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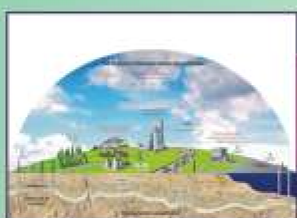

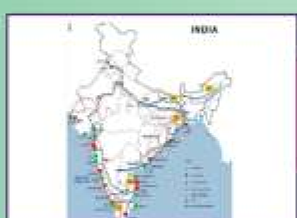

ENERGY DIGEST
Economy•Energy•Environment
Vol. 7, No. 2, July 2015

From the Editor's Desk

We are in the middle of 2015 and it has been projected by the World Bank that global economic growth is expected to be 2.8 percent in 2015 as compared to 2.6 percent in 2014. However, the global economic growth during the first half of 2015 has been dismal, mainly on account of slow growth in developing countries. It is expected that in 2015, high income countries may see the increase of 0.2 percent and developing countries may witness the decrease of 0.2 percent in their economic growth in comparison to 2014.

Among high income countries, Eurozone PMI hit a four-year high in June, 2015 mainly due to improvements in both manufacturing and services sectors. However, the recent default by Greece in repayment of loan to International Monetry Fund (IMF) has raised eyebrows on the future of Greece continuing its membership of the monetary union.

On the other side, decrease in economic growth of developing countries is mainly due to slowing growth in China, recession in Russia, deteriorating prospects in Brazil and across major oil exporters (Nigeria, Angola, Venezuela, Colombia, Mexico, Kazakhstan). In addition to this, appreciation in the US dollar, due to anticipated tightening of monetary conditions in the US along with monetary expansion in ECB has restricted capital inflows in many developing countries. On the other side, in oil-exporting countries, lower crude oil prices are adversely affecting the economic activities by increasing fiscal deficit, exchange rate, or inflationary pressures.

However, on the brigher side, India being an exception to the group of developing contries is showing growth in economic activities. India's Gross Domestic Product (GDP) growth accelerated by 7.3% in FY15 compared to 6.9% in FY14 and Current Account Deficit (CAD) declined to USD 27.5 billion (1.3% of GDP) in FY15 from USD 32.4 billion (1.7% of GDP) in FY14, helped by a lower trade deficit due to decrease in crude oil prices.

On the energy front, as per BP Statistical Review, 2015, global primary energy consumption increased by a mere 0.9% in 2014, a marked deceleration as compared to 2% growth recorded in 2013 and well below the 10-year average of 2.1%. On crude oil side, a dramatic shift has been seen, with the US becoming the world's largest oil producer by recording the growth of 1.6 million b/d in crude oil production.

This issue of Energy Digest covers topics of "Outlook for Natural Gas Industry in India & Dependence on Policy Initiative"; "Gas Hydrates" and "Carbon Capture & Storage (CCS)".

Article titled "Outlook for Natural Gas Industry in India & Dependence on Policy Initiatives" discusses the present and future demand/supply scenario for natural gas in India along with the criticality of various policies initiatives in various sectors on demand/supply of natural gas. Another article named "Gas Hydrates" presents the various attributes of gas hydares such its chemical strucutue, conditions required for its formation and its geological prsesnce. It also covers the importance of gas hydrates in meeting global and domestice energy requirements. The third article titled "Carbon Capture & Storage (CCS)" discusses the need of CCS in mitigating anthropogenic CO_2 emissions along with various technologies available, policy requirements and the efforts being taken by India for its implementation. In addition to this, a brief on "Project Sagarmala", an integrated infra cum policy initiative to develop India's maritime sector that will contribute to the inclusive growth of the Indian economy has also been included.

We hope this issue would enrich your knowledge further by providing valuable insights. We look forward to your valued comments, suggestions and feedback.

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Outlook for Natural Gas Industry in India & Dependence on Policy Initiatives

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India's expanding economy and growing population have lead to increase in consumption of primary energy resources. While factors such as demographic profile, change in lifestyle, and consumer preferences dictate the quantum of useful energy demands, the availability and prices of resources and technologies influence the demand and patterns of final energy requirements in the future. Energy sector growth and fuel choices are dependent on policy initiatives taken by the Government taking into consideration the overall developmental goals of the country.

Introduction

India's expanding economy and growing population have led to increased consumption of primary energy resources such as coal, oil and natural gas in the country. According to BP PLC's Statistical Review of World Energy, the primary energy consumption of India was 637.8 million tonnes of oil equivalent in 2014 notching a CAGR of about 7% over the last decade. In this coal constitutes an important part of India's energy needs. The last thirty years have seen a shift in the global energy fuel mix towards an increased role for natural gas. Attractive for its cleaner and more efficient combustion relative to other fossil fuels, natural gas has assumed a significant role in power generation, industrial applications, residential cooking and in some cases as a transport fuel as well. According to Hydrocarbon Vision 2025 of MoP&NG, in the most optimistic scenario, India's overall gas demand is expected to grow from 20 bcm/y in 1999 to 143 bcm/y in 2025 while the share of gas in the economy will increase to 20% provided adequate supply is available.

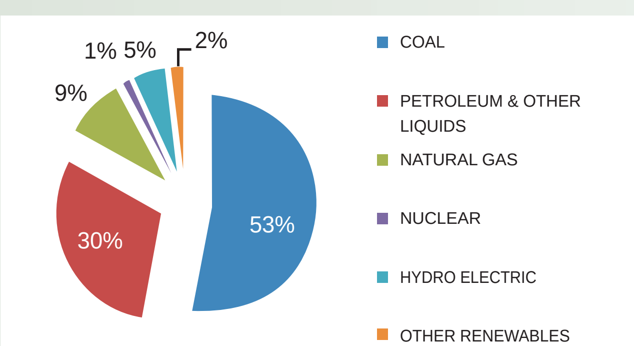

Figure 1: Primary Energy Mix of India; Source BP Stat

Presently, the share of natural gas in India's primary energy mix is 9% (Figure 1). This is fairly low compared to the global average of 24% primarily due to supply side constraints. Further in terms of individual consumption, India's annual gas consumption of 44 cubic metres per capita is far behind the global per capita average of 470 cubic metre. As per MoP&NG, the demand which was 138 mmscmd in 2014-15 is expected to reach 230 mmscmd by 2017-18. The demand is expected to reach 517 mmscmd by 2021-22 as per Platts registering a CAGR of 5.26% against the world average of 2.55%. However actual consumption of natural gas registered a drop of 9.25% during 2014-15 compared to previous year. Excepting for City Gas Distribution, this fall is prevalent in all the other sectors where natural gas is being used. Fall in domestic gas production, drop in crude prices and highly priced long term LNG contracts being the chief contributors for the decline in consumption.

Natural gas available in India can be broadly classified into two categories, viz. (i) Domestic Natural Gas and (ii) Imported Re-gassified Liquefied Natural Gas (R-LNG). A supply deficit is prevalent in the Indian market for Natural gas due to low domestic production and inadequate transmission and distribution infrastructure. Therefore, the Government allocates domestically produced gas at subsidized rates to different states and individual users on recommendations of the Gas-Linkages Committee (GLC) which is an inter-Ministerial Committee with representatives from the Ministers of Finance, Power, Chemicals & Fertilizers and Steel. Priority in gas allocation is given to the power, fertilizer and transport sectors. After coming to power, the new Central Government has shown its intent towards modifying the allocation of domestically produced gas. There has been a recommendation by the Committee of Secretaries to modify the allocation of domestically produced natural gas as per the following order of priority – CGD, Atomic and Space research, Urea Plants, Power Plant, Petrochem and LPG Plants. This document has been sent to the Cabinet Committee on Economic Affairs which is yet to take a decision. As such the allocation of domestic gas continues to be as per the earlier GLC. Since domestic production of natural gas is stagnant, allocation for various sectors has been frozen at 2013-14 levels for all sectors except CGD and LPG plants. Further as per Gujarat High Court order 100% of CGD requirement needs to be fulfilled by domestic gas. In this regard Mo&PNG has decided to proportionately cut the allocation for non-priority sectors in order to fulfill the additional demand for CGD. Public gas is provided at subsidized rates through the so-called Administered Pricing Mechanism (APM) while private and JV gas is sold at market prices. In case of imported gas, the marketers are free to import LNG and sell the RLNG to customers. Due to fall in domestic production of gas the country is increasingly dependent on imported liquefied natural gas (LNG). The country's LNG imports have increased from approx 8 million MT in 2008-09 to 13 million MT in 2013-14. This accounted for 28% of the total supply. India incidentally is the fourth largest importer of LNG in the world. Over the next few years the shortfall in natural gas production in the country is expected to continue with its supply trailing demand.

In order to ensure transport of domestic as well as imported LNG to areas of demand, aggressive laying of pipelines has been undertaken. As of March 2015, a total of 15340 km of pipelines with a capacity of 351 mmscmd have been laid across the country for the transport of LNG/natural gas. It is pertinent to mention here that the capacity utilization of these pipelines is less than 30% currently except for the Hazira-Vijaipur-Jagdhishpur (HVJ) pipeline for which it was 81%. The total supply of natural gas through pipelines is expected to reach 359 mmscmd in 2016-17, a CAGR of 15% from 2013-14 in India. Most of this incremental supply is expected to be met by LNG imports since the growth in domestic supply is likely to fail to keep pace with the anticipated rise in demand. The country's potential to import LNG is expected to increase to 150 mmscmd in 2016-17 contributing around 42% of the total supply.

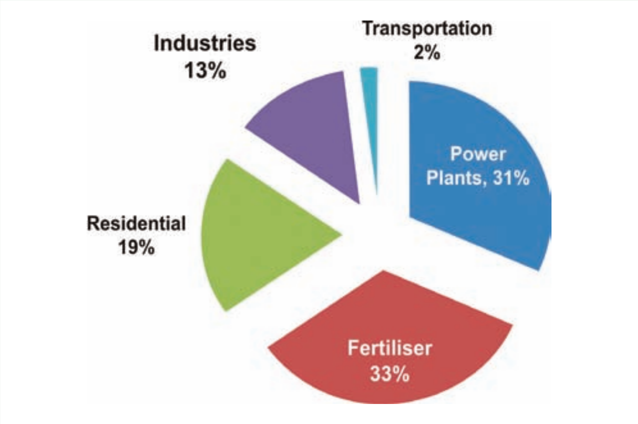

Figure 2: Natural Gas Consumption in India

The sectoral consumption of natural gas is given in Figure 2. It can be seen that the demand for natural gas is primarily from power and fertilizer sectors which cumulatively accounted for more than 64% of gas consumption in 2013-14. The demand is also driven by its growing usage in the city gas distribution sector and industrial sectors such as refining and petrochemicals. Rising concerns on carbon emissions have also contributed to the demand for natural gas in the country.

This article focuses in particular on the evolution of natural gas demand in India over the next 20 years. It considers the major gas-consuming industries in India – power generation, fertilizer production, and industrial users as they together constitute 77% of the natural gas consumption, and tries to find out how fuel choices in these sectors are linked to a range of market and policy considerations. Although environmental considerations are beginning to play a role in the choice of fuel, India's reluctance to accept punitive emission norms at the cost of its developmental goals would mean laissez-faire for the short and medium term with regards to its energy mix.

Power Generation

India's total installed capacity for electricity generation as on December, 2014 is 2,55,6681 MW. Out of this, 62% of power plants are thermal power plants, 19% are hydro electric power plants, 11.84% run on renewable sources, 8.6% on natural gas and 2% on oil.

Geographically the demand for electricity is predominant in the Western and Southern parts of India excluding the New Delhi area. However most of the coal based thermal power plants are situated in the eastern and central parts of India whereas the gas based power plants are situated on the western and southern parts of India. This is due to the proximity of fuel sources for the respective power plants.

Therefore, transmission of power generated would also be a parameter to consider in availability of electricity. In order to understand scope of natural gas in power generation, it is required to see reform related to coal and electricity distribution and tariff.

Coal Sector Reforms: Within the power sector, natural gas competes largely with coal, and the liberalization of the Indian coal sector, which is underway, could squelch the rise of natural gas. Such reforms are likely to make coal a bit more expensive in India, but they will also liberalize large new coal supplies (both within the country and imports). Head-to-head, a competitive coal sector will out-compete gas for most electric power applications because coal is much cheaper as a fuel. Failure to reform, on the other hand, could reduce available coal supplies and expand the window of opportunity for natural gas. Stringent pollution control norms would also give a fillip to natural gas usage over coal.

The Indian coal sector has historically been run entirely through Coal India Limited (CIL), the national government-owned coal company of India. However due to lack of infrastructure as well as competitive prices for coal generated, production of coal by CIL has not kept up with the demand. This is reflected by the fact that during 2009-15 while the coal based power capacity has grown by 73%, the coal production has increased by only 8%.

Catalyzed by these woes, the Indian coal sector has begun a series of overhaul that could revitalize the sector. The central government has taken steps to increase competition by opening some mines to private and foreign companies. Instead of the allocation system that was adopted initially, now coal mines are being sold through e-auction. The government in the process has earned more that Rs.2.0 lac crores through these e-auctions. All these would ensure expansion of domestic coal production capability leading to drop in dependence of imports. The impact of coal sector reforms on availability as well as cost benefits likely to accrue are depicted in Figure 3.

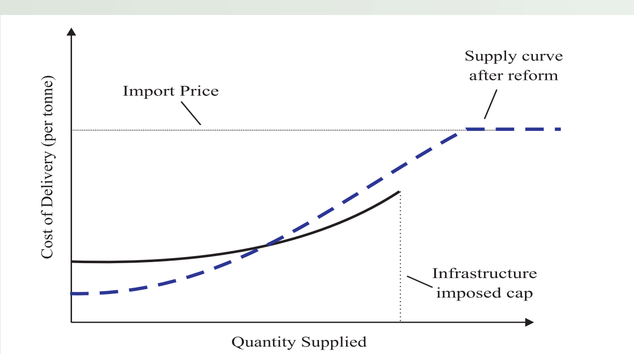

Figure 3: Impact of Coal Sector Reform; Source: Mike.P. Jackson, IIM(A), IRADe

A conceptual supply curve as shown in Figure 3 portrays how reforms to the coal sector are likely to impact the pricing and availability of coal in India. At present, before significant reforms are implemented, the solid-line supply curve illustrates that coal prices are low but the volume that can be delivered is constrained by inadequate investment in infrastructure. As Figure indicates, coal reforms (dotted line) are likely to reduce the cost of some supplies (mainly from pit-head generation applications) while, at the same time, increasing the volume of coal that can be delivered at higher prices that eventually equilibrate with international levels due to a larger role for imported coal. In effect, there would be a marginal increase in price of coal but so will volumes available. As per a study carried out by Asian Development Bank, when domestic coal prices reach import parity then gas fired generation becomes affordable at natural gas delivered rate of $4.0 per mmbtu.

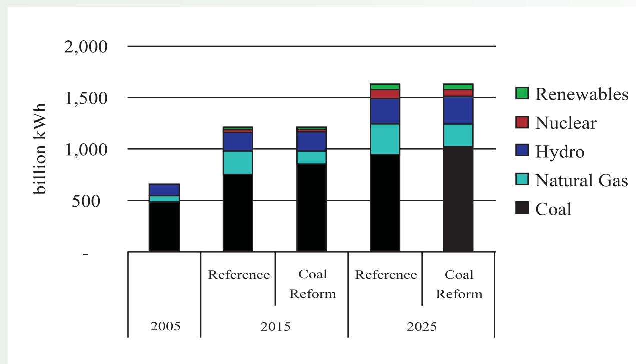

Figure 4: Electricity Generation Mix, 2005-2025; Source: Mike.P. Jackson, IIM(A), IRADe

The scenario wherein such reforms kick in the coal sector and its likely impact on natural gas demand is depicted in Figure 4. It can be seen that by 2025 there is a shift towards coal for power generation due to increased availability although there is also an increase in prices. Coal is expected to be cheaper compared to natural gas even under these scenarios.

