PROJECT COMPLETION REPORT

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PROJECT TITLE

Analysis of Carbon Capture and Storage (CCS) Technology in the Context of Indian Power Sector

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EXECUTIVE SUMMARY

A. Introduction

The climate change and climate variability is evident world over, which can be attributed to global warming. According to the IPCC 2007 "most of the observed increase in global average temperatures since the mid-20th century is very likely due to the observed increase in anthropogenic GHG [Green House Gas] concentrations in atmosphere." There are many greenhouse gases, of which CO2 is main component, is emitted by various industrial processes and burning of various types of carbonaceous fuels. In addition many natural phenomena, agriculture, live-stock also emit greenhouse gases.

The nature has its own mechanism (carbon cycle) to absorb carbon dioxide from atmosphere to sustain biosphere balance. However, since the beginning of the industrial revolution the GHG emissions to atmosphere is increasing due to use of fossil fuel by industry, thermal power generating stations, transport and logistics.

The UNFCCC was adopted in 1992 and has been ratified by 192 countries, including India. Its objective is "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system."[1]

Power Sector is the largest consumer of coal accounting for about 70% of total coal consumption in the Indian economy. India being in an accelerated phase of economic growth, aiming to add more than 600,000 MW of power generation capacity in the next two decades needs special interventions to restrict CO_2 emission to minimize global warming. Despite emphasis on nuclear, hydro and renewable energy, fossil fuel power especially, coal based power will produce large share of power. Therefore, the clean coal technologies and "efficient and clean" combustion of coal are being developed to reduce CO_2 emission from the power sector. Carbon

[1] http://www.fas.org/sgp/crs/misc/R40910.pdf

Capture and Storage (CCS) technology is emerging as a promising technology to reduce GHG emission by capturing CO_2 from flue gas and storing it under the viable surface.

This project intends to define and carry out the research in a predetermined manner to achieve the research objectives under "**National Programme on Carbon Sequestration"** Research programme of DST and formulate policy recommendation for appropriate authority**.**

A.1. Objective

The key objective of the Research Project is "To study, analyze, evaluate and assess the importance and development of CCS technology in reducing the GHG emissions to restrain global warming and its economic implications."

In pursuing the above research objective, the study focused on the components of CCS technology with reference to power sector in detail so as to understand the feasibility of the concerned technologies; their applicability to the Indian Power Sector; and further applied research and demonstration project requirements to establish viability of this technology.

The scope of CCS Technology aims to:

- Enhancing efficiency of power plants by emerging technologies to reduce emission of CO_2 per megawatt to reduce process load on capture technology;
- Capturing and Separating CO_2 from the gas streams emitted from combustion;
- Transporting the captured CO_2 to underground storage;
- Storing CO_2 underground in deep saline aquifers, sedimentary basins, basalt formation and depleted Oil and Gas or Coal reservoirs. The potential areas in the country where CO_2 can be stored, and how the storage can be conducted (trapping mechanism);
- Will the storage site be safe?

Thus the CCS, technology aims at reducing CO_2 percentage in the atmosphere by storing the CO_2 produced by the fossil fuel fired plants in secure sinks at affordable prices for hundreds of years.For the above purpose, the IRADe team conducted extensive literature review; carried structured interviews to assess the development and opinion of stakeholders on various aspects of carbon capture and storage technology, conducted, analyzed individually for major component of the project based on the scope of the project. The analysis included the assessment of general progress with a detailed description of relevant developments. A detailed description of the options, scenarios, present status, R&D road map etc. was analyzed. This includes description of a range of features like CCS technological status, Indian energy sector- potential sources of GHG, clean coal technologies, capture, transport and storage technologies, stakeholders view etc. It was assumed that India will take up CCS only after it is successfully demonstrated and implemented elsewhere in the world. However, India will continue the R & D work for CCS in order to develop clean technologies and explore business opportunities for CCS in order to develop clean technologies and explore business opportunities in CCS in future.

The aim of the research study was to conduct an analytical study of CCS technology for Indian power sector analyzing Potential sources of GHG emissions in Indian energy sector with focus on power sector, major fossil fuels (Hydrocarbons) used in India and their characteristics, thermal technologies for efficiency improvement and clean coal usage, Status and development of CCS technology ,CO2 capture technologies, CO2 transportation technologies ,CO2 storage locations and initial characteristics of the sites, economics and cross cutting issues, Roadmap of CCS R&D for India.

B. CCS Technology and Status

CO_2 capture & storage (CCS) is a 3-step process including CO_2 capture from power plants, industrial sources, and natural gas wells with high CO_2 content; **transportation** (usually via pipelines) to the storage site; and **geological storage** in deep saline formations, depleted oil/gas fields, un-mine-able coal seams, and enhanced oil or gas recovery (EOR or EGR) sites. In combustion processes, CO_2 can be captured either in pre-combustion mode (by fossil fuel treatment) or in post-combustion mode (from flue gas or by oxy-fuel).

Technologies for CCS are rather well known, but system integration and commercial demonstration are needed. If CCS is to play a significant role in the coming decades, demonstration must be accelerated. In particular, underground storage needs to be proven. Given the range of technologies under development, CCS demonstration would require at least ten major power plants (globally) with CCS to be in operation by 2025. Substantially larger demonstration budgets as well as private/public partnerships and outreach to emerging economies are essential. As CCS implies an incremental cost, economic incentives are needed for CCS to be commercially demonstrated and deployed. Major barriers to CCS deployment are cost, demonstration of commercially viable operation and safe permanent storage. The status of these three segments is described below.

B.1. CO2 Capture

Efficiency improvements in coal fired power plants will definitely help towards lowering CO_2 emissions; however, further steps are necessary in order to make significant reductions in CO_2 emissions. CCS offers a longer term option for achieving reduced CO_2 emissions from coal based power. The technologies basically involved are pre-combustion capture from the exhaust streams of coal combustion or gasification processes and geologically disposing of it so that it does not enter the atmosphere. Several projects are now underway to push this technology ahead in countries such as Australia, Canada, Germany, the UK, and the USA.

B.2. Carbon Transportation

Transport is that stage of carbon capture and storage that links sources of captured carbon dioxide and storage sites. In the context of long-distance movement of large quantities of carbon dioxide, pipeline transport is part of current practice. CO_2 is transported in three states: gas, liquid and solid. Commercial-scale transport uses tanks, pipelines and ships for gaseous and liquid carbon dioxide. The use of ships for transporting CO_2 across the sea is today in an embryonic stage. Worldwide there are only four small ships used for this purpose. These ships transport liquefied food- grade CO_2 from large point sources of concentrated carbon dioxide such as ammonia plants in northern Europe to coastal distribution terminals in the consuming regions.

B.3. Carbon Storage

The carbon storage is the critical component of the CCS technology. At this stage CO_2 emission to the atmosphere are finally restricted by storing the captured gas in the selected geological site. The concept emerged as the subsurface of the Earth is large carbon reservoir, where the coals, oil, gas organic-rich shales exists. The best sites for CO_2 storage from economic point of view are deep saline formations, depleted oil/gas fields, un-mineable coal seams, and enhanced oil or gas recovery (EOR or EGR) .The CO_2 is injected and stored into geological “storage reservoirs” using standard techniques that have been used in the oil and gas industry for many decades.

C. The Current Status of CCS:

While technologies of CCS are relatively mature individually, but to date there are no fully integrated, commercial scale CCS projects in operation. They are used in different context in various industries already around the world.

a. Capture Technology- Applied in chemical and refining industry for decades but integration in the context of power production still needs to be demonstrated.

b. Transportation of CO_2- Central utilities has more than 5000 Km of pipelines and proven successful for more than 30 yrs. in injection of CO_2 into oil fields for enhanced oil recovery.

c. Storage of CO_2- Operational worldwide for 10 years Norway, Canada, Algeria. The industry can build on knowledge obtained through geographical storage of natural gas. Yet, there is uncertainty in respect of storage in deep saline aquifers.

D. Potential sources of GHG emissions- Power

In the context of power, India is divided into five power regions namely Northern, Western, Southern, Eastern and North-Eastern. The resources (units) of power generation in the country are quite diversified. The coal is located mainly in the eastern, central regions and southern region (Andhra), lignite in the southern region, and big hydro-power which needs to be developed mainly in the northern and north-eastern region. In order to meet the growing needs of power it is essential to develop all the indigenous resources in an optimal manner using most efficient technologies and also keeping in view the GHG emission and environmental concerns.

The Installed Capacity in the country has increased from a mere 1,713 MW in December 1950 to 1,59,398 MW at the end of March, 2010 whereas during the same period the annual electricity generation has grown from about 5 BU to about 723.5 BU by March 2009. So far electricity generation achieved till 31.3.2010 is 771.5 BU as against of 789.5 BU target for 2009-10 which is approximately 97.7%.

Growth in demand has exceeded the supply and power shortages persist. The power supply position at the end of 2009-10 indicates an energy deficit of 11% on all India basis, varying from 4.6% lowest in eastern region to about 16 % highest in the Western region. Similarly over all peak shortage has been 13.3% varying in the range of 7.4% in the southern region to about 25.4% in the North eastern region.

However, power sector being the largest source of GHG emissions due to the major part of base load electricity supplied by the fossil fuel fired power plants requires immediate attention. The possible solutions to reduce the GHG emissions from the fossil fuel fired power plants are:

- Increase the overall efficiency of the power plants by timely maintenance and reduction of wastage
- Application of new technologies and retrofitting of the old power plants
- Shifting base load generation from fossil fuel fired power plants to renewable energy based power plants
- Application of CCS technologies to existing power plants and essentially incorporating these technologies to the upcoming new power plants

Future projections are done up to 15th five year plan (2031-32) under two scenarios of 8% and 9% GDP growthas per the report of Integrated Energy Policy (2006), which has following details.

D.1. Sources of Data:

The actual data for the purposes of further analysis in respect of Installed capacity, Electricity generation by different modes has been taken from CEA publications for the end of 10th plan (2006-07) and first 3 years of 11th plan i.e. 2007-08, 2008-09 and 2009-10. Based on this data source wise operating parameters of various generating capacities i.e. Hydro, Thermal, Nuclear etc has been worked out and used for further calculations of capacity additions, installed capacity requirement and generation etc for the period of 12th five year plan to 15th five year plan.

The report of Integrated Energy Policy published in 2006 have carried out various energy sector projections up to the year 2031-32 under GDP growth rate scenarios of 8% and 9%. As per these the installed capacity of power plants in country will increase to increase from about 115,000 MW at the end of 11th plan to about 382,000 MW in the year 2031-32 under 8% scenario to about 479,000 MW under 9% scenario, in spite of high hydro, nuclear and gas capacity development. However, this will depend upon availability of natural gas and also nuclear fuel and capability to execute such large capacities The future projections of source wise capacity addition and calculation of CO_2 emissions are done up to end of 15th five year plan (2031-32) under these two scenarios :

Head	8% GDP Growth	9% GDP Growth
Capacity Addition	89 GW (12th five year plan) to 202 GW(15th five year plan)	117 GW (12th five year plan) to 276 GW(15th five year plan)
Installed Capacity	326 GW (12th five year plan) to 794 GW(15th five year	354 GW (12th five year plan) to 978 GW(15th five year

	plan)	plan)
CO2 Emissions	1141 Mt CO2 (12th five year plan) to 2800 Mt CO2 (15th five year plan)	1280 Mt CO2 (12th five year plan) to 3474 Mt CO2 (15th five year plan)

Table D-1 Power Sector Forecast (12th & 15th Five Year Plan)

The above mentioned projections shows under 8% GDP growth scenario the CO_2 emissions will increase from 788 Mt CO_2 at the end of 11th plan to about 2800 Mt CO_2 at the end of 15th plan i.e nearly 3.5 times. Similarly in case of 9 % scenario CO_2 emissions will further be further higher at 3474 Mt CO_2 i.e. nearly 4.4 times the levels at the end of 11th plan. Keeping in view the global concern on Climate change way and means have to be found for reduction of GHG emissions by fossil fuel based thermal power plants. These options are discussed in subsequent paragraphs.

E. Fossil fuel resources and likely CO2 emissions and storage sites

E.1. Coal

Coal resources determine the likely CO2 emissions in future. Although coal can be imported, transportation costs are high. Moreover old coal fields can also serve as CO2 storage sites. As per the estimates of Geological Survey of India, the coal reserves of India stand at 267 Billion Tonnes as on 01.04.2009 with more than 87% of these being of the non-coking grade. The geographical distribution of these coal reserves is primarily in the states of Bihar, Jharkhand, West Bengal, Orissa, Madhya Pradesh, Chattisgarh, Maharashtra and Andhra Pradesh. The total coal production in the country during 2008-09 was 493 MT, of which about 355 MT was used for power sector (excluding captive power plants). In addition to this, about 20 MT was imported for Power Sector. The total coal availability from domestic sources is expected to be 482 MT per annum by 2011-12. This includes coal production from captive mines.

E.2. Lignite

The geological reserves of lignite have been estimated to be about 35.6 BT. Lignite is available at limited locations such as Neyveli in Tamil Nadu, Kutchh, Surat and Akrimota in Gujarat and Barsingsar, Bikaner, Palana, Bithnok in Rajasthan. Since, lignite is available at a relatively shallow depth and is non-transferable, its use for power generation at pithead stations is found to be attractive. The cost of mining lignite has to be controlled to be economical for power generation

Coal will continue to be major fuel source for power generation, till foreseeable future. In the economic analysis the additional costs of capturing and storing CO2 is to be considered for coal based power plant. The location issue is relevant since it has to be observed that optimum logistics and raw material issues are addressed. The options for new power plants will be where it will be installed are; (a) close to the fossil fuel reserves, (b) next to consumers/ load centers, (c) coast based generation units or (d) adjacent to potential storage sites. The quantity of coal availability might become relevant since CCS requires between 20 and 30% more coal for the same electricity output.

E.3. Coal Bed Methane

Under India's coal bed methane (CBM) policy, formulated by the Indian government in 1997, 26 virgin coal bed methane (VCBM) blocks have been allotted for commercial development to different operators through global bidding. Increase in demand of coal from power sector has resulted in the allotment of coal blocks within India's CBM blocks. This has caused an overlap in the allotment of coal and CBM blocks.

E.3.1. Indian Fuel Scenario for Thermal Power Generation unit

- Raw High Ash and Washed low ash Non coking Sub bituminous coals (85 %)
- Middlings of Caking Bituminous Coals (rest)
- Imported low ash ,high moisture ,high volatile coals
- Fresh Water origin Lignite (Neyveli)

- Marine water Origin Lignite (Gujarat & Rajasthan)
- Bio Mass (Agri. Wastes & Non carpentry wood wastes) & alternate Fuel Availability

E.4. Hydro Carbons--Petroleum and Natural Gas

India has total reserves of 775 million metric tonnes of crude oil and 1074 billion cubic metres of natural gas as on 1.4.2009. While CCS is thought appropriate for coal based power, it is hydro carbon industry which has considerable experience regarding CO_2 injection for enhanced recovery, transportation etc and also after storage sites.

The total number of exploratory and development wells and metreage drilled in onshore and offshore areas during 2008-09 was 381 and 888 thousand metres respectively. The Crude oil production during 2008-09 at 33.51 million metric tonnes is 1.79% lower than 34.12 million metric tonnes produced during 2007-08. Gross production of Natural Gas in the country at 32.85 billion cubic metres during 2008-09 is 1.33% higher than the production of 32.42 billion cubic metres during 2007-08.

The refining capacity in the country increased to 177.97 million tonnes per annum (MTPA) as on 1.4.2009 from 148.968 MTPA as on 1.4.2008. The total refinery crude throughput during 2008-09 at 160.77 million metric tonnes is 2.99% higher than 156.10 million metric tonnes crude processed in 2007-08 and the pro- rata capacity utilization in 2008-09 was 107.9% as compared to 104.8% in 2007-08.

The production of petroleum products during 2008-09 was 152.678 million metric tonnes (including 2.162 million metric tonnes of LPG production from natural gas) registering an increase of 3.87% over last year's production at 146.990 million metric tonnes (including 2.060 million metric tonnes of LPG production from natural gas).

The country exported 36.932 million metric tonnes of petroleum products against the imports of 18.285 million metric tonnes during 2008-09. The sales/consumption of petroleum products during 2008-09 were 133.400 million metric tonnes (including sales through private imports) which is 3.45% higher than the sales of 128.946 million metric tonnes during 2007-08.

F. Clean Coal Technologies

The future technology trends are being driven by three main criteria viz. efficiency, environment and economics. Green House Gas (GHG) emission from thermal power stations has been drawing greater attention in the recent past. Any improvement in efficiency would result in lesser fuel being burnt and in corresponding economic and environmental benefits. Therefore, the conversion efficiency which is a function of turbine and boiler efficiency needs to be improved to reduce the GHG emissions. The steam turbine efficiency has been increasing with the increase in unit size accompanied by increase in steam parameters.

Constant efforts have been made in the past to improve the technology and efficiency of thermal generation, and units with higher steam parameters have been progressively introduced. Increase of steam parameters i.e. temperature and pressure is one of the effective measures to increase efficiency of power generation.

In the 12^{th} Plan, based on the experience gained by NTPC, other generating companies should also adopt super critical technologies so as to reduce green house gases emissions.

However, the approach of efficiency improvement would yield environmental benefit only to a limited extent and there is a need to look beyond for larger quantum of environmental benefits which is possible only by adopting new clean coal technologies.

F.1. Clean Coal Technologies

This group of technologies basically focuses on conversion process which, by virtue of either improved efficiency or better amenability to pollution control measures result in reduced environmental degradation. These technologies include fluidized bed combustion, integrated gasification combined cycle etc.

F.2. Fluidized Bed Combustion (FBC) technology

The quality of coal available in India is of low quality, high ash content and low calorific value. The traditional grate based fuel firing systems have got performance limitations and are techno-economically unviable to meet the rising demand and techno-economic challenges of future.

Fluidized bed combustion has emerged as a viable alternative and has significant advantages over conventional firing system and offers multiple benefits –

1) Compact boiler design
2) Fuel flexibility;
3) Higher combustion efficiency; and
4) Reduced emission of noxious pollutants such as SOx and NOx.

F.3. Fluidized Bed Combustion Systems:

These boilers operate at atmospheric pressure.

F.4. Pressurized Fluidized Bed Combustion Systems (PFBC):

These systems operate at elevated pressures and produce a high-pressure gas stream at temperatures that can drive a gas turbine. Steam generated from the heat in the fluidized bed is sent to a steam turbine, creating a highly efficient combined cycle system.

F.5. Integrated Gasification Combined Cycle (IGCC)

Integrated Gasification Combined Cycle (IGCC) System is one of the clean coal technologies in which coal is converted into gaseous fuel, which after cleaning is used in CCGT plants. The IGCC systems which are commercially available have shown higher efficiencies and exceptionally good environmental performance in SOx removal, NOx reduction and particulate removal. IGCC, if commercially proven, will be one of the most attractive power generation technologies for the 21st century.

The following essential properties of coal gasification process differentiate this process from coal combustion:

1) Process of coal gasification is conducted with low gasifying medium (oxidizer) number to obtain high chemical efficiency in the process and low content of NOx in the gas.
2) About **99%** of sulphur is converted into **H_2S** and **COS,** and only a little into **SO_2;** these gases are removed from the gas in the cleaning process.
2) Ash is efficiently removed from the gas in melted form.
3) High pressure of the process of coal gasification allows the construction of a combined gas-steam power plant with high efficiency.
4) Gas is cleaned of sulphur compounds and of ash before burning.

The process of coal gasification, as a part of the technology used in generation of electric energy, allows producing "clean" gas fuel from "dirty" coal.

F.6. Oxy –Fuel Technology:

Oxy-fuel technology refers to technology where pure oxygen is mixed with fuel instead of air for the purpose of combustion.

Atmospheric air contains 20.95% oxygen, 78.08% nitrogen and rest part is occupied by the inert gases like Neon, Helium Xenon etc.

Generally atmospheric air is used to form a mixture along with the fuel for combustion purposes but as the oxygen content in air is only 20.95%, higher temperature cannot be reached on account of energy used in diluting the inert gases.

Higher temperature can be reached if pure oxygen is mixed with the fuel and then that mixture is used for combustion. This negates any chance of energy being used for dilution of the inert gases.

Approximately the same total energy is produced when burning a fuel with oxygen as compared to with air; the difference is the lack of temperature diluting inert gases like nitrogen, Helium, Xenon etc.

Oxy-fuel combustion process is the process of burning a fuel by making fuel-pure oxygen mixture using pure oxygen instead of mixing the fuel with air where air acts as the primary oxidant. In oxy-fuel combustion process, since there is no nitrogen component and only pure oxygen is mixed with the fuel to make oxygen- fuel mixture, the fuel consumption is reduced, and higher flame temperatures are possible, thereby increasing the efficiency of the process.

F.6.1. Application of Oxy- Fuel Technology in Fossil Power Plants

Oxygen fired pulverized coal combustion (Oxy-Fuel), offers a low risk step development of existing power generation technology to enable carbon dioxide capture and storage. The justification for using oxy-fuel is to produce a CO_2 rich flue gas ready for sequestration.

F.6.2. Importance

Oxy-fuel technology is important for clean electricity generation using fossil fuel for the following reasons:

1. The potential for a medium- to long-term, lower cost and lower technology risk, option for achieving near zero emissions from coal-based electricity generation;
2. The potential to retrofit this technology to standard PF technology (sub-critical as well as super/ultra-super critical PF technology).
3. The prospect of applying the technology to new coal-fired plant with significant reductions in the capital and operating cost of flue gas cleaning equipment such as deNOx plant.
4. The mass and volume of the flue gas are reduced by approximately 75%.
5. Because the flue gas volume is reduced, less heat is lost in the flue gas.
6. The size of the flue gas treatment equipment can be reduced by 75%.
7. The flue gas is primarily CO_2, suitable for sequestration.

F.7. Integrated Solar Combined Cycle (ISCC)

Our country is gifted with vast potential of solar energy. which can be utilized to generate power. Direct solar insolation for over 10 months in a year are available in the Thar desert stretching over vast areas of Rajasthan and Gujarat. Even if 1% of it is used, it can generate about 6000 MW of electric power.

F.8. Fuel Cell Technology

Fuel cells are electro-chemical devices that convert energy from fuel directly into electricity through electro-chemical reactions. These cells normally use hydrogen directly as fuel or as derived from natural gas or other hydro carbons. About 4-5 major technologies for fuel cells are in various stages of development worldwide.

All the technologies mentioned above if applied can help to reduce the CO_2 emissions from the atmosphere sustainably. Oxy fuel technology and IGCC can be integrated with other technologies at various stages of development and can be used for CCS purpose which can reduce the CO_2 and other emissions from the atmosphere and reduce the level of harmful gases in the environment.

G. Carbon Capture and Transport

The CCS process chain commences with CO_2 being captured from the flue gas of the industrial combustion process (power plant) using fossil fuel. This process design is for post-combustion capture process. In pre-combustion capture process solid/ liquid/ gaseous fossil fuel is first converted to a synthetic gas, which is mixture of hydrogen, carbon mono-oxide and carbon dioxide using gasification process. The synthetic gas can be reformed to hydrogen, and carbon dioxide. The CO_2 of the synthetic gas stream is captured to obtain concentrated synthetic gas stream.

The capture process is designed to capture CO_2 by absorbing it in a suitable solvent from flue/ synthetic gas stream. The CO_2 rich solvent is subsequently processed to remove CO2 in a stripper reactor to recover solvent for reuse. The removed CO_2 is compressed to super-critical state for transport it to geological site for storage.

Various processes have been developed for separating CO_2 from gas stream. These can be categorized as Absorption, Adsorption, Membrane, Cryogenic, Microbial/ Algal process. For large industrial process absorption process is being used. Ammonia and urea industries are using amine solvent (chemical) for capture and separation.

