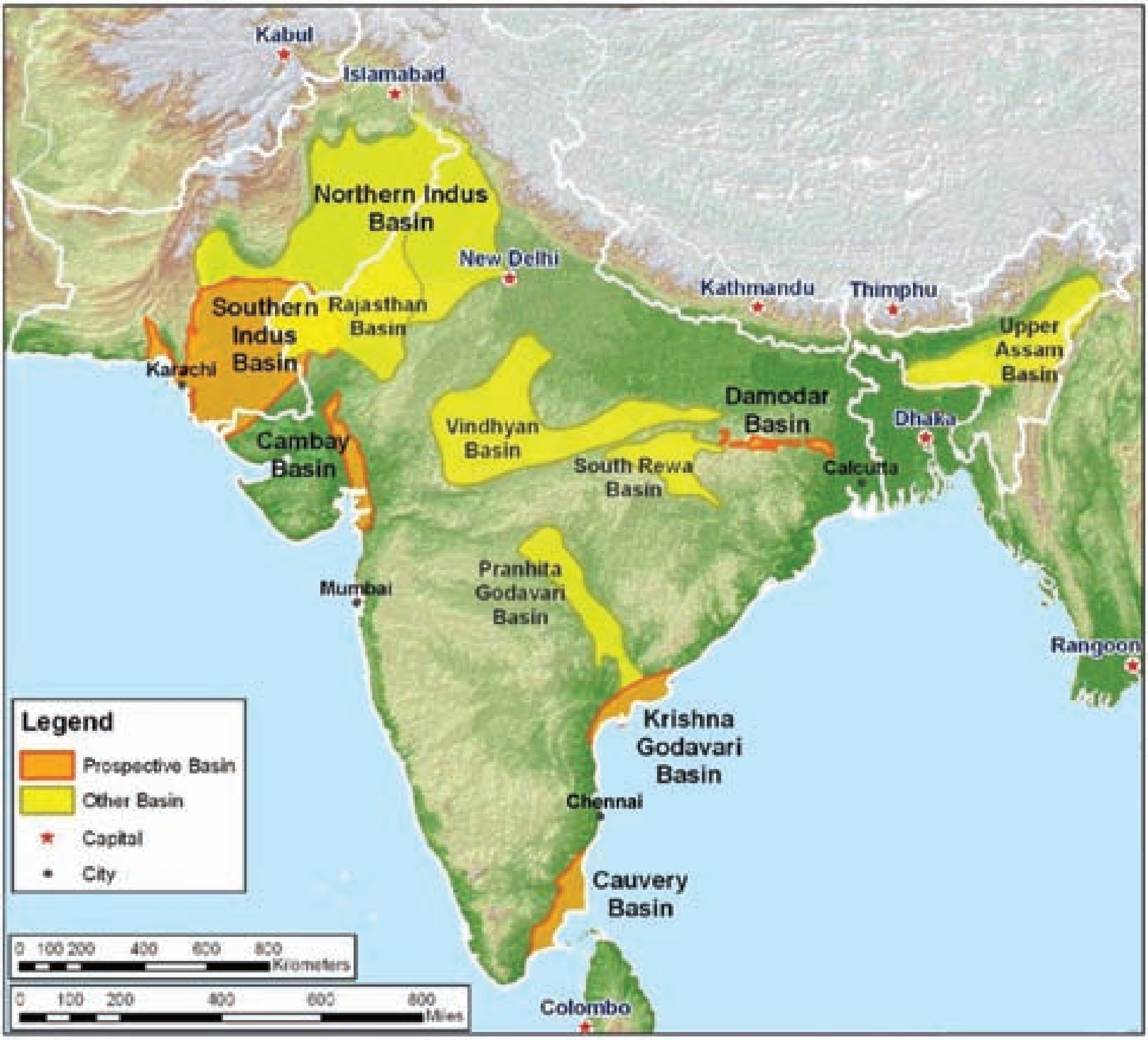

Figure 3 Shale gas sedimentary basins in the Indian sub-continent
Source: Adapted from http://suvratk.blogspot.in/2011/05/india-basin-wise-shale-gas-estimates.html (Mr Suvrat Kher, Sedimentary Geologist)

- Possibility of contamination of aquifer (both surface and subsurface) from hydro-fracturing and fracturing fluid disposal and the need for safeguarding the aquifer. Multiple casing programme (at least 2 casings) will be a mandatory requirement across all sub-surface freshwater aquifers.