Figure 5 indicates the fixed and variable costs for various fuel sources for power generation. It can be seen from the above that if coal sector reforms are not aggressively pursued and we need to import coal to meet the indigenous power requirement then natural gas becomes an option if the delivered rate is $6 per mmbtu.

It can be seen that coal as a source fuel for power generation simply out competes natural gas as it is available in abundance and economical (both domestic as well as

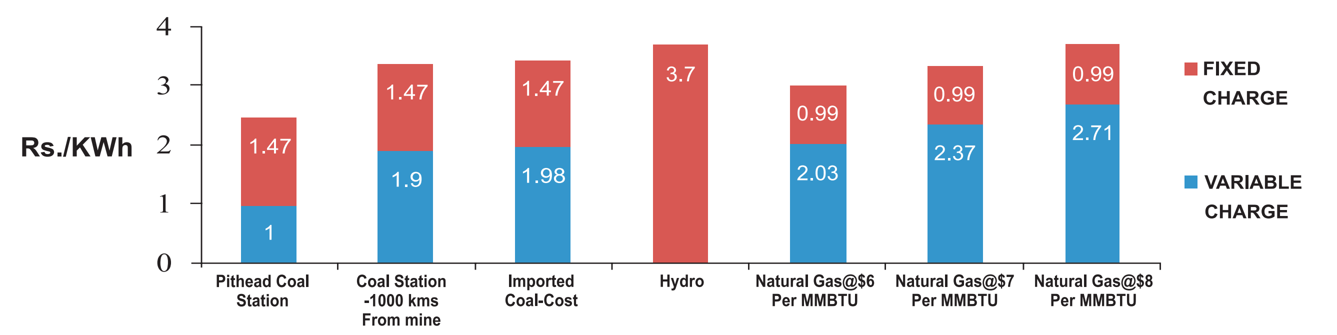

Figure 5: Comparison of Charges for Various Fuels; Source: Crisil

imports). The only constraint on coal could be imposition of stringent emission norms which is not likely to be accepted by developing economies like India and China.

The coal reserves of India have been estimated to be around 51 Billion Tonnes. As per a research report of World Institute of Sustainable Energy, domestic coal production is likely to peak around 2031/32 and 2036/2037 at 1110 mtpa. Therefore it would be prudent to reduce dependence on coal based power projects after 2022 by resorting to suitable alternatives.

Electricity Distribution and Tariff Reforms: The Indian power sector is set up as a single-buyer model; the State Electricity Boards (SEB) and Electricity Departments are the sole buyers of power produced by the power utilities. With the power sector reforms in the mid-1990s an increasing number of the states having re-organized their SEBs. Typically this includes the vertical unbundling of the single entity i.e SEB into separate companies for generation, transmission and distribution; however, a few states also opted to partially or entirely privatize generation and distribution while keeping transmission as a state monopoly. The reforms therefore did not fundamentally change the market model which remains principally a single-buyer one represented by the Distribution Corporation but also consists of several monopolies like Generation Corporation and Transmission Corporation all being State Controlled entities.

The electricity transmission and distribution sector is mired with exorbitant transmission losses, and an average tariff system that is kept below the cost of supply. 24% of entire electricity supplied flows to the agricultural sector, but yields less than 6% of the total revenues.

While all three segments of the sector—generation, transmission, and distribution—are important, revenues originate with the customer at distribution end and poor performance there hurts the entire value chain. Persistent operational and financial shortcomings in distribution have repeatedly led to central bailouts for the whole sector. It may be brought out that even though power is a "concurrent" subject under the Indian Constitution, distribution is almost entirely under state control. The Government, committed to addressing these problems, introduced The Electricity Act 2003 thereby introducing a fundamental sector reform with the aim of making the sector commercial and competitive. The Act seeks to effectively insulate the tariff setting process from political considerations and limits the roles of the Central and State Governments to providing overall policy guidance. Accordingly, regulatory responsibility for the sector is vested in the Central Electricity Regulatory Commission (CERC) and the State Electricity Regulatory Commissions (SERC) whose establishment has been made mandatory. It has been made mandatory for States to unbundle their respective Electricity Boards as envisaged by the Act to make them eligible for Central loans and grants. Accordingly most of the States have established SERCs and tariff orders have been issued in 18 states. The Act also allows for introduction of a multi-year tariff framework.

After a landmark judgement in 2011 by the Appellate Tribunal For Electricity wherein SERC's were empowered to suo moto take up tariff revision without the need for discom's to file revision petitions, there has been a lot of movement on tariff restructuring. During 2012 and 2013, seven states revised tariff by 7% to 37% It is interesting to note that 23 more states have filed tariff revision petitions during 2014 and have announced new rates for sale of power.

Inspite of the above reforms, the financial health of the sector is very fragile, limiting its ability to invest in delivering better services. Total accumulated losses in the sector stood at Rs. 1.14 trillion ($25 billion) in 2011. These losses are overwhelmingly concentrated among distribution companies, or discoms, which supply power to millions of consumers. Sector's losses have led to heavy borrowing

– power sector debt reached Rs. 3.5 trillion ($77 billion) in 2011, as much as 5% of the GDP. Over 60% of the accumulated losses in 2011 came from the states of Uttar Pradesh, Madhya Pradesh, Tamil Nadu, and Jharkhand, with UP alone accounting for 40%.

Although electricity tariffs are being rationalized and is bound to increase in the long term, yet cost of source fuel for generation would ultimately decide the choice of fuel. However the ongoing rationalization of the Indian electricity grid could provide an opportunity for natural gas to play a larger role in power generators that provide electricity during the few hours of the day of maximum demand – so called “peaking” power generators.

Fertiliser Sector

Within the domestic fertiliser industry, which uses natural gas as a primary (and highly subsidized) feedstock, India’s fertiliser import policy is probably the single most important factor affecting future gas demand. While India currently maintains a domestic self-sufficiency goal for nitrogenous fertiliser production, this policy is very costly, as it precludes much cheaper fertiliser imports from countries where natural gas can be sourced cheaply and fertiliser sold to India on long term contracts. Despite being a relatively high cost producer of fertiliser, India produces essentially all of the nitrogenous fertiliser it uses – imports are limited to only meeting unforeseen supply shortfalls.

Since the 1970s, India has maintained a cost-plus pricing regime for domestic fertiliser producers, guaranteeing them an attractive rate-of-return over their production costs. Through the 1980s and early 1990s, Indian policymakers encouraged construction of fertiliser plants along the HVJ pipeline that connects gas fields in the west with the major consuming centers in the interior to Delhi, and provided these plants with inexpensive natural gas. As a result, India has been able to achieve 100% self-sufficiency in nitrogenous fertiliser production. Farm-gate prices for nitrogenous fertilisers have always been maintained well below the cost of production, with the difference between production costs and farm-gate prices paid by the central government as a subsidy.

The annual demand for urea in the country was 30 million tonnes during 2013-14 whereas the production in the country was 22 million tonnes. During 2013-14, fertiliser plants consumed about 42.25 mmscmd of gas for manufacture of subsidised urea. Out of this, 26.50 mmscmd came from domestic fields and the balance 15.75 mmscmd was imported liquefied natural gas.

The introduction of nutrient-based subsidy (NBS) in complex fertilisers has helped the government contain its bill on phosphate and potash fertilisers. The subsidy for urea however continues to be vulnerable to increasing share of expensive regassified liquefied natural gas (R-LNG) in total gas consumption for indigenous urea manufacture and farm gate prices of urea not being cost reflective.

Since January 2014, MoP&NG has made the price of natural gas market-driven and linked it to international benchmarks. This could result in a significant increase in domestic gas prices going forward (already the prices have been increased from $4.2 mmBtu to $5.18 mmBtu) and lead to increase in the subsidy burden for the Government. It may be brought out that nearly 70% of the gas requirement of indigenous urea manufacturers is estimated to have been met from domestic gas. The increase in the price of domestic gas will raise the subsidy burden on the indigenous urea manufacturers using the feedstock. For every $1/mmBtu increase in the price of gas, the government’s additional subsidy outgo is estimated at Rs. 3,000 crore. On the other side, producers in nearby Persian Gulf can make fertilisers at less than half the real Indian cost because cheap natural gas is abundant in the Gulf. A future shift to a greater role for imports would dramatically reduce domestic gas consumption and lessen the subsidy burden on the central government. As per a study done by IIM, Ahmedabad and IRADe it is estimated that without reform, subsidy to the fertilizer sector could rise to as much as $8 billion by 2025. Figure 6 shows the production cost of fertilisers with various fuels. It can be seen that it is economical to import fertilisers into the country.

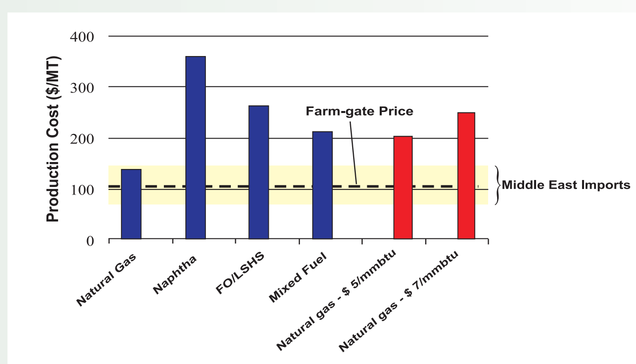

Figure 6: Fertiliser Production Cost by Feedstock; Source: Natural Gas Pricing in India, Ernst & Young

The gas demand from the Indian fertilizer sector will be driven by two main factors. The first is the extent to which imports of fertilizer is allowed and second is the demand of fertilizer in agriculture sector. It is estimated that the government would save Rs. 50 billion (approximately $1.3 billion) per year by pursuing a more liberal import strategy associated with moving from 95% to 70% self sufficiency. However if the current mode of 100% self-sufficiency in fertiliser production continues, then the Indian fertilizer sector could consume very large quantities of gas into the future. Gas demand from the fertilizer sector would likely to decline as farm-gate fertilizer prices increase or cheap imports gain market share.

Industrial Users

For industrial users, natural gas competes with liquid (oil-based) and solid (coal-based) fuels, distribution of industrial gas demand is given Figure 7. In general, where gas competes with oil, firms find it cost-effective to switch if they can obtain regular gas supplies. These consumers have historically had difficulty securing gas supplies, which were allocated through a political process that gave priority to electricity generators and fertilizer producers. New supplies coming online through domestic production and imports afford much greater access to gas for industrial consumers who will readily consume them even though this new gas is 2-3 times more costly than traditional price-regulated supplies. As a result, industrial demand will largely be limited only by the magnitude and structure of Indian economic growth as well as infrastructural deficiencies. For gas suppliers, this is the most lucrative market and is a major growth opportunity.

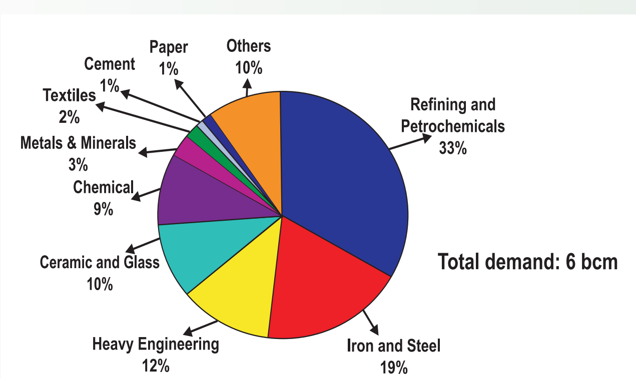

Figure 7: Distribution of Industrial Gas Demand; Source: www.indiaenergyportal.org

Technically natural gas is capable of meeting the entire demand of industrial users. However, the only constraint is the price of natural gas compared to other liquid fuels. The demand curve for industrial gas shown in Figure 8 suggests two important findings. First, significant additional natural gas could be consumed by the industrial sector if gas prices were low enough wherein gas could compete directly with coal. That scenario would require gas prices much lower than those seen in India today, which is implausible. However, if tight environmental controls were applied to coal-based industrial boilers then gas might find itself in a much more competitive position relative to coal in the industrial sector.

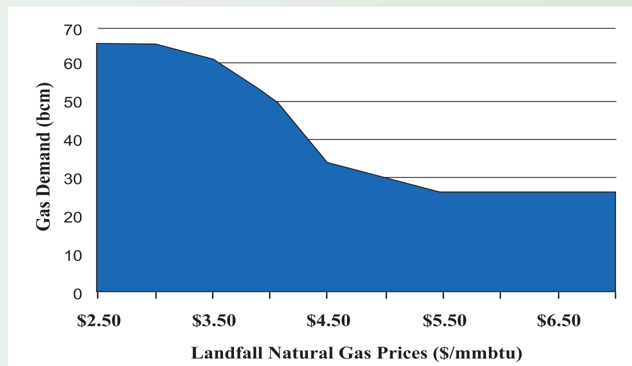

Figure 8: Industrial Natural Gas Demand Curve, 2025; Source: Ernst & Young Llp

Second, demand for natural gas is highly inelastic at prices above about $5.00/mmbtu. This is largely because in this price range, most switching is to oil from natural gas; even at very high natural gas prices, gas is more economical than oil. This supports the finding that most of the growth in gas consumption comes from refining and petrochemicals, where coal use is low. Conversely, steel and iron producers' share of the industrial gas demand declines, because most of their consumption continues to be met by cheap coal. This would suggest that Indian industry should not be constrained on price in accessing LNG from overseas because they are able to pay prices seen around the world today. Furthermore, it explains why Indian LNG importers have been able to import and sell gas at very expensive prices on the spot market.

City Gas Distribution (CGD)

CGD comprises of CNG for vehicular use and PNG for residential purposes as well as for industrial and commercial users having a demand of less than 50 cubic metres per day. It may be brought out that for a CGD operator to become viable he needs to increase the share of industrial/commercial users in his portfolio. In fact for most CGD companies these consumers constitute one fifth of their total volume. The balance primarily constitutes residential users.

Natural gas supplied through CGD networks competes with alternate fuels such as liquefied petroleum gas (LPG), diesel (HSD), petrol (MS), furnace oil (FO) and low sulphur heavy stock (LSHS). The price of these alternate fuels is a function of crude oil prices. Therefore, the price of natural gas supplied to these segments has to be economical vis-à-vis the price of petroleum products.

The CGD pipeline network has continued to grow, spanning 40,535 km in 2014-15. It already covers 90 cities across 52 Geographical Areas (GAs). The number of CNG stations also increased from 783 as of March 2013 to 913 as of March 2014. Gas consumption for the CGD segment was about 4187 mmscm during 2014-15 registering a growth of 12% over previous year. This demand is expected to witness robust growth in the next few years as well, given that gas is the most eco-friendly and cost-efficient fuel as compared to other alternative fuels in the CGD segment. Gas is also expected to be the most affordable amongst its substitutes even after the increase in price of domestically produced gas, given that subsidies on LPG and diesel have been reduced considerably making them costlier.

PNGRB has enacted various regulations to encourage investments through prospects of promising returns as well as promotion of competition to improve service delivery. Licenses are issued with an exclusive marketing right for five years for a new company and three years for an entity that has been operating a CGD network for at least three years prior to the creation of PNGRB. Pipeline infrastructure exclusivity is offered for 25 years, which means that no other entity will be authorized to lay a CGD network in that geographical area during this period. Further the Government has informed that the entire demand for CGD would henceforth be met from domestic production treating them on par with Power and Fertiliser sectors. However, declining domestic production is not expected to offer any succour in the near term.

Despite supply and infrastructural constraints, CGD entities have managed to take on these challenges and register a steady growth in the business. The sector seems to have managed to carry the burden of high cost imported natural gas, as the CGD gas basket consisted of around 52% imported natural gas and the remaining share consisted of domestic gas through tapered supply as per EGoM allocation. Further, based on plans of PNGRB to roll-out around 300 cities and towns across various states for CGD network development, the total natural gas demand from CNG and CGD sector, according to the report “Vision 2030” by industry group to PNGRB, is expected to reach 85.6 mmscmd in 2029-30 at a CAGR of 11% from 2013.