The primary constraint of designing capture process are thermodynamic parameters of gas stream i.e. temperature, concentration, pressure. These parameters value in flue gas are inadequate to ensure efficient extraction. The parameter values in synthetic gas are somewhat favourable.

Another emerging capture technology is application of high pressure membrane. It is a single stage separation process. The type of membrane being studied are (a) inorganic membrane e.g. silica / alumina / zeolites / palladium (b) Organic Polymers- the research include liquid membrane supported ionic liquids. For sustaining long term use of membrane the strength of membrane have to be ensured, and gas stream should be free from fine particulates.

In order to enhance performance of capture technology at thermodynamic condition of gas stream, a series of R&D is needed. These include

(a) Technology selection absorption or membrane
(b) Development inhibitors, catalyst & contactor
(c) Optimum use of waste heat
(d) Recycling of capturing solvent

The new solvents development should also have low vapor pressure, highly resistant to degradation, display low corrosivity in the presence of oxygen. New solvents should comply with technical attributes of

(i) Higher equilibrium capacity for CO_2
(ii) High CO_2 reaction rates
(iii) Having low regeneration energy requirement
(iv) Having good capture efficiency at low partial pressure and
(v) Higher yield during regeneration process.

The high reaction rate will in turn reduce the size of the absorption towers that will reduce capital and operating costs.

The tangible cost incurred in capture process is the maximum. All the research and development processes are focused on reducing cost of capture cycle. The capture process as described with MEA solution processing accounts for 80% of the total cost of CCS process. This excludes cost of monitoring and verification. Within the complete capture process, capture by absorbent accounts for approximately 34% of the total capture process cost. The circulation of the solvent and gas through the columns by pumps and blowers, accounts for approximately 17% of the total operating cost. The maximum cost of CO2 capture cycle is in solvent regeneration process occurring due to the energy requirement, enhanced yield of solvent regeneration. This phase accounts for 49% of the total capture cost. Applied R&D and design of the packed bed to reduce pressure drop can facilitate the cost reduction in all reaction phases.

Carbon capture units have capacity to capture 85 to 95% of CO_2 emissions from the exhaust gases of coal- and gas-fired power plants, oil refineries and steel plants. The subsequent process after capture is it to transport carbon dioxide to appropriate geological site for storage.

NEERI, India team is doing R&D on biomimetics to stabilize and immobilize the enzymes or alternately use a combination of both these approaches to achieve sequestration reaction at a satisfactory level. There have been several exploratory studies of the use of the enzyme carbonic anhydrase, which is one the most efficient catalyst of CO2 reaction with water, to produce carbonate ions to promote CO2 scrubbing from flue gases. The aims to mimic the reaction for fixation of anthropogenic CO_2 into calcium carbonate using carbonic anhydrase (CA) as a biocatalyst.

G.1. CO2Transportation

The separated CO_2 is further processed for transportation. The CO_2 transportation with pipelines is in practice in USA for enhanced oil recovery projects. The experiences indicate that CO_2 transportation in super-critical fluid state is highly economical in comparison to gaseous phase. The super-critical state has its own challenges such as leakages and associated cooling, fractures at joints and defects, purity norms. The necessary conditions for CO_2 supercritical fluid are (i) Critical Temperature in Kelvin, 304.2 degrees (ii) critical Pressure in bar (atmosphere) 73.8 for super-critical state (iii) CO_2 gas Density Kg/m3 (at 0 degree C) 1.9767 (iv) Super Critical fluid Density is 468 Kg/ m3. The 304 degree Kelvin is equivalent to 31 degrees centigrade, which is approximately room temperature.

There are purity norms of CO_2 for transportation. Captured CO_2 may contain impurities like water vapor, H_2S, N_2, methane (CH4), O_2, mercury, and hydrocarbons. A requirement exists for specific processing for removal of impurities. Before transport, the CO_2 is dehydrated to levels below 50 ppm of water. CO_2 reacts with water to form carbonic acid, which corrodes the pipeline, and changes super-critical conditions. H_2S is toxic gas. The pipeline and compressor design for CO_2 transport in super-critical state has its own design constraints.

The design of compressor is the primary applied research project as it will have to boost pressure from 1 bar to 110 bar (above 73.8 bar for safety factor). NETL, USA and South West Research Institute have developed multi-stage compressor for liquefying CO2 to super-critical fluid. The said compressor consumes less energy and occupies less space.

The pipeline lengths have to be computed in segments to align with booster pump, geographical profile, and design capacity of CO_2 mass flow. These will be used to compute pipe diameter. The pipeline is modeled as a series of pipe segments located between booster pumping stations. Based on the input information to the transport model, the required pipeline diameter for each segment is calculated. The pipeline segment diameter is calculated from a mechanical energy balance on the flowing CO_2. The energy balance is simplified by approximating supercritical CO_2as an incompressible fluid and the pipeline flow and pumping processes as isothermal. Booster pumping stations may be required for longer pipeline distances or for pipelines in mountainous or hilly regions. Additionally, the use of booster pumping stations may allow a smaller pipe diameter to be used, reducing the cost of CO_2 transport. The pumping station size is also developed from an energy balance on the flowing CO_2 in a manner similar to the calculation of the pipe segment diameter. Both the booster pumping station size and pipeline diameter are calculated on the basis of the design mass flow rate of CO_2.

Currently CO_2 storage in ocean is being explored actively. Carbon dioxide is continuously captured at the plant on land, but the cycle of ship transport is discrete. The marine transportation system includes temporary storage of CO_2 may be in liquefied state on land, and on shore loading facility in a tanker or pipeline transport to sea-shore, temporary storage at sea-shore , offshore reloading in the ship/ tanker and ship and injection in the sea. The total process is designed in semi-pressurized state at pressures near the triple point (6.5 bar,-52 degree Centigrade). The capacity, service speed, number of ships and shipping schedule will be planned, taking into consideration, the capture rate of CO_2, transport distance, and social and technical restrictions. This issue is, of course, not specific to the case of CO_2 transport; CO_2 transportation by ship has a number of similarities to liquefied petroleum gas (LPG) transportation by ship. The process competes with pipelines over large distances.

Costing is an important issue is deigning transportation scheme. It is cheaper to collect CO_2 from several sources into a single pipeline (hub) than to transport smaller amounts separately. Early and smaller projects will face relatively high transport costs, and therefore be sensitive to transport distance, whereas an evolution towards higher capacities (large and wide-spread application) may result in a decrease in transport costs. Implementation of a ‘backbone’ transport structure may facilitate access to large remote storage reservoirs, but infrastructure of this kind will require large initial upfront investment decisions. Further study is required to determine the possible advantages of such pipeline system. Similarly cost of marine transportation system should be estimated.

H. Carbon Storage

The carbon storage is the critical component of the CCS technology. At this stage CO_2 emission to the atmosphere are finally restricted by storing the captured gas in the selected geological site. For millions of years, crude oil and natural gas (in fluid form) have been stored naturally underground, where it is trapped in deep reservoirs or sedimentary basins protected by cap rock. CCS technology duplicates this process by safely storing CO_2 within similar geologic formations, such as depleted petroleum fields or deep natural gas reservoirs.

H.1. Sequestration of CO2

The carbon storage in geological sites has its logic from replacing carbon extracted from geological sites as fossil fuel and restoring them with CO_2 wherever feasible. The stored CO_2 in geological sites have to be protected from subsequent release to atmosphere with proper capping

The CO_2 is injected and stored into geological "storage reservoirs" using standard techniques that have been used in the oil and gas industry for many decades. During the storage process conceived in CCS, CO_2 is injected at least 1,000m (1km) deep into rock formations in the subsurface. For storing CO_2 the identification of secure storage site is essential. Each geological site must contain trapping mechanisms such as cap-rock (dense rock) that is impermeable to CO_2, which surrounds the storage area and acts as a seal to stop any upward movement of CO_2. It is also desired that CO_2 react with the porous surface of the rock to form stable compound, but in the process of reaction it should not weaken the rock structure. The storage site should have a stable geological environment to avoid disruption in storage on a long term. The basin characteristics such as tectonic activity, sediment type, previous drilling activity, geothermal and hydrology regimes of the storage site should be analyzed prior to site selection.

Storage of CO_2 in deep saline formations with fluids having long residence times (millions of years) is conducive to hydrodynamic and mineral trapping.

H.2. Saline Aquifers

Global studies indicate that saline aquifers are present in onshore and offshore sedimentary basins. Saline aquifers have been identified as the inland storage site having maximum CO_2 storage capacity. In Indian context following study is needed.

- To estimate storage capacity of the saline formation to evaluate commercial viability;
- Proximity of thermal power stations to saline aquifer;
- Thickness of impervious (clay / sandstone) cap rock to ensure storage integrity;
- The reservoir pressure to estimate the storage capacity. Location of geological faults in the adjacent area; and
- Use of water of saline aquifers, in case they can be extracted from reservoir.

The saline aquifers content do not have any commercial value; it has not been adequately studied. In view of CCS the saline aquifers should be studied extensively. The study should include physical, chemical, and geological analysis. The analysis is needed to evaluate the nature and composition of the rock, porosity & permeability of the reservoir, and surrounding rock formation. The information obtained can be superimposed on GIS environment.

The saline aquifers are present in India different geological formations as revealed by exploratory drillings for the delineation of aquifer zones by Central Ground Water Board.

Maximum saline areas fall in parts of Rajasthan, Haryana , Punjab, Uttar Pradesh, Gujarat and Tamil Nadu. Some of the mega thermal power plants are also coming up in these areas. In India, the deep saline aquifers may prove out to be a very efficient option for carbon sequestration. There are insufficient public domain data available to estimate accurately the storage capacity of saline aquifers. In order to study deep saline aquifers, the sedimentary Basins have to be short-listed with adequate storage capacity estimates. Resistivity surveys for Deep aquifers are needed for delineating Rock type and the aquifers.

H.3. CO2 Storage potential in India

The CO_2 storage potential in India has been studied as a part of International Energy Agency (IEA) greenhouse gas programme (GHG), Holloway et. al. (2008). They carried out Regional Assessment of the potential geological CO_2 storage sites in Indian Sub-Continent. The CO_2 storage potential of India's sedimentary basin, and their classification of basin into good, fair and limited, is based on their expert judgment, and have to be established with field test using stratigraphic methodology. India has hydrocarbon fields in Barmer basin, Cambay basin, Mumbai Off-shore basin, Bombay High fields, off-shore Krishna Godavari basin, and oil fields in upper Assam.

The Basalt Formations are most viable options for environmentally safe and irreversible long time storage of CO_2. The basalts are attractive storage media as they provide solid cap rocks and have favourable chemical compositions for the geochemical reactions to take place between the CO_2 and the formation minerals, rendering high level of storage security. The Deccan trap has a vast basalt formation. The Intertrappeans between basalt flows also provide major porosity and permeability for injection. The largest lava flows of 1500 km across India from Deccan trap took place in the direction of Rajamundry and into the Gulf of Bengal. The basalts provide solid cap rocks and thus can ensure high level of integrity for CO_2 storage.

There are number of research opportunities in Carbon Storage which include;

- Mineral/ Physical Trapping of CO_2;
- Enhanced oil and Gas Recovery;
- Microbial – Biogeochemical Transformation of CO_2;
- Geophysical site selection and Monitoring;
- Chemical/ Kinetic behaviour in real time
- Well integrity- CO_2 resistant cement / steel;
- Numerical Simulation;
- Risk Assessment (FEP – Procedure);

- Hydrodynamic models of Aquifers; and
- Geo-mechanical rock behaviour etc.

H.4. Enhanced Coal Bed Methane Recovery (ECBM)

CO_2 sequestration in the un-mineable coal seams serves the dual purpose i.e. CO_2 storage and enhanced coal bed methane recovery. Coal beds typically contain large amounts of methane rich gas which is adsorbed onto the surface of the coal. The injected CO_2 efficiently displaces methane as it has greater affinity to the coal than methane in the proportion of 2:1 and is preferentially adsorbed displacing the methane absorbed in the internal surface of coal layers.

India has vast coal bed methane potential (1000 BCM.) The un-mineable coal seams in India occur in many Gondwana and Tertiary coal fields. The CO_2-ECBM can be advantageously used for exploiting the coal bed methane resources of India. The development and application of this technology is still at an early stage in the country. Directorate General of Hydrocarbons (DGH), New Delhi has planned to initiate CO_2-ECBM technology in some selected Gondwana coal fields.

I. Economics of CCS

CCS is in relatively early phase of development in respect of its costs, timings and relative attractiveness versus other low carbon opportunities. There is high degree of uncertainty in estimating the cost of CCS because of significant variations between project's technical characteristics, scale and application. There is also uncertainty over how costs will develop with time and variability of input costs such as steel, engineering and fuel development.

The cost of CCS is defined as additional full cost i.e. initial investments (capital costs) and ongoing operational expenditure of a CCS ready power plant compared to cost of state of the art non- CCS power plants with the same net electricity output and using the same fuel. The cost to include all components of value chain: CO2 capture at the power plant, its transport and permanent storage. The cost of CCS is expressed in expenditure incurred for per tonne of net CO2 emission reduction, to allow comparison with other abatement technologies

- The capture costs also includes the initial compression of CO2 to a level that would not require additional compression or pumping if the storage site were closer than 300 km;
- Transport cost to include any boosting requirements beyond 300 km;
- For storage only geographical storage options such as depleted oil or gas fields and saline aquifers.

The estimation of CCS costs is based on the following parameters:

1. Demonstration phase: Sub commercial scale to validate CCS as an integrated technology at scale and start learning curve- 300 MW capacity coal fired plant- by 2015 in Europe.($ 80-120 per ton CO2 abated),
2. Early commercial phase: first full scale projects to start ramp up of CO2 abatement potential 900 MW coal fired thermal unit – by 2020; (US $ 50-70 per ton CO2 abated) and
3. Mature commercial phase: wide spread roll out of full scale projects: significant abatement is realised – by 2030(US$ 40-65 per ton of CO2 abated)

Beyond early commercial development, the cost of CCS is expected to evolve differently at each stage of value chain and according to different driving factors, and effective cost reductions in capital expenditure of capture equipment, combustion technology efficiencies, source sink matching i.e. onshore and offshore mix etc. The overall impact of these factors on CCS costs would depend on the roll out scenario after the early commercial phase. The introduction of new 'breakthrough' technologies, currently in the early stages of development phase such as chemical looping or membranes, could potentially lead to a step like reduction in cost of CO2 capture. The estimates of long term CCS costs are structurally more uncertain and are highly dependent on the assumptions such as:

- Learning rates on currently non operational processes;
- Possible new technologies;
- Storage locations and availability;

- Rule out hypothesis; and
- Costs may come down faster with broader roll out, so global introduction of CCS would increase the overall cost efficiency.

The costs will be higher in case of retrofitting of Carbon Capture equipments/ facilities in the existing thermal power plants or other industrial installations due to availability of space and also shutting down of plant for carrying out modifications.

I.1. Stakeholders Survey

The survey of stakeholders' perception on Carbon Capture and Storage technology was undertaken by IRADe to support the research project. The questionnaire was designed to conduct the survey in June-July 2008 and restructured in February 2009, to seek elaborate answers on some issues, needed to analyze the CCS technology in the context of Indian power sector. A total of 54 interviews were collected from the respondents who are the key players from the target groups at various venues and locations. The team also tried to gather the information from the experts in the fields throughout the country. It was intended to elicit viewpoints from the top-level experts and stakeholders related to Indian Energy and Power sector, their perception on the following matters:-

i. Their understanding about the importance of CCS technology in restricting the concentration of CO_2 (as a GHG) in the atmosphere.
ii. Importance of the CO_2 emissions from Power Plants as a threat to global warming.
iii. Chances of developing efficient CO_2 capture technologies with low marginal energy consumption after R&D.
iv. Difficulties in reaching energy efficient and safety technology components of CCS.
v. Whether India can benefit due to the business opportunities offered by R&D needed to develop energy efficient CCS technology.
vi. Time horizon perceived for use of CCS technology in view of high-energy consumption in developing world.
vii. Key barriers affecting progress in R&D in developing CCS technology.

viii. The barrier to use CCS which can be overcome by undertaking R&D

ix. Specific ideas on the necessity of utilizing CCS technology in the context of Indian Power sector to arrest climate change.

The key stakeholders and decision makers were identified on the basis of their occupation and influential capabilities. The respondents were then divided into five broad categories namely:

i) Industry,

ii) Academic + Research + Modeller,

iii) Government + Bank + Regulators,

iv) Consultant + Project' and

v) Media + NGO + Environment.

The survey covered 54 individuals' professionals/ experts covering the whole spectrum of stakeholders without depending on the industry associations such as FICCI, ASSOCHAM, and CII. There are a number of respondents who are involved from various stakeholders in CCS R&D projects. These respondents are working on development of clean technologies, carbon capture technologies and carbon storage technologies.

The group 3 and 5 among the respondents were of the view that developed countries should lead by example by establishing successful demonstration CCS. Projects ongoing R&D work to make CCS technologies techno-economic viable was indicated by the survey. Few respondents suggested that global R&D center on CCS be established in India. There could be business opportunities for India because we are in a position to establish manufacturing base. Referring to regulatory issues, the emerging suggestion appears that a body in India may compile development in regulatory aspect in developed countries and its tuning to Indian scenario may be worked out. Responding to funding issue respondent referred to the need of specific financial support. The CDM may be applicable only after demonstration projects have reached cost effective deployment. Except for international support for the project no other suggestion emerged from the survey.

J. Roadmap of CCS Technology in India

Current trends in energy supply and use are patently unsustainable – economically, environmentally and socially. Without decisive action, energy-related emissions of CO2 will more than double by 2050 and increased oil demand will heighten concerns over the security of supplies. Energy efficiency, many types of renewable power, hydro power,, nuclear power and new transport technologies will all require widespread deployment if we are to reach our greenhouse gas mission goals. Every major country and sector of the economy must be involved. Many other cheaper and simpler options need to be pursued prior to CCS which may be needed even after all is exhausted. They are:

- end use fuel efficiency by all economic sector;
- end use electricity efficiency – by using energy efficient equipments, and cut down on consumption ;
- end use fuel switching with focus on renewable and clean energy ;
- Power generation efficiency and fuel switching – super-critical, ultra super-critical, IGCC, oxy-fuel etc;
- Renewable as replacement of fossil fuel, waste heat deployment;
- Nuclear as alternate source of energy and resolving issues connected with nuclear energy application;
- CCS in power generation; and
- CCS in Industry and process transformation.

The current developments in India connected with CO_2 emissions mitigation in practice are as follows;

- Preparation of CO_2 and GHG Emissions Inventory at the national level (Central Electricity Authority)
- Improvement in efficiency of existing (old, inefficient plants) thermal plant by Renovation and Modernization. Mapping of thermal power station for higher energy

efficiency is being carried by Central Electricity Authority, Bureau of Energy Efficiency in collaboration with GTZ. Use of automation, communication, and IT are being applied for enhancing process, logistics and management efficiency.

- The new Greenfield plants having the state of art technology ensuring higher efficiency technologies (Super/ Ultra super critical) are being incorporated in UMPP). Most of these units are pit head power plant with captive mines and will be using best mining practices. The UMPP at Krishnapatnam, Mundra, Tadri, Girye, Cheyyur are coastal power plants and they plan to use of imported coal.
- R&D on Oxyfuel, ultra-super critical (steam temperature above 700 degree centigrade and 300 ata) and IGCC pilot plant are being developed by BHEL and NTPC
- Use of renewable energy, biomass, carbonaceous waste in the existing heating scheme of the boilers.
- The research and academic institutions are working on development of Carbon Capture and Storage technology (CCS) and its components need to set up a network to exchange information and for co-ordination.

Indigenous developments of the mitigation process require active participation of the government bodies, scientific community (academics & research institutions), design bureaus and consultants, manufacturing technologists. Each has a defined role. These design development leading to successful execution of demonstration project have to be established with:

(a) Basic and applied research on each component of CCS technology;
(b) Gap analysis between indigenous capability and off the shelf-technology availability in developed countries will guide scope of technology transfer;
(c) Analysis of technology of each component for their maturity for pilot project;
(d) Planning for capture ready plant. Define profile of capture ready plant;
(e) Project design for an integrated CCS pilot /demonstration project;
(f) Approval and permission of competent authority for regulatory checks and land use;

(g) Execution of demonstration projects; and

(h) Lessons learnt for subsequent project up-gradation, and scalability.

India is the member of Carbon Sequestration Leadership Forum (CSLF), and FutureGen project. The state owned leading Indian exploration company 'Oil and Natural Gas Corporation' (ONGC,) is establishing a carbon sequestration pilot project for EOR at Ankleshwar. Clearance of MoEF is essential for Environment Impact assessment (EIA). The state governments and the states sharing boundaries with the plant location where project will be implemented have permit issuance authority on the project, in context of state and national regulatory framework, health & safety, and land use. Without resolving risk factors associated with geological storage & transport, and pollution at capture stage, it will be difficult to obtain EIA approval.

Analyzing the current scenario of power sector development, it appears that earliest testing of CCS demonstration project can be feasible in the thirteenth five year plan i.e. 2017-2022. The eleventh five year plan is nearing its end. The large numbers of power plants to be commissioned during 12th plan are under construction or are in the process of placing orders for equipment and starting construction. The innovative concept for capture ready units can be thought of for thermal power plants to be commissioned in 13th plan and beyond.

IEA has made an elaborate study on the role of CCS technology in mitigation of global carbon dioxide emission and documented a roadmap for development and implementation of the CCS scheme in power sector. Each developed country has a road-map for implementation of CCS technology. Key actions needed as recommended by IEA are as following

- Develop and enable legal and regulatory frameworks for CCS at the national and international levels, including long-term liability regimes and classification of CO_2 for storage.
- Incorporate CCS into emission trading schemes and in post-Kyoto instruments.

- RD&D to reduce carbon capture cost including development of innovative technology, and improve overall system efficiencies in power generation, also including innovative technologies such as IGCC, oxy-fuel, chemical looping to enhance CO_2 concentration in flue gas to enhance efficiency of carbon capture process.
- RD&D for storage integrity and monitoring, Validation of major storage sites, Monitor and valuation methods for site review, injection & closure periods. Define ownership issues of storage site for defining short term responsibilities.
- Raise public awareness and education on CCS.
- Assessment of storage capacity using Carbon Sequestration Leadership Forum methodology at the national, basin, and field levels.
- Governments and private sector should address the financial gaps for early CCS projects to enable widespread deployment of CCS for 2020.
- New power plants to include capture/storage readiness considerations within design by 2015.

The Key areas for international collaboration are summarised as following:

- Development and sharing of national and global legal and regulatory frameworks.
- Develop international, regional and national instruments for CO_2 pricing, including CDM and ETS.
- Global participation in development and execution of demonstration projects similar to schemes proposed by Organizations: CSLF, IEA GHG, IEA CCC, IPCC.
- Sharing best practices and lessons learnt from demonstration projects (pilot and large-scale).
- Joint funding of large-scale plants in developing countries by multi-lateral lending institutions, industry and governments.
- Route identification for CO_2 pipelines.
- Development of standards for national and basin storage estimates and their application.

K. Basic Research Work in field of CCS in India

The government institutions are pursuing basic research on CCS technology independently. The Government is supporting basic research on carbon sequestration, carbon capture through department of science and technology and clean coal technologies, IGCC, underground coal gasification, enhanced oil recovery and enhance energy efficiency etc are being pursued with participation of public sector units BHEL, NTPC, ONGC etc. The R&D on CCS being capital intensive, the private sector participation will be needed. For transition to applied research stage few research groups have to come together to form collaboration for pilot projects. The government will have to approve few pilot projects separately for carbon capture, carbon storage, and monitoring verification for validation of conceptual technology emerging from basic research. The transportation process design may be according to the existing standards of ASTM. The governments in principal approval will be needed for demonstration of CCS technology by integrating technology component at a future date. They are aware of the administrative issues such as

(a) Regulatory framework on health, safety, protection scheme,
(b) Financing of the project
(c) Environment impact assessment clearance
(d) Technology transfer,
(e) Land use and
(f) Compliance with existing legal provisions.