The government's draft policy further suggests that there should be a mandatory rainwater harvesting provision in the exploration area, which trivializes 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 re-use/recycling of water should be the preferred method for water management. The environmental concerns in using water for fracking (see Figure 4) have been considerably downplayed and their significance underestimated. Further, enforcing legislation on environmental and water issues is a problem in India, and such legislation has been more in breach than in observance.

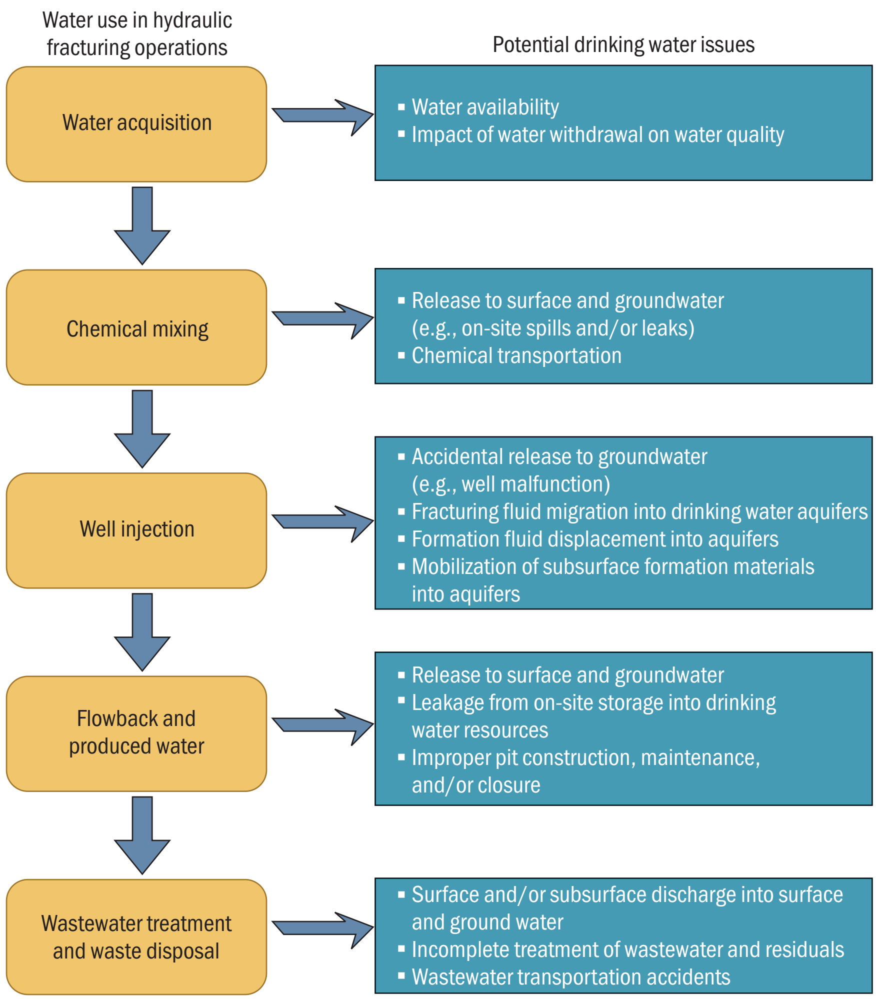

Figure 4 Water use in hydraulic fracturing operations
Source: US EPA (http://www.waterworld.com/articles/wwi/print/vol-ume-27/issue-2/regional-spotlight-europe/shale-gas-fracking.html)

Fresh water availability in India

Figure 5 shows that India suffers from physical and economic water scarcity whereas the US and Europe do not have the same water worries.

The website 'Indiawaterportal' points out that in the next 12–15 years, while the consumption of water will increase by over 50%, the supply will increase by only 5 to 10%, leading to a water scarcity situation.

This year, seven drought-affected states—Maharashtra, Andhra Pradesh, Himachal Pradesh, Sikkim, Gujarat, Kerala, and Uttarakhand — have been provided a relief package of ₹2,892 crore by the Centre under the National Disaster Relief Fund with retrospective effect from 1 March 2013.