The biggest challenge for the segment however is the shortage of domestic gas and infrastructural inadequacies to reach end users. Declining gas production in the country has led CGD operators to increasingly rely on costly imports of LNG. However, operators have observed consumers' willingness especially industrial users to pay for the high-priced LNG and have thus been able to operate successfully, although their profit margins have reduced.

Against this background it may be brought out that during the fifth round of auction for laying infrastructure to new GA's has not found enthusiasm amongst bidders. In fact in 8 out of the 20 districts not a single bid was received. It only goes to show the difficulty of the sector against structural and availability constraints and needs a lot of initiative and support from the Government to push the use of natural gas.

Natural Gas Pricing Scenario

There are multiple gas pricing regimes currently in vogue in India. Brief on them is given below:

Administered Pricing Mechanism (APM) Pricing: Natural gas from the existing fields of nominated blocks of State Owned Companies like OIL and ONGC cater to fertiliser and power plants. Being priority sectors, the Government controls the price of gas produced on a cost plus basis.

Non APM Gas Pricing: Non APM gas pricing is divided into two categories: i) Imported LNG for which prices are determined by the market; and ii) Domestically produced gas from New Exploration Licensing Policy (NELP) and pre –NELP fields. Pre- NELP fields are those of Panna-Muktha, Tapti and Ravva fields. Gas price are based on Production Sharing Contracts (PSC) and is between $3.5 to $5.7 per mmbtu. NELP gas pricing is determined on the basis of arms length (market prices) subject to Government approval and is controlled by PSC agreements. As per revised mechanism approved in October 2014, price of domestically produced natural gas are to be revised every six month using weighted average or rates prevalent in gas surplus economies of US/Mexico, Canada and Russia. Indian gas price is calculated by taking weighted average price of Henry Hub of US, National Balancing Point of UK, rates in Alberta (Canada) and Russia with a lag of one quarter. The current rate for domestically produced natural gas was reduced to $5.18 per mmbtu on net calorific value from $5.61 per mmbtu in tune with the fall in crude prices. This price is already among the lowest in Asia Pacific.

Import Price: The price of long term LNG imports from Qatar entered by GAIL is operated on a take or pay basis with prices linked to Japanese Custom Cleared price. The average cost of such supplies is around $13-$18 per mmbtu. The spot rates which were $13.419 during November, 2012 have reduced considerably due to fall in crude prices and were hovering around $7-$7.5 per mmbtu during May, 2015. Despite India's insistence for reduction in prices commensurate with spot prices Qatar has not agreed for the same. As a result India is currently not in a position to take advantage of the falling LNG import prices.

Contemporary pricing of natural gas and recent initiative taken in pricing have implications on its supply and demand scenario. Its effects on various sectors are discussed below:

Upstream Sector: The domestic gas production has been hampered due to lack of investment in new discoveries and development of existing fields primarily due the non-attractive pricing of gas produced. Against the industry demand of $8.0 per mmbtu the prices had fallen to $5.61 per mmbtu. With the fall in crude prices the rate has been further brought down to $5.18 per mmbtu for the April, 2015-September, 2015 period.

China pays explorers $11.9 per mmBtu rate for new projects while Indonesia and the Philippines price the fuel at $11 and $10.5 respectively. Gas from offshore fields in Myanmar, where Indian firms ONGC and GAIL have stake, are sold to China for $7.72. Thailand prices gas from new projects at $8.2 per mmBtu.

Increase in domestic gas prices is a pre-requisite for enhancing domestic production due to enhanced commercial viability of gas fields which in turn is expected to reduce the prevalent gas supply deficit. It could lead to reduction in LNG import bill. According to Morgan Stanley, gas pricing of more than $8 per mmbtu would result in incremental production of nearly 95 mmscmd over 20 years. This would reduce the import cost by $16 billion.

Power Sector: Power plants are currently being supplied APM gas at $4.2 per mmbtu at a variable cost of Rs. 2.1 per unit. At a Plant Load Factor (PLF) of 50% this translates to a generation cost of Rs. 4.8 per unit for newly commissioned private power plants. The increase in gas prices to $5.18 per mmbtu based on the new pricing mechanism adopted is expected to result in a rise in variable cost and increase the generation cost to Rs. 5.7 per unit. This price would be attractive only for peak load purposes. As stated earlier gas as a fuel becomes attractive only at prices around $3-$4 per mmbtu with respect to coal.

Fertiliser Sector: According to a report submitted by the Government's Parliamentary Standing Committee every rise of $1 per mmbtu in gas prices would increase the fertiliser subsidy by Rs. 3000 crore. Therefore, any increase in natural gas price could lead to an increase in the Government's subsidy burden. An increase in gas prices to around $8 per mmbtu would increase the subsidy burden by Rs. 120 billion.

The Government has recently approved a proposal to pool or average out prices of domestic natural gas and imported LNG used by fertiliser plants to make the cost of fuel uniform and affordable. The cost of gas, which is the most important component for production of urea, varies from plant to plant owing to differential rates at which imported LNG is contracted as well as cost of transportation. The Cabinet Committee on Economic Affairs has proposed making state-owned gas utility GAIL India Ltd. as the pool operator The Department of Fertilisers will determine the total requirement of natural gas and draw plant-wide requirement, which would then be informed to the pool operator, GAIL. The pool operator will tie-up imports after considering domestic availability and after averaging out price of both, delivery of the fuel at uniform rate will be made to all plants. Gas pooling is expected to save Rs. 1,550 crore in subsidy and will benefit 30 urea plants.

Demand for natural gas is bound to increase as a result of rationalization of gas pricing through the mechanism of pooling as it is bound to increase the production of fertilizer plants. With the fall in crude prices, imported LNG prices have also fallen to less than $10 per mmbtu for the first time in four years and would help to bridge the gap between domestic gas supply and demand for natural gas. Fall in prices is also bound to save considerable amount by way of subsidy in the sector.

Conclusion

To conclude, in terms of the sensitivity of demand to natural gas price, the demand arising from the power and fertilizer sectors is expected to remain highly sensitive to the price at which the entities in these sectors are able to procure gas due to the issues around affordability by end consumers for basic food products and electricity. However, the demand from other consuming sectors is expected to remain relatively less sensitive to the price levels as long as availability is ensured.

While the Government is striving to increase the share of natural gas in the overall energy mix of the country yet it is constrained by local considerations as well as structural inadequacies. Natural gas although is definitely the favoured fuel for India's development engine, yet a lot of initiatives needs to be taken by the Government in achieving it.

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Gas Hydrates

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Gas hydrate is a solid ice-like form of water that contains gas molecules in its molecular cavities. One cubic meter of gas hydrates is converted into 164 cubic meter of gas under atmospheric conditions. In nature, this gas is mostly methane. Methane gas hydrate is stable at seafloor at water depths beneath about 500 m. The gas hydrate stability zone extends into the seafloor sediments down to a depth where temperature exceeds gas hydrate stability, usually some 10s to 1000s of meters beneath the seafloor. The following article, tries to explain the nature of gas hydrate, factors affecting its presence, their occurrence and the importance of gas hydrate in mitigating Indian energy crisis.

Introduction

Natural gas hydrates are members of a highly varied class of substances called clathrates. These are solids formed by the inclusion of molecules of one kind (guest molecules) within the intermolecular cavities of a crystal lattice composed of molecules of another kind (host molecules). The guest molecules are necessary to support the cavities, and the association between host and guest molecules is principally physical because such bonding exists due to the weak attraction between adjacent molecules, rather than due to the stronger chemical bonding responsible for most compounds.

Gas hydrates are ice-like substances composed of a host lattice of water molecules (H_2O) and one or more of a potential two suite of guest molecules which at normal temperatures and pressures occur in the gaseous phase and are capable of physically fitting into the interstices of the water-ice lattice. This suite includes the noble gases (the elements helium, neon, krypton, argon, xenon, and radon), the halogens (chlorine, bromine, iodine, and astatine) and hydrogen sulphide, sulphur trioxide, sulphur hexafluoride, and carbon dioxide (CO_2). Significantly, it also includes the low molecular-weight hydrocarbons like methane (CH_4), ethane (C_2H_6), propane (C_3H_8). A particular natural gas hydrate can contain from one to all of these.

The significance of natural gas hydrates is largely due to the huge volume of methane which is assumed to be stored in hydrates.

Structure of Gas Hydrates

Depending on the size of the guest molecule, natural gas hydrates can consist of any combination of three crystal structures: Structure I, Structure II, and Structure H. When pure liquid water freezes it crystallizes with hexagonal symmetry, but when it "freezes" as a hydrocarbon hydrate it does so with cubic symmetry for structures I and II, reverting to hexagonal symmetry for Structure H (Figure1).

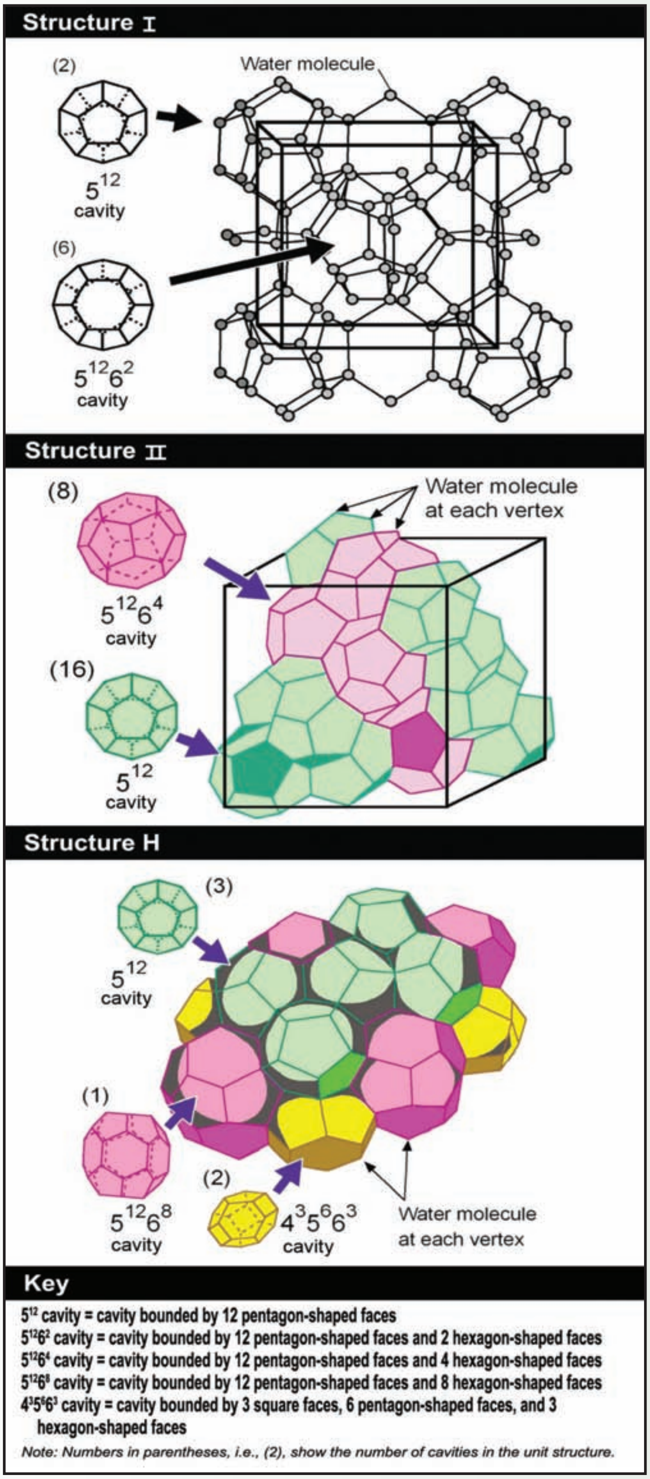


Figure 1: Lattice structures of Gas Hydrate; Source: http://www.beg.utexas.edu/

- Structure I gas hydrates contain 46 water molecules per unit cell arranged in 2 dodecahedral voids (any polyhedron with twelve flat faces is a dodecahedron) and 6 tetrakaidecahedral voids (any polyhedron with fourteen flat faces is a tetradecahedron), which can accommodate at most 8 guest molecules up to 5.8 Angstroms in diameter. Structure I allows the inclusion of both methane and ethane but not propane.
- Structure II gas hydrates contain 136 water molecules per unit cell arranged in 16 dodecahedral voids and 8 hexakaidecahedral voids, which can also accommodate up to 24 guest molecules, but to a larger diameter of 6.9 Angstroms. This allows inclusion of propane and iso-butane in addition to methane and ethane.
- The rare Structure H gas hydrates, which contain 34 water molecules per unit cell arranged in 3 pentagonal dodecahedral voids, 2 irregular dodecahedral voids, and 1 icosahedral void, can accommodate even larger guest molecules such as iso-pentane.

Presence of Gas Hydrates

Naturally occurring natural gas hydrates were first discovered in 1964 in association with cold subsurface sediments located in Siberian permafrost terrains. The discovery of oceanic gas hydrates within the upper tens to hundreds of meters of continental margin sediments was reported in 1977.

It is estimated that 99% of the world's gas hydrate occurs in marine sediments. This estimate was made before modern drilling of permafrost-associated gas hydrates, but scientists still believe that most of the global gas hydrates occur in the uppermost hundreds of meters of sediments at ocean water depths greater than ~500 m and close to continental margins.

Except on upper continental slopes (300-700 m water depth), the sea floor of most of the world's oceans lies within the hydrate stability zone. Apart from a few locations, though persistent, sea floor gas hydrate mounds are relatively rare and not volumetrically important compared to the size of the global reservoir. Gas hydrate is in theory also stable in the lower part of the ocean water column, and gas bubbles rising from the sea floor sometimes form a shell of gas hydrate that usually does not survive very long.

In the marine environment the gas hydrate stability zone is determined by water depth, seafloor temperature, pore pressure, thermal gradient and the gas & fluid composition.

The base of the zone in which hydrate can exist is limited by the increase in temperature with depth beneath the seabed. Gas hydrate formation irrespective of its depth of occurrence requires:

- Suitable Pressure-Temperature (P-T) regime within the hydrate stability region;
- Source of Methane;
- Concentration of Methane.

Gas hydrates form in high pressure, low temperature environments where sufficient gas and water are present. Figure 2 shows the phase diagram for methane hydrate formation. The hydrate formation requirements limit the occurrence of natural gas hydrates to two types of geologic locations: i) under permafrost areas (Arctic) and ii) in sediments beneath the ocean floor (marine). The red sections in the generic curves shown in Figure 2 illustrate regions in permafrost and oceanic sediments where the pressure and temperature conditions and the concentration of methane gas are within the hydrate formation and stability zone. These curves are based on pressure-temperature phase equilibrium data and correspond with reflection seismic data collected in these environments.

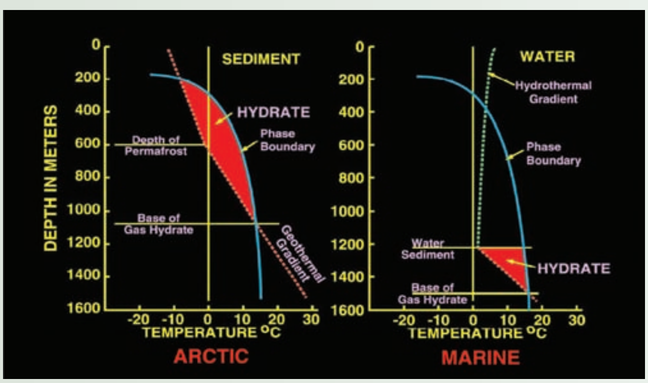


Figure 2: Natural Gas occurrence P-T illustration

Assuming a seafloor depth of 1,200 m, temperature steadily decreases with increase in water depth, and a minimum value near 0°C is reached at the ocean bottom. Below the sea floor, temperatures steadily increase, so the top of the gas hydrate stability zone (GHSZ) occurs at roughly 400 m, while the base of the GHSZ is at 1,500 m. From the phase diagram, it appears that hydrates should accumulate anywhere in the ocean-bottom sediments where water depth exceeds about 400 m. Very deep (abyssal) sediments are generally not thought to house hydrates in large quantities. In fact deep oceans lack both the high biologic productivity (necessary to produce the organic matter that is converted to methane) and rapid sedimentation rates (necessary to bury the organic matter) that support hydrate formation on the continental shelves. As the research work in Arctic region is still going on and yet to be established, more data is essential to explain it further. Many scientists have worked on predicting the actual Pressure-Temperature conditions for hydrate stability and many equations to fit the equilibrium curve have been devised. Gibbs Free energy is the best known method to explain this phenomenon.