The important institutions and researchers working on CCS scheme in India are as follows:

a. The Government Organizations – such as Ministries of Power, Coal, Water resources and Mines, Department of Science and Technology, Geological Survey of India, CSIR institutions (NEERI, NIO, NGRI, CMRI, CMMS etc.)
b. Public Sector Units – BHEL, NTPC, GAIL, CIL

c. Private sector units – Tata Power, Reliance Power, L&T, PunjLloyd, Tata Bluescope, Shiv Vani oil etc.
d. Others such as Iron and steel Units, Instrumentation and Control system manufacturer for monitoring and safety
e. Regulators and government authorities and advisors.

CCS Being a complex process will require efforts of experts from multiple discipline and organizations. The progresses made in developed countries are very significant. The challenge is in integrating different indigenous engineering modules, technology transfer, and subsequent analysis of operation data. The formation of multi-disciplinary taskforce is needed to kick-start the project at pilot and then at demonstration. One of the options of initiating integrated effort is to have at least one Indian institution as knowledge center of CCS. The expected function of knowledge center could be:

- Develop a global network with international stakeholders associated with development of the technology for commercial application, and compile information on scientific, technological, regulatory developments;
- To bring together Indian stakeholders, especially business investors, and government, academic and others also who are interested in this area;
- To identify key questions & concerns with regard to CCS technology;
- To develop study projects to address the questions and issues, particularly which are of relevance to India;
- To study the cost of CCS and to suggest financing and cost-reduction measures;
- To study technology gaps in CCS and to suggest ways of bridging the technology gap;
- To make policy recommendations;
- To propose projects, including pilot and demonstration projects, to stakeholders;
- To interact with similar institutions and bodies overseas and to make available the latest information and insights to Indian stakeholders;

- To disseminate reliable and usable information ; and
- To promote study and research in this area & facilitate capacity building.

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CHAPTER 1. INTRODUCTION TO THE PROJECT

1.1. Introduction to the Concept

The phenomenon of Global Warming is studied by various international scientific organizations and researchers. The climate change and climate variability world over is evident which could be attributed to global warming. According to the Inter-governmental Panel on Climate Change (IPCC 2007), “most of the observed increase in global average temperatures since the mid-20th century is very likely due to the observed increase in anthropogenic GHG [Green House Gas] concentrations.” There are many greenhouse gases emitted by various industrial processes and burning of various types of fuels. In addition many natural phenomena, agriculture, live-stock also emit greenhouse gases.

The economic growth of nation is primarily reliant on fossil fuels, such as coal, petroleum product, natural gas etc. which results in Carbon dioxide (CO_2) emissions, the most important among all green house gases. The current power plant technologies in India, which are primarily coal based, emit enormous amounts of CO_2. Total carbon dioxide emission in India, for the year 2007 had been 1.3 Giga tonnes (Gt). The world energy outlook has projected 2.2 Gt and 3.4 Gt for the year 2020, and 2030 respectively. Projection of Emissions from industry will grow by 180% up to 2030. Per capita CO2 emission in India is 1.1 tons at present[1].

CO_2 is one of the biggest causes of human-induced global warming. Coal combustion dominates the fuel mix used to produce electricity in the world which generates the highest carbon dioxide emissions during its burning process. Carbon capture and storage (CCS) for mitigating carbon emissions from fossil-fired power plants and industrial sources is discussed intensively on a global scale. CCS is considered as one of the technological option which could reduce greenhouse gas emissions significantly. Their reduction is needed in order to limit the global

[1] BP statstics-2009

average temperature below the threshold of 2 °C, and limit CO_2 concentration in atmosphere at 450 PPM.

Carbon Capture and Storage (CCS) refers to a set of technologies to be implemented in the hope of capturing large amounts of carbon dioxide currently going up in the atmosphere through power plant chimneys, and store it underground or under seas for a long period of time. Although CO_2 has been injected into geological formations for different purposes in the past, its long term storage is a relatively untried concept. Therefore, while geological carbon storage appears to be the most promising option in the near future, it is believed to be more feasible only for large, centralized CO_2 sources, coal-burning electric power plants, where the CO_2 gas could be easily collected/ captured.

1.2. Carbon Capture and Storage Externalities

"…it's important to understand that three hard truths are shaping the future and will lead to important changes to the world's energy system in coming decades. First, there has been a surge in energy demand as the world's industrializing giants like China and India enter the energy-intensive phase of growth. Second, the supply of conventional energy from sources like easy-to-access oil and gas fields will soon struggle to keep up with this pace of growth, forcing us to look for other energy options. And third, as energy consumption grows, environmental strains – due partly to energy-related emissions of greenhouse gases thought to cause climate change – are rising too." (Jeremy Bentham, Shell Vice President Global Business Environment)[2]

In October 2008, the International Energy Agency (IEA) announced that CCS is "the only technology available to mitigate greenhouse gas emissions from large-scale fossil fuel usage". The IEA report states that CCS has the potential to deliver 20% of the greenhouse gas reductions needed to halve global emissions by 2050, but stressed that the window of opportunity was

[1] Source: www.shell.com – Is a scramble for energy inevitable?

closing and substantial investment is required now to develop the technology further. Even though CCS technology represents an important option of the world's emissions reduction, it is far less likely to be feasible for other, more diffuse CO_2 sources like automobiles, which make up another important fraction of emissions. CCS is then hardly to be considered a complete solution.

1.3. Background and Climate Change

Nature has its own mechanism to absorb carbon dioxide from atmosphere to sustain biosphere and to establish carbon cycle. Since the beginning of the industrial revolution the emission is increasing due to use of fossil fuel by mankind thereby rising CO_2 level in the atmosphere, which in turn is leading to global warming. Emission from industry, thermal power generating stations is a major contributor to global climate change and the GHG emission from the sector. The Central Electricity Authority (CEA) has estimated that meeting electricity demand over the next ten years will require more than doubling the existing capacity, from about 132 GW in 2007 to about 280 GW by 2017, of which at least 80 GW of new capacity is expected to be based on coal. That makes it 54% of new capacity, that's more than half of new capacity addition to be based on coal: Sub-critical pulverized coal (PC) combustion power plants manufactured by Bharat Heavy Electricals Limited (BHEL) – based on technologies licensed from various international manufacturers – have been the backbone of India's coal-power sector. Although the unit size and efficiency of these BHEL-manufactured power plants have steadily increased, the basic technology has not changed much.[3]

Today's decisions about power plant technologies will have consequences over the plant's entire lifetime – a period of about 25-30 years.

[3] Thermal Performance Review 2009 Highlights- CEA

Coal combustion accounts for about 40% of total CO_2 emissions of the country. Given that more than 70% of the coal consumed in country is used for power generation, reduction of CO_2 emissions will significantly impact coal power plants.

Preliminary studies show that CCS would need to make a significant contribution to reducing atmospheric CO_2 concentration, even after maximum feasible emissions reductions are achieved by utilizing all mitigation options / low carbon technology for reducing CO_2 emissions, such as energy efficiency, fuel switching, renewable energy sources, and reforestation etc. CO_2 cycle is necessary for life on earth.People and animals inhale oxygen from the air and exhale CO_2. Meanwhile, green plants absorb $CO_2$for photosynthesis and emit oxygen back into the atmosphere during daytime. CO_2 is also exchanged between the atmosphere and the oceans and is emitted or absorbed in other natural processes. This natural system is called the carbon cycle. These processes have maintained a balance level of CO_2 in the atmosphere over time. During pre-industrial times atmospheric CO_2concentration was 200 ppm but in recent time the concentration is estimated to be at approximately 400 ppm. This rise in concentration has severely impacted Global average temperature (currently approximate 15 degree centigrade) and has resulted into global warming. The increase in use of fossil fuel to meet the high demand by the industry has resulted in imbalanced carbon trend. The larger uses of fossil fuel have accelerated the rise in CO_2 concentration.

CCS technology enables industry to continue with less disruption while minimizing impact of industry on climate change. The projections are that the commercial viability of the technology may be possible in next decade if carbon price is high . The technology uses solvent to capture carbon; transport of carbon (in supercritical state) at high pressure, and geological storages which may be vulnerable to leakages. Once the application may be feasible, regulatory and legal issues associated with the scheme with respect to safety, monitoring, health and land needs to be resolved.

Though CCS technologies / methodologies are in development stage, its estimated potential to reduce GHG emission and contribution to mitigate climate change is generating interest in Research Development and Demonstration (RD&D) projects around the world. IPCC research suggests that worldwide, many large sources of CO_2 are potentially near areas that potentially hold formations suitable for geological storage. IPCC has estimated that by 2050, 30-60% of fossil fuel CO_2 emissions from electricity generation could be technically suitable for capture

The aim of Carbon Capture and Storage is to address climate change issues by reducing CO2 emissions from power plants operating on fossil fuels. There are analytical opportunities to:

1. Strengthen energy supply security through a wider energy basket, and using coal as primary energy source
2. Participate in global development and application of CCS technology and thereby generate business and export opportunities for Indian entrepreneur;
3. The developed countries are indicating Large-scale efforts and availability of this technology by the year 2020 onwards;
4. Improve energy efficiency in the power plant units, reduce energy losses by harnessing existing waste energy;
5. Use innovative power plant technologies, especially in the boiler section, so that a higher concentration of CO2, can be obtained in the flue gas (oxy-fuel)/ fuel gas (IGCC) stream. Higher concentration, higher pressure and temperature provide appropriate thermodynamic condition for CO2 from gas stream;
6. Identify carbon storage sites, and their characteristics. Develop rugged storage sites;
7. Develop transport infrastructure (pipelines, storage tanks, booster station). ; and

8. Evolve methods for monitoring and evaluation to ensure safety and security of the scheme.

In addition to technical problems, there are issues of infrastructure, legal and regulatory framework and acceptance in society. There is need of regulatory and legal framework, for even undertaking pilot and demonstration projects. The union government may review the formulation of regulation to promote demonstration project. There are also issues of land use, pipeline layout etc.

1.4. Background, Objective and Methodology of the Project:

In 1992, United Nations Framework Convention on Climate Change (UNFCCC) was signed by the Heads of large number of States including India, seeking to stabilize GHG concentration in the atmosphere at a level that prevents dangerous anthropogenic interference with the climate change.

Power Sector is the largest consumer of coal accounting for about 70% of total coal consumption in the Indian economy. India being in an accelerated phase of economic growth, aiming to add more than 600,000 MW of power generation capacity in the next two decades needs special interventions to restrict CO_2 emission to minimize global warming.

Conventionally, the clean coal technologies and efficient and clean combustion of coal are being used to reduce CO_2 emission from the power sector. Carbon Capture and Storage (CCS) technology is emerging as a promising technology with high potential to reduce GHG concentrations.

In the foregoing background, IRADe was awarded for a research study titled **“Analysis and Strategy Development for Carbon Capture and Storage (CCS) Technology in the context of Indian power sector”** by the Department of Science and Technology , Ministry of S&T, Govt. of India towards the end of 2007.

IRADe has also conducted a conference on CCS Technology in January 2008 at New Delhi.

This project intends to define and carry out the research in a predetermined manner to achieve the research objectives under National Programme on carbon sequestration Research of DST.

1.4.1 Objectives of the Research Project:

Objective:

The key objective of the Research Project is "To study, analyze, evaluate and assess the importance and development of CCS technology in reducing the GHG emissions to restrain global warming and its economic implications."

In pursuing the above research objective, the study focused on the components of CCS technology with reference to power sector in detail so as to understand the techno-economics of the concerned technologies; their applicability to the Indian Power Sector; and further Research and Demonstration requirements if any to utilize this technology.

The CCS Technology aims at

- Enhancing efficiency of power plants by emerging technology to reduce emission of CO2 to reduce process load on capture technology;
- Capturing (Separating) CO2 from the gas streams emitted from combustion;.
- Transporting the captured CO2 to underground storage;
- Storing CO2 underground in deep saline aquifers, sedimentary basins, and depleted Oil and Gas or Coal reservoirs. The potential areas in the country where CO2 can be stored, and how the storage can be conducted (trapping mechanism);
- Will the storage site be safe?

Thus the CCS, technology aims at reducing CO2 percentage in the atmosphere by storing the CO2 produced by the fossil fuel fired plants in secure sinks at affordable prices for hundreds of years.

1.4.2 Competitors of the Technology:

The solutions presented by CCS has a number of competing actions which can be considered by global community for analyzing the competitive advantage of CCS and what are the best mechanisms to achieve reductions in CO2 in the atmosphere.

All such alternative actions which can be taken by global community to achieve the CO2 reductions in the atmosphere, as done by CCS technology are the competitors to CCSand shall have to be studied to arrive at conclusions out of this Research Project of DST.

The key alternatives include:

- Increase in use of new and renewable energy;
- Increase Power Plant efficiency to generate electrical energy;
- Reduce the cost of components of CCS technology;
- The emerging clean coal technologies such as Oxy-fuel and IGCC;

Using CCS by eliminating or modifying the carbon capture technologies to reduce energy loss (There are considerable progress in solvent, and solid state membrane development for separating CO2 from the flue gasses. The development of IGCC and Oxyfuel technology has been significant. These aspects have to be studied under Indian context.

1.4.3 Methodology adopted for the Research Project

The IRADe team conducted extensive literature review at regular interval, carried structured interviews to assess the development and opinion of stakeholders on various aspects of carbon capture and storage technology, conducted, analyzed individually for major component of the project based on the scope of the project. The analysis included the assessment of general progress with a detailed description of relevant developments. The lists of possible options were selected and were discussed in detail keeping constraints and opportunities in mind. The strengths, weakness, opportunities and threats were described in detail. A detailed description of the options, scenarios, present status, R&D road map etc. was analyzed. This includes description of a range of features like CCS technological status, Indian energy sector- potential sources of GHG, clean coal technologies, capture, transport and storage technologies, stakeholders view etc. It was assumed that India will take up the scheme only after it is successfully demonstrated and implemented elsewhere in the world but will continue the R&D work in order to develop clean technologies and explore business opportunities in CCS in future. The following components were studied and analyzed while executing the research;

1.4.3.1 Literature Survey

- Carried out extensive literature survey at regular intervals to study the issues involved in:
    - Development of CCS Technology;
    - Plants and Equipments;
    - Fuels and processes use; and.
    - Technology growth and gap analysis for identifying development.
- Status of Carbon Capture and Storage technology worldwide.

1.4.3.2 Stockholder's Survey:

Conducted Survey through structured and well researched questionnaire on different class of experts/stakeholders on specific issues and understandings which have provided inputs to analyze the CCS technology with reference to Indian power sector.The respondents were then divided into five broad categories. The categories being:

i. Industry inputs

ii. Academic + Researchers + Modeler

iii. Government + Bank + Regulators

iv. Consultant + Project developers & managers

v. Media + NGO + Environmentalists

The broad issues covered in the survey were:

- Understanding about the importance of CCS technology
- Importance of CO_2 emissions in power plants
- Chances of developing efficient Capture technologies with low marginal energy consumption after R&D
- Difficulties in reaching energy efficient and safe technology components of CCS.
- Business opportunities offered by R&D needed to develop energy efficient CCS technology
- Time horizons perceived to necessarily use CCS technology
- Key barriers affecting progress in R&D in developing CCS technology

- The barrier to use of CCS, which can be overcome by undertaking R&D
- Ideas on necessity of utilizing CCS technology in the context of Indian power sector to arrest climate change.

1.4.3.3 Indian Energy Sector

- Studied and Prepared potential Sources of GHG emission in Indian energy sector with special focus on Power generation
- Analyzed the fossil fuels (Hydrocarbons) used in these technologies and their characteristics.
- Explored the energy efficiency improvement and use of clean coal technologies

1.4.3.4 Carbon Capture and Storage

- Classified the key components of CCS technologies with respect to the
    - Primary Thermal technology for power generation
    - Alternative CO2 Capture technologies
    - Type of CO2 Transportation technologies.
    - The type of storage reservoirs & their environment risks.
    - Impact of CCS on fixed costs and energy costs in power generation projects of identified types.
- Evaluated potential and proven (in other industries at different scales) Carbon Capture.
- Identified and analyzed possible transportation technologies.

- Studied & identified potential CO2 storage options and their characteristics in the country with emphasis on geological options
    - Depleted Oil fields and Enhanced Oil Recovery (EOR)
    - Saline Aquifers
    - Sea Bed
    - Old coal mines and Coal Bed Methane (CBM)
- Evaluated the Cross-cutting issues
    - Cross cutting issues for India
    - SWOT analysis of CCS technology for India.
- Policy initiatives and references needed for CCS , if found feasible to India
    - Listed the Research and Development opportunities for India
- Roadmap of CCS R&D for India
    - Way Forward
    - Suggested strategy and policy for CCS technology in Indian Power Sector.
- Conclusion and Recommendations derived from the study

1.5. Deliverables:

The aim of the research study was to conduct an analytical study of CCS technology for Indian power sector. CCS is a combination of various technologies undertaken by different industries for their specific use at different stages; some technologies are yet to be successfully demonstrated. IRADe team has prepared an analytical report to capture the findings of the studies, surveys and analysis to arrive at conclusions on the following aspects:

- Introduction to CCS
- Status and development of CCS technology
- Potential sources of GHG emissions in Indian energy sector with focus on power sector
- Major Fossil fuels (Hydrocarbons) used in India and their characteristics.
- Thermal technologies for efficiency improvement and clean coal usage.
- CO2 Capture technologies.
- CO2 Transportation technologies
- CO2 Storage locations and initial characteristics of the sites.
- Economics and Cross cutting issues
- Roadmap of CCS R&D for India
- Conclusion and Recommendation

****

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1. BP statstics-2009
2. Thermal Performance Review2009 Highlights- CEA
3. www.shell.com – Is a scramble for energy inevitable?

CHAPTER 2. CCS TECHNOLOGY AND STATUS

2.1. Introduction

This chapter describes the components of the components of CCS and indicate its status as of now in the world and in India . The efforts carried out all over the world and various research projects and their status is shown in this chapter and also the status of various research projects that are carried out in India are shown in annexure 2.1

2.1.1 Process:

CO_2**capture** & storage (CCS) is a 3-step process including CO_2 capture from power plants, industrial sources, and natural gas wells with high CO_2 content; **transportation** (usually via pipelines) to the storage site; and **geologicalstorage** in deep saline formations, depleted oil/gas fields, un-mineable coal seams, and enhanced oil or gas recovery (EOR or EGR) sites. In combustion processes, CO_2 can be captured either in pre-combustion mode (by fossil fuel treatment) or in post-combustion mode (from flue gas or by oxy-fuel).

2.1.2 Status:

CCS is being demonstrated in 3 industrial storage facilities (storage capacity >3 Mt CO_2 /year) using CO_2 sources other than power plants. Several dozen oil fields use CO_2 for EOR (some 40 Mt CO_2 /year). Acid gas geological storage is a common practice in Canada. CCS in power plants is being demonstrated in a few, small-scale pilot plants. Full-scale projects are underway or planned. Global geological storage potential is at least 2000 Gt CO_2. While in India various elements of CCS viz. carbon capture, storage and transportation are tried separately for different purposes, it is not in process tried with a single purpose of reducing GHG emissions.

Technologies for CCS are rather well known, but system integration and commercial demonstration are needed. If CCS is to play a significant role in the coming decades, demonstration must be accelerated. In particular, underground storage needs to be proven. Major ongoing demonstration projects include the offshore Sleipner project (Statoil, Norway - 1MtCO safe and permanent CO_2 /year storage in a deep saline aquifer, since 1996); the Weyburn project (Canada - 1Mt CO_2 /year storage with EOR, since 2001); the In-Salah project (BP, Sonatrach, Algeria). They use CO_2 sources other than power plants. In these projects, the underground behaviour of the CO_2corresponds to expectations. No leakage has been detected, and natural chemical-physical phenomena such as CO_2 dissolution in the aquifer water are expected to minimise the risks of long-term leakage. Pilot projects suggest that storage in unmineable coal seams may also be viable. Enhanced oil & gas recovery (EOR, EGR) at several sites offers demonstration opportunities and revenues that may offset the CCS cost. Several projects aim to demonstrate the CCS technology in IGCC plants (US-led FutureGen, European Zero Emission Technology Platform). Existing and planned demonstration projects (Gorgon in Australia, Miller in the UK) are likely to reach only 10 Mt CO_2 /year in the next decade. Given the range of technologies under development, CCS demonstration would require at least ten major power plants with CCS to be in operation by 2015. Substantially larger demonstration budgets as well as private/public partnerships and outreach to emerging economies are essential. As CCS implies an incremental cost, economic incentives are needed for CCS to be commercially demonstrated and deployed.

2.1.3 Barriers:

Major barriers to CCS deployment are cost, demonstration of commercially viable operation and safe permanent storage. CCS investment (hundreds of millions of dollars for a single power plant) poses a major financing challenge. A regulatory framework (liability, licensing, royalties, leakage cap) is needed for private investment and public acceptance. Governments should establish credible, long-term policies to stimulate private investment. Emission mitigation mechanisms such as emission trading should include CCS. A substantial increase in the global RD&D budget and outreach to emerging countries are essential.

2.2. CO2 Capture

Efficiency improvements in coal fired power plants will definitely help towards lowering

CO_2emissions; however, further steps are necessary in order to make significant reductions in CO_2 emissions. Carbon dioxide capture and storage (CCS) offers a longer term option for achieving near zero CO_2 stripping out CO_2 emissions. These technologies basically involve capture are pre-combustion capture from the exhaust streams of coal combustion or gasification processes and geologically disposing of it so that it does not enter the atmosphere.

Although the concept of capturing green house gas (GHG) emissions sounds like a new

idea, in reality it isn’t. Canadian firms, for instance, injected nearly 200 million cubic meters of acid gas, comprising of CO_2 and H_2S, into more than 30 locations in 2001.The Intergovernmental Panel on Climate Change (IPCC) recently stated in 2005 “that most existing CCS technologies are mature or economically feasible under specific conditions and that CCS could contribute 15-55% to the cumulative mitigation effort worldwide until 2100, averaged over a range of baseline scenarios”. However, none of these commercial applications were built for large power plants, and scaling them up is both expensive and energy intensive. Table 2.1 shows the different phases that carbon capture technology.

Several projects are now underway to push this technology ahead in countries, such as Australia, Canada, Germany, the UK, and the USA. One such example is the Future Gen project, which is a \$1 billion (USD) public-private partnership that was set up to build a coal fuelled IGCC plant with both CO_2 separation and geological storage capability.

Table 2.1: Viability of various stages of Carbon Capture Technology

CCS Component	CCS Technology	Status
Capture	Post combustion	Economically feasible under specific conditions
	Pre combustion	Economically feasible under specific conditions
	Oxy fuel Combustion	Demonstration phase
Transport	Pipeline	CO_2 pipeline existing in USA and other places
	By ship	Embryonic Stage- Similar to transport of LNG etc. Needs development of large ships suitable with liquefied CO_2 characteristics
Geological Storage	deep saline formations	Already being done at a smaller scale in Canada and Norway
	depleted oil and gas-fields	Already being done in small quantities in USA , Norway, Algeria for enhanced oil recovery
	Un-mineable coal seams	Pilot study in CBM extraction in USA

2.3. Carbon Transportation

Transport is that stage of carbon capture and storage that links sources and storage sites. The beginning and end of ‘transport’ may be defined administratively. ‘Transport’ is covered by the regulatory framework concerned for public safety that governs pipelines and shipping. In the context of long-distance movement of large quantities of carbon dioxide, pipeline transport is part of current practice. Pipelines routinely carry large volumes of natural gas, oil, condensate and water over distances of thousands of kilo-meters, both on land and in the sea. Pipelines are laid in deserts, mountain ranges, heavily- populated areas, farmland and the open range, in the Arctic and sub-Arctic, and in seas and oceans up to 2200 m deep. Carbon dioxide pipelines are not new: they now extend over more than 2500 km in the western USA, where they carry CO_2 to gas fields for enhanced recovery.