TERI's own study in 2010, Looking Back to Change Track, demonstrates that India is already a water-stressed country and is fast approaching the scarcity benchmark of 1,000 m^3 per capita with unabated growth in the irrigation sector and even more rapid growth in industrial and domestic water demand. Another detailed study released in January 2013 by UNICEF and FAO, Water in India: Situation and Prospects, points in the same direction. A map of India showing various river basins and their projected status by 2030 in another study by the Water Resources Group in 2010 is provided in Figure 6. This group consists of the consultancy firm McKinsey, the World Bank, and a consortium of business partners.

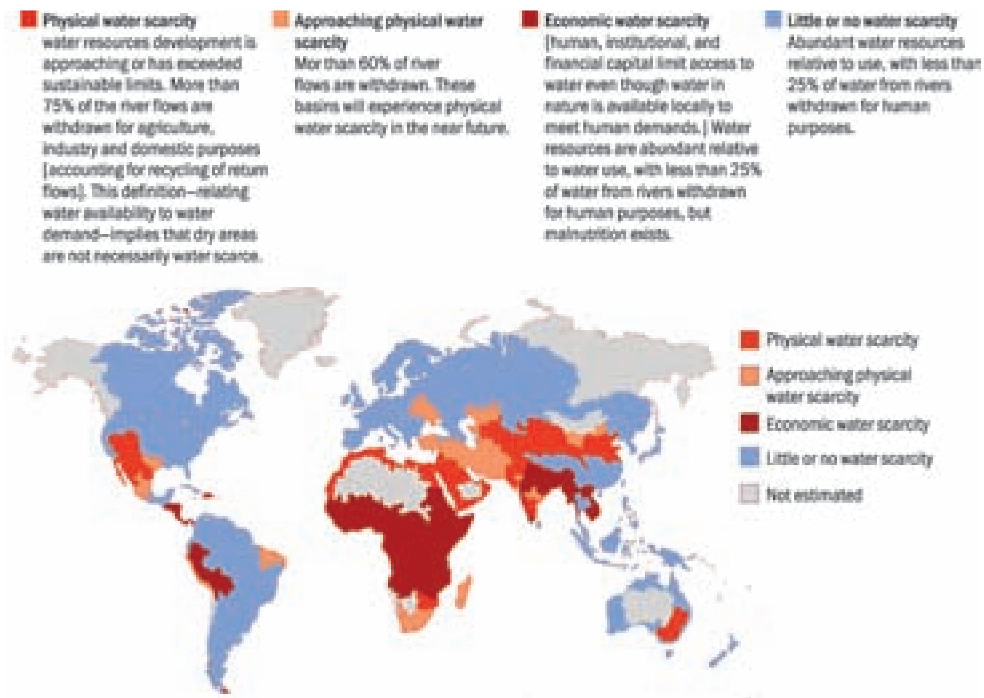

Figure 5 Areas of physical and economic water scarcity
Source: Comprehensive Assessment of Water Management in Agriculture, 2007

Figure 6 Water basin projections for 2030 – the unconstrained projection of water requirements under a static policy regime and at existing levels of productivity and efficiency
Note: WFR = western-flowing coastal rivers; EFR = eastern-flowing coastal river
Source: Council on Energy, Environment and Water, 2011

It is evident that potential shale gas bearing areas, such as Cambay, Gondwana, Krishna-Godavari, and the Indo-Gangetic plains are also areas that will experience severe water stress by 2030.

Land acquisition is not covered in the shale gas policy, but will be a serious issue because of the large area required for fracking and the consequent displacement of people.

When the government invites bids, they are expected to cover three major basins, i.e., Cambay, Krishna-Godavari, and Raniganj (Damodar basin). According to the Oil and Natural Gas Corporation (ONGC), there are about 34 tcf of shale gas in the Damodar basin alone (compared to India's total conventional gas reserves of 47 tcf) of which 8 tcf are recoverable. However, in an address to the Bengal Chamber of Commerce and Industry in May 2013, the Chairman and Managing Director (C&MD) of ONGC, while highlighting the potential of shale gas in the Damodar basin, also mentioned "land use for drilling operations may face severe resistance from the locals", and "availability of huge water resources for its shale gas operation is also apprehended to be a great challenge for us".