Indicators for Gas Hydrate Presence

The occurrence of hydrates can be estimated in well logs (the detailed record of physical properties of a geologic formation according to depth. A tool is lowered through a bore hole which records the properties). Gas hydrate bearing sediments show anomalously high electrical resistivity and high acoustic velocities. At the base of the GHSZ, which marks the contact between gas-hydrate and free-gas-bearing sediments, a distinct drop in acoustic velocity is often characterized by the acoustic log.

Currently, the principal indicator of marine methane hydrates is the detection of bottom-simulating reflectors (BSR's) on a seismic section, the BSR is a physical boundary between gas hydrate-bearing sediments above and free gas-saturated sediments below, and is often associated with the base of gas-hydrates stability zone on seismic data. Unfortunately, in older data these may have been removed while processing away as they were not recognized for what they are. BSR is reflected on the seismic section of crest of Blake Ridge as shown in Figure 3.

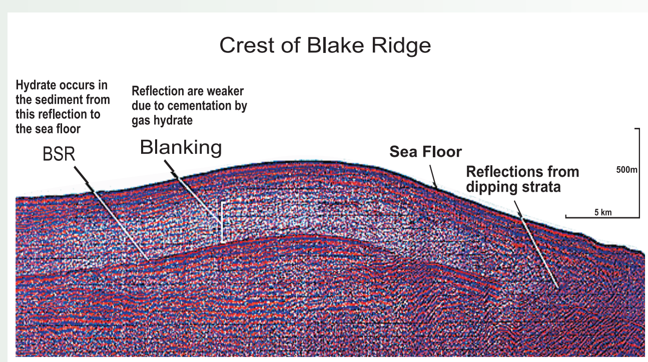


Figure 3: Seismic section of Blake Ridge indicating BSR; Source: www.woodshole.er.usgs.gov

Gas Hydrate Formation & Stability

As brought out in the earlier section of the article, gas hydrate formation requires:

1. Suitable P-T regime within the hydrate stability region;
2. Source of Methane; and
3. Concentration of Methane should exceed its solubility limit in water as the excessive methane only precipitates to form hydrates.

1) **Suitable P-T Conditions:** The phase equilibrium curve on the P-T diagram shows areas where the hydrate-water system or free gas phase-water are stable. Any gas hydrate is stable only within a specific combination of pressure and temperature. The natural bounds in terms of temperature and pressure that would control the distribution of gas hydrates is shown in Figure 4. Pressure in this context represents hydrostatic pressure (water depth plus sub-seabed depth, assuming no excess pore pressures) and temperature is largely controlled by the geothermal gradient. Accordingly, most of the ocean below 500 m water depth has low temperatures and high pressures to form and sustain methane hydrate.

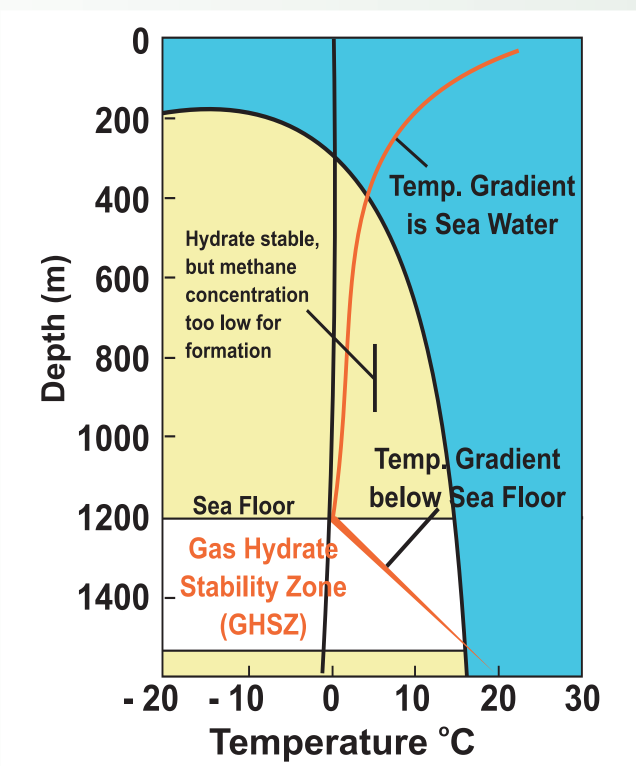


Figure 4: Phase equilibrium curve on P-T diagram in marine region

2) **Source of Methane:** Such high concentrations of methane, required for formation of gas hydrates, in water can be assigned to either Biogenic or Thermogenic origin.

- o Biogenic gases are those produced by the bacterial activity in the sediments with very high initial organic content. These are generally associated with the early diagenesis of organic matter rich in shallow fine-grained sediments.
- o Thermogenic gases are produced from kerogens at high temperature and pressure conditions. These gases occur generally at greater depths exceeding 1000 m. These are formed at the metagenesis stage or in the last stage of hydrocarbon generation.

Worldwide most of the sampled hydrates show organic origin. This is mainly due to the shallow depths of formation for methane. The shallow depths fall well within the P-T conditions of hydrate formation and they also have abundant water. Thermogenic gases need considerable upward migration for hydrate formation. Therefore, thermogenic gas hydrates are characterized by an area with either of the following geological features: faults, vents, diaper, mud volcanoes.

3) **Concentration of Methane:** Availability of proper methane concentration is one of the major factor for hydrate formation. Hydrate (CH_4nH_2O, where $5.75 < n <= 19$) formation generally require extreme concentrations of methane in the interstitial water of the sediments. This maximum concentration is designated by solubility. If the methane concentration in water is higher than solubility, excessive methane will precipitate from solution to form gas hydrates. In ideal case seawater must be supersaturated with methane by a factor of 20 or more in order for hydrate nucleation to take place.

Geological Occurrence of Gas Hydrates

Gas hydrate occurrence has been reported from varied physiographic provinces such as continental margins, deep-sea trenches, submarine canyons, continental slopes, intra-slope basins. Figure 5 shows the hydrate resource pyramid showing the relative amounts of gas hydrate in the global system. The hydrates at the top of the pyramid are most likely to be exploited for energy resources. Their

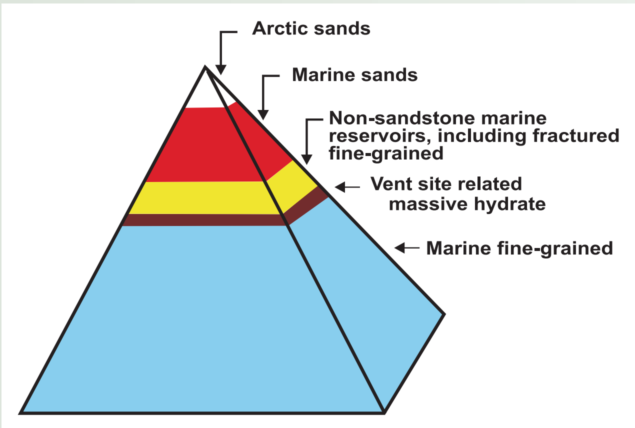


Figure 5: The hydrate resource pyramid; Source: US Geological Survey

occurrences are often in proximity to fault zones. Globally, gas hydrate has been recovered or inferred in many continental margin settings and in onshore permafrost or offshore relict permafrost that was flooded by sea level rise over the past ~15,000 years. Gas hydrate has also been recovered from sediments beneath Lake Baikal, Earth's largest freshwater lake.

Methane hydrate occurs in all the oceans as well as some locations on land. Figure 6 illustrates the most important research sites as published by world ocean review and areas worldwide are also highlighted with numbers.White dots indicate occurrences identified by geophysical methods. The blue dots show occurrences proven by direct sampling.

1) **Mallik:** High concentrations of gas hydrates were documented in sands of the Mallik site on Richards Island in Canada's Northwest Territories in 1972. This resulted in three landmark gas hydrate evaluation programmes with corresponding test wells being carried out here in 1998, 2002 and 2007/2008. These programmes confirmed that gas hydrates could be produced by drilling wells and that depressurization appeared to be the most favourable method.

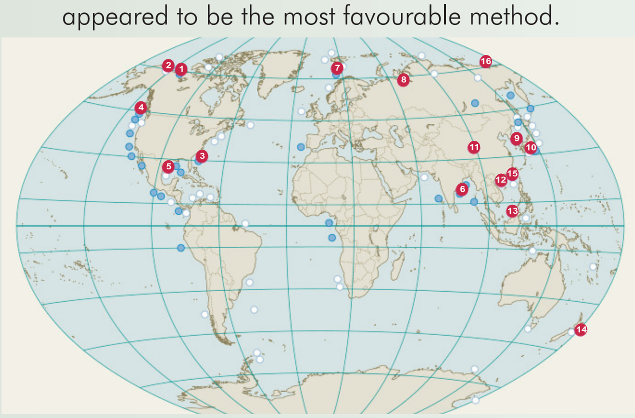


Figure 6: Major Gas Hydrate occurrences; Source: World Ocean Review

2) **North Slope:** Gas hydrates were discovered and tested in the North Slope region of Alaska in 1972 at the Northwest Eileen State #2 well. The objective of the test wells was to evaluate the oil reserves, but the drilling also enabled initial estimates of the reserves of gas hydrate. The magnitude of the hydrate deposits was estimated at around 16 trillion cubic metres. Little further attention was paid to the hydrate deposits until the Mount Elbert test well was drilled nearby in 2007. In 2008 the United States Geological Survey (USGS), the most important organization for official mapping in the USA, assessed a volume of 2.4 trillion cubic metres of recoverable gas in the region with the technology existing at that time. A well was drilled in Prudhoe Bay in 2011 to test for the production of gas hydrates.

3) **Blake Ridge:** This area of the continental slope off the coast of North Carolina was one of the initial sites for gas hydrate research in the marine realm. Hydrate deposits were discovered during a seismic and geophysical survey of the sea floor. The methane hydrate layers below the sea floor were revealed by conspicuous reflection patterns in the seismic profiles, referred to as BSR. Scientific drilling in 1995 confirmed the existence of an extensive deposit. The gas volumes were assessed at around 28.3 trillion cubic metres. Concentrations of the gas here, however, are relatively low.

4) **Cascadia Continental Margin:** This area off the Pacific coast of the United States was drilled by the Ocean Drilling Program (ODP). The objective of this international programme is to acquire new knowledge about the structure of the Earth and its history through scientific drilling of a large number of holes in the sea floor. On two cruises in this region, in 2002 and 2005, the "hydrate ridge" off Oregon was drilled.

5) **Gulf of Mexico:** Massive gas hydrate mounds were discovered on the sea floor here in 1995. These structures are particularly interesting because of the special biological communities that have developed here. Later, gas hydrates were found in marine sands in a well in Alaminos Canyon Block 818. These kinds of deposits are significant because it is relatively

easy to recover hydrates from sands. In 2005, a joint project involving researchers and industry partners addressed the safety aspects of deepwater drilling. A second drilling expedition in 2009 revealed high concentrations of gas hydrates in sand reservoirs. The resources estimated as per Bureau of Ocean Energy Management (BOEM) are 6,700 tcf.

6) **Indian Ocean:** Gas hydrates were investigated during a 113-day expedition at one site in the Arabian Sea, two sites in the Bay of Bengal, and one site in the Andaman Islands. Off the southeast coast of India, at "site 10" in the Krishna-Godavari Basin, the researchers discovered a 130 metre-thick layer containing gas hydrate. This exhibited high gas hydrate concentrations. Government of India initiated the surveys in the early 90s. A total volume of ~1900 tcm of methane gas, stored in the form of gas-hydrates, has been prognosticated within the vast exclusive economic zone (EEZ) of India.

7) **Svalbard:** A number of studies have been carried out on the shelf off the western coast of Svalbard Island, located in the Arctic Ocean. Early in this century several active methane gas seeps were found. These presumably originate at the edge of GHSZ. Scientists believe that the hydrates are dissociating here due to climatic changes.

8) **Messoyakha:** This oil and gas field in western Siberia provided the first solid evidence for the existence of gas hydrates in nature. Drilling and various measurements suggest that the gas hydrate contributes a share to the production of natural gas in this area.

9) **Ulleung-Basin:** Deep-sea drilling was carried out in the Ulleung Basin off the coast of South Korea in 2007 and 2010. The conservative estimates are of the order of 3.03 tcm .The expedition also retrieved cores. Numerous vertical "chimney" structures were discovered with high concentrations of gas hydrates. The hydrates apparently occur here in the pore spaces of sands and in deformed muds.

10) **Nankai Trough:** The first resource-grade gas hydrates in marine sands were discovered in this area off Japan in 1999. Further geophysical studies and a second drilling programme in 2004 revealed the presence of gas volumes in the Nankai Trough of 1.1 tcm. Around 566 bcm of this occur in high concentrations in sands. Methane was produced for the first time from a test well in the sea here in 2013. After the well in the Nankai Trough in 1999, the industry well in Alaminos Canyon Block 818 in the Gulf of Mexico in 2003 was the second discovery of gas hydrate in marine sands.

11) **Qilian Mountains:** This mountain range on the Tibetan Plateau in western China has permafrost extending to depths of up to 100 metres. Drilling projects here in 2008 and 2009 confirmed the presence of gas hydrate occurrences in fractured sandstones and mudstones. These rocks were formed during the Jurassic geological period around 200 million years ago.

12) **Shenhu Basin:** This area of the South China Sea was explored in early 2007 during marine geological mapping by the Guangzhou Marine Geological Survey (GMGS), a Chinese state institute for marine geology. Gas hydrate concentrations discovered in the fine-grained sediment layers were higher than expected, probably as a result of relatively high silt content and deposits of planktonic foraminifera, microscopic organisms with carbonate shells.

13) **Gumusut-Kakap:** In this oil field off the shore of eastern Malaysia potential geohazards with respect to industrial production of deeper oil and gas deposits were studied for the first time in 2005. The project concentrated mainly on oil and gas deposits underlying gas-hydrate bearing layers.

14) **New Zealand:** Strong BSR seismic signals were recorded in the early 1980s during sea-floor investigations of this area on the margin of the Hikurangi Trough off the East Coast of New Zealand. Since then the region has been studied more intensively using a variety of other kinds of measurements. Further expeditions to various sites within the EEZ of New Zealand suggest that gas hydrate deposits could be present in many other areas there.

15) **Taiwan:** Taiwan lies in a region where continental plates converge. In this area methane-bearing water

is pressed out of the sediments so that methane is available for the formation of hydrates. The tectonic collision zone has been intensively studied by drilling since 2004. The drilling programme has produced clear evidence of the presence of gas hydrates. The hydrates presumably encompass around 11,000 square kilometres of sea-floor area, which is equal to the size of the West African country of Gambia.

16) **East Siberian Shelf:** The East Siberian shelf is a former coastal area with permafrost that was flooded by sea-level rise after the last Ice Age. Scientific studies discovered high concentrations of methane in the sea water and upper layers of the sea floor. The origin of the methane is uncertain. It may possibly come from methane hydrates stored in the relict permafrost of the submerged coastal area.