CO_2 is transported in three states: gas, liquid and solid. Commercial-scale transport uses tanks, pipelines and ships for gaseous and liquid carbon dioxide. Gas transported at close to atmospheric pressure occupies such a large volume that very large facilities are needed. Gas occupies less volume if it is compressed, and compressed gas is transported by pipeline. Volume can be further reduced by liquefaction, the use of ships for transporting CO_2 across the sea is today in an embryonic stage. Worldwide there are only four small ships used for this purpose. These ships transport liquefied food- grade CO_2 from large point sources of concentrated carbon dioxide such as ammonia plants in northern Europe to coastal distribution terminals in the consuming regions. From these distribution terminals CO_2 is transported to the customers either by tanker trucks or in pressurized cylinders. Design work is ongoing in Norway and Japan for larger CO_2 ships and their associated liquefaction and intermediate storage facilities. Table 2.2 gives the details of existing CO2 transportation line worldwide.

Table 2.2[4]: Existing long-distance CO_2 pipelines (Gale and Davison, 2002) and CO_2 pipelines in North America (Courtesy of Oil and Gas Journal)

Pipeline	Location	Operator	Capacity Mt CO2/ year	Length Km.	Year finished	Origin of CO2
Cortez	USA	Kinder Morgan	19.3	808	1984	McElmo Dome
Sheep Mountain	USA	BP Amoco	9.5	660	-	Sheep Mountain
Bravo	USA	BP Amoco	7.3	350	1984	Bravo Dome
Canyon Reef Carriers	USA	Kinder Morgan	5.2	225	1972	Gasification plants
Val Verde	USA	Petrosource	2.5	130	1998	Val Verde Gas Plants
Bati Raman	Turkey	Turkish Petroleum	1.1	90	1983	Dodan Field
Weyburn	USA &Canada	North Dakota Gasification Co.	5	328	2000	Gasification Plant
Total			49.9	2591		

2.4. Carbon Storage

The carbon storage is the critical component of the CCS technology. At this stage CO_2 emission to the atmosphere are finally restricted by storing the captured gas in the selected geological site. The concept emerged as the subsurface of the Earth is large carbon reservoir, where the coals, oil, gas organic-rich shales exists. The best sites for CO_2 storage from economic point of view

[4] IEA Energy Technology Essentials- Dec 2006

are deep saline formations, depleted oil/gas fields, unmineable coal seams, and enhanced oil or gas recovery (EOR or EGR) .The CO_2 is injected and stored into geological "storage reservoirs" using standard techniques that have been used in the oil and gas industry for many decades. During the storage process conceived in CCS, CO_2 is injected at least 1,000m (1km) deep into rock formations in the subsurface. For storing CO_2 the identification of secure storage site is essential. Each geological site must contain trapping mechanisms such as cap-rock (dense rock) that is impermeable to CO_2, which surrounds the storage area and acts as a seal to stop any upward movement of CO_2.

2.4.1 The Current Status of CCS:

While many of the component technologies of CCS are relatively mature, but to date there are no fully integrated, commercial scale CCS projects in operation.

A. Capture Technology → It has been applied in chemical and refining industry for decades. In the context of power viability needs to be demonstrated.

B. Transportation of CO2 → Central utilities (US & Canada) has more than 5000 Km of pipelines of CO2, proven successful for more than 30 yrs. CO2 injection into oil fields for enhanced oil recovery has been

C. Storage of CO2 → Operational worldwide for 10 years in Norway, Canada, Algeria. The industry can build on the knowledge obtained through geographical storage of natural gas. Uncertainty in respect of

Figure 2.1: Current status of component technologies of CCS

The details of the Major existing CO_2 capture projects are given in Table 2.3 and Table 2.4 gives the details proposed power projects which will be implemented with CCS technology.

Table 2.3[5]: Major Existing Storage Projects

Storage Project	Location	CO2 Source	CO2Storage	CO2 Quantity
Sleipner (offshore)	Norway	nat. gas field	saline formation	1 Mt/year since 1996
In Salah	Algeria	nat. gas field	gas-saline formation	1.2 Mt/year since 2004
K12b	Netherlands	nat. gas field /gas field	-EGR	Over 0.1 Mt/year since 2004
Snohvit, (offshore)	/Norway	nat. gas field	gas-saline formation	0.75 Mt/year, from 2007
Gorgon (offshore)	Australia	nat. gas field	saline formation	129 Mt total storage from 2008
Weyburn	Canada-USA	coal gasific	oil field –EOR	1 Mt/year since 2000
Permian Basin	USA	industrial & natural source	EOR	500 Mt since 1972
Nagaoka	Japan	industrial & natural source	saline formation	10.4 Kt in 2004-2005
Ketzin	Germany	industrial & natural source	saline formation	60Kt, since 2006

[5] IEA Energy Technology Essentials- Dec 2006

Table 2.4[6]: Major Proposed Power Plant CCS Projects

PP Project	Location of Power Plant	Technology Project Cost	Storage options	Starting Date
BP/SSE	Peterhead Miller, UK	NGCC 0.35 GW ($0.6bn)	Autoth reformer, precombustion, EOR,	2010
BP DF2	Carson, USA	IGCC petcoke 0.5 GW ($1bn)	shift, precombustion, EOR	2011
Huaneng,	GreenGen, China	IGCC 0.1 GW	shift, precombustion	2015
E.ON	Killingholme, UK	IGCC 0.45 GW (£1bn)	shift, precombustion. (capture ready)	2011
SSE	Ferrybridge, , UK	SCPC 0.5 GW	retrofit, postcombustion	2011
FutureGen,	USA	IGCC 0.27 GW ($1bn)	shift, precombustion	2012
GE	Polish utility, Poland	IGCC 1 GW	shift, precombustion	NA
Karstø	Norway	NGCC 0.43 GW	postcombustion amine, EOR	2009
Nuon	Eemshaven, NL	IGCC coal/biomass/gas 1.2 GW	option to capture	2011
Powerfuel	Hatfield, UK	IGCC 0.9 GW	shift, precombustion	2010
Progressive Energy	UK	IGCC 0.8 GW ($1.5bn)	shift, precombustion, H2 to grid	2009
SaskPower	Canada	PC lignite 0.3 GW ($1.5bn)	postcombustion or oxyfuel, DSF/EOR	2011
Siemens	Germany	IGCC 1 GW (€ 1.7bn)	shift, pre-combustion	2011
Statoil/Shell	Draugen, Norway	NGCC 0.86 GW	Post-combustion amine, EOR	2011
RWE	Germany	IGCC 0.45 GW (€ 1bn)	shift, pre-combustion saline formation	2014

[6] IEA Energy Technology Essentials- Dec 2006

Table 2.5: List of Leading institutes researching on CCS

S. No	Institutes/organization	Topic
1	Oil and Natural Gas Corporation	EOR
2	National Geophysical Research Institute, Hyderabad	Carbon di oxide adsorption
3	National Environmental Engineering Research Institute (NEERI), Nagpur	
4	Indian Institute of Technology-Kharagpur/Kanpur/Mumbai/Delhi/Guwahati etc.	Carbon Capture and Sequestration Research
5	Geological Survey of India	Geological Storage Capacity and characteristcs
6	Indian Institute of Chemical Technology, Hyderabad	EOR/ECBM
7	Directorate General of hydro Carbon	
8	National Thermal Power Corporation	Clean Coal
9	Indian Institute of Petroleum, Dehradun	Absorption/CO2 recovery
10	Global Hydrogeological Solutions, New Delhi	Saline Aquifers
11	Central Mining Research Institute, Dhanbad	ECBM/CO2 storage in Coal Seams
12	National Chemical Laboratory, Pune	Carbon Capture
13	Center for Energy and Enviornment Science and Technology(CEESAT), NIT,tiruchirapalli	Experimental and stimulation studies on CO2 sequestration
14	National Bureau of Soil Survey and land Use Planning (an ICAR Laboratory), Nagpur	Predicting Soil Carbon changes
15	Institute of Himalayan Bio-resources Technology (a CSIR Laboratory), Palampur, Himachal Pradesh	Improving carbon and nitrogen sequestration:
16	AMM Murugappa Chettiar Research Center, Chennai	CO2 Sequestration using Micro algae
17	Jawaharlal Nehru University, Delhi	Carbon Sequestration by higher plants and algae
18	Delhi University, Delhi	

19	Department of Botany, Andhra University, Vishakaptnam	Carbon Di-oxide Sequestration through Culture of Medically useful Micro-algae in Photo-bio-reactor linked to Gas outlets of Industries
20	Bharat Heavy Electrical Limited	IGCC
21	APGENCO	
22	Indian Institute of Chemical technology, Hyderabad;	Developing solution for Capturing
23	National Institute of Oceanography	Ocean Sequestration
24	Indian Agricultural Research Institute, Jhansi	Terrestrial Sequestration

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CHAPTER 3. POWER SECTOR IN INDIA

3.1. Introduction

India is a large country consisting of 28 states and seven Union Territories. The country has been divided in to five power regions namely Northern, Western, Southern, Eastern and North-Eastern. The resources of power generation in the country are quite diversified. Whereas the coal is located mainly in the eastern, western regions and southern region, lignite in the southern region, and hydro which needs to be developed mainly in the northern and north-eastern region. In order to meet the growing needs of power it is essential to develop all the indigenous resources in an optimal manner using most efficient technologies and also keeping in view the GHG emission and environmental concerns.

The power sector is India has been the responsibility of respective state governments, to generate and supply power to ultimate consumer. The State Electricity Boards were looking after overall activities of generation ,transmission and distribution of power to ultimate consumer singularly .However, keeping in view the national interest some large Multipurpose Hydro projects for irrigation and power generation were developed jointly by a group of states such as Bhakra-Nangal project on River Satluj , Hirakud Dam Project in Orissa on river Mahanadi, Gandhi Sagar, Jawahar Sagar and Ranapratp Sagar on Chambal River jointly by states of Rajasthan and Madhya Pradesh and few projects in the Southern States of Tamilnadu, Karnataka and Andhra Pradsesh, on Krishna Godavari Basins on benefit sharing basis both for irrigation and power. Similarly Satpura Coal based thermal power plant was set up jointly by Madhya Pradesh and Rajasthan. There are many more such examples of coordinated development in Indian power sector.

In mid–seventies (1975) it was felt that Central Government should come forward to take up generation and transmission projects under the Central Sector to assist and augment the efforts of States for improving the power supply position and also to develop the national resources in an integrated and optimal manner keeping in view the National interests. Agencies like National Thermal Power Corporation (NTPC) , National Hydro-electric Power Corporation (NHPC) & Power Grid Corporation of India (PGCIL) were accordingly set up in a phased manner. Prior to this also centre had set up organisations like Damodar Valley Corporation (DVC) , Neyveli Lignite Corporation(NLC) etc. to take care of integrated development of resources in the region. The development of Nuclear Power was under Atomic Energy Commission set up by Central Government and it only included uranium mining, heavy water plants, fuel processing etc. apart from setting up power plants. Later on for power generation was brought under public sector and Nuclear Power Corporation of India Ltd.(NPCIL) was set up.

3.2. An overview

The Installed Capacity in the country has increased from a mere 1,713 MW in December 1950 to 1, 59,398 MW at the end of March, 2010 whereas during the same period the annual electricity generation has grown from about 5 BU to about 723.5 BU by March 2009. So far electricity generation achieved till 31.3.2010 is 771.5 BU as against of 789.5 BU target for 2009-10 which is approximately 97.7%. The details are given in Table 3.1

Table 3.1[7]: Installed Electrical Power Generation Capacity (MW)

Thermal		102,453 MW
Coal	84,198.38 MW	
Gas	17,055.85 MW	
Liquid Fuels	1,199.75 MW	
Hydro-		36,863.40 MW
Nuclear-		4,560MW

[7] CEA Monthly Performance Report- March 2010

RES(MNRE)-Renewable		15,521.11MW
Total		1, 59,398.49 MW

India has achieved 82.3% of village electrification (488926 villages) till Feb, 09. The agricultural pump sets energized are 81.2% (15.9 million).

Growth in demand has exceeded the supply and power shortages have continually been experienced. The power supply position at the end of 2009-10 indicates an energy deficit of 11% on all India basis, varying from 4.6% lowest in eastern region to about 16 % highest in the Western region. Similarly over all peak shortage has been 12% varying in the range of 7.4% in the southern region to about 25.4% in the North eastern region.

The 11th plan approved plan envisages a total capacity addition of 78,700 MW in the country comprising of 15,627 MW Hydro 59,693 MW Thermal (50570 coal, 2280 lignite and 6843 gas) and 3,380 MW Nuclear. So far a capacity of 22,302 MW has been added in the country till 31.03.10 which is about 28.3 % of plan target.

The Electricity Act, 2003 which came into being on June 10th 2003, provides a framework conducive to development of the Power Sector, promoting transparency and competition and protecting the interest of the consumers. CEA is responsible for overall planning & development of the power sector in the country. As per stipulation of Section 3(4) of the Electricity Act 2003, CEA is required to prepare and notify the National Electricity Plan after approval of the Central Government. Plan shall serve as a road map towards optimum growth of the Power Sector. ThePlan covers the 10th Plan in detail and 11th Plan & 12th Plan in perspective. Volume I covers the Generation Plan. Associated transmission facilities and related aspects have been covered in Volume II of the Plan.

3.3. National Electricity Policy

The Government has notified the National Electricity Policy on 12th February 2005, which provides direction to the evolution of the power sector within the ambit of the Electricity Act 2003.. The objectives include demand to be fully met by 2012 and per capita availability of electricity to be increased to over 1000 units by 2012. Various other issues listed in the policy like rural electrification, generation, energy conservation, environmental issues, etc., have also been addressed in the Plan. The Plan also includes measures being taken to achieve the objectives of the policy.

3.4. Electricity Demand Forecast

The 17th Electric Power Survey Committee was constituted by the Central Electricity Authority on 24th November, 2003 with the concurrence of the Ministry of Power. The terms of reference of the Committee were as under:

i) To forecast year-wise electricity demand for each State, Union Territory, Region and All India in detail up-to the end of 11th Plan i.e. Year 2011-2012.

ii) To project the perspective electricity demand for the terminal years of 12th and 13th Five Year Plans i.e. Year 2016-2017 and 2021-2022.

The electricity demand forecast is an important input for planning of the power sector to meet the future power requirement of various sectors of electricity consumption. A planned load growth in industry, agriculture, domestic and other sectors is necessary to have unified growth in all sectors of economy and therefore it is necessary that infrastructure is planned in various sectors of electricity consumption so as to direct the overall growth of economy in rational manner. The 17th EPS has considered appropriate growth rate in all sectors of the Indian economy to remove the constraints in the electricity supply and achieve accelerated GDP growth over the growth achieved during the last 5-8 years.

The electricity forecast exercise, the planning of the generation capacity and development of the infrastructure in various sectors of electricity consumption are complementary to one another. The generation capacity expansion planning and development of corresponding power transmission systems is planned by Central Electricity Authority on medium and long term basis. The present plans for generation and transmission are aiming to meet the electricity requirement in full by 2011-2012, make power available on demand and also provide for spinning reserve to improve the quality and reliability of electricity supply.

The electricity consumption by the end consumer is the guiding factor for evaluating the electricity demand for the future. The energy consumption pattern is changing with the invention of technology and energy conservation measures initiated by Government and the industrial sector. Efforts have been made to collect the data on electricity saving on account of energy conservation measures initiated by HT industries and the results have shown above 1.5% saving in energy consumption during the year 2004-05. It has not been possible to capture the electricity saving in all sections of energy consumption. However, the higher weightage provided to the latest trends in the energy conservation follows the latest trend in technology and energy conservation efforts by various stake holders.

It has been noticed in the past that there had been a gap between the electricity forecast and the actual achievements on all India basis. For some of the States the gap between the demand projections and the actual load requirement had been very large due to scanty growth of the load demand. There are 8 States for which the load growth had been scanty (less than 4%) while 17 States achieved moderate load growth of 4-7% against 16th EPS growth rate of 6.33% and a few achieved high growth rates. The States with lower electricity demand growth rate are comparatively less developed States and if these States have to catch up with others, then they are required to accelerate their electricity consumption in industry, commerce and agriculture so as to generate sustainable economic development. The electricity demand forecast has been prepared based on the aforesaid philosophy so as to provide equitable growth in the country.

The electricity demand projections are based on various assumptions. However, to achieve the maximum benefit of the forecast it would be necessary to develop infrastructure for transmission and distribution for uninterrupted flow of power to the consumer in all sectors of consumption like industry, agriculture, domestic, etc. particularly rural sector, commercial, etc. The partial end use method has been used for forecasting the sectoral electricity consumption for various categories of consumption such as domestic, commercial, public lighting, public water works, agriculture and LT industry etc. In case of HT industry more than 1 MW data is collected from individual industry and included accordingly. The total electricity consumption is worked out by aggregating sectoral projections. The exercise in detail is carried out for each state of the country separately and subsequently regional and All India forecasts are worked out taking into account suitable diversity factors.

3.5. Energy Demand and the Peak Load Demand

Electrical Energy Requirement and the Peak Load Demand are important elements of the electrical supply projections. The electrical energy demand represents the productive element which goes into the capital building of the nation while peak demand is the operational parameter of the utilization of electrical energy. The ideal energy requirement would point towards constant load throughout the period under consideration and for the purpose of EPS the same is on yearly basis. However the energy requirement of various consumers is different for different season, time, place and process and energy and peak demand changes accordingly. The ratio of peak demand and the off-peak demand in the All India System varies upto 150% over short period and upto 200% (monthly basis) over long term (yearly basis) on annual basis. The reduction of gap between peak load and off-peak load would mean higher utilization of the installed generating capacity. The peak demand could be managed with prudent Demand Side Management and co-ordination between various industrial, agriculture, commercial and bulk consumers. Though various State utilities are making effort to shave off the peak through various initiatives like Time of the Day (ToD) metering and imposing load restrictions in various load centers by rotation, it has been, however, noted in many States that the peak load growth has been much higher than the corresponding increase in the energy requirement. While there is regular pattern in the growth of electrical energy, the peak load has noticed quantum jumps at irregular intervals over the years. The sudden jump in the peak demand growth are noticeable in States with high industrialization, agriculture or commercial activities like Maharashtra, Punjab, Gujarat, Andhra Pradesh etc. A study of the regional Load Duration Curve (LDC) reveals that the high peak persists for short period of less than half an hour on an average which contributes to 5% peak demand, whereas the 2nd peak persists for over 4 hours a day.

The high peak can be managed through various DSM and energy conservation measures, thus the 2nd peak which is of the order of 95% of the high peak is the real system peak. The freak variations of 5-6% in peak demand can appear for short duration on State basis.

The summary of the energy requirement and expected peak demand by the end of year 2011-12 are given in Table 3.2

Table 3.2[8]: EPS Forecast by 17th Electric Power Summit (EPS)

A.Energy Requirement at Power Station Bus Bars (Utilities only)(in GWh)								
State/UT	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12
Northern Region	181203	195359	209137	223928	239807	256859	275171	294841
Western Region	204819	223054	233486	244481	256075	268307	281220	294860
Southern Region	150457	163710	176037	189312	203606	219001	235582	253443
Eastern Region	59015	64498	70547	77221	84601	92767	101805	111802
North-Eastern	7145	7812	8534	9326	10193	11141	12184	13329
ISLANDS								

[8] 17th EPS Report-2007

Andaman & Nicobar	126	146	193	219	248	281	316	344
Lakshadweep	22	24	26	28	31	34	37	40
All India	602787	654603	697961	744515	794561	848390	906316	968659
B. Peak Load at Power Station Bus Bars (Utilities only) (in MW)								
Northern Region	27759	30030	32487	35145	38021	41131	44496	48137
Western Region	31256	33142	35143	37264	39513	41898	44427	47108
Southern Region	23516	25673	27441	29854	32192	34715	37434	40367
Eastern Region	9317	10322	11436	12670	14037	15552	17230	19088
North-Eastern	1272	1404	1549	1710	1888	2083	2299	2537
ISLANDS								
Andaman & Nicobar	28	33	43	49	56	63	71	77
Lakshadweep	7	7	8	8	9	10	11	11
All India	90221	97269	104867	113059	121891	131413	141678	152746

3.6. Generation Resources and Technologies

In order to meet the growing need for power in the country, it is essential to exploit all available energy resources. Priority has been set for developing cleaner sources of energy like hydro power and other renewable and non- conventional sources. However, coal based thermal generation is expected to continue to dominate power generation and therefore requisite thrust is essential for the development of various technologies including clean coal technologies promoting high efficiency. Nuclear power being clean & environment friendly, needs to be developed to the maximum extent possible.

3.6.1 Hydro

An assessment has been made of the hydroelectric potential in the country. According to the Studies, the total theoretical potential is estimated to be about 3,00,000 MW and economic power potential as about 50,000 MW (firm), equivalent to about 84,000 MW at 60% Load Factor from 845 schemes.

The basin-wise summary of hydro potential is given in Table 3.4

Table 3.3[9]: Hydro Electric Potential in India

Sl. No.	River System	No. of Basins Study	Firm Potential (MW)	Potential at 60% LF (MW)	Theoretical potential (MW)	Annual Energy-90% Dependable Year (MU)
1	Indus	6	11,993	19,988	50,712	1,47,751
2	Brahmaputra	9	20,952	34,920	1,46,170	2,67,663
3	Ganga	10	6,429	10,715	52,938	81,100
4	Central Indian Rivers	8	1,644	2,740	14,888	14,998
5	West Flowing Rivers	7	3,689	6,149	9,437	35,680
6	East Flowing Rivers	9	5,719	9,532	26,972	52,901
	Total	49	50,426	84,044	3,01,117	6,00,093

A judicious blend of Storage & Run of River Schemes is to be considered particularly with a view to derive peaking benefits from hydro projects. Out of 845 schemes, 331 schemes have been identified by CEA as storage schemes and their possible installed capacity could be 73,172 MW.

With an objective of taking up the hydro development in an appropriate sequence, CEA undertook Ranking Studies to determine the inter se priority of hydro projects based on desk

[9] CEA

studies, available data and weightage criteria for various aspects involved, for their development. Considering these aspects, the schemes have been graded as 'A', 'B' and 'C' categories in order of their priority for development, with priority decreasing from A to C. This exercise was considered helpful to facilitate in identifying the projects for implementation in order of their priority so that hydro development is taken up in appropriate sequence. A total of 399 Schemes with an aggregate installed capacity of about 1, 07,000 MW have been prioritized.

3.6.2 Thermal

Thermal Power Generation is the backbone of the Indian Power system. Technology trends in thermal generation as well as other important issues such as water optimization, coal quality improvement; ash utilisation, coal based clean technology, etc., have also been considered. All efforts need to be made to tap the potential in an environment friendly, cost effective and sustainable manner.

Various fuels are available for thermal generation in the country and the techno-economics of each fuel type needs to be established on a case- to- case basis, depending on factors such as availability of fuel, location of fuel, nature of load requirement and load centre etc. This National Electricity Plan has been evolved based on detailed studies carried out taking into account these factors. Salient features of the various fuels for thermal generation are as follows:

3.6.3 Solid Fuels

3.6.3.1 Coal

As per the estimates of Geological Survey of India, the coal reserves of India stand at 267 Billion Tonnes as on 01.04.2009 with more than 87% of these being of the non-coking grade. The geographical distribution of these coal reserves is primarily in the states of Jharkhand, West Bengal, Orissa in the Eastern region which accounts for about 64 %, Madhya Pradesh, Maharashtra, Chattisgarh in the western region accounting to 28 % , and Andhra Pradesh in southern region accounting for 7% and balance 1% in rest of the country including some reserves in Meghalaya in the North Eastern Region.