Conclusion

While the potential shale gas reserves overshadow those of conventional gas, we have a long way to go in identifying shale gas rich basins and acquiring the necessary technology and experience to extract shale gas. Meanwhile, the water situation will only get worse due to the reducing availability of fresh drinking water year by year, dropping groundwater levels, and the increasingly polluted rivers and other water bodies. Unless, there is some revolutionary technological breakthrough, which does not need the use of fresh water and chemicals, it is vital that we seriously ask ourselves this question: Should we further endanger a rapidly depleting resource on which all life depends? The answer should be a resounding "NO", and instead the focus must be on the following:

- **Removing the bottlenecks in CBM exploration and production while safeguarding the environment:** This gas is formed in association with coal at shallow depths. Its extraction does not entail horizontal drilling and requires a much smaller degree of fracturing compared to shale gas. However, a considerable amount of water associated with the gas needs to be removed to allow the gas to flow. This water can contain dissolved solids and pollutants, which will need to be treated or disposed of safely. Although 33 blocks have been awarded since 2001, mainly in east India, production is currently around just 3 bcm per annum. Delays have been due to obtaining environmental clearances, acquisition of land, and governmental approval on pricing.
- **Establishing a national research and development (R&D) Centre for gas hydrates, as requested by DGH Hydrocarbons:** These are methane and water molecules in seabed sediments that get frozen into ice due to low temperatures and high pressures. India's offshore reserves have been tentatively estimated at around 66,000 tcf or 1,500 times more than the known conventional gas reserves. Though the government formulated a National Gas Hydrate Programme in 1997 and under an Indo–US initiative a drilling ship explored four seabed areas in 2006, nothing much has happened since. So far no commercial production has started globally, though Japan has announced it may do so by 2016.
- Expanding our exploration of conventional gas through investor-friendly policies by reducing their risks and allowing market driven prices.
- **Acquiring gas equity abroad:** The success of BPCL and Videocon in Mozambique is a case in point.
- **Continuing to import LNG from the Middle East and expanding our sourcing to the US, Australia, etc.**
- **Giving a big push to renewable energy.**
- **Last, but not the least, taking urgent steps to protect, augment, and conserve our water resources for other critical uses.**

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The Shale Gas Revolution and its Implications for Europe and Germany

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The global energy landscape has seen remarkable changes over the last couple of years. With the increasing exploitation of shale gas reserves in the United States (US), a shift of supply patterns has occurred. While for many years the US was viewed as a potential importer of natural gas, today the US administration has begun to consider exports of Liquefied Natural Gas (LNG) to other markets in the world. This would be a massive change to the North American position on energy markets, turning from an importer to an exporter of natural gas.

In addition, experts from the International Energy Agency (IEA) now predict a 'golden age of gas'. Demand of gas is expected to rise due to increasing availability and the lesser environmental effects it has as compared to other fossil fuels. This situation would not only impact the status of the US on energy markets, but also have implications for other regions in the world.

So far, Europe has not been directly involved in this discussion. Shale gas production has not started yet and governments are still discussing the pros and cons of this development. This article serves as an update on implications of changing global energy patterns for Europe and looks at the state of the debate in Germany and other European Union (EU) member states.

Indirect Implications for the European Union

While shale gas production has not kicked off in Europe so far, indirect consequences of the US development can be seen in many respects. Because gas markets are still regionally organized, LNG will at best only slowly enter the European gas market. LNG exports from the US will most likely be directed to the Asian Pacific market, mainly because of the larger spread between the North American and Asian spot market prices. However, two other consequences can already be seen in energy policy debates in the EU today.

With cheap gas entering the US electricity market, coal has a hard time competing with this incumbent. Therefore, more coal is being exported, putting coal prices under pressure. Coal prices have seen a notable drop since 2011, making it more competitive in European markets, especially compared with oil price indexed natural gas. This goes hand in hand with cheap prices for CO_2 emissions certificates in the EU cap-and-trade-system and creates a generally favourable position for coal in European electricity markets. At the same time, this might have negative long-term effects for the transformation process towards a low-carbon economy in Europe. Paradoxically, at the moment, coal is the European winner of the shale gas revolution in the US.

A second implication of the changing energy supply pattern in the US touches upon the question of the competitiveness of energy-intensive industries in Europe. While energy prices show a significant downward trend in the US, the EU is struggling with increasing production costs. European companies see massive disadvantages compared to their US colleagues. As a consequence, European business is either announcing to re-invest in new production sites in North America or asking for political support. The European heads of states and governments — the European Council — has reacted by declaring increased competitiveness to be one of the main aspects surrounding the future architecture of EU energy policy.