Gas Hydrate Importance to the Energy Industry and Society

Gas hydrates are of interest for researchers and governments primarily for three reasons:

1) **Gas hydrates are a potential energy resource:** Considering the planet as a whole, the quantity of natural gas in sedimentary gas hydrates greatly exceeds the conventional natural gas resources. As a result, numerous studies have discussed the energy resource potential of gas hydrates. However, utilization of gas hydrates as an energy resource has been largely inhibited by the lack of economical methods in addition to the technological advancements for production for most hydrate accumulations, especially continental shelf hydrates. A variety of different mechanisms have been proposed for economically developing gas hydrates as an unconventional gas source.

   Thus far, the only method that has been successfully used to economically produce gas from gas hydrates is the "depressurization method". This method is applicable only to hydrates that exist in polar regions beneath permafrost. This method is applicable when a free gas phase exists beneath the hydrate accumulation. Under such circumstances, production of the free gas leg using conventional gas development techniques produces a pressure drop. This pressure drop causes the overlying hydrate to become unstable and to progressively disassociate into free gas + water, a process that adds gas to the underlying free gas accumulation.

2) **The role of gas hydrates in past and future climate changes:** Gas hydrates are also of interest because of their potential role in climate change. Gas hydrates in continental shelf sediments can become unstable either as a result of warming bottom water, or as a result of a pressure drop due to a reduction in sea level (such as during an ice age). If these marine gas hydrates begin to rapidly disassociate into gas + water, then the methane trapped in the gas hydrates can be released to the atmosphere.

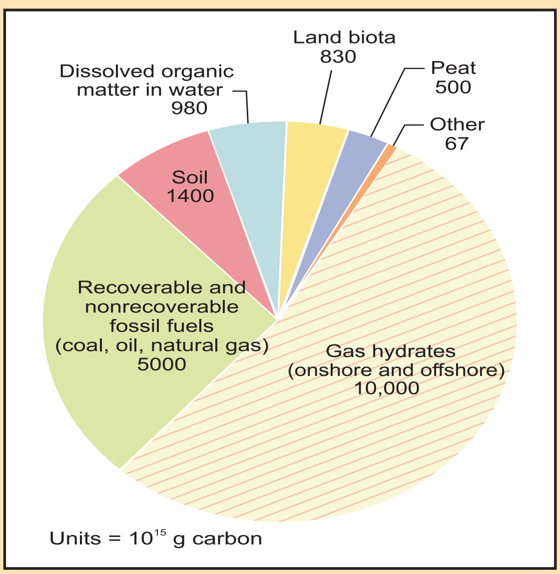
   Methane is a greenhouse gas. In fact, methane is many times more effective as a greenhouse gas than CO_2. Therefore, if the flux of methane to the atmosphere from dissociating hydrates is sufficient in quantity, this methane can cause global warming. This process is believed to have influenced past climate changes, and may enhance the current global warming episode by way of a "positive feedback" loop. Specifically, as the earth warms, increasing bottom water temperatures could cause gas hydrate disassociation in many marine shelf locations. This gas hydrate disassociation would cause further warming due to the greenhouse effects of the gas which is released.

3) **Production (flow assurance) problems:** Anthropogenically formed gas hydrates create another reason that these substances are of interest. Gas hydrates can spontaneously form in petroleum production equipment and pipelines associated with deep-water petroleum production and arctic on-shore petroleum production. These unwanted hydrates can clog equipment, preventing the optimum production of hydrocarbons. Various methods are used to prevent hydrate formation in petroleum production and transportation equipment.

Gas Hydrates- A probable solution to India's Energy crisis

India has the third largest energy demand in the world after China and the United States and just ahead of Russia (as per the recently released BP Statistical Review, 2015). However, India's per-capita energy consumption is still at a much lower level than that of developed countries and even of some developing countries. The low per-capita energy consumption level indicates that India's energy demand still has a long way to reach saturation. With a growing economy and a 1.25 billion population aspiring for a better quality of life, India's energy demand growth is inevitable. As per World Energy Outlook 2014, India's total primary energy demand is likely to be more than double over the period of 2012-2040 to about 1757 Mtoe at a CAGR may of about 2.9%. Gas hydrates reserves of India, may provide a feasible solution in long-term to India's growing energy demand.

Vast amounts of methane hydrate are buried in sediment deposits on the continental slopes. The total global amount of methane carbon bound up in these hydrate deposits is in the order of 1000 to 5000 gigatonnes – i.e. about 100 to 500 times more carbon than is released annually into the atmosphere by the burning of fossil fuels (coal, oil and gas).



Organic Carbon distribution; Source: USGS

In India, gas hydrates were first recognized by ONGC in the Andaman (Am) region. The bathymetry, seafloor temperature, total organic carbon (TOC) content, sedimentary thickness, rate of sedimentation, geothermal gradient indicate that shallow sediments along the Indian shelf are good hosts for gas-hydrates

As mentioned earlier, a total volume of ~1900 tcm of methane gas, stored in the form of gas-hydrates, has been prognosticated within the vast EEZ of India. This volume of gas is greater than 1500 times of India's present natural gas reserve. Only 10% production from this huge deposit can overcome India's burgeoning energy demand for about a century. One cubic meter of gas hydrates is converted into 164 cubic meter of gas under atmospheric conditions. Hence, it is desirable to identify the most prospective zones of gas-hydrates and evaluate their resource potential before the commercial production of gas hydrates becomes available.

In this regard, Directorate General of Hydrocarbons (DGH) has done pioneering work for initiating gas hydrate exploration in the country. Reconnaissance surveys carried out by DGH in the East Coast and Andaman Deepwater areas in 1997 deciphered the most promising areas for Gas Hydrates. The surveys have indicated the presence of several Gas Hydrate leads/ prospects. The total prognosticated gas resource from the gas hydrates in the country is placed at 1894 TCM. The National Gas Hydrate Program (NGHP) is a consortium of National E&P companies (Oil and Natural Gas Corporation Ltd 'ONGC', GAIL India Ltd & Oil India Ltd 'OIL') and National Research Institutions (National Institute of Oceanography, National Geophysical Research Institute and National Institute of Ocean Technology), it is steered by the Ministry of Petroleum & Natural Gas and technically coordinated by DGH. NGHP is given the responsibility to explore the Gas Hydrates in India. In NGHP-1 programme 21 sites were studies in four basins: 1 site was studied in Kerela-Konkan basin; 15 sites were studied in Krishna-Godawari Basin; 4 sites were studied in Mahanadi Basin; and 1 site was studied in Andaman Islands. The NGHP-1 efforts in Indian offshore for gas hydrate exploration led to the following:

- Conducted comprehensive analyses of gas-hydrate-bearing marine sediments in both passive continental margin and marine accretionary wedge settings.
- Discovered gas hydrate in numerous complex geologic settings and collected an unprecedented number of gas hydrate cores (more than 2800 m from 21 sites and 39 holes).
- Delineated and sampled one of the richest marine gas

hydrate accumulations discovered in the world (Krishna-Godavari basin).

- Discovered one of the thickest and deepest gas hydrate occurrences yet known (Andaman Islands) which revealed gas-hydrate-bearing volcanic ash layers as deep as 600 meters below the seafloor. Established the existence of a fully developed gas hydrate system in the Mahanadi basin of the Bay of Bengal.

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Carbon Capture & Storage (CCS)

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The last decade has witnessed an increase in the annual GHG emissions at an average rate of 2.2 % per year(from 2000 to 2010) as compared 1.3 % per year in the preceding decades (from 1970 to 2000). Concern about global climate change has led to efforts to find a way for reducing carbon dioxide emissions. Several mitigation measures have been proposed to offset the negative externalities associated with efforts to augment energy access across the globe. Power generation especially employing coal as the source has largely been attributed as the most significant source of CO_2 emissions. However, to meet the requirement of uninterrupted and affordable energy for economic development, role of coal in the energy mix cannot be neglected for coming decades. Considering, the criticality of coal in the energy mix and growing risk of climate change, mitigation technologies such a Carbon , Capture & Storage (CCS) present promising option to slow down CO_2 emissions in the future.

Introduction

Increase in CO_2 emissions from fossils fuels in last few decades is mainly driven by population growth and economic development. Between 2000 and 2010, contribution of population growth in CO_2 emissions is almost identical to the previous three decades, while the contribution of economic growth has risen sharply. Total anthropogenic Green house gas (GHG) emissions were the highest in human history from 2000 to 2010 and reached 49 (±4.5) Gt CO_2 eq / yr in 2010.The United Nations Intergovernmental Panel on Climate Change (IPCC) has concluded that 50% to 80% cuts in global CO_2 emissions by 2050 compared to the 2000 level will be needed to limit the long-term global mean temperature rise to the range of 2.0°C to 2.4°C.

Uninterrupted supply of affordable energy is fundamental for economic stability and development. However, on environmental front the use of energy represents the largest source of emissions of GHGs among the many other human activities. The use of energy holds the largest share of 69% in global anthropogenic GHGs, followed by agriculture with 11% share. CO_2 and CH_4 constitute 90% and 9% respectively of GHG emissions caused due to the use of energy. It means energy emissions, mostly CO_2, account for the largest share of global GHG emissions.

Currently, global energy mix is dominated by fossil fuels to have secure, reliable and economical energy supply. As per World Energy Outlook (WEO), 2014 fossil fuels had a share of about 82% in meeting total primary energy demand (TPED) in 2012 and it is projected that fossil fuels will have dominating share of about 74% (in New Policy Scenario) even in 2040. Growing world energy demand which is primarily being met from fossil fuels plays a key role in upward trend in CO_2 emissions. Since industrial revolution (1870), CO_2 emissions dramatically increased from almost zero to about 32 Gt CO_2 (in 2012) due to combustion of fossil fuels (Figure 1).

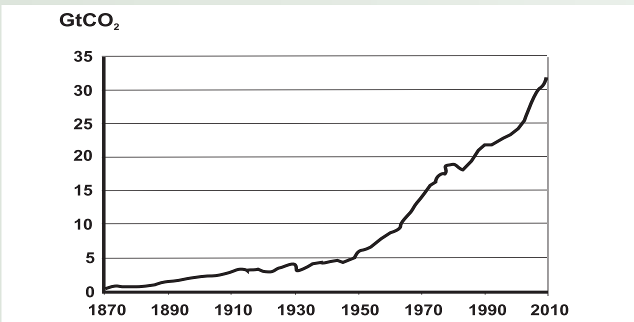
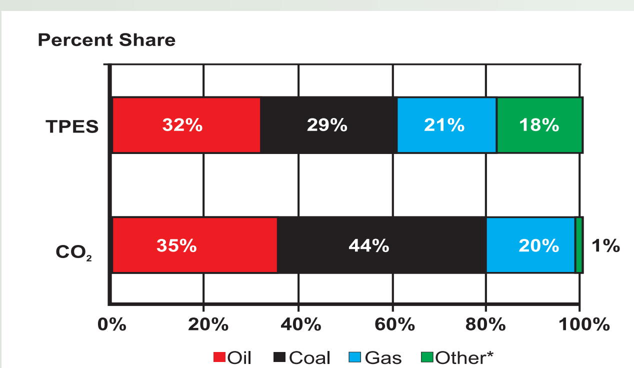


Figure 1: Trend in CO_2 emissions from fossil fuel combustion; Source: IEA Statistics, 2014

Among fossil fuels coal is the major contributor of CO_2 emissions, although it holds share of 29% (in 2012) in the world total primary energy supply (TPES) but it accounted for 44% of the global CO_2 emissions due to its heavy carbon content per unit of energy released (Figure 2). Present energy mix of developing countries (such as China and India) is dominated by coal where energy- intensive industrial production is growing rapidly and large coal reserves exist.



** Other includes nuclear, hydro, geothermal, solar, tide, wind, biofuels and waste.*

Figure 2: World primary energy supply and CO_2 emissions: shares by fuel in 2012; Source: IEA Statistics, 2014

Major chunk of the global CO_2 emissions are contributed by generation of electricity and heat and transportation. Power generation is largely done using coal as a source which is the most carbon intensive fossil fuel. CO_2 emissions due to generation of electricity and heat almost doubled between 1990 and 2012, driven by the large increase of generation from coal (Figure 3). Countries like China, India, Australia, Poland and South Africa produce more than two-thirds of their electricity and heat through the combustion of coal. It is evident that the share of coal increased significantly, from 65% in 1990 to 72% in 2012 with comparatively insignificant increase in share of gas as a source. Carbon intensity developments for power sector will strongly depend on the fuel mix used to generate electricity, including the share of non-emitting sources, such as renewables and nuclear, as well as on the potential penetration of Carbon Capture & Storage (CCS) technologies. CCS is a critical technology available to mitigate GHG emissions caused by large scale usage of fossils fuels.

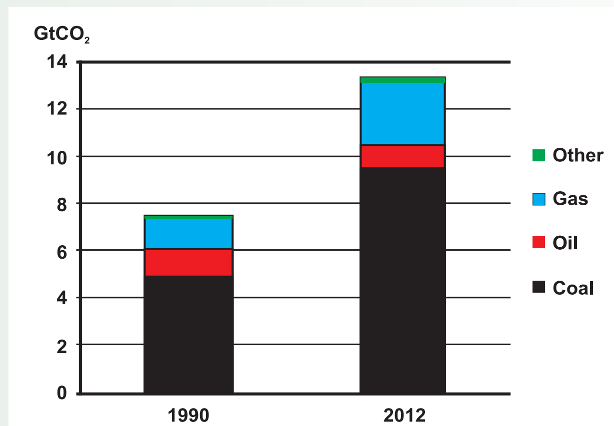


Figure 3: CO_2 emissions from electricity and heat generation; Source: IEA Statistics, 2014

Understanding CCS

Carbon Capture & Storage is considered as an important technology for carbon sequestration that seems to have potential for reducing CO_2 emissions from power stations and other fossil fuel industrial emitters in substancial amounts. As per IEA, CCS could deliver 19% of global emissions reductions, and account for over 30% of reductions from the power sector by 2050. Until world can produce enough reliable, affordable low carbon electricity from nuclear and renewables, this technology will slow the increase of CO_2 in atmosphere from fossil fuels used in electricity generation and help in mitigating global warming and reduce the effects of climate change.

Carbon Sequestration: It is used to describe both natural and deliberative processes which are used to either remove CO_2 from the atmosphere or divert CO_2 from emission sources and stored in the ocean, terrestrial environments (vegetation, soils, and sediments)

CCS consists of three processes: 1) separation and capture of CO_2 from industrial and energy-related sources; 2) transportation of the captured CO_2 to a storage location; and 3) long-term isolation from the atmosphere. All these process are decribed below in detail:

- **Climate Change Mitigation:** As per IPCC, an anthropogenic intervention to reduce the sources or enhance the sinks of greenhouse gases.
- **Climate Change Adaptation:** As per IPCC, adjustment in natural or human systems in response to actual or expected climatic stimuli or their effects, which moderates harm or exploits beneficial opportunities.

Capture: To produce a concentrated stream of CO_2 that can be transported to a CO_2 storage site. CO_2 capture is mainly done at large point sources such as fossil fuel power plants, fuel processing plants and other industrial plants, particularly for the manufacture of iron, steel, cement and bulk chemicals. Currently, three main technologies are present for CO_2 capture in electricity and heat generation: 1) post-combustion; 2) pre-combustion; and 3) oxyfueling (or denitrogenation) (Figure 4) and all are described below:

1. In post-combustion process, CO_2 is captured from flue gases that are released from power plants. These gases contain 12% to 15% of CO_2 by volume for coal-fired power plants and 4% to 8% of CO_2 by volume for natural gas-fired power plants. Solvents and subsequent solvent regeneration, sometimes in combination with membrane separation, are used to capture CO_2 from flue gases. Most existing CO_2 capture systems are based on chemical absorption in combination with heat induced CO_2 recovery (using solvents such as MonoEthanolAmine). CO_2 is already captured in a wide range of industrial manufacturing processes, refining and gas processing.