The details of coal reserves are given in Table 3.4 and 3.5.*the country (in Million Tonnes)*

Table 3.4[10]: State wise details of geological Coal reserves in the country (in Million Tonnes)

State	Geological Resources of Coal in Million Tonnes			
	Proved	Indicated	Inferred	Total
Andhra Pradesh	9194	6748	2985	18927
Southern Region(%) share				7.08
Chhattisgarh	10910	29192	4381	44483
Madhya Pradesh	8041	10295	2645	20981
Maharashtra	5255	2907	1992	10154
Western Region	24206	42394	9018	75618
Western Region(%) share				28.30
Jharkhand	39480	30894	6338	76712
Orissa	19944	31484	13799	65227
West Bengal	11653	11603	5071	28327
Eastern Region	71077	73981	25208	170266
Eastern Region(%) share				63.72
	104477	123123	37211	264811
Others	1343	347	709	2399
Total	105820	123470	37920	267210

[10] Annual Report 2007-08- Ministry of Coal

The total coal production in the country during 2008-09 was 493 MT, of which about 355 MT was used for power sector (excluding captive power plants). In addition to this, about 20 MT was imported for Power Sector. The total coal availability from domestic sources is expected to be 482 MT per annum by 2011-12.This includes coal production from captive mines.

Table 3.5[11]: Classification of Coal reserve according to type of coal (in Million Tonnes)

Type of Coal	Proved	Indicated	Inferred	Total
(A) Coking :-				
-Prime Coking	4614	699	0	5313
-Medium Coking	12449	12064	1880	26393
-Semi-Coking	482	1003	222	1707
Sub-Total Coking	17545	13766	2102	33413
(B) Non-Coking:-	87798	109614	35312	232724
(C) Tertiary Coal	477	90	506	1073
Grand Total	105820	123470	37920	267210

Use of imported coal with high calorific value and low ash content may be the preferred choice for coastal thermal power plants in Tamil Nadu, Gujarat, Maharashtra, Karnataka and Andhra Pradesh depending upon competitive pricing. After ensuring compatibility, blending of imported and domestic coal for plants in coastal areas minimises the variable charges without affecting the performance of the boilers. Feasibility of acquisition of coal mines including joint venture abroad and on entering into long-term contract with the companies supplying imported coal should be considered by large organisations such as NTPC and Indian Coal Companies.

[11] Annual Report 2007-08- Ministry of Coal

3.6.3.2 Lignite

The geological reserves of lignite have been estimated to be about 35.6 BT. Lignite is available at limited locations such as Neyveli in Tamil Nadu, Surat, Akrimota in Gujarat and Barsingsar, Giral, Jalipa Kapurdi in Rajasthan, Over 86% of the resources are located in the State of Tamil Nadu alone, whereas the rest 14% are distributed in other States.

Since, lignite is available at a relatively shallow depth and is non-transferable, its use for power generation at pithead stations is found to be attractive. The cost of mining lignite has to be controlled to be economical for power generation. The Neyveli Lignite Corporation under administrative control of Ministry of coal is primarily responsible for development of lignite mines and thermal power stations in the states of Tamilnadu and Rajasthan. In Gujarat lignite projects are put up by state sector corporations and the private sector namely JSW energy (Raj West Power) is also putting up a large (8x135 MW) lignite based power plant in Barmer ditrict of Rajasthan.

3.6.4 Liquid Fuels

A wide variety of liquid fuel options are available for power generation. In general, liquid fuels have certain basic advantages in terms of

- Easy handling
- Good combustion/fuel characteristic- High calorific value
- No post-combustion solid residue

Heavy oils such as Low Sulphur Heavy Stock (LSHS), Heavy Petroleum Stock (HPS), Heavy Fuel Oil (HFO) are suitable for power generation especially in areas where coal cannot be transported easily. The Ministry of Environment & Forests has stipulated maximum sulphur content of 2% of power generation. Further, there is a limit to capacity of DG set, which is of the order of 20 MW for four stroke engines and 60 MW for two stroke engines. Therefore diesel engine stations are used for power generation mainly as standalone systems in Islands and isolated locations in NE Region.

In isolated difficult areas like Kashmir Valley, Ladakh etc., distillate liquid fuels such as distillate No.2, HSD, naphtha, condensates are some preferred fuels from environmental angle because of very high conversion efficiency achievable through advanced technology gas turbines and non-polluting nature of these fuels. Due to high price of naphtha, the cost of generation with naphtha as the primary fuel is very high in spite of low fixed charges on account of the low capital cost of the CCGT plant. HSD is used in Diesel Engines and Combined Cycle Plants for power generation as well as in industries as captive power plants. HSD oil is a better fuel than naphtha for gas turbines (GTs) because of its lesser flammable characteristics. However, the sulphur content of domestic HSD is somewhat higher than 1% as permitted by IS 1460. As per Ministry of Power resolution dated 19.1.2001, indigenously produced HSD is allowed for power generation. Import of HSD will be considered on a case-to-case basis if there is a shortfall in the availability of domestic HSD. In view of high cost of liquid fuel, it will have very limited utilization in power generation and will remain as an option for captive use and standby source for emergency.

3.6.5 Gaseous Fuels

Natural gas is the best fuel from environmental angle and hence it is being increasingly used in Combined Cycle Gas Turbine power stations in view of the very high efficiencies with advanced technology gas turbines. Natural Gas, owing to its non-polluting nature and ease of use as compared to oil, is expected to gain significance in the primary mix for power generation.

A major increase in the production & utilization of Natural gas took place in the late seventies with the development of Bombay High fields and again in the late eighties when the South Basin field in Western Offshore was brought to production. Domestic production of gas increased more than tenfold from 1981 to 2003.

Limited gas resource is available in our country. The National Oil companies viz. Oil & Natural Gas Corporation Ltd. (ONGC) and Oil India Ltd. (OIL) have made 25 significant hydrocarbon discoveries in the last 4 years, of which 10 are offshore and 15 are inland. Private/ Joint Venture companies have also made 27 hydrocarbon discoveries both in NELP & pre-NELP blocks. Recently major gas discoveries have been made by M/s Reliance Industries Ltd in Krishna-Godavari basin. Discoveries have also been made by M/s GCPL. Currently, there is a shortage of gas and demand –supply gap is projected to increase with strong growth in demand vis-à-vis slower growth in domestic production.

GAIL (India) Ltd. distributes almost all the gas produced in India. It operates over 4000 km of gas pipeline, the most prominent being the 2300 km HBJ pipeline with a capacity to handle 33.4 MMSCMD. GAIL (India) Ltd. has recently been nominated to construct national pipeline grid by Government of India which is planned to be completed by the year 2008. The grid will comprise a nationwide pipeline network covering a length of about 7900 km. The 18 MMSCMD gas from KG Basin fields of Reliance have also been allocated to various power stations in the country and the production of this field is expected to increase further and more and more power plants will be given gas allocation.

To supplement the gas availability, there are plans for import of natural gas in the form of Liquefied Natural Gas (LNG) from other countries. There is also possibility of import of natural gas from neighboring countries namely Bangladesh, Myanmar, Iran and Turkmenistan through pipelines. LNG based CCGT plants are best suited for coastal areas since after re-gasification, transportation of gas for peaking may not be economical over long distances unless the quantum of gas transported is large. However, utilization of natural gas /LNG for future power projects will depend on availability and price.

Oil and natural gas reserves in the country are given in Table 3.6

Table 3.6[12]: Oil and Natural Gas Reserves

OIL AND NATURAL GAS RESERVES (Year wise Status)					
AREA	2005	2006	2007	2008	2009
CRUDE OIL (Million Metric Tonnes)					
Onshore	376	387	357	403	405
Offshore	410	369	368	366	369
Total	786	756	725	769	775
NATURAL GAS (Billion Cubic Metres)					
Onshore	340	330	270	264	287
Offshore	761	745	785	786	787
Total	1101	1075	1055	1050	1074

Note: The oil and natural gas reserves (proved and indicated) data relate to 1st April of each year.

Coal bed methane (CBM) is found in a number of coalfields in the country. This CBM reserve has been estimated to be 486.55 billion cubic meters. The exploitation of CBM in addition to being a viable fuel option for power generation could also reduce the methane emission in the atmosphere. However, its use would largely depend on its economic viability. It is felt that the Indian coal companies may take initiative to develop CBM based power projects.

[12] Annual Statistical report- MOPNG

3.6.6 Nuclear

Nuclear power, being a clean and environment friendly source of energy, is a good option for power generation. The details in Table 3.8includes various technologies, including future unit sizes and evolution of future programmes for development of nuclear power up to the year 2020.

Table 3.7[13]: Nuclear Power Programme up to 2020

Details	Capacity Addition (MWe)	Cumulative Capacity (MWe)
Nuclear Power Reactors in Operation		3900
Projects Under Construction To be Completed in first 2 years of 11th Plan Kaiga-3 220 MWe Kaiga-4 220 MWe KKNPP-1&2 2X1000 MWe RAPP-5&6 2X 220 MWe	2,880	6,780 (By 12/2008)
To be completed during 2009-12 PFBR-500 MWe at Kalpakkam, Tamil Nadu	500	7,280(By 2011-12)
Future Units for Completion by 2020 Mix of 1000 MWe LWRs, 700 MWe PHWRs, 500 MWe FBRs.	About 12,700	About 20,000 (By 2020)

[13] NPCIL.

CEA Report

3.6.7 Non-Conventional Energy Sources

Source-wise details of potential and cumulative Installed Capacity as on 31.12.2009 of Grid Interactive Renewable Power (including captive capacity) are given in Table 3.8:

Table 3.8[14]: Cumulative Potential And Achievements For Grid Interactive Renewable Power As On 31.12.2009 (Figures In MW)

Sources / Systems	Estimated mid-Term (2032) Potential	Cumulative Installed Capacity (As on 31.12.2009)
Wind Power	45,000	
Bio- Power (Agro residues & Plantations)	61,000	
Co-generation Baggasse	5,000	
Small Hydro (up to 25 MW)	15,000	
Waste to Energy	7,000	
Solar Photovoltaic	50,000	
TOTAL	1,83,000	15225*

** Includes Captive capacity*

A target of 3075 MW was set for the 10th Plan in respect of grid interactive renewable power against which an achievement of 6132 MW has been made during the 10th Plan. Detailsof 11th Plan target of Grid Interactive renewable power are furnished below:

[14] MNRE

Table 3.9[15]: 11th Plan Tentative Targets for Grid Interactive Renewable Power (Figures in MW)

Sources / Systems	Target for 11th plan
Wind Power	10,500
Biomass Power, Baggasse Co-generation , Biomass Gasifiers	2,100
Small Hydro (up to 25 MW)	1,400
TOTAL	14,000

Considering the 10th Plan and tentative 11th Plan capacity addition,Summary of Installed Capacity is furnished below**:**

Table 3.10: Summary of Installed Capacity (Considering the 10th Plan and tentative 11th Plan capacity addition)

Installed capacity by the end of 9th Plan (As on 31.3.2002)	3,475 MW
Installed capacity by the end of 2005-06 (As on 31.3.2006)	8,088 MW
Programme for 2006-07	1,888 MW
11th Plan programme for 2007-12	14,000 MW
Total Installed Capacity expected by the end of 11th plan	23,976 MW
Say	24,000 MW

Development of renewable energy is very important & should be encouraged. However, benefit from renewable energy sources has not been considered in the planning studies as electrical energy fed into the grid from these sources is small and considered non-dispatch able**.**

[15] ***MNRE***

3.7. Generation Expansion Planning

3.7.1 Eleventh Plan (2007-12)

The demand projections as per the provisions of National Electricity Policy(NEP) i.e. the per capita electricity consumption to increase to 1,000 units by the year 2011-12, have been taken as the base in the planning studies. Therefore the requirement of generation (from utilities) for planning purpose adopted is 1038 BU, which is nearly the same as per the 17th EPS. This would require a generation growth rate of 9.5 % p.a. (CAGR) for utilities above 2006-07 generation level. The 17th EPS Report stipulates peak demand of 1,52,746 MW by 2011-12. This has been considered while assessing the 11th Plan capacity addition.

Generation expansion planning studies for 11th plan end (2011-12) have been carried out to assess the requirement of additional generating capacity during the 11th plan period (2007-12), based on above demand. The latest norms for the availability of Generating stations, auxiliary consumption, heat rate, financial parameters and reliability indices, as approved by the Authority based on the past actual performance data, have been taken into consideration. Fuel requirement has been worked out on a normative basis.

De-rating, up-rating and retirement of generating units already done as well as programmed has been accounted for in the studies. Benefits from Non conventional energy sources and surplus power from captive plants fed into the grid have not been considered as these benefits would only serve as bonus to the total capacity addition Programme.

Spinning Reserve requirement of 5% as spelt out in the Electricity Policy has been considered. This has been accounted for by reducing the availability norms of generating units by 5% for each category of units.

The requirement of additional capacity during 11th plan works out to about 82,500 MW taking into account 10th plan actual capacity addition of 21,180 MW. However, depending upon the preparedness of various projects only about 78,530 MW capacity addition is feasible during 11th plan. This shortfall viz-a-viz the required capacity addition as per stipulations of National Electricity Policy is expected to be met from renewable energy sources and surplus from captive power plants. MNRE has projected a grid connected renewable capacity addition of 14,000 MW during 11th plan. The demand side management and energy efficiency measures would further help in bringing down the peak demand. In addition, efforts shall also be made to realize benefits from projects which can be commissioned with additional efforts (best effort projects, totalling to about 11,545 MW) during the 11th plan. Efforts are also underway to tap surplus power from grid connected captive power plants. A capacity of about 12,000 MW is likely to be commissioned during 11th plan period, 20% of which is likely to be available to the Grid. As regards the creation of spinning reserve of 5%, it may be mentioned that based upon proposed capacity addition of 78,530 MW during 11th plan, about 5,500 MW (2.8 %) spinning reserve is likely to be created in the system by 2011-12.

Taking into account the uncertainty in the availability of Gas and prevailing high price of petroleum products, the thermal capacity addition is predominantly coal based and a small gas based capacity of about 4,242 MW has been included in the 11th Plan. These gas based projects are already under execution or gas has been tied up from local sources. However, a large number of gas based power plants totalling to 12,980 MW have been identified at various locations in the country. If gas becomes available at a reasonable price, more gas based projects may be taken up during later half of 11th plan.

3.7.2 12th Plan Capacity Additions-Scenario Approach

A large capacity of hydro and nuclear plants needs to be taken up during 12th plan for energy security of the country and to minimize green house gas emissions caused by thermal generation. In the 11th plan only 16,553 MW hydro capacity has been proposed keeping in view the preparedness of the hydro projects. In case of hydro projects, investigation, preparation of DPR and construction of infrastructure facilities takes about two years and project execution may take another five years. In view of large gestation period of hydro projects, survey and investigation, preparation of DPR, providing initial infrastructure, concurrence of CEA/State Government, environmental clearance and LOA for main packages of the projects planned for 12th Plan has to be completed well before commencement of the 12th Plan. CEA and MoP have to monitor the progress in respect of all the projects to ensure placement of LOA for main equipment during the 11th Plan itself. Similarly, a modest target of 3,380 MW has been set up for nuclear capacity during 11th Plan. The present programme of Nuclear Power Corporation for 12th plan is about 11,000 MW. Another 2,000 MW is being planned by NTPC. However, with opening up of the sector to other players and availability of fuel from international market, we can expect an increase in the target for nuclear power capacity for 12th Plan.

As per 17th EPS Report, the energy requirement by Utilities in 2016-17 is 1392 BU at the bus bar. Considering 6.5% auxiliary consumption, the gross energy requirement is about 1488 BU. Various Scenarios based on GDP growth rates of 8%, 9%and 10% and GDP Electricity elasticity of 0.9 and 0.8 have been worked out and details of the results are as furnished in the Table 3.11.

Table 3.11: Capacity addition required during 12th plan (2012-17)

GDP Growth	GDP /Electricity Elasticity	Electricity Generation Required (BU)	Peak Demand(GW)	Installed Capacity (GW)	Capacity Addition Required During 12th PLAN (GW)
8 %	0.8	1,415	215.7	280.3	70.8
	0.9	1,470	224.6	291.7	82.2
9 %	0.8	1,470	224.6	291.7	82.2
	0.9	1,532	233.3	303.8	94.3
10 %	0.8	1,525	232.3	302.3	92.8
	0.9	1,597	244.0	317.0	107.5

It would be seen from the above table that under various growth scenarios, the capacity addition required during 12th plan would be in the range of 70GW – 107.5 GW, based on normative parameters.

Keeping in view the economic development scenario during the 12th Plan period, a GDP growth rate of 9% per annum and elasticity 0.8 as compared to elasticity of 1.0 during 11th Plan has been assumed mainly due to adoption of energy efficient technologies and other Energy Conservation and Demand Side Management measures being taken up during 11th Plan. Accordingly, it emerges that electricity demand is likely to grow @ 7.2% per annum. Keeping this in view, the energy generation should increase to a level of 1470 BU by 2016-17 from a level of 1038 BU in 2011-12

For the purpose of planning capacity addition during 12th Plan, Electricity generation requirement of 1470 BU as per 9% GDP growth rate and 0.8 elasticity has been adopted. This is very close to the projections of 17th EPS.

A capacity addition of 82,200 MW for the 12th Plan based on Scenario of 9% GDP growth rate and an elasticity of 0.8% is recommended.

The scenario approach as adopted for 12th plan demand assessment will be further extended upto 2050 based on 5 year intervals and also keeping in view the goals set in the report of Integrated energy policy which covers up to 2032. The total installed capacity required for meeting the projected demand is worked out and subsequently the capacity additions required are assessed. The mix of capacities would depend upon resources available for power generation and the potentials exploited. As far as hydro is concerned total hydro electric capacity feasible is about 150 GW which may be totally achieved by 2050 or so, development of nuclear is related with fuel availability under international agreements will be taken as per the programmes drawn up by NPCIL. The balance demand has to be met from thermal resources like coal, lignite and natural gas. The renewable energy sources would continue to play the complimentary role because of the inherent nature of their availability.

3.8. Environmental Aspects

The Clean Development Mechanism (CDM) under the Kyoto Protocol to United Nations Framework Convention on Climate Change (UNFCCC) provides an opportunity for the Indian power sector to earn revenue through the reduction of greenhouse gas emissions (GHG), particularly carbon dioxide (CO2). India has tremendous potential for CDM projects. Power generation based on higher efficiency technologies such as supercritical technology, integrated gasification combined cycle, and renovation and modernization of old thermal power plants, co-generation along with renewable energy sources are some of potential candidates for CDM in the power sector. Energy efficiency and conservation projects also present themselves as eligible CDM projects, as these would also result in energy savings and displace associated CO2 emissions which otherwise would be produced by grid-connected power stations.

The CDM has by now become an established mechanism for crediting climate friendly projects. Projects involving displacement or saving of grid electricity must calculate their emission reductions based on a grid emission factor which needs to be determined in accordance with the rules set by the CDM Executive Board. Central Electricity Authority (CEA) accordingly took up in cooperation with GTZ, to compile a database for all grid-connected power stations in India. The purpose of the database is to establish authentic and consistent quantification of the CO2 emission baseline which can be readily used by CDM project developers in the Indian power sector. This would enhance the acceptability of Indian projects and would also expedite the clearance/approval process. India is the first country in the world to have ventured to take up the complex task of developing such an official baseline for the power sector as a whole.

Emission reductions from CDM projects in the power sector are calculated based on the net electricity generated by the project, and the difference between the emission factors (in tCO2/

MWh) of the baseline and the project activity. The baseline emission factor reflects the carbon intensity of the displaced amount of grid electricity. This baseline emission factor can be derived from the data provided in the CO2 Database. Specifically, the database contains the following elements:

- Worksheet "Data" provides the net generation and the absolute and specific CO2 emissions of each grid-connected power station. It also indicates which stations and units have been included in the operating margin and build margin, respectively.
- Worksheet "Results" provides the most commonly used aggregate emission factors. These are calculated from the station data in accordance with the most recent Grid Tool.2
- Worksheet "Abbreviations" explains the abbreviations used in the "Data" worksheet.
- Worksheet "Assumptions" shows the assumptions that were used for the calculation of the CO2 emissions at station and unit level, to the extent required.
- Worksheet "Transfers" shows the inter-Grid and cross-border power transfers.

3.8.1 Different Types of Emission Factors

The CDM methodologies which have been approved to date by the CDM Executive Board distinguish a range of different emission factors. In the Indian context, the following four are most relevant, and were therefore calculated for each regional grid based on the underlying station data:

3.8.1.1 Weighted average:

The weighted average emission factor describes the average CO2 emitted per unit of electricity generated in the grid. It is calculated by dividing the absolute CO2 emissions of all power stations in the region by the region's total net generation. Net generation from so-called low cost/must-run sources (hydro and nuclear) is included in the denominator.

3.8.1.2 Simple operating margin (OM):

The operating margin describes the average CO2 intensity of the existing stations in the grid which are most likely to reduce their output if a CDM project supplies electricity to the grid (or reduces consumption of grid electricity). “Simple” denotes one out of four possible variants listed in the Grid Tool for calculating the operating margin. The simple operating margin is the weighted average emissions rate of all generation sources in the region *except* so-called low-cost or must-run sources. In India, hydro and nuclear stations qualify as low-cost / must run sources and are excluded. The operating margin, therefore, can be calculated by dividing the region’s total CO2 emissions by the net generation of all thermal stations. In other words, it represents the weighted average emissions rate of all thermal stations in the regional grid. Values for operating margins given in this User Guide and the Database are always based on the “ex post” option as set out in the Grid Tool.

3.8.1.3 Build margin (BM):

The build margin reflects the average CO2 intensity of newly built power stations that will be (partially) replaced by a CDM project. In accordance with the Grid Tool, the build margin is calculated in this database as the average emissions intensity of the 20% most recent capacity additions in the grid based on net generation. Depending on the region, the build margin covers units commissioned in the last five to ten years.

3.8.1.4 Combined margin (CM):

The combined margin is a weighted average of the simple operating margin and the build margin. By default, both margins have equal weights (50%). However, CDM project developers may chose to argue for different weights. In particular, for intermittent and non dispatchable generation types such as wind and solar photovoltaic, the Grid Tool allows to weigh the operating margin and build margin at 75% and 25%, respectively. However, the combined margins shown in the database are calculated based on equal weights. In line with the Grid Tool, if a station is registered as a CDM activity, it is excluded from the build margin but not from the operating margin. The two variants "Simple adjusted operating margin" and "Dispatch data analysis operating margin" cannot currently be applied in India due to lack of necessary data.

3.8.2 Scope of Database

The database includes all grid-connected power stations having an installed capacity above 3 MW in case of hydro and above 10 MW for other plant types. The data covers power stations of both public utilities and independent power producers (IPPs). Breakdown of generation capacity covered by the database corresponding to a installed capacity of 134,941(excluding RES-MNRE) MW as on 31.03.2009 is as following.

Coal - 54.0%, Diesel- 0.9%, Gas-9.1%, Lignite-2.9%, Naphtha- 0.4% and

Oil- 1.0%

Nuclear -3.0%

Hydro-27.8%

The following power stations are currently not accounted for in the database:

- Stations or units installed in Andaman and Nicobar Islands and Lakshadweep.
- Captive power stations: As on 31 March 2008, the installed capacity from captive stations was 24,680.70 MW. The generation of these stations in 2007-08 was 85431GWh, equalling 12.12% of total generation in India.
- Non-conventional renewable energy stations: These include power generation from wind, biomass, solar photovoltaic, and hydro below 3 MW capacity. The installed, grid-connected capacity of these sources was approx. 13242.41 MW as on 31. 03. 2009
- Small decentralized generation sets.