Another Shale Gas Revolution in Europe?

Gas has been an important fuel in the European energy mix for many years. Despite some domestic production in the North Sea, the largest suppliers of gas to European markets have been Russia, Norway, and Algeria. With the development of hydraulic fracturing in the US, geologists started to explore whether European formations would also be promising for unconventional gas production. Recent studies, such as the latest EIA report from 2013, show that the conditions for shale gas extraction in Europe differ among member states. While Poland, France, Denmark, the Netherlands, or the United Kingdom seem to have recoverable reserves, no European state finds itself among the 10 potentially largest suppliers of shale gas in the world, according to the study.

Looking at the political landscape, there is a long tradition of national sovereignty in energy matters in Europe. While an integrated EU energy market is developing, member states still decide autonomously on their energy mix. The EU is only allowed to interfere for environmental reasons or on grounds of distractions to competition on the markets. This explains to a large extent, why the debate about shale gas extraction is so far mainly a national one. Despite this background, the European Commission, the EU's executive, has welcomed steps by member states to start exploration. However, it wants to start a legislative process on environmental standards for fracking in the coming months. Especially the impacts on water supply and potential methane leakages might be objects of EU regulation.

Governments of EU member states have reacted very differently on shale gas development in the US. While some countries, such as France and Bulgaria, have directly announced a moratorium on the technology, others see a business case behind it. Countries such as Poland and the United Kingdom are especially keen to start fracking. The former, in order to reduce their dependence on Russian imports and due to the need to clean up the coal-dominated energy mix — one of the challenges to the Polish energy sectors resulting from EU law. The latter, mainly because of depleting gas fields in the North Sea and a foreseeable supply shortage in the coming years. However, public protests against hydraulic fracturing and the uncertainty of investment conditions have hindered a fast start so far.

Even with political support for shale gas extraction, one should not overlook the large differences between the European and the US framework conditions. While in the US, small innovative companies pushed fracking forward, there are mainly large gas companies active on the European gas market. Additionally, property and land use laws differ. While farmers in the US have shown an overwhelmingly positive response to this additional source of income, European landowners are much more reserved on this issue. In summary, shale gas extraction will face more resistance and higher production costs in Europe, compared to the US.

Shale Gas and the German Energy Transition

In 2011, Germany started one of the world's most ambitious energy transition programmes. When the German government announced that it wanted to reduce its greenhouse gas emissions drastically, extend the share of renewable energies in its energy mix, and move out of nuclear energy. Many observers noted that gas could play an important role in this transition process. Therefore, the shale gas development in the US was recognized as one possible pathway which Germany could follow to achieve its goals, besides its renewable energy support policy.

However, two trends have proved this estimate wrong. First, there is no trend towards gas in the German electricity mix. It is rather coal taking over, joining the renewable energies in the transformation process. The reasons for this are, as already mentioned, mainly an oversupply of certificates in the cap-and-trade-market and the low-coal prices on world markets. Also, the German public reacted negatively on first announcements of test drillings, and within a relatively short time, opposition against the technology was formed. So far, no regulatory framework has been worked out by the government.

Shale Gas and the European Energy Security Debate

While the transformation of the energy sector towards a low-carbon economy has dominated the discussion in Europe over the last couple of years, competitiveness seems to be the new topic at the moment. While this could dominate policy discussions in the coming years, energy security receives little attention from policy-makers at the moment. One of the reasons for this might be the oversupply with gas due to the economic crisis. The overall gas consumption has dropped slightly since 2008. Another reason is the stable energy supply by the biggest single supplier, Russia, since the last major gas crisis in 2009. With energy security not being a top priority, it will be very hard to advocate shale gas development in the coming years.

Looking again at the global landscape, it is very likely, that Russia might be among the losers of the shale gas revolution. High Russian production costs could pose a problem to the gas industry of the country. This could be a reason to protect its dominant role on the most important export market: Europe. With a closer connection between Europe and Russia on energy issues and a drop in Russian pipeline-gas prices in the coming years, an extended use of shale gas remains unlikely in most EU member states.