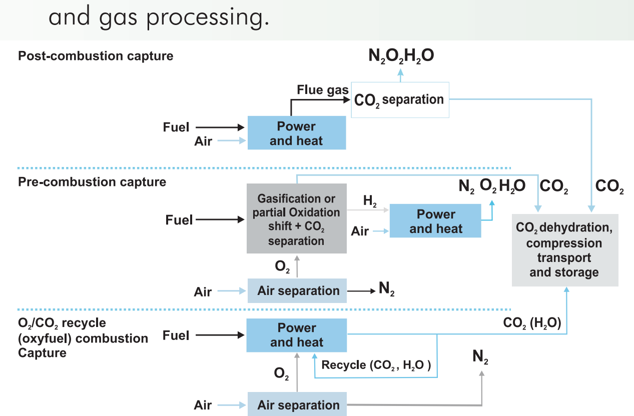


Figure 4: CO_2 Capture Processes; Source: IPCC, 2005

2. Pre-combustion capture processes can also be used in coal or natural gas based power plants. The fuel is made to react first with oxygen and/or steam and then further processed in a shift reactor to produce a mixture of hydrogen and CO_2. The CO_2 is captured from a high-pressure gas mixture (up to 70 bars) that contains between 15% and 40% CO_2. The hydrogen is used to generate electricity and heat in a combined-cycle gas turbine. Pre-combustion capture technologies are used commercially in various industrial applications such as the production of hydrogen and ammonia from hydrocarbon feedstocks.
3. The oxy-combustion process involves the removal of nitrogen from the air in the oxidant stream using an air separation unit (ASU). The fossil fuel is then combusted with near-pure oxygen using recycled flue gas to control the combustion temperature.

Oceanic carbon sequestration: The world's oceans are the primary long-term sinks for human-caused CO_2 emissions, currently accounting for a global net uptake of about 2 gigatons of carbon annually. This uptake is not a result of deliberate sequestration, but occurs naturally through chemical reactions between seawater and CO_2 in the atmosphere. While absorbing atmospheric CO_2, these reactions cause the oceans to become more acidic.

Terrestrial carbon sequestration: Terrestrial sequestration (sometimes termed "biological sequestration") is typically accomplished through forest and soil conservation practices that enhance the storage of carbon (such as restoring and establishing new forests, wetlands, and grasslands) or reduce CO_2 emissions (such as reducing agricultural tillage and suppressing wildfires). The capacity of terrestrial ecosystems to sequester additional carbon is uncertain.

Geologic carbon sequestration: Geologic sequestration begins with capturing CO_2 from the exhaust of fossil-fuel power plants and other major sources. The captured CO_2 is piped 1 to 4 km below the land surface and injected into porous rock formations.

CO_2 capture requires energy, so it reduces overall energy efficiency and adds cost. The best technology for individual CCS applications depends on the power plant and its fuel characteristics. Post combustion capture based on chemical absorption is the technology of choice for current coal and gas fired power plants. Pre-combustion capture based on physical absorption would be the preferred option for coal fired integrated gasification combined cycle (IGCC) plants

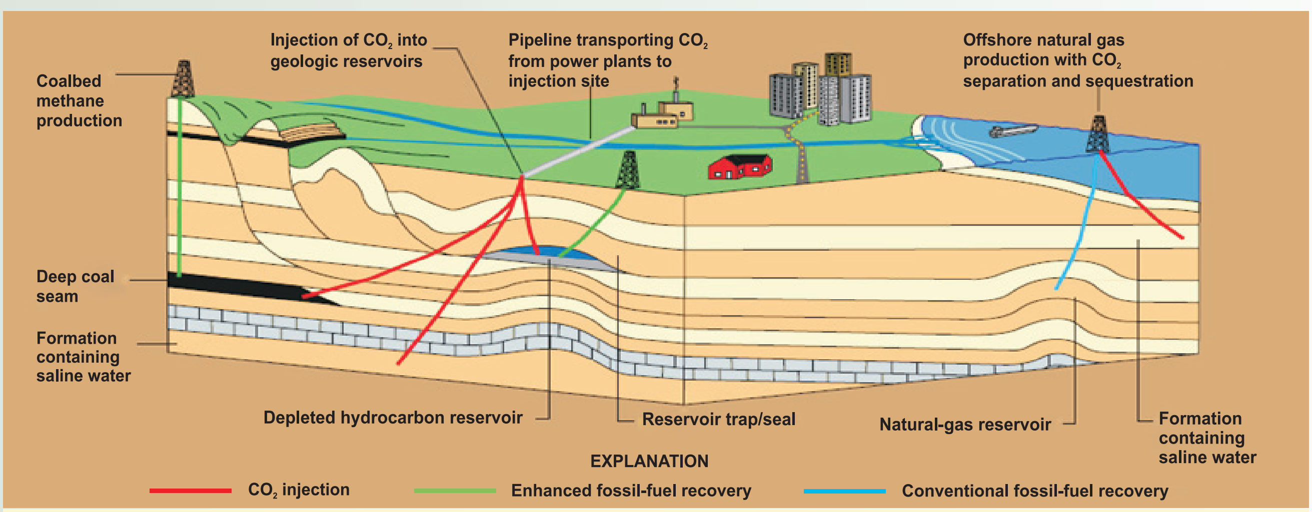
Transportation: CO_2 can be transported as gas or as liquid. As a gas, it can be transported in pipelines and ships and as a liquid, it can be transported in pipelines, ships and road tankers. Transporting CO_2 as a solid is not currently cost-effective or feasible from an energy usage standpoint. Transporting CO_2 via pipelines is an established technology and large volumes are being handled in the United States. Pipelines are a cost effective mode of transport for large quantities of CO_2.

CO_2 pipelines are similar to natural gas pipelines. The CO_2 is dehydrated to reduce the likelihood of corrosion. Pipelines are made of steel, which is not corroded by dry CO_2. CO_2 pipelines have an excellent safety track record, as such CO_2 presents no explosive or fire-related risks but gaseous CO_2 is denser than air and can accumulate in low-lying areas where, at high concentrations, it can create a health risk. The presence of impurities such as hydrogen sulphide (H_2S) or sulphur dioxide (SO_2) can increase the risks associated with potential pipeline leakage from damage, corrosion, or the failure of valves or welds.

Storage: The IPCC report (IPCC, 2005) describes three main mechanisms for CO_2 storage:

- Physical trapping by immobilising CO_2 in a gaseous or supercritical phase in geological formations.
- Chemical trapping in formation fluids (water/ hydrocarbon) either by dissolution or by ionic trapping. Once dissolved, the CO_2 can react chemically with minerals in the formation (mineral trapping) or adsorb on the mineral surface (adsorption trapping).
- Hydrodynamic trapping through the upward migration of CO_2 at extremely low velocitie leading to its trapping in intermediate layers of geological formations. Migration to the surface would take millions of years. Large quantities of CO_2 could be stored using this mechanism.

Currently, physical trapping by immobilising CO_2 in a gaseous or supercritical phase in geological formations is considered as the most promising and developed mechanism. There are three main proposed underground storage sites: depleted oil and gas reservoirs; deep saline formations; and deep unmineable coal seams (Figure 5). A brief about all these three is given below:



	Oil and gas reservoirs	Formations containing saline water	Unmineable coal beds
Advantages:	• Well-characterized volume • Known seal • Potential fuel recovery to offset cost	• Largest capacity (~250 to 900 gigatons carbon) • Wide distribution	• Adjacent to many large power plants (CO_2 source) • Potential fuel (methane) recovery to offset cost
Disadvantages:	• Smallest capacity(~25 gigatons carbon) • Limited in number • Requires infrastructure to transport CO_2	• Poorly characterized • Greatest geologic uncertainty • Unknown seal effectiveness	• Poorly characterized • Difficult to define 'unmineable' coal • Potential coal resources may be rendered unusable
Environmental issues:	Potential for mobilization of ground-water contaminants; leakage of CO_2 and CO_2-saturated saline water; induced seismicity		
Regulatory issues:	Determination of rules affecting injection well; multiple regulatory jurisdictions (State, Federal, local); post-injection ownership and liability		

Figure 5: Types of geologic CO_2 sequestration, their advantages and disadvantages, and potential environmental and regulatory issues; Source: USGS

1) **Depleted Oil and Gas reservoirs:** CO_2 injected into oil reservoirs can also increase the oil production of the field. This process is called Enhanced Oil Recovery (EOR). In the United States approximately 30 to 50 million tonnes of CO_2 is injected annually into declining oil fields. This option is attractive for geological storage because the geological character of hydrocarbon reservoirs is well known, and because costs of injection may get partly offseted by the sale of additional oil that is recovered.

   The main disadvantages of using depleted oil fields are their geographic distribution which may not be ideal in relation to point sources, their limited capacity in comparison with the size of big point sources. Also the subsequent burning of the additional oil so recovered through EOR will offset much or all of the reduction in CO_2 emissions.

2) **Unmineable Coal Seams:** CO_2 is adsorbed in coal if the coal is permeable enough to allow CO_2 to penetrate. In the process of absorption the coal releases previously absorbed methane, and the methane can be recovered. This methane can be used and the process of extracting useful methane from a coal seam when it is injected with CO_2 is called ECBM (or enhanced coal bed methane).

   The sale of the methane can be used to offset a portion of the cost of the CO_2 storage. However as in EOR, burning the resultant methane would produce CO_2 which would reduce some of the benefit of storing the original CO_2.

3) **Saline Formations:** Formations filled with brine offer excellent potential for CO_2 as they have the biggest capacity. However, relatively little is known about them, compared to oil fields and unlike storage in oil fields or coal beds no useful by-product will offset the cost of storage.

Policy for CCS Demonstration and Deployment

Presently, there is an absence of clarity on clear business case for investment in integrated CCS projects. The ultimate motive for CCS is a drive to reduce CO_2 emissions. This implies that the deployment depends entirely on strong policy action by government, to rectify the negative externality represented by anthropogenic CO_2 emissions. CCS or, for that matter, any other technology whose sole purpose is emission reduction is not something that a market will deliver if left alone. Only when the externality is corrected – i.e. vide imposition of a price or other measures, such as direct regulation – will private entities invest in measures to avoid negative externalities associated with generation and use of energy, including CO_2 emissions.

The IEA released an update to its, "2009 Technology Roadmap: Carbon capture and storage" in July 2013 (CCS Roadmap). The CCS Roadmap aims to assist governments and industry in integrating CCS in their emissions reduction strategies and in creating the conditions for scaled up deployment, consistent with the IEA's Energy Technology Perspectives 2°C Scenario (2DS).In the 2DS, total CO_2 capture and storage rates must grow from the tens of megatonnes of CO_2 captured in 2013 to thousands of megatonnes of CO_2 in 2050.

To achieve this, the CCS Roadmap identifies multiple actions for government, and its recommendations with suggested timelines are indicated as in Table 1:

Policy and regulatory frameworks are critical to CCS deployment

Roadmap recommends the following actions	*Time frame*
Action 1: introduce financial support mechanisms for demonstration and early deployment of CCS to drive private financing of projects.	2013-20
Action 2: develop national laws and regulations as well as provisions for multilateral finance that effectively require new-build, base-load, fossil-fuel power generation capacity to be CCS-ready.	2013-20
Action 3: significantly increase efforts to improve understanding among the public and stakeholders of CCS technology and the importance of its deployment.	2013-20
Action 4: governments and international development banks should ensure that funding mechanisms are in place to support demonstration of CCS in non-OECD countries.	2013-20
Action 5: governments should determine the role they will play in the design and operation of CO2 transport and storage infrastructure.	2013-20

Table 1: Recommendations of CCS Roadmap by IEA, 2013

These five actions concern the entire CCS chain. They relate to policy measures that establish a pathway for CCS deployment, through important gateways that distinguish between technology demonstration, early deployment in selected applications, and widespread deployment. The suggested policy actions in view of the above recommendations are as follows:

i. *Action 1: Introduce financial support mechanisms for demonstration and early deployment of CCS to drive private financing of projects:* Policies can include: direct financial support by governments (grants, investment tax credits, preferential loans, public-private partnerships, etc.) to share the burden of the learning; direct support for operation (feed-in tariffs, production tax credits, etc.) to cover, partly or totally, the increased operating costs for a limited period of time, supportive tools to address the issue of carbon leakage and international competitiveness that industrial facilities with CCS in sectors such as cement and steel may face in relation to competitors that are not required

The world's first large-scale power station equipped with CCS technology was launched in October, 2014 at Canada. The 110 MW retrofit of SaskPower's Boundary Dam coal-fired power plant in Saskatchewan, Canada will trap around 1 million tonne of carbon dioxide (CO_2) per year. The captured CO_2 will be injected into nearby oilfields to enhance oil recovery. As per IEA, This launch represents "a momentous point" in the history of the development of CCS, the family of technologies and techniques that enable the capture of CO_2 from fuel combustion or industrial processes, its transport via ships or pipelines, and its storage underground.

to invest in comparable levels of GHG abatement (or are not currently required to undertake any GHG abatement);support for the development and access to infrastructure to facilitate early project developers' access to CO_2 transportation pipelines and injection facilities; leverage of existing markets for CO_2 utilisation options where possible to facilitate deployment.

ii. *Action 2: Develop national laws and regulations as well as provisions for multilateral finance that effectively require new-build, base-load, fossil-fuel power generation capacity to be CCS-ready:* Governments should formulate laws and regulations that new-built base-load fossil-fuel power plants be constructed in a way that allows for the addition of CO_2 capture at a later date. These steps include: ensuring that sufficient space is available on site for the installation of additional capture-related equipment; installing high-performance flue-gas desulphurisation; allowance for extra cooling (i.e. water) and heating (i.e. steam) needs; and ensuring that appropriate rights-of-way are available to allow for CO_2 transport to identified potential storage sites.

iii. *Action 3: Significantly increase efforts to improve understanding among the public and stakeholders of CCS technology and the importance of its deployment:* Governments must undertake responsibility for explaining the role of CCS in national energy and climate strategies, along with discussions on the risks of CCS and the ways of addressing them. National, regional and local government, where political, social and cultural traditions allow, should work with important stakeholders at both national and CCS project levels to facilitate information exchange and fair dialogue. Industry must take responsibility for explaining the benefits and risks of particular CCS projects to the local population. Working actively to gain public acceptance is an integral part of any single CCS project and subsequently of wider deployment.

iv. *Action 4: Governments and international development banks should ensure that funding mechanisms are in place to support demonstration of CCS in non-OECD countries:* Some of the lowest-cost opportunities for demonstration projects, and some of the largest potential for deployment sites exist in non-OECD countries. Several international financing mechanisms like the Clean Development Mechanism (CDM), Nationally Appropriate Mitigation Actions (NAMAs) and the Green Climate Fund have been established by the UNFCCC to facilitate climate change mitigation actions in developing countries and assist developing countries in implementing those measures that they select as appropriate for their national circumstances and priorities. These mechanisms have to be made suitable for financing CCS projects, technical studies and CCS-related policy development.

v. *Action 5: Governments should determine the role they will play in the design and operation of CO_2 transport and storage infrastructure:* Scaling up CCS deployment is not possible without transport and storage infrastructure. As policies move CCS towards commercial viability in the coming years, these components of the CCS chain will need to develop into industrial activities with established revenue streams. However, at this early stage of CCS development, there may be a need for governments to step in and initiate activities that are normally performed by the private sector. Governments should consult with stakeholders on the options for future ownership and operation of CO_2 transport and storage infrastructure, and the extent to which government co-ordination might be required.

In addition to the above recommendations, IEA has also suggested policies that encourage storage exploration, characterisation and development for CCS projects, policies encouraging efficient development of CO_2 transport infrastructure by anticipating locations of future demand centres and future volumes of CO_2. Policies to increase Research and Development and Deployment collaboration among nations to further decrease the electricity cost and resource footprint of fossil-fired plants equipped with capture is also suggested by IEA so as to strengthen the deployment of CCS around the globe.