3.8.3 Calculation of CO_2 Emissions

CO_2 emissions of thermal stations were calculated using the formula below:

$$AbsCO_2(station)_y = \sum_{i=1}^{2} FuelCon_{i,y} \times GCV_{i,y} \times EF_i \times Oxid_i \qquad (1)$$

Where:

$AbsCO_{2,y}$ Absolute CO_2 emission of the station in the given fiscal year 'y'

$FuelCon_{i,y}$ Amount of fuel of type i consumed in the fiscal year 'y'

$GCV_{i,y}$ Gross calorific value of the fuel i in the fiscal year 'y'

EF_i CO_2 emission factor of the fuel i based on GCV

$Oxid_i$ Oxidation factor of the fuel

The emission factors for coal and lignite were based on the values provided in India's Initial National Communication under the UNFCCC (Ministry of Environment & Forests, 2004).. For all other fuels, default emission factors were derived from the IPCC 2006 Guidelines[16]. In line with the Grid Tool, The IPCC default factors were converted to GCV basis using IEA default conversion factors.

The oxidation factor for coal and lignite were derived from an analysis performed with data on the un-burnt carbon content in the ash from various Indian coal-fired power stations. The value of 98% is consistent with the default value provided in the IPCC 1996 Guidelines.[17] For all other fuels, default values provided in the more recent IPCC 2006 Guidelines were used.

Specific CO_2 emissions of stations ($SpecCO_2(station)_y$) were computed by dividing the absolute emissions ($AbsCO_2(station)_y$) estimated above by the station's net generation ($NetGen(station)_y$).

$$SpecCO_2(station)_y = \frac{AbsCO_2(station)_y}{NetGen(station)_y}$$

3.8.4 Results for Fiscal Year 2008-09

Table 3.12 below indicates the development of total emissions by grid over the last four years covered by the database.

Table 3.12[18]: Total emissions from the power sector by region for the years 2006-07to 2008-09 (in million tonnes CO2)

	2005-06	2006-07	2007-08	2008-09
NEWNE	368.2	385.7	406.9	430.4
South	101.6	109	113.6	117.9
All India	469.7	494.7	520.5	548.3

[18] CEA Data Base

Table 3.13 shows the emission factors for FY 2008-09 excluding inter-grid and cross-border power transfers, whereas Table 3.14 shows the emission factors for the same year including these power transfers. The weighted average emission factor for India has increased from 0.79 in the previous year to 0.82, mainly due to below-average nuclear and hydro-based generation in FY 2008-09.

Table 3.13[19]: Emission factors, of grids for 2008-09 (not adjusted for inter-grid and cross country electricity transfers),(in tCO2/MWh)

	Average	OM	BM	CM
NEWNE	0.84	1.02	0.68	0.85
South	0.75	0.97	0.82	0.89
All India	0.82	1.01	0.71	0.86

Table 3.14[20]: Emission factors, of grids for 2008-09 (adjusted for inter-grid and cross-country electricity transfers) (in tCO2/MWh)

	Average	OM	BM	CM
NEWNE	0.83	1.01	0.68	0.84
South	0.76	0.97	0.82	0.9
All India	0.82	1.01	0.71	0.86

[19] CEA Data Base

[20] CEA Data Base

The observed variations in the emission factors between the different grids originate from the differing availability and use of coal, gas and hydro resources. Stations fired with other fossil fuels such as diesel as well as nuclear stations play a less significant role. A comparison of Table 3.13 and Table 3.14 shows that electricity transfers between grids did not have a significant influence on the emission factors in 2008-09.

Table 3.15 shows the weighted average specific emissions for fossil fuel-fired power stations in the two grids. Inter-grid variations arise chiefly from differences in station age and build (installed capacity and conversion technology).

Table 3.15[21]: Weighted average specific emissions for fossil fuel-fired stations in FY 2008-09 (in tCO2/MWh)

	Coal	Diesel	Gas	Lignite	Naphtha	Oil
NEWNE	1.11	0	0.46	1.43	0.41	0.78
South	1	0.63	0.47	1.44	0.6	0.64
All India	1.09	0.63	0.47	1.44	0.44	0.73

Note: Stations for which assumptions had to be made are included in this analysis

3.8.5 CO_2 emission projections for 11th and 12th plan

For calculating the CO2 emissions by new units to be commissioned during 11th plan period unit specific normative figures of gross heat rate, efficiency, specific coal consumption and secondary oil consumption have been considered.

The details of assumptions for coal, lignite and gas units are given in Table 3.16 below.

[21] CEA Data Base

Table 3.16: Assumptions at unit Level for units to be commissioned in 11th and 12th plan period

Coal	Unit	200/250/300 MW	500/600 MW	super critical 660/800 MW
Gross Heat Rate	kcal /kWh	2,500	2,425	
Auxiliary Power Consumption	%	9	7.5	
Net Heat Rate	kcal /kWh	2,747	2,622	
Net Efficiency	%	31%	33%	
Specific Oil Consumption	ml /kWh	2	2	
Specific CO2 Emissions	tCO2 /MWh	1.05	1	
Lignite	Unit	125/210/250 MW		
Gross Heat Rate	kcal /kWh	2,713		
Auxiliary Power Consumption	%	10		
Net Heat Rate	kcal /kWh	3,014		
Net Efficiency	%	29%		
Specific Oil Consumption	ml /kWh	3		
Specific CO2 Emissions	tCO2 /MWh	1.28		
Gas	Unit	>100 MW		
Gross Heat Rate	kcal /kWh	1,970		
Auxiliary Power Consumption	%	3		
Net Heat Rate	kcal /kWh	2,031		
Net Efficiency	%	42%		
Specific CO2 Emissions	tCO2 /MWh	0.42		

Based on base line data and user manual the CO_2 emission and fly ash generated based on capacity addition required during 11th and 12th plan has been calculated. Considering actual capacity addition of 21,180 MW during 10th Plan, total CO_2 emission/year at the end of 10th plan 2006-07 has been taken as 495 Million tonnes per as per actual published in base line data on a normative basis works out to about 480 Million Tonnes. Additional CO_2 emission/year during 2011-12 i.e. terminal year of 11th Plan, on a normative basis on account of tentative thermal capacity addition of 59,693 MW (during 11th plan) works out to about 360 Million Tonnes/annum, resulting in total CO_2 emission/annum of 855 Million Tonnes during 2011-12.

In the 12th plan, thermal units with supercritical technology have to be encouraged to reduce CO_2 emission.

Additional CO_2 emission/year during 2016-17, on a normative basis on account of tentative thermal capacity addition of 40,000 MW (during 12th plan) works out to about 252 Million Tonnes/annum during 2016-17, resulting in total CO_2 emission/annum of 11117 Million Tonnes during 2016-17.

3.8.6 Fly Ash

Fly ash generated per annum at the end of 10th plan (2006-07) is about 98 Million Tonnes. Additional Fly ash generated on a normative basis during 11th plan (2007-12) works out to about 82 Million Tonnes/annum during 2011-12, resulting in total fly ash generation of about 180 Million Tonnes in that year.

Additional Fly ash generated on a normative basis during 12th plan (2012-17) works out to about 60 Million Tonnes/annum during 2016-17 resulting in total fly ash generation of about 240 Million Tonnes in that year.

The present utilization of ash at thermal power plants is about 46 %. This has to be enhanced to 100 % utilization. All new thermal projects should have dry ash storage system (silos) to facilitate transportation of ash.

3.9. Long term Projections of Generating Capacity requirement and CO2 emissions

3.9.1 Introduction:

The Integrated Energy Policy Report was published in 2005 that had made plan wise projections for electricity requirement for various years starting from 2003-04 and up to the year 2031-32 under two alternative scenarios of development of economy in the country i.e. 8% and 9% GDP growth rate. The report has projected total energy requirement (Gross generation), energy required at bus bars, peak demand and installed capacity required. As per this the demand for electricity is likely to grow from 633 BU in 2003-04 to about 3880 BU – 4800 BU in 2031-32 under two growth scenarios and the installed capacity required to meet this demand will be in the range of 788,000 MW – 960,000 MW in 2031-32 as against 131,000 MW in 2003-04, almost 6 to 7 fold increase. The assumptions made in arriving at projections are as following:

i. Electricity generation and peak demand in 2003-04 is total of utilities and non- utilities above 1 MW size.

ii. Energy demand at bus bar is estimated assuming 6.5% auxiliary consumption.

iii. Peak demand is estimated assuming system load factor of 76% up to 2010, 74% for 2011-12 to 2015-16, 72% for 2016-17 to 2020-21 and 70% for 2021-22 and beyond.

iv. The installed capacity has been estimated keeping the ratio between total installed capacity and total energy required constant at the 2003-04 level. This assumes optimal utilisation of resources bringing down the ratio between installed capacity required to peak demand from 1.47 in 2003-04 to 1.31 in 2031-32.

Based on the report of the Working Group on Power set up by Planning Commission for formulation of 11th plan, the planning commission has approved 11th plan (2007-12) power program of 78,700 MW capacity additions in the country during five year period of 2007-08 to 2011-12. The status of development of 11th plan so far has already been discussed in earlier paragraphs. As per the latest assessment, a capacity addition of 62374 MW, comprising of 8237 MW hydro, 50,757 MW thermal and 3380 MW nuclear is found to be feasible with high degree of certainty.

3.9.2 Sources of Data:

The actual data for the purposes of further analysis in respect of Installed capacity, Electricity generation by different modes has been taken from CEA publications for the end of 10th plan (2006-07) and first two years of 11th plan i.e. 2007-08 and 2008-09. Based on this data source wise operating parameters of various generating capacities i.e. Hydro, Thermal, Nuclear etc has been worked out and used for further calculations of capacity additions, installed capacity requirement and generation etc for the period of 12th five year plan to 15th five year plan.

3.9.2.1 Assumptions:

The assumptions made to access the source wise capacity addition, generation etc. to develop the scenarios are as follows:

1. The 11th plan's likely capacity addition of 62,374 MW comprising of 8,237 MW hydro; 50,797 MW thermal; and 3,380 MW nuclear has been taken as completed in both 8% and 9% growth rate scenarios. In addition, 10,000 MW capacity addition is envisaged from New & renewable sources of energy and another 10,000 MW by non- utilities, thus making total capacity addition of 11th plan as 82,374 MW.

2. The plant load factor (PLF) of various types of power generation plants is considered according to capacity addition.

   - The overall all India average PLF for hydro power plants has been in the range of 35% to 38% depending upon the rains and availability of water in the reservoirs and release of water for agricultural needs in case of multipurpose hydro projects. For future projections of generation from new hydro plants a marginal reductions in the PLF on account of high installed capacity plants planned for future has been assumed. The range is 37% to 33% for new power plants.

   - The PLF for coal and lignite based thermal power plants is assumed to be on marginally higher side on account of high efficiency plants introduced in the system. It is assumed to increase gradually from about 76% in 11th plan up to 82% in 15th plan for new capacity additions.

   - The PLF of gas based power plants is increased gradually from present level of 56% at present in 11thplan to 63% in 15th plan. This could be much higher and can even go up to 90% if sufficient quantity of gas is available.

   - The PLF of nuclear power plants is very low at present on account of shortage of fuel. However, for future the PLF has been assumed to increase gradually from 50% in 11th plan to about 65% in 15th plan.

   - The PLF for non-utilities is also increased gradually form about 42% at present to 48% in the 15th plan. Being non- utility and mostly used for captive power by industries, their PLF also depends up on availability of power from grid.

3. For calculating generation from new power plants it is presumed that of all the capacity planned to be added in each five year plan, 60% of the capacity will be available for generating at designated PLF while balance 40 % new capacity which will be commissioned in the 4th and 5th year will generate only 40 % of the scheduled generation and will be able to give full output only in the next plan period. However, this 40% capacity will start giving full generation at designated PLF in the next plan and all these have been suitably taken care off in the formula used for calculating electricity generation during a particular plan period.

The forecasts of Integrated Energy Policy Report are summarized in Table 3.17.

Table 3.17[22]: Projections for Electricity Requirement (in Billion Kwh) (Based on falling elasticities)

YEAR	Billion KWh				Projected Peak Demand (GW)		Installed Capacity Required (GW)	
	Total Energy Requirement		Energy Required At Busbar					
	@GDP growth Rate		@GDP growth Rate		@GDP growth Rate		@GDP growth Rate	
	8%	9%	8%	9%	8%	9%	8%	9%
2003-04	633	633	592	592	89	89	131	131
2006-07	761	774	712	724	107	109	153	155
2011-12	1097	1167	1026	1091	158	168	220	233
2016-17	1524	1687	1425	1577	226	250	306	337
2021-22	2118	2438	1980	2280	323	372	425	488
2026-27	2866	3423	2680	3201	437	522	575	685
2031-32	3880	4806	3628	4493	592	733	778	960

Using above data and its break up for various sub sector the requirement of capacity additions during various five year plan periods from 12th plan (2016-17) to 15th plan (2031-32) have been

[22] *Integrated Energy Policy 2006*

worked out separately for 8% and 9% GDP growth rate scenario. The likely capacity addition of 62,374 MW during 11th plan as per midterm review has been considered as fixed and any slippages etc. would have to be taken care off in 12th plan. Plan wise likely capacity additions and installed capacity including Renewable Energy sources and Non Utilities at the end of plan are summarized in Table 3.18 and details are given in annexure. 3.1

Table 3.18: Plan wise Capacity Additions and Installed Capacity

Plan period	At 8% GDP Growth Rate		AT 9% GDP Growth Rate	
	Capacity additions(GW)	Installed capacity(GW)	Capacity additions (GW)	Installed capacity (GW)
11th (2011-12)	82	237	82	237
12th (2016-17)	89	326	117	354
13th (2021-22)	119	445	152	506
14th (2026-27)	147	592	196	702
15th (2031-32)	202	794	276	978

The installed capacity requirement figures are on higher side as compared to the projection in the report on the account of the facts that large capacities based on new and renewable energy sources are planned whose PLF is in the range of 20% and contribution to peak demand is negligible except for bio mass and small hydro plants.

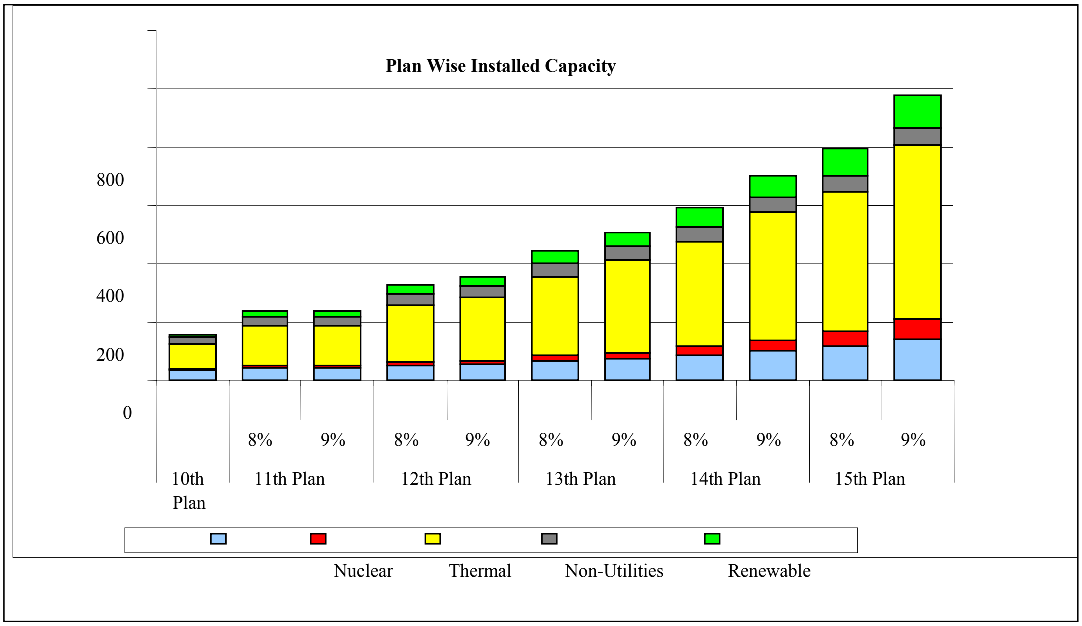

Figure 3.1: Plan wise capacity additions and added capacity

Table 3.19: Plan wise source wise Capacity Additions

Plans	Capacity Additions from Various Power Generation Sources(GW)					
	@GDP Growth Rate	Hydro	Nuclear	Thermal	Non-Utilities	Renewable Energy Sources	Total
11th Plan	8%	8.23	3.38	50.75	10.00	10.00	82.37
	9%	8.23	3.38	50.75	10.00	10.00	82.37
12th Plan	8%	8.00	4.80	56.00	8.00	12.00	88.80
	9%	12.00	4.80	80.00	8.00	12.00	116.80
13th Plan	8%	15.00	8.00	75.00	6.00	15.00	119.00
	9%	20.00	8.00	100.00	6.00	18.00	152.00
14th Plan	8%	20.00	12.00	90.00	5.00	20.00	147.00
	9%	27.00	16.00	121.00	5.00	27.00	196.00
15th Plan	8%	30.00	20.00	120.00	4.00	28.00	202.00

	9%	40.00	32.00	160.00	4.00	40.00	276.00

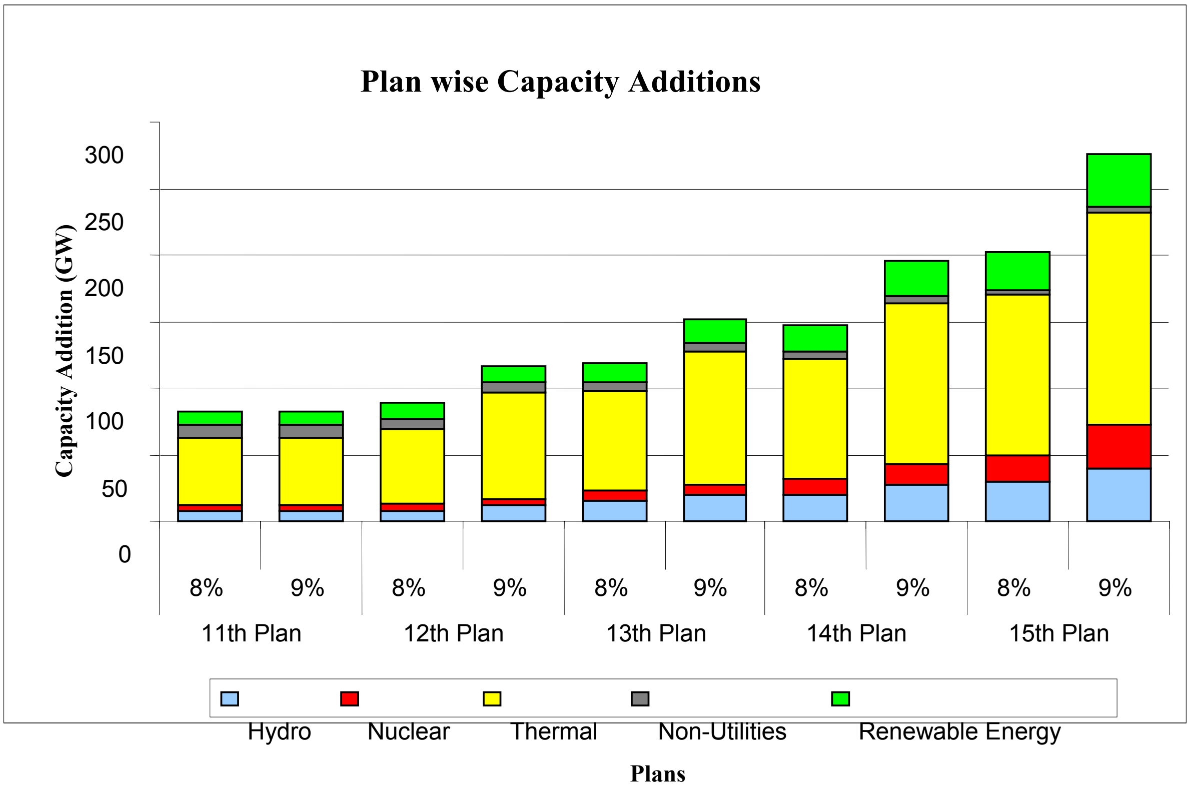

Figure 3.2: Plan wise source capacity additions

3.9.3 Analysis of results

The analysis of capacity additions during various plan periods indicates that the installed capacity of coal based power plants will increase from about 115,000 MW at the end of 11th plan to about 382,000 MW in the year 2031-32 under 8% scenario and this would further increase to about 479,000 MW under 9% scenario, in spite of high hydro, nuclear and gas capacity development. However, this will depend upon availability of natural gas and also nuclear fuel and capability to execute such large capacities. In case of Non Utilities at present about 50 % capacity is coal based and 35-40 % is oil/gas based. This would also have to be kept in mind while working out coal requirement and CO2 emissions etc.

The Central Electricity Authority is regularly publishing the CO2 baseline database for the Indian power sector. The latest being version 5.0 published in November, 2009. The details of data base user guide have already been described in earlier paras. The absolute emission of CO2 during a year from thermal power plants has been calculated as under;

The formula used for calculation of CO_2 emissions is

$$AbsCO_2(station)_y = \sum_{i=1}^{2} FuelCon_{i,y} \times GCV_{i,y} \times EF_i \times Oxid_i$$

Where:

$AbsCO_{2,y}$ Absolute CO_2 emission of the station in the given fiscal year 'y'

$FuelCon_{i,y}$ Amount of fuel of type i consumed in the fiscal year 'y'

$GCV_{i,y}$ Gross calorific value of the fuel i in the fiscal year 'y'

EF_i CO_2 emission factor of the fuel i based on GCV

$Oxid_i$ Oxidation factor of the fuel i

Based on this formula and normative parameters taken as per the figures given in user guide the values of emission factors used to to calculate the emissions are 1.00 t CO_2/MWh for coal, 0.46t CO_2/MWh for gas and 0.65 CO_2/MWh for diesel. Using these normative parameters the CO_2 emissions are calculated for each source of generation and then added up to arrive at the figures of total CO_2 emissions of in million tonnes per annum.

The table containing the calculated CO_2 emissions is as under:

Table 3.20: CO_2 Emissions across the five year plans

Plan period	At 8% GDP Growth Rate			AT 9% GDP Growth Rate		
	Thermal Capacity (GW)	Thermal generation (BU)	CO2 Emissions (MT CO2)	Thermal Capacity (GW)	Thermal generation (BU)	CO2 Emissions (MT CO2)
11th (2007-12)	137	777	788	137	810	821
12th (2012-17)	193	1133	1141	217	1276	1280
13th (2017-22)	268	1592	1576	317	1897	1864
14th (2022-27)	358	2166	2108	438	2662	2572
15th (2027-32)	478	2931	2800	598	3663	3474

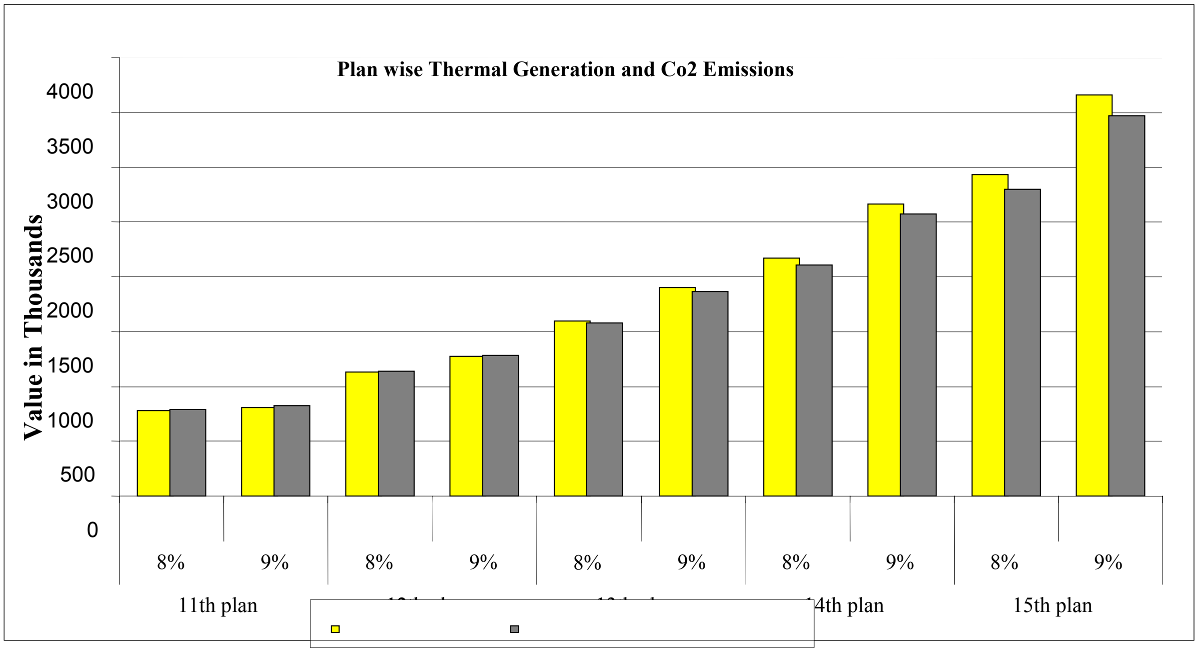

Figure 3.3: CO_2 emissions across five year plans

3.9.4 Potential for Carbon Capture

In India, the 11th five year plan is in its last phase of completion and 12th five year plan will start from year 2012.We are in middle of 11th five year plan for which most of the capacities planned were ordered during 10th five year plan and some in the first year of the 11th five year plan.