Roundtable on the Global Gas Scenario and India

TERI organized a Roundtable on the Global Gas Scenario and India on Friday, 6 September 2013. The discussions were spearheaded by around 20 senior experts from the Government, TERI, Oil and Gas Companies, Business Councils, and the US Embassy in India.

The Round Table aimed to bring together policy makers, industry players and experts to discuss the issues affecting the development of energy sources to bridge the energy demand supply gap in the country. The panelists discussed the following issues:

Geopolitical Implications of the Changing Energy Market Landscape for Energy Supply Scenario

Production of shale gas has already impacted the gas market in USA and Canada. Production of shale is also expected to greatly impact the volume and direction of global energy trade flows. The USA, which was the largest consumer of energy and a large energy importer is now moving towards becoming self-sufficient and will also export some of its surplus gas. Energy exporting countries in the Middle East will also witness some changes and might have to reorient their strategies to align with the changing global scenario. Which are the emerging players in the global gas markets? Can the success of US markets be emulated in other regions that hold reserves of shale gas? What are the likely trends and what will be the larger geopolitical implications of the rise in production of gas?

Evolving International Gas Markets and Their Implications on Large Consuming Countries

Consumers of gas are dispersed across the globe. Consumers in Europe purchase gas through a combination of gas from pipelines as well as LNG imports whereas Asian countries largely rely on LNG imports from the Middle East. What will be the likely scenario of gas trade for consuming countries? Will consuming countries also reorient the uses to which gas is put given the availability and the forms in which gas is available?

Convergence in Global Gas Prices

Historically, three gas markets have existed — the North American market, the European Gas market and the Asian (and now Asia/Oceania) markets. While prices in the first two do move in step with spot gas markets, Asian gas prices are largely linked to oil prices and are much higher than the prices in the other two markets. While some change may already be visible in gas prices across the continents, will these varying prices eventually converge? Will there be a sustained delinking of oil and gas prices and what will it take for Asia to develop a regional gas market?

Impact on Other Energy Sources Due to Rising Availability of Gas

Natural gas can act as a substitute for coal in power generation and industrial use as well as for petroleum products for use in transportation. Rise in availability of gas will, therefore, have an implication on other energy sources. This is already visible in the reduction in coal prices, re-emergence of coal in Europe and the competition that renewable energy sources are facing from shale gas production. What will the scenario be in the long term? Will gas compete with coal in large consuming countries? Is gas proving to be a serious threat to the developing renewable energy markets?

Lessons for India in the Evolving Markets

The lessons for India and its strategy need to be examined on two fronts. First, on developing an import strategy and securing gas for meeting the rising demand-supply gap. Collaborating with emerging suppliers of gas and establishing adequate import infrastructure will be critical. Second, investing in research and development to facilitate the exploitation of resources domestically will also be needed. In this context, facilitating research on methods that are environmentally benign and are appropriately suited for the Indian situations will go a long way in increasing the country's gas production. Will India be able to adequately leverage the changing global scenario to meet its requirements? What are the policy and regulatory changes needed to facilitate this?

The deliberations of the Roundtable will be taken forward at the next edition of the US–India Energy Partnership Summit, held annually in Washington, DC. The outcome document proposed will identify and comment on the key challenges affecting the global and domestic energy markets in the context of emergence of shale gas as an alternative.

Centre for Research on Energy Security

Centre for Research on Energy Security (CeRES) was set up on 31 May 2005. The objective of the Centre is to conduct research and provide analysis, information, and direction on issues related to energy security in India. It aims to track global energy demand, supply, prices, and technological research/breakthroughs—both in the present and for the future—and analyse their implications for global as well as India's energy security, and in relation to the energy needs of the poor. Its mission is also to engage in international, regional, and national dialogues on energy security issues, form strategic partnerships with various countries, and take initiatives that would be in India's and the region's long-term energy interest. *Energy Security Insights* is a quarterly bulletin of CeRES that seeks to establish a multistakeholder dialogue on these issues.

Previous issues of this newsletter are available at <http://www.teriin.org/div_inside.php?id=41&m=3>.

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Printed and published by Dr R K Pachauri on behalf of The Energy and Resources Institute, Darbari Seth Block, IHC Complex, Lodhi Road, New Delhi – 110 003 and printed by him at Innovative Designers and Printers and published at New Delhi.