Projections for CCS Deployment in Electricity Sector

In the 2DS of IEA, capture-equipped power generation is installed in almost all regions of the world. By 2050, 15% of net power generation might be available from CCS-equipped plants. However, the types of power generation equipped with CCS (i.e. coal, gas and biomass), the amount of generation capacity, and rates at which this capacity is built vary widely from region to region. Of the total 964 GW of power generation capacity equipped with capture in the 2DS in 2050, over 60% (586 GW) are located in China and the OECD Americas. In China more than 90% of this capacity is coal-fired, while in the United States only about half of capture-equipped capacity is coal-fired, the remainder being mainly gas-fired capacity (Figure 6).

The rate of CCS deployment and the year in which deployment starts differ widely around the world in the 2DS. India, Southeast Asia, Russia, and Africa do not have any capture-equipped capacity in 2020 while OECD member countries have nearly 13 GW, with smaller amounts in China and the Middle East. By 2050, the growth in capture-equipped capacity has flattened in China, OECD Europe, and Africa; however, the amount of CCS-equipped capacity continues to grow rapidly in India, the Middle East, and Southeast Asia.

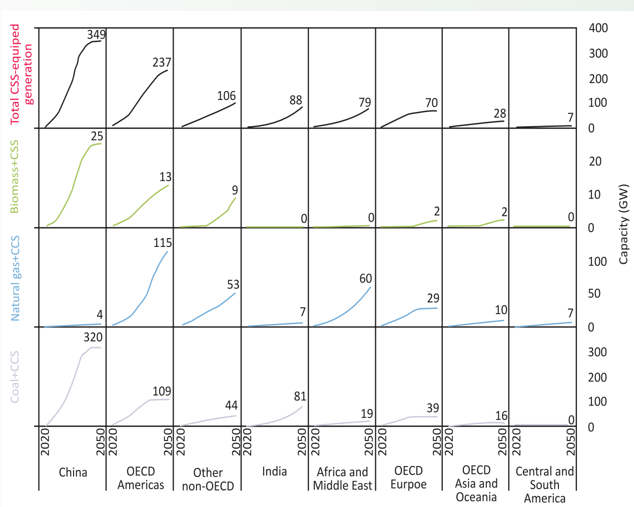


Figure 6: Power generation capacity equipped with capture (along with total capacity) for ten regions of the world 2020-2050 in 2DS; Source: IEA

Indian Perspective of Policy and Implementation of CCS

India is one of the lowest emitters of GHGs in the world on per capita basis. At 1.4 tCO_2/person in 2010, India's emissions were less than one third of world average of 4.5 tCO_2/person, less than one fourth that of China and one twelfth that of the US. Despite this, India is highly vulnerable to climate change, and has an interest in a fair and equitable global compact to minimise the risk of climate change. Climate change is already an existing threat, manifesting itself in the form of increased frequencies and intensities of extreme events. India has also prepared a National Action Plan for Climate Change (NAPCC) and said that it will reduce the emission intensity of its GDP by 20 to 25 percent, over 2005 levels, by 2020.

Largely, the focus of policymakers in India has been towards terrestrial biological sequestration. Over the past decades, national policies for conservation and sustainable management have transformed the country's forests into a net sink of CO_2. From 1995 to 2005, carbon stocks stored in Indian forests are estimated to have increased from 6245 m tons to 6622 m tons, thereby registering an annual increment of 37.68 million tons of carbon or 138.15 million tons of CO_2 equivalent. This annual removal by forests is enough to neutralize 9.31 percent of total GHG emissions in year 2000.

The National Mission for a Green India (GIM) was announced as one of the eight Missions under the National Action Plan on Climate Change (NAPCC). GIM is based on a holistic view of greening and focuses not on carbon sequestration targets alone, but, on multiple ecosystem services, especially, biodiversity, water, biomass etc. along with climate adaptation and mitigation as a co-benefit. It has the following broad objectives to be covered over next 10 years:

i. Increased forest/tree cover to the extent of 5 million hectare (mha) and improved quality of forest/tree cover of another 5 mha of forest/non-forest lands

ii. Improved/enhanced eco-system services like carbon sequestration and storage (in forests and other ecosystems), hydrological services and biodiversity; along with provisioning services like fuel, fodder, and timber and non-timber forest produces (NTFPs)

iii. Increased forest based livelihood income of about 3 million households

CCS in India started gaining interest in 2008, when publications first mentioned CCS as a possible mitigation measure in coal-using countries. Study conducted by Wuppertal Institute for Climate, Environment and Energy on "an integrated assessment for exploring whether CCS could be a viable technological option for significantly reducing future CO_2 emissions in India" provides, a holistic, long-term analysis of the potential role of CCS in India for the first time. An integrated approach covering five assessment dimensions is chosen (Figure 7).

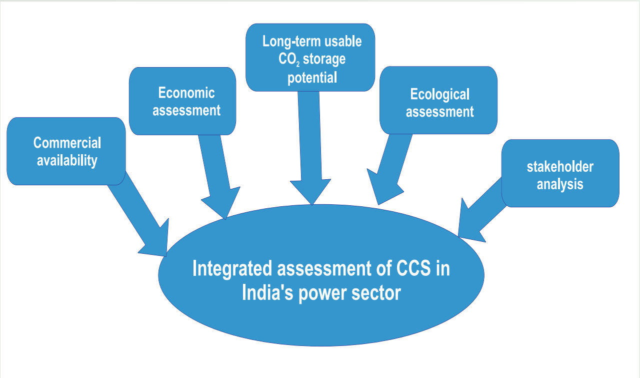


Figure 7: Set of methods used for integrated assessment; Source: P. Viebahn et al. / Applied Energy 117 (2014)

The results of the study bring out that the most crucial precondition that must be met is a reliable storage capacity assessment based on site-specific geological data since only rough figures concerning the theoretical capacity exist at present. The projections of different trends of coal-based power plant capacities up to 2050 ranges between 13 and 111 Gt of CO_2 that may be captured from coal-fired power plants to be built by 2050. If very optimistic assumptions about the country's CO_2 storage potential are applied, 75 Gt of CO_2 could theoretically be stored as a result of matching these sources with suitable sinks. If a cautious approach is taken by considering the country's effective storage potential, only a fraction may potentially be sequestered. In practice, this potential is likely to decrease further with the impact of technical, legal, economic and social acceptance factors. Further constraints may be the delayed commercial availability of CCS in India, a significant barrier to achieving the economic viability of CCS.

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Brief on Project "Sagarmala"

Sagarmala is a strategic, customer oriented initiative of Government of India to evolve a model of port led development by which India's long coastline will become the gateway of India's prosperity. The concept of Sagarmala was first announced in 2003. However, it did not materialize at that time. The concept has been reintroduced again and Ministry of Shipping released a detailed concept note on this in October, 2014. Subsequently, the Union Cabinet chaired by the Prime Minister, gave its 'in-principle' approval for the concept and institutional framework of Sagarmala project in March, 2015.

"The prime objective of the Sagarmala project is to promote port-led direct and indirect development and to provide infrastructure to transport goods to and from ports quickly, efficiently and cost-effectively. Therefore, the Sagarmala Project shall, inter alia, aim to develop access to new development regions with intermodal solutions and promotion of the optimum modal split, enhanced connectivity with main economic centers and beyond through expansion of rail, inland water, coastal and road services."

Rational behind Sagarmala: Presently, 90% of India's EXIM trade is being handled by Indian ports, however, the current proportion of merchandize trade in Gross Domestic Product (GDP) of India is only 42%, whereas for country like Germany it is 75% and for region like European Union it is 70% (Figure 1). Therefore, India still has a potential to increase the share of merchandising trade in India's GDP.

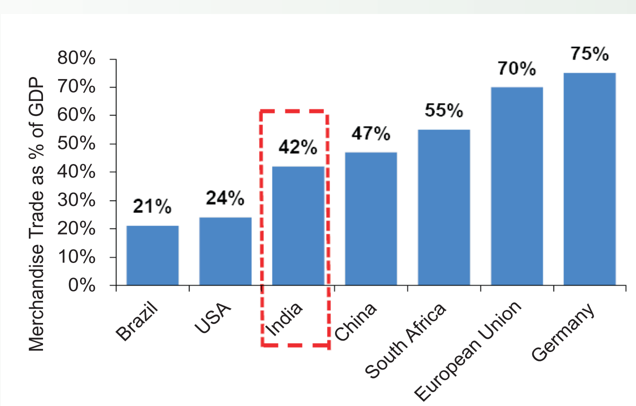


Figure 1: Merchandize Trade as a percentage of GDP; Source: World Bank data, 2012

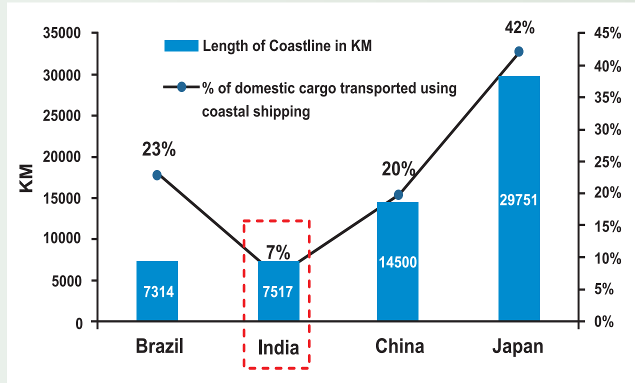


Figure 2: Share of total coastal shipping in total port traffic; Source: Economic databases, Research reports, KPMG analysis

With the current emphasis on "Make in India" initiative, it is expected that share of merchandise trade in India's GDP will increase and reach to levels of developed countries. However, compared to other modes of transportation, ports and logistics infrastructure lag far behind in India. Against a share of 9 percent of railways and 6 percent of roads in the GDP the share of ports is only 1 percent.

In spite of having inherent advantage of being safer, cheaper and cleaner compared to other modes of transportation, domestic cargo transported by coastal shipping in India is only 7% which is far lower than comparable countries with long coastlines (Figure 2). Further, the optimal modal share for traffic evacuation at major ports through coastal / inland waterways in India is 2% whereas it should be 10%.

In view of the above, the current scenario of India's underdeveloped port infrastructure, sub optimal traffic/ coastline ratio and share of domestic cargo transported using coastal shipping present a significant potential for India to develop its maritime capabilities. Considering this, Sagarmala has been visualized as ports would play pivotal role in enhancing trade and commerce potential of the country in future.

Challenges faced by the Maritime sector in India: The growth of India's maritime sector has been embroiled by many developmental, procedural and policy related challenges. Few of the challenges are enlisted below:

- Involvement of multiple agencies in development of infrastructure to promote industrialization, trade, tourism and transportation across country
- Presence of a dual institutional structure which has led to development of Major and Minor ports as individual projects
- Lack of infrastructure for evacuation at major and minor ports leading to sub-optimal transport modal mix
- Limited hinterland linkages that further increase the cost of transportation and cargo movement
- Limited development of coastal centers for manufacturing, urban and economic activities
- Low penetration of coastal and inland shipping in India due to limited facilities, higher costs and policy constraints
- Presence of selective mechanization and procedural bottlenecks at ports
- Lack of scale, deep draft and other facilities at various ports in India

Key Components of Sagarmala: The key components of Sagarmala Project are:

1. **Port Modernization:** This includes transformation of existing ports into world class ports by modernization of port infrastructure and existing systems. The same would require ensuring inter-agency coordination for synergistic development at both major and minor ports
2. **Efficient Evacuation Systems:** This component development of efficient rail, road and coastal / Inland Waterways(IWT) networks to the hinterland and promote inland / coastal shipping as a most preferred mode of transportation
3. **Coastal Economic Development:** Encouraging coastal economic activity in coastal regions by:
   - Development of Coastal Economic Zones (CEZ), port based SEZs / Free Trade and Warehousing zone (FTWZ)s, captive ancillary industries
   - Promotion of coastal tourism

These three outcomes will in turn be supported by enabling policies, robust institutional structure and appropriate financing & funding mechanism to ensure inclusive growth (Figure 3):

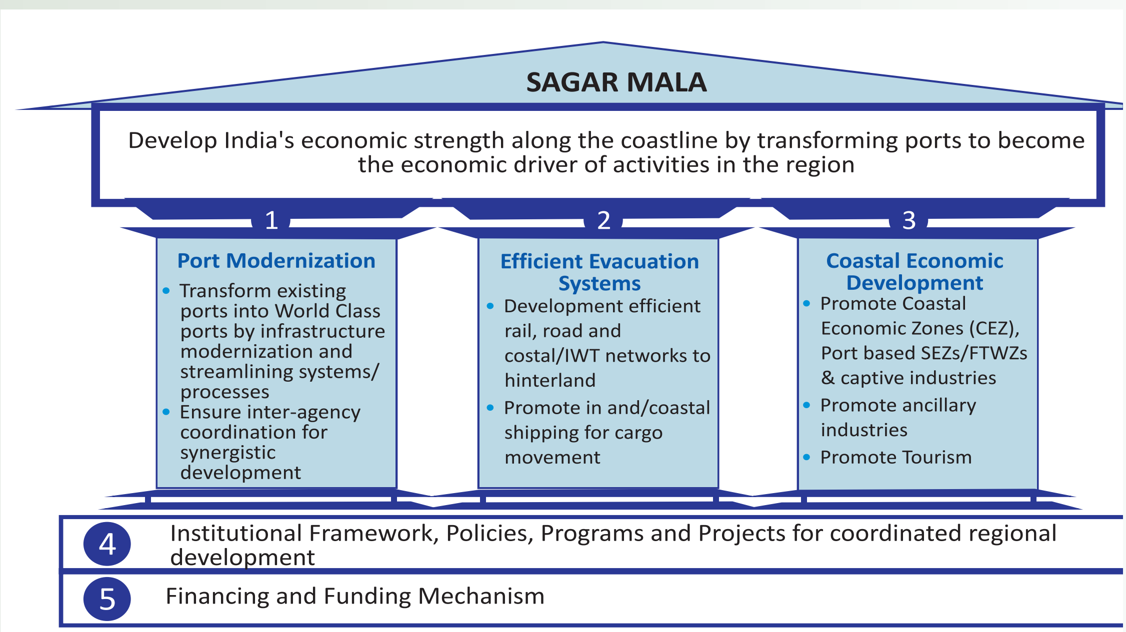


Figure 3: Pillars of Sagarmala; Source: Concept Note on Sagarmala Project: Working Paper, Ministry of Shipping, GoI

Broad initiatives under Sagarmala: The two broad initiatives that will drive Sagarmala are:

1. *Development of Coastal Economic Regions (CER):* A CER is a contiguous region comprising Major and Non Major Ports and their hinterland. A CER will have the following characteristics:

- Single state based economic region that will encompass both major and minor ports within a state
- Can extend along 300 to 500 km of coastline and 10 to 30 km inland/offshore
- Enable identification of new ports and industrial / economic clusters within a state, as required
- Foster development of maritime ecosystem and extended supply chain e.g. logistics, shipping agencies, service providers, education & training, etc. through institutional and/or infrastructure mechanisms
- Enable sustainable growth of the rural communities by providing employment opportunities and ensuring economic development of the region

2. *Policy initiatives to promote coastal shipping and seamless operations in Ports:* Coastal Shipping and Inland Waterways (IWT) can be enhanced through a mix of infrastructure and policy initiatives related to conducive policy and regulations, port infrastructure and national mega waterways development projects.