For 12th five year plan benefit also about 40,000 MW of thermal power plants have already been ordered and some of them are in the process of ordering because keeping in view the gestation period required almost all the capacities should be ordered before beginning of plan which gives a high comfort level in execution of the plants. Moreover 60% of new capacity is expected to be supercritical units of 660 MW and 800 MW. Keeping in view the present status of development carbon capture and storage technologies and its availability on commercial scale it will be technically difficult and economically not viable to retrofit the existing power plants and new power plants under construction for 11th and 12th plan benefits with carbon capture and transportation technologies. Also, the carbon capture technologies in today's scenario are in elementary and experimental stage and will take some time to build a large (>1 MT CO2 per year) power plant as CCS ready demonstration plant and technology is proven to be scaled up and made commercially available. The orders for the establishment of new power plants in the 13th five year plan, will be placed somewhere down the 12th five year plan period. Thus, provisions can be made in 13th five year plan onwards to include the carbon capture and transportation technologies as the integral part the of the power plants envisaged to be established in 13th five year plan and beyond and the planning and construction of those power plants can be done accordingly, subject to availability of proven technologies for carbon capture and storage. As the capacity of coal based power plants will increase in succeeding five year plans starting from 13th five year plan, there will be a great opportunity to capture the carbon dioxide emitted from these power plants.

The CO2 emissions (in Mt of CO2) for 11th five year plan end (2011-12) work out to be 788 which will increase up to 1576 Mt of CO2 in 13th five year plan and will further increase in subsequent plans. This increase will be on the account of increase in the installed capacity of coal based power plants during 11th five year plan, 12th five year plan, and 13th five year plan and beyond. As per the government policy in respect of ultra mega power projects and the economics, the new power plants which will be established in the country are most likely to be situated at coal pit heads primarily in the states of Chattisgarh, Jharkhand, Orissa, Maharashtra, West Bengal, Madhya Pradesh etc. where the most of the coal reserves for power generation are available. The power plants using the imported coal will be concentrated at the coastal locations in the states of Gujarat, Karanataka, Maharashtra, Tamil Nadu and Andhra Pradesh.

Ultra Mega Power Projects with super critical technology and with an installed capacity of 4000 MW each at about 9 locations are under various stages of planning & implementation. Of these four projects had already been allotted to private sector developers; namely TATAPOWER (Mundra coastal in Gujarat) and three to Reliance Energy (Sasan in MP, Tillaya in Jharkhand at pit head and Krishapatnam coastal in Andhra Pradesh). The other UMPPs are under various stages of allocation/ biding.

These locational advantages will provide a good opportunity for carbon capture, transportation and storage, as sinks i.e. coal mines and sea beds will be available near the power plants. It is not worthy that most of the capital cost incurred in implementation of carbon capture is in the transportation of CO_2 to sinks through pipelines & other means and also modifications at plant site for CO2 capture, compression and storage. Thus, the suitable location of the power plants will reduce this cost and make application of CCS more financially viable.

The retrofit for CCS at existing power plants to further reduce the CO_2 emissions could be considered in second stage as this will require retrofitting of equipment for carbon capture, compressing facilities and laying of CO2 pipelines upto the sink and will also require shutting up of the plant for some time.

The table 3.21 shows the amount of CO2 emissions (in Million tonnes of CO_2) both for 8% GDP growth and 9% GDP growth taking the assumption that the CO2 emissions will decrease from 13th five year plan onwards on the account of adoption of supercritical and ultra supercritical technologies for conventional power plants and clean coal technologies like IGCC etc when they become commercially viable for large scale operations

Table 3.21: Coal capacity additions and additional CO2 emissions

Plan	At 8% GDP Growth			At 9% GDP Growth		
	Coal Capacity Addition (GW)	Additional CO_2 Emission (Mllion tonnes of CO2)	Expected Additional CO_2 Emissions (Million tonnes of CO_2) after application of Clean coal Technologies)	Coal Capacity Addition (GW)	AdditionalCO_2 Emission (Mllion tonnes of CO2)	Expected Additional CO_2 Emissions (Million tonnes of CO_2) after application of Clean coal Technologies)
12th (2012-17)	48	480	480	68	680	680

13th (2017-22)	60	600	570	80	800	760
14th (2022-27)	70	700	630	96	960	864
15th (2027-32)	90	900	765	120	1200	1020

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CHAPTER 4. FOSSIL FUEL RESOURCES AND LIKELY CO_2 EMISSIONS AND STORAGE SITES

4.1. Coal

Coal resources determine the likely CO_2 emissions in future. Although coal can be imported, transportation costs are high. Moreover old coal fields can also serve as CO_2 storage sites. As per the estimates of Geological Survey of India, the coal reserves of India stand at 267 Billion Tonnes as on 01.04.2009 with more than 87% of these being of the non-coking grade. The geographical distribution of these coal reserves is primarily in the states of Bihar, Jharkhand, West Bengal, Orissa , Madhya Pradesh, Chattisgarh, Maharashtra and Andhra Pradesh. The total coal production in the country during 2008-09 was 493 MT, of which about 355 MT was used for power sector (excluding captive power plants). In addition to this, about 20 MT was imported for Power Sector. The total coal availability from domestic sources is expected to be 482 MT per annum by 2011-12. This includes coal production from captive mines.

Use of imported coal with high calorific value and low ash content may be the preferred choice for coastal thermal power plants in Tamil Nadu, Gujarat, Maharashtra, Karnataka and Andhra Pradesh depending upon competitive pricing. After ensuring compatibility, blending of imported and domestic coal for plants in coastal areas minimises the variable charges without affecting the performance of the boilers. Feasibility of acquisition of coal mines including joint venture abroad and on entering into long-term contract with the companies supplying imported coal should be considered by large organisations such as NTPC and Indian Coal Companies.

4.2. Lignite

The geological reserves of lignite have been estimated to be about 35.6 BT. Lignite is available at limited locations such as Neyveli in Tamil Nadu, Kutchh, Surat and Akrimota in Gujarat and Barsingsar, Bikaner, Palana, Bithnok in Rajasthan, Over 86% of the resources are located in the

State of Tamil Nadu alone, whereas the rest 14% are distributed in other States. Since, lignite is available at a relatively shallow depth and is non-transferable, its use for power generation at pithead stations is found to be attractive. The cost of mining lignite has to be controlled to be economical for power generation.

Coal will continue to be major fuel source for power generation, till foreseeable future. In the economic analysis the additional costs of capturing and storing CO2 is to be considered for coal based power plant. The quality and quantity as well as the geographical location of coal reserves and resources in India is important for planning future power plants in India. The location issue is relevant since it has to be observed that optimum logistics and raw material issues are addressed. The options for new power plants will be where it will be installed are; (a) close to the fossil fuel reserves, (b) next to consumers/ load centers, (c) coast based generation units or (d) adjacent to potential storage sites. The quantity of coal availability might become relevant since CCS requires between 20 and 30% more coal for the same electricity output.

India is the world’s third largest producer of coal with the sixth highest Coal mine methane (CMM) emissions globally, and that the commercial development of CMM is a top priority for the Indian coal industry. Under India’s coal bed methane (CBM) policy, formulated by the Indian government in 1997, 26 virgin coal bed methane (VCBM) blocks have been allotted for commercial development to different operators through global bidding. Increase in demand of coal from power sector has resulted in the allotment of coal blocks within India’s CBM blocks. This has caused an overlap in the allotment of coal and CBM blocks. To address this issue, the Ministry of Coal currently is working on a regulatory framework for the harmonious and simultaneous exploitation of CMM and CBM. With this new framework in place, coal mining and CBM activities can take place concurrently and without any safety hazard. The samples collected from boreholes of about 1000 meters deep indicate that the methane in coal mine gas is more than 90 percent.

In India coal mines are primarily located in the eastern part of the country. Gondwana group of coal-bearing formation occur in aborted rift grabens along Rajmahal - Damodar, Sone-Mahanadi, Wardha-Godavari and Satpura-Narmada river valleys from Satpura in the west to Raniganj in the east. Some of these Gondwana coalfields like Jharia, East Bokaro, Raniganj, Karanpura and Sohagpur are known for quality coals have a CBM prospectivity. Substantial amount of surface and shallow-depth coal characteristic data is available for the coalfields occurring in the Gondwana grabens, while data in the Tertiary basins are usually lacking on account of greater depths of occurrence and lack of exploration for methane in the lignites. Considering the strong linkages of power plants and steel industry with raw materials, utilities , and logistics; it is expected that future industry will be to located in the state of Chhattisgarh, Orissa, Jharkhand, Gujarat, North-east, and Karnataka, Uttar Pradesh and coast based states of West Bengal, Orissa, Andhra Pradesh, Tamil Nadu, Kerala, Karnataka, Maharashtra, Gujarat. The coast based states have been indicated for imported coal from Australia, South Africa, and Indonesia. For other states such as Bihar, Uttar Pradesh, Madhya Pradesh, Rajasthan, Haryana, Punjab, Uttarakhand, Himachal Pradesh, Jammu & Kashmir the focus will be on alternate source of energy and linkages with gas grids. Setting up new plants also creates problems related to obtaining fresh clearance after the Environment Impact Assessment (EIA). All these factors would influence future investment decisions, capacity addition at the existing large point sources (LPS) of CO2 emission during future expansions, keeping in view a strong likelihood of coal dominant energy basket. The state-wise coal mines locations are indicated in Table 4.1

Table 4.1[23]: State-wise coal reserves in India

State	Geological Resources of Coal in Million Tonnes			
	Proved	Indicated	Inferred	Total
Andhra Pradesh	9194	6748	2985	18927

[23] Statistical Database: Ministry of Coal

Arunachal Pradesh	31	40	19	90
Assam	348	36	3	387
Bihar	0	0	160	160
Chhattisgarh	10910	29192	4381	44483
Jharkhand	39480	30894	6338	76712
Madhya Pradesh	8041	10295	2645	20981
Maharashtra	5255	2907	1992	10154
Meghalaya	89	17	471	577
Nagaland	9	0	13	22
Orissa	19944	31484	13799	65227
Sikkim	0	58	43	101
Uttar Pradesh	866	196	0	1062
West Bengal	11653	11603	5071	28327
Total	105820	123470	37920	267210

Coal has many anchor consumers, and the coking coal is used in metallurgical industries. The non-coking coal is used for power sector. The tertiary coal reserve in north-east can be used for power sector, which have not been exploited adequately. The coal classification is based on proximate analysis, and classification wise coal reserves have been shown in Table 4.2 and depth wise coal reserves in Table 4.3

Table 4.2[24]: Classification of Coal reserve according to type of coal (in Million Tonnes)

Type of Coal	Proved	Indicated	Inferred	Total
(A) Coking :-				

[24] Annual Report 2007-08 Ministry of Coal

-Prime Coking	4614	699	0	5313
-Medium Coking	12449	12064	1880	26393
-Semi-Coking	482	1003	222	1707
Sub-Total Coking	17545	13766	2102	33413
(B) Non-Coking:-	87798	109614	35312	232724
(C) Tertiary Coal	477	90	506	1073
Grand Total	105820	123470	37920	267210

Table 4.3[25]: Classification of Coal reserve according to depth (in Million Tonnes)

Coal Reserve as on 1.4.2009 in Billion Metric Tonnes					
Depth	Proved	Indicated	Inferred (Exploration)	Inferred (Mapping)	Total
0-300	82.8	65.8	13.3	0.5	162.3
0-600	13.7	0.5	0.0	0.0	14.2
300-600	7.7	45.5	18.1	0.0	71.2
600-1200	1.7	11.7	6.1	0.0	19.5
Total	105.8	123.5	37.5	0.5	267.2

[25] wwwcmpdi.co.in/geological_report.htm

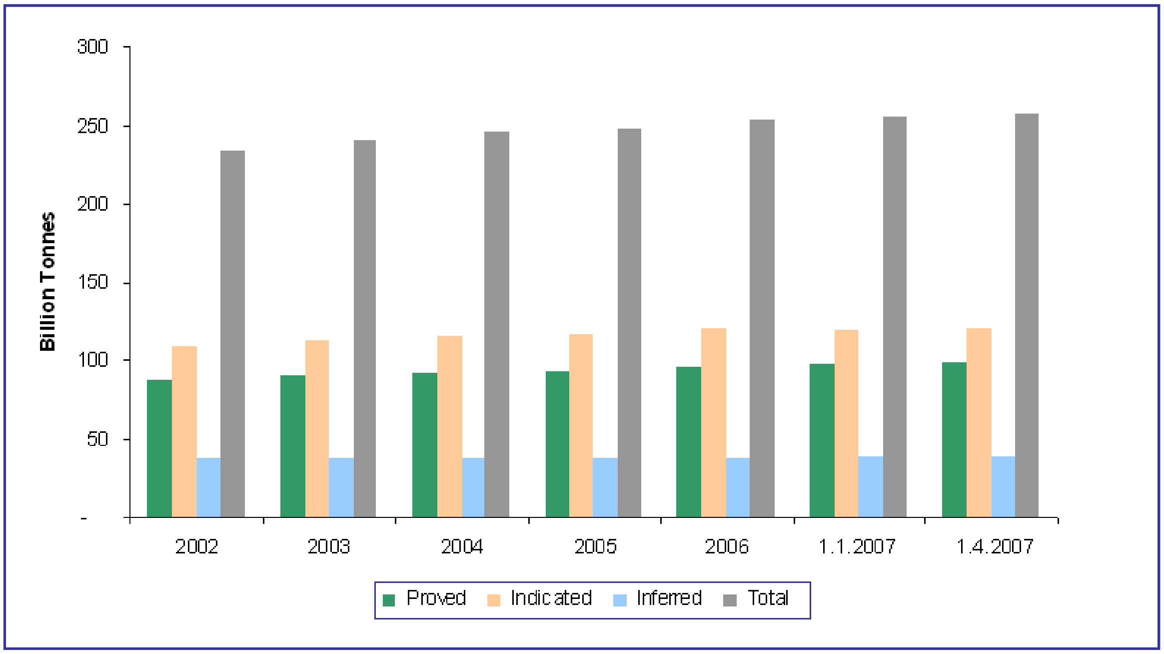

Figure 4.1[26]: Category Coal Reserves in India

Based on the characteristics of coal evaluated in terms of chemical analysis, proximate analysis, caking index, rank etc, the coal fields in India has been Categorised as follows,

Category I: These are Gondwana Coals Ranking High Volatile Bituminous 'A' and above. available in the Jharia, Bokaro, Raniganj and North Karanpura coalfields. These coals have the best CBM potential in India. Estimated resource in these basins is 350 - 400 BCM and a producible reserve of 85–100 BCM.

Category II: These are also Gondwana Coals Ranking below High Volatile Bituminous 'A'. The mines are located in South Karanpura, Rajmahal, Pench – Kanhan and Sohagpur coalfields

[26] Annual Report 2007-08 Ministry of Coal

Category III: These are Low ranking Gondwana Coals (Talcher, Ib, Pranhita- Godavari Valley and Wardha Valley. Coals in these basins occur at lesser depth, have extensive thickness and may provide suitable hydrodynamic conditions for methane recovery.

Category IV: The category four basis have tertiary coals and Lignite mines. These mines occurrences are in Cambay, Bikaner - Nagaur, Barmer, Assam-Arakan, Cauvery, and Himalayan Foothill basins. These basins have low CBM capcity. These seams have good permeability and reservoir properties. The economic analysis is needed for commercial exploitation.

Coal in India occurs in two stratigraphic horizons viz., Permian sediments mostly deposited in intracratonic Gondwana basins and early Tertiary near-shore peri-cratonic basins and shelves in the northern and north-eastern hilly regions of the Eocene-Miocene age. Lignite deposits are of younger formations, and these mines occur in the western and southern part of India.

The Gondwana sedimentation occurred in graben or half graben trough alignment due west to east and two parallel drainage channels north west to south east. These are

(1) Singarauli basin of Son valley

(2) Damodar Koel graben

(3) Son Mahanadi valley

(4) Godavari Wardha rivers in the south

(5) Satpura valley

(6) River Damodar delineate Rajmahal group of coalfields.

The coal and lignite deposits in Indian sedimentary basins are shown in Figure. 4.2.

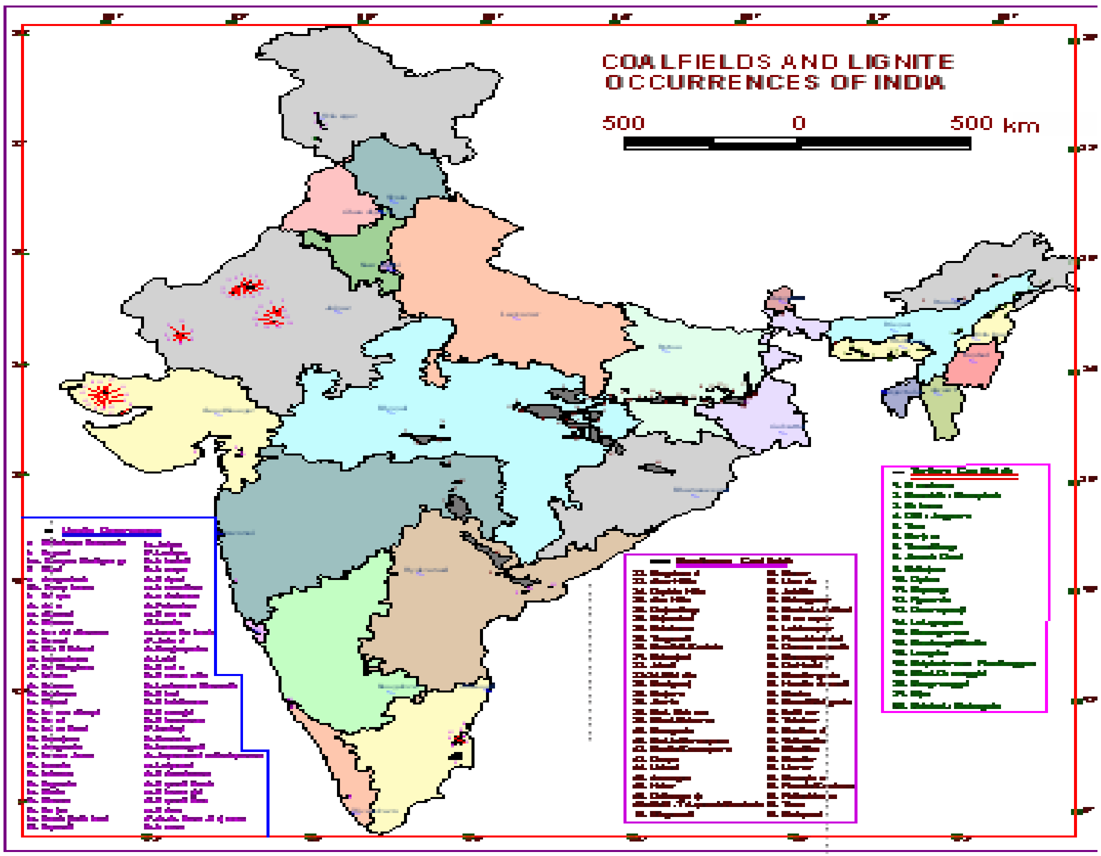

Figure 4.2[27]: Coalfields and lignite Occurrences of India

A typical stratigraphic sections of Karharbari, Barakar& Raniganj coal measures are shown in figure 4.3. There are schematic process of a typical coal seam formation with characteristic litho types stages that include layers of sand stone, shale, carbonaceous shale, shaly coal and coal etc formation from various stages of biomass and sedimentary materials maturing process that include Humus, Water release, Durain, Vitrain, Shaly Coal, Carbonaceous Shale, Shale, Sandstone.

[27] Potential storage sites for CO_2 in Godwana Basin- G. Mukhopadhayay(Geographical Survey of India)

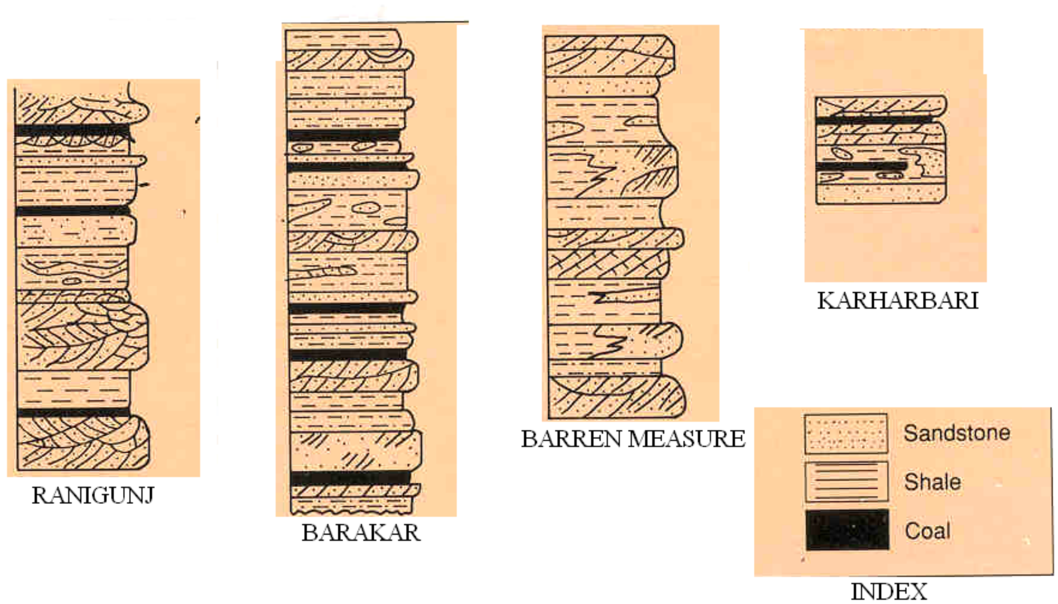
RANIGUNJ
BARAKAR
BARREN MEASURE
KARHARBARI
Sandstone
Shale
Coal
INDEX

Figure 4.3[28]: Stratigraphic sections of Karharbari, Barakar& Raniganj coal measures

Tertiary formation spread over the periphery of peninsula along the coast in Tamilnadu, Kerala, Gujarat and Himalayan foothills from Pir Panjal of Jammu and Kashmir to Abor Hills and Kuen Bhum range of Arunanchal Pradesh. Substantial reserves of lignite exist in the region of Kalol of Cambay basin, Barmer and Sanchor basin. The exploration of the coal reserves in the north east region have to be accelerated. There are coal mines in the state of Assam, Meghalaya, Nagaland, and Arunachal Pradesh and have exhibited in Figure 4.4. Geologically these mines are termed as young reservoirs.

[28] R&D requirement of Oxyfuel combustion in Boilers of India- A prespective- Dr. Nand Kumar (B.H.E.L)

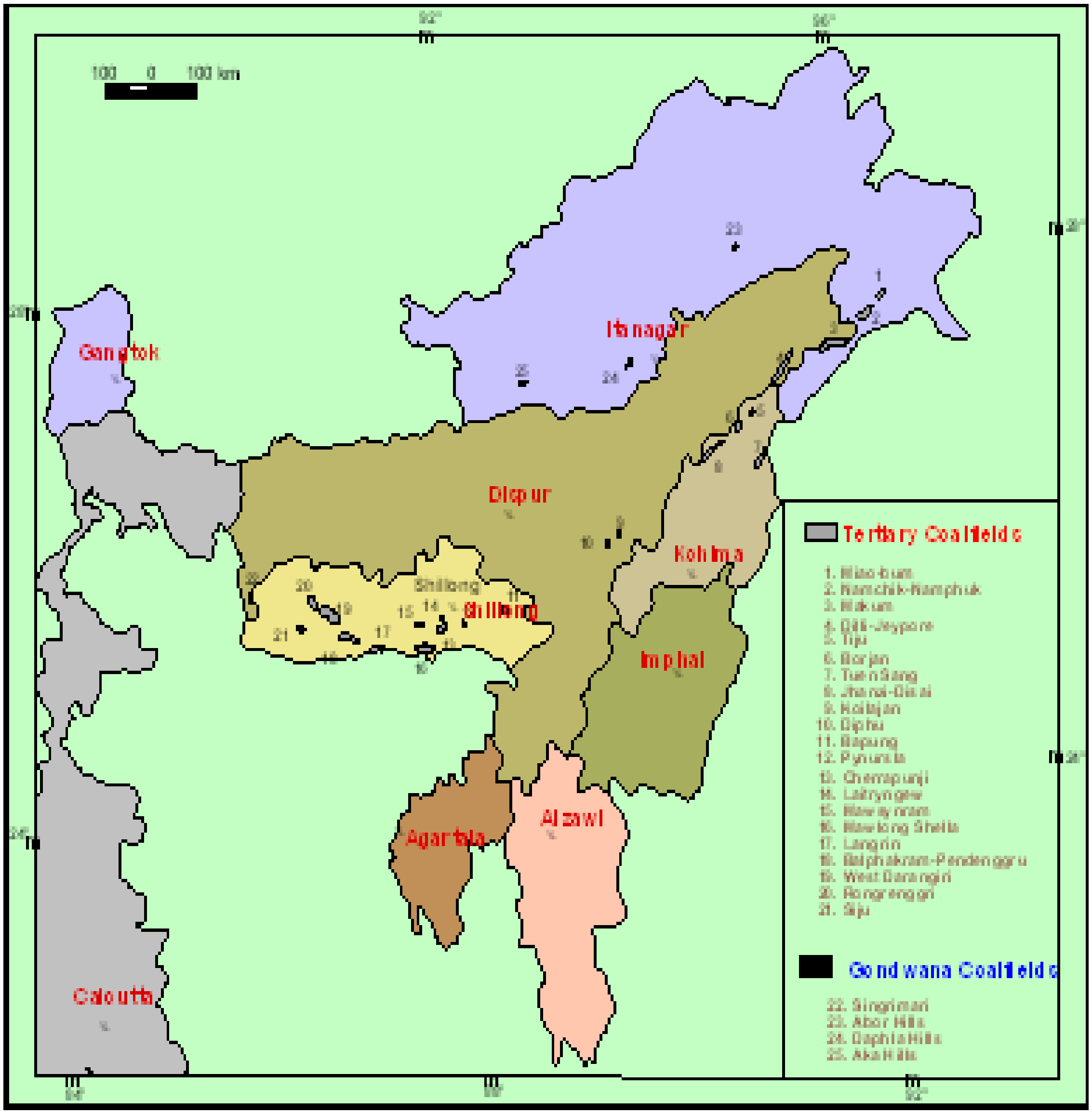

Figure 4.4[29]: Tertiary Coal Mines of India in North East (Assam, Meghalaya, Nagaland, Arunachal Pradesh)

[29] Geograpical Survey of India

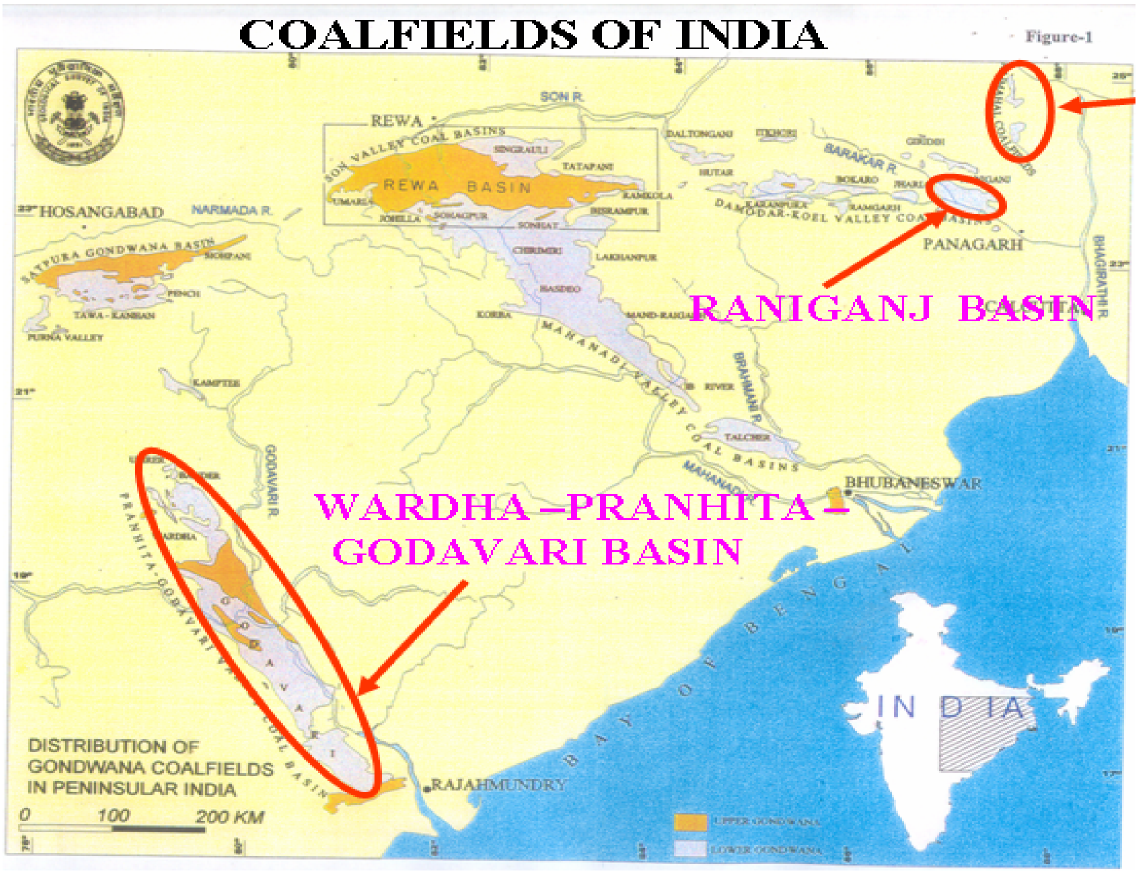

Figure 4.5[30]: Gondwana Coal Fields in India

Gondwana coal[31] formation in India is continuation of Great Gondwana formation of the Indian Peninsula comprising 6-7 km thick clastic sequence formed in Paleozoic to Mesozoic era during Permian to Cretaceous period. Gondwana sedimentation , the main repository of coal in India is divided in Lower Gondwana corresponding to Lower and Upper Permian and Upper Gondwana corresponding to Lower Cretaceous and Lower Jurassic age. The location and map of gondwana region in India is shown in figure 4. The Lower Gondwana belts are controlled by Pre-Cambrian

[30] Gegraphical Survey of India

[31] A Perspective of Enhanced Coalbed Methane Recovery in India by Injection of CO2 in Coal Seams; Dr. A K Singh

crustal structure like Archean cratonic sutures and Protozoic mobile belts (Acharya, 2000)[32]. The geological map of the lower Gondwana Basin in the Pranhita- Godavari valley, in Andhra Pradesh indicating formation profile is indicated in Figure 4.6.

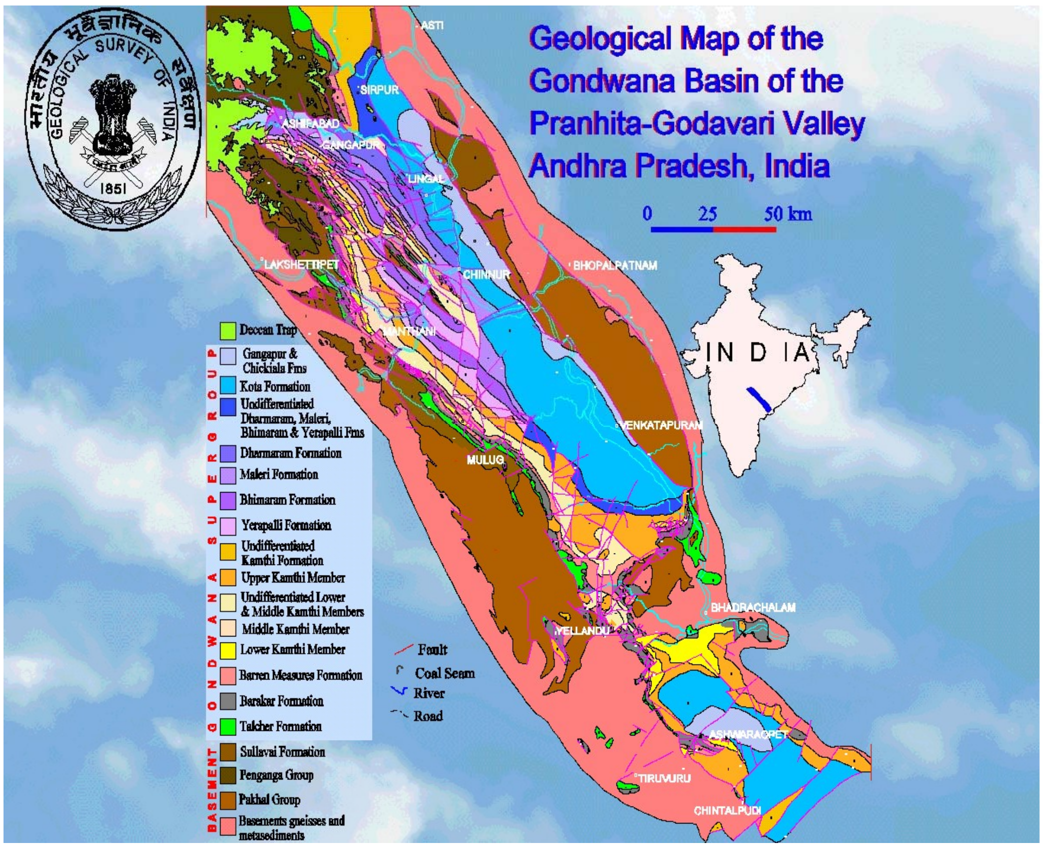

Figure 4.6[33]: Geological Map of Lower Gondwana Coal Fields

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[32] Acharya S K (2000) Comments on Crustal Structre Based on Gravity Magnetic Modeling Constrianed from Seismic Studies under Lambert Rift, Antarctica and Godavari and Mahanadi rifts.

[33] Geographical Survey of India

4.3. Indian Fuel Scenario for Thermal Power Generation unit

- Raw High Ash and Washed low ash Non coking Sub bituminous coals (85 %)
- Middling of Caking Bituminous Coals (rest)
- Imported low ash ,high moisture ,high volatile coals
- Fresh Water origin Lignites (Neyveli)
- Marine water Origin Lignites (Gujarat & Rajasthan)
- Bio Mass (Agri Wastes & Non carpentry wood wastes) & alternate Fuel Availability

4.3.1 Quality and Type of Domestic Coal

Indian coal overall is rated as a poor quality coal. Most of the Indian coal reserves are of low calorific value and high ash & moisture content. As much as 87% of the non-coking coal reserves in Indian basins are of lower grades that is c-d-e-f grade. Reserves suitable for power sector are in abundance, as against for other industries requiring coking or high quality of coal. India’s reserves can support power sector requirements because most of the power plants are designed to handle Indian coal, and lignite. The energy characteristics of Indian coal are shown in annexure. Table 4.4 gives the comparison of Indian coal with American coal and Table 4.5 Indian coal with coals of other selected countries.

Table 4.4[34]: Comparison of Indian and American Coal

Parameters	Indian	North American
Era of formation	Lower permian (200-250 million years)	Carboniferous (> 300 million years)
Vegetation	Small bushes and ferns	Big trees with big leaves
Deposition	Sedimentation along river basins	In-situ due to earth movements
Minerals content	High 25 to 50% homogenous mix of minerals	Low 3 to 12% as found in wood minerals are extraneous
Wash-ability index	30-40	70
Sulphur content	Low	High
Rank	Mainly sub-bituminous to low rank bituminous	Bituminous
Macerals	Rich in fusinite semi-fusinite, macrinite & sceleronite	Rich in vitrinite

[34] *Source: BHELResearchCenter, Presentation of Dr. Nand Kumar*

Table 4.5[35]: Comparison of Indian coals with other coals

	Australia	China	South Africa	Indian Coal (Dadri)	Indonesia		
					Type A	Type B	Type C
Total Moisture(AR)%	9	10.0	8	12	14 max	20 max	12-25
Inherent Moisture (AD)%	2-4	2-4	2.0-3.5	9	10 max	12 typical	10-18
Ash Content (AD)%	15	15.0	15	38	12 max	8 max	7-8
Volatile Matter (AD)%	23-30	25-32	23-38	24	39-45	38-44	30-42
Sulphur (AD)%	0.7	0.7	0.7	0.5	0.9-1.0	0.7 max	0.5-0.6
Fixed Carbon (AD)%	45 approx	40-45		29			25
Gross Calorific Value (AD)%	6700	6800	6600	3692	6200-6400	5800-6500	5400-6200
HGI	50	55	50	66	35-45	40-55	54-65
HighAsh Fusion Temperature(◦C)				+1400	1250	1250	1150
					1300	1300	1200
					1350	1350	1250

4.3.2 Imported Coal

Government of India permits import of Coal under Open General License by the Industry (power sector, steel) themselves considering their needs and commercial judgments. Import duty on coal has been reduced to 5% now from earlier figure of 30% five years back. So far whatever are the shortages in demand – supply of coal are met through importing coal from outside world. India imports it coal from Indonesia, Australia, South Africa and China. The coast based UMPP are

[35] Information compiled on the basis of BHP Billiton;

planning to import their coal requirements from the above countries. In view of continuing shortage of coal being supplied by indigenous suppliers i.e. Coal India coal imports have grown at an annualized rate of 14% in the last five years. For the non-coking coal growth rate was even higher at 18%. The details are given in Table 4.6

Table 4.6[36]: Coal Imports in the Last Five Years by Coal Type (Million Tonnes)

Type	2002-03	2003-04	2004-05	2005-06	2006-07
Coking	12.95	12.99	16.93	16.83	22.00
CAGR		0.31	30.33	-0.59	30.72
Non-Coking	10.31	8.69	12.07	21.70	23.00
CAGR		-15.71	38.90	79.78	5.99
Coke	2.25	1.89	2.84	2.62	3.80
CAGR		-16.00	50.26	-7.75	45.04
Total	25.57	23.57	31.80	41.21	48.80

[36] *Annual Report 2007-08 Ministry of Coal*

In the past year the prices of coal have increased significantly in line with the prices of crude oil. Government is focusing on improvement in the coal mining and production in the domestic sectors and have also allocated captive coal mining blocks to private power producers as well as other industry for their own use.

Methane is a powerful green house gas. Methane is associated with coal during coal formation process. The trapped methane in coal beds are released during mining. The methane extraction in in-situ state in coal seams in underground coal mines, if effectively recovered, can be a potential source of energy, otherwise lost to atmosphere during mining. The primary challenge is the economic efficiency of methane extraction from mines, and cleaning of gas for subsequent commercial application as a fuel and feed stock in fertilizer (Urea).

Coal bed methane (CBM) is produced commercially in the USIn India, the coalbed methane resource exploration is regulated by the Ministry of Petroleum and Natural Gas, Government of India. Blocks have been allotted to the public and private sector companies by three rounds of global bidding, CBM I, CBM II, and CBM III.. CBM is being actively explored in India and having matured from the R&D stage in the third round bidding for CBM blocks (2006) by DGH 54 bids were received from 26 companies, which included 8 foreign and 18 Indian Companies, for 10 blocks. India, with the fourth largest proven coal reserves in the world, holds significant prospects for exploration and exploitation of CBM. The total sedimentary area for CBM exploration is of the order of 26,000 sq. km. Out of this, exploration has been initiated in only 52% of the area. The indicated CBM resource is about 50 TCF, out of which only 6.24 TCF has been established. The exploration carried out by various operators in the state of Jharkhand, West Bengal and Madhya Pradesh reveals that Gondwana coals has CBM that can be harnessed . Commercial production of CBM has begun from Raniganj CBM block in West Bengal. It is expected that from, current level of CBM production of 0.15 MMSCMD, it may to go up to 7.4 MMSCMD by the year 2013.The details of CBM block are given in Table 4.7

Table 4.7[37]: Available Coal blocks in India

Sl.No.	Coal Field	Block Name	Area (Sq.km2)	State
1	Raj Mahal	RM(E)-CBM-2008/IV	1128	Jharkhand
2	Talcher	TL-CBM-2008/IV	557	Orissa
3	Ib Valley	IB-CBM-2008/IV	209	Orissa
4	Singrauli	SR(W)-CBM-2008/IV	269	MP
5	Sohagpur	SP(NE)-CBM-2008/IV	339	MP & Chattisgarh
6	Satpura	ST-CBM-2008/IV	714	MP
7	North East	AS-CBM-2008/IV	113	Assam
8	Wardha	WD(N)-CBM-2008/IV	442	Maharashtra
9	Wardha	WD(E)-CBM-2008/IV	503	Maharashtra
10	Mannargudi	MG-CBM-2008/IV	766	Tamil Nadu

Some of the important geological blocks being explored are Ranigunj, Jharia, Bokaro, North Karanpura, South Karanpura, Barmer-Sanchor Block India has a large reserve of coal at a un-mine-able depth.[38] For the coal seams beyond 300 meter the Underground coal gasification is one of the options.

4.3.3 Underground Coal Gasification

Underground Coal Gasification (UCG) is one of the technologies being researched in India by ONGC in their research institute in K D Malviya Institute of Petroleum Exploration, Dehradun. The gasification process is applied to non-minable coal seams, by injecting gaseous media (blend of oxygen, air, water and carbon dioxide) into the seam. After appropriate site selection and

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[37] Directorate General of Hydrocarbons

[38] http://www.cmpdi.co.in/coalreserve_010409.pdf

evaluation, the process is commissioned by drilling two well holes into the coal seam a few hundred feet apart through production wells drilled from the surface. The gas generator well head is drilled in the coal seam plane at an inclination then horizontally. The air injection well tip in the coal seam is the reaction head. Figure 4.7 indicates a separate drill hole for ignition. The combustion face is located in the air injection well and the injection point moves upwards the injection channel. The gas production well is cased only up to the coal layer. Bottoms of both these wells are connected into single hydraulic system by any available method. Thus the oxygenizing agent flow is controlled and directed to the reacting coal face. The reactions taking place are as below

Table 4.8: Reactions during UCG

Heterogeneous water- gas shift reaction	$C + H_2O = H_2 + CO$
Shift conversion	$CO + H_2O = H_2 + CO_2$
Methanation	$CO + 3H_2 = CH_4 + H_2O$
Hydrogenating gasification	$2H_2 = CH_4$
Partial oxidation	$C + > C + ½O_2 = CO$
Oxidation	$C + O_2 = CO_2$
Boudouard reaction	$C + CO_2 = 2CO$

The process is designed such that the coal is converted in situ into combustible synthetic gas. Operators inject air, water, oxygen into one of the wells and then start a carefully-controlled combustion reaction. The heat and pressure created by the reaction provides hydraulic power and converts the coal into synthetic gas. The oxidant of the gaseous medium under controlled environment reacts with coal in the underground coal seams, and the sensible heat released is used in coal drying, pyrolysis and endothermic reactions that may occur during the process. The composition of the combustible gas depends on the proximate analysis of coal, coal morphology and Process design parameters. Use of Carbon dioxide using Boudwards Reaction can be an efficient development of CCS storage technology.

The UCG process has the engineering challenge of different nature of coal ash, slag handling in the subsurface. The UCG gas can be used for power generation and chemical processes for extraction of chemicals. The UCG gas has to be cleaned prior to use in power plant. The reaction occurs in a closed system hence efficiency of the process is high, and with improved design yield can be enhanced. Important parameters are

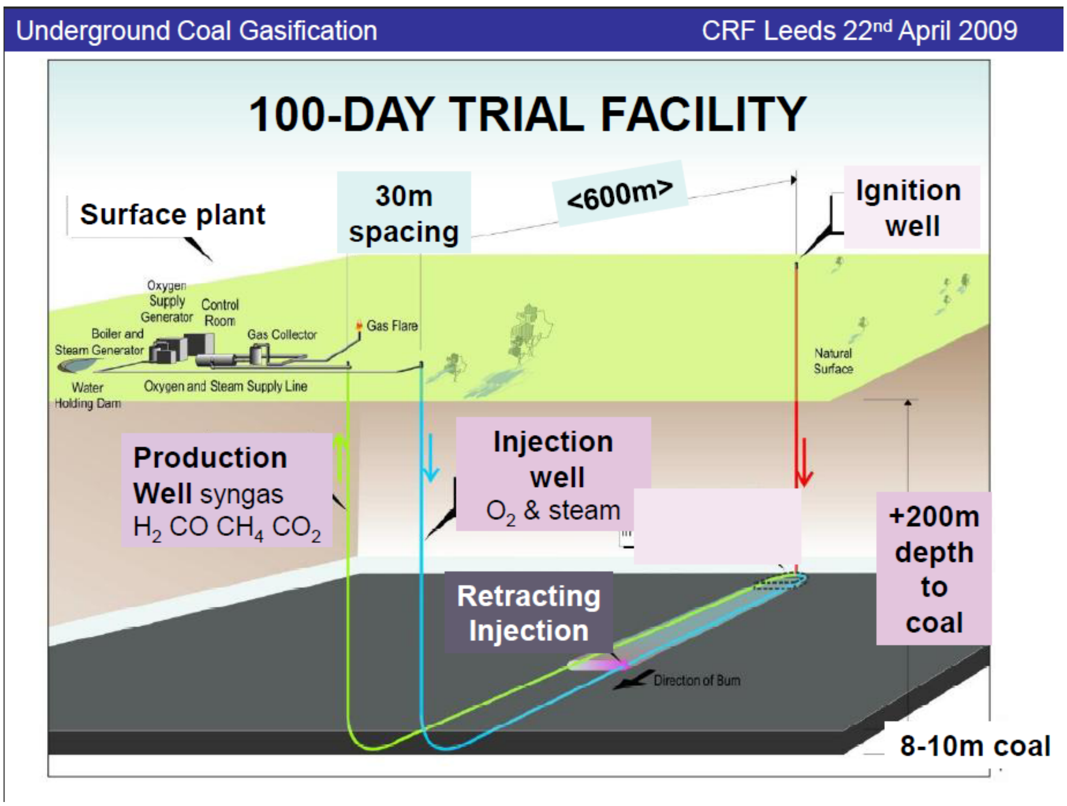

Figure 4.7: Trial facility developed for Underground Coal Gasification; UK Initiative under UCG Partnership: 100 day trial at Bloodwood Creek, Austratlia

- Depth of coal seam from 30 to 800 meters and coal seam thickness from 0.5 to 30 meters. Seam should have minimum discontinuity.
- pressure of inlet gases;