The development and infrastructure modernization initiatives must be supported by conducive policies and regulations that foster growth and development of Coastal Shipping and IWT. Some of the policy initiatives have been enlisted below:

- Provide Green channel and easier ingress/ egress from ports
- Simplify procedures on manning norms, fuel taxes and compliances for coastal/ inland vessels
- Incentivize commodities to use coastal mode
- Promote research and manufacturing of equipment and vessels for coastal/ inland use
- Provide provisions for setting up a Coastal shipping promotion fund for development of coastal shipping
- Provide provisions for a proportionate reduction in CSR obligation for every unit of lowered carbon emission through coastal shipping and IWT
- Make allocations for coastal shipping and IWT usage for PSUs

Institutional Framework: The GoI press release on "Sagarmala: Concept and implementation towards Blue Revolution" outlines the institutional framework for implementation of Sagarmala project. A National Sagarmala Apex Committee (NSAC) is envisaged for overall policy guidance and high level coordination, and to review various aspects of planning and implementation of the plan and projects. The NSAC shall be chaired by the Minister incharge of Shipping, with Cabinet Ministers from stakeholder Ministries and Chief Ministers/Ministers incharge of ports of maritime states as members. This committee, while providing policy direction and guidance for the initiative's implementation, shall approve the overall National Perspective Plan (NPP) and review the progress of implementation of these plans.

At the Central level, Sagarmala Development Company (SDC) will be set up under the Companies Act, 1956 to assist the State level/zone level Special Purpose Vehicles (SPVs), as well as SPVs to be set up by the ports, with equity support for implementation of projects to be undertaken by them. The SDC shall also get the Detailed Master Plans for individual zones prepared within a two year period. The business plan of the SDC shall be finalised within a period of six months. The SDC will provide a funding window and/ or implement only those residual projects that cannot be funded by any other means/mode.

Key Benefits of Sagarmala: Sagarmala is an integrated infra cum policy initiative to develop India's maritime sector that will contribute to the inclusive growth of the Indian economy.

The key preliminary/indicative benefits of Sagarmala initiative have been enlisted below:

Infrastructure and Developmental Benefits	Economic Benefits
• 3-4 modern world class Mega ports of 200 MT capacity each • Transhipment terminal as a Regional Container Hub • Establishing 10 state - specific Coastal Economic Regions that will foster economic growth in ports and their hinterlands • Better integrated connectivity in an CER and hinterland • Fully integrated coastline through inland and mega waterways (National navigation channels) • Greenfield / brownfield options for river & coastal ports • Shift of modal mix to an optimal modal mix (increase of coastal shipping and inland water transport) • Seamless dedicated backward linkages with key Transport / Infra projects e.g. DMIC, AKIC, CBIC,DFC, PCPIR • 3-4 Coastal Tourist circuits to position India as a prominent tourist destination	• 15 times growth in Coastal / IWT traffic increase over next 20 years • Capacity augmentation to handle 5X ports traffic increase over next 20 years • Coastal Economic Regions (CER) leading to increased GDP/ EXIM • Significant employment creation in ports, shipping and ancillary areas/ecosystem • Structured urbanization of coast/rivers and development of riverine/ coastal communities • Revenue generation though increased economic activity due to all round development of the coastal cities and tourism

References

- http://pib.nic.in/newsite/PrintRelease.aspx?relid=117691
- Concept Note on Sagarmala Project: Working Paper, Ministry of Shipping, GoI
- http://pmindia.gov.in/en/news_updates/sagarmala-concept-and-implementation-towards-blue-revolution/

World Primary Energy* Consumption

S. No.	Countries/ Regions	2014			2013	
		MTOE	% Change over 2013	% share of total	MTOE	% share of total
1	China	2972.1	2.6	23.0	2898.1	22.6
2	US	2298.7	1.2	17.8	2270.5	17.7
3	Russian Federation	681.9	-1.2	5.3	689.9	5.4
4	**India**	**637.8**	**7.1**	**4.9**	**595.7**	**4.7**
5	Japan	456.1	-3.0	3.5	470.1	3.7
6	Canada	332.7	-0.5	2.6	334.3	2.6
7	Germany	311.0	-4.5	2.4	325.8	2.5
8	Brazil	296.0	2.5	2.3	288.9	2.3
9	South Korea	273.2	0.9	2.1	270.8	2.1
10	Iran	252.0	3.3	1.9	244.0	1.9
	OECD	5498.8	-0.9	42.5	5548.5	43.3
	Non-OECD	7429.6	2.4	57.5	7258.7	56.7
	Total World	**12928.4**	**0.9**		**12807.1**	

*Primary energy comprises commercially traded fuels including modern renewable energy used to generate electricity; Source: BPStat, 2015

World Primary Energy* Consumption by Fuel-2014

S. No.	Countries/ Regions	Oil		Gas		Coal		Nuclear		Hydro		Renewable		Total
		MTOE	% of total	MTOE	% of total	MTOE	% of total	MTOE	% of total	MTOE	% of total	MTOE	% of total	
1	China	520.3	17.5	166.9	5.6	1962.4	66.0	28.6	1.0	240.8	8.1	53.1	1.8	2972.1
2	US	836.1	36.4	695.3	30.2	453.4	19.7	189.8	8.3	59.1	2.6	65.0	2.8	2298.7
3	Russian Federation	148.1	21.7	368.3	54.0	85.2	12.5	40.9	6.0	39.3	5.8	0.1	0.0	681.9
4	India	180.7	28.3	45.6	7.1	360.2	56.5	7.8	1.2	29.6	4.6	13.9	2.2	637.8
5	Japan	196.8	43.2	101.2	22.2	126.5	27.7	0.0	0.0	19.8	4.3	11.6	2.6	456.1
6	Canada	103.0	31.0	93.8	28.2	21.2	6.4	24.0	7.2	85.7	25.8	4.9	1.5	332.7
7	Germany	111.5	35.9	63.8	20.5	77.4	24.9	22.0	7.1	4.6	1.5	31.7	10.2	311.0
8	Brazil	142.5	48.2	35.7	12.1	15.3	5.2	3.5	1.2	83.6	28.2	15.4	5.2	296.0
9	South Korea	108.0	39.5	43.0	15.7	84.8	31.0	35.4	13.0	0.8	0.3	1.1	0.4	273.2
10	Iran	93.2	37.0	153.2	60.8	1.1	0.5	1.0	0.4	3.4	1.4	0.1	0.0	252.0
	OECD	2032.3	37.0	1432.6	26.1	1052.5	19.1	449.8	8.2	315.7	5.7	215.9	3.9	5498.8
	Non-OECD	2178.9	29.3	1632.9	22.0	2829.3	38.1	124.2	1.7	563.3	7.6	101.1	1.4	7429.6
	Total World (2014)	4211.1	32.6	3065.5	23.7	3881.8	30.0	574.0	4.4	879.0	6.8	316.9	2.5	12928.4

*Primary energy comprises commercially traded fuels including modern renewable energy used to generate electricity; Source: BPStat, 2015

Oil - Consumption

S. No.	Countries/ Regions	2014			2013	
		Thousand barrels daily	% Change over 2013	% share of total	Thousand barrels daily	% share of total
1	US	19034.8	0.5	19.9	18961.1	20.8
2	China	11056.5	3.3	12.4	10664.4	11.7
3	Japan	4298.1	-5.2	4.7	4520.8	5.0
4	**India**	**3845.9**	**3.0**	**4.3**	**3727.2**	**4.1**
5	Brazil	3228.8	5.4	3.4	3047.6	3.3
6	Russian Federation	3195.9	0.9	3.5	3178.7	3.5
7	Saudi Arabia	3185.5	7.3	3.4	2999.5	3.3
8	South Korea	2456.0	-0.3	2.6	2455.4	2.7
9	Germany	2371.5	-1.7	2.6	2408.1	2.6
10	Canada	2370.6	-0.5	2.4	2382.9	2.6
	OECD	45057.4	-1.2	48.3	45533.1	49.9
	Non-OECD	47028.8	2.7	51.7	45710.2	50.1
	Total World	**92086.2**	**0.8**		**91243.3**	

Notes:

1. Annual changes and share of total are calculated using million-tonnes per annum figures.
2. Figures include inland demand plus international aviation and marine bunkers and refinery fuel and loss. Consumption of fuel ethanol and bio-diesel is also included

Source: BP Stat, 2015

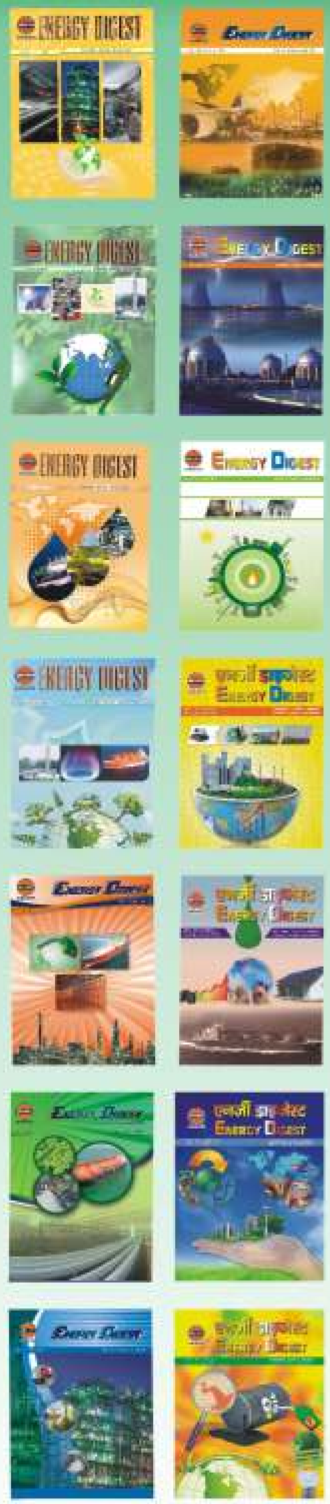
Natural Gas - Consumption

S. No.	Countries/ Regions	2014			2013	
		Billion cubic meters	%Change over 2013	% share of total	Billion cubic meters	% share of total
1	US	759.4	2.9	22.7	739.9	21.9
2	Russian Federation	409.2	-1.0	12.0	413.5	12.2
3	China	185.5	8.6	5.4	170.8	5.1
4	Iran	170.2	6.8	5.0	159.4	4.7
5	Japan	112.5	-0.9	3.3	113.5	3.4
6	Saudi Arabia	108.2	8.2	3.2	100.0	3.0
7	Canada	104.2	0.3	3.1	103.9	3.1
8	Mexico	85.8	1.4	2.5	84.7	2.5
9	Germany	70.9	-14.0	2.1	82.5	2.4
10	United Arab Emirates	69.3	3.8	2.0	66.8	2.0
14	**India**	**50.6**	**-1.5**	**1.5**	**51.4**	**1.5**
	OECD	1578.6	-1.8	46.7	1609.7	47.6
	Non-OECD	1814.3	2.4	53.3	1771.3	52.4
	Total World	**3393.0**	**0.4**		**3381.0**	

Notes:

Annual changes and share of total are calculated using million-tonnes oil equivalent figures

Source: BP Stat, 2015



Inviting articles for ENERGY DIGEST

Energy Digest, IndianOil's quarterly corporate journal started in 2009, is published by IndianOil's Corporate Planning & Economic Studies Department. This journal has been conceptualized with an aim to act as a medium of knowledge sharing and present views on the issues and developments related to energy, economy and environment (3Es). Considering the criticality of 3Es for any nation in achieving inclusive and sustainable growth, it has become imperative to be abreast of evolving paradigms in 3Es to take informed decisions promptly. Energy Digest focuses on the issues related to 3Es, thereby making professionals aware of latest economical, technical and regulatory developments.

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Last date for submission of theme/abstract (100-150 words) of article

- 35 days prior to 1st working day of a quarter (before 25th August, 2015 for the October, 2015 issue), subsequent to receipt of abstract, approval (of editorial committee) for the same with suggested improvisations will be sent in next 2-3 working days.

Last date for submission of article

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List of Suggested Topics For Energy Digest

Exploration & Production

- Traditional & New Exploration Challenges: Current Scenario of Oil & Gas Reserves
- New Technologies in E&P: Optimal Usage of Oil & Gas Reserves
- Deep and Ultra Deep Offshore Drilling: Developments & Concerns
- Evolving Regulations in Deep and Ultra Deep Offshore Drilling: After Macondo Blowout
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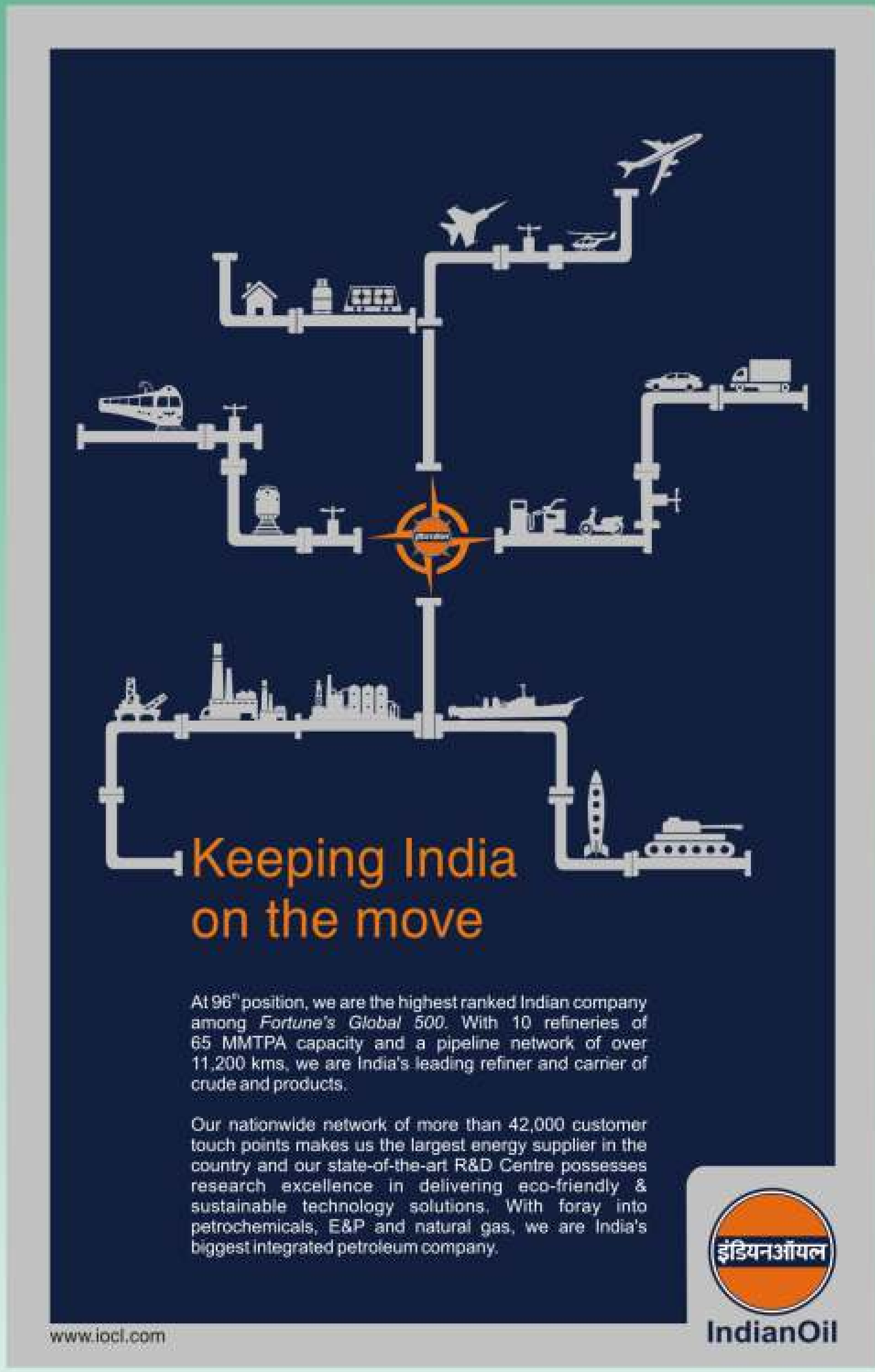
- Beyond Kyoto Protocol
- Aviation Industry in EU-ETS
- CSR& Commitment towards society
- CDM projects in Indian Energy Sector
- Battery driven vehicles - road map for development

This list is only a suggestive list; articles on other topics related to Energy, Economy and Environment can also be sent.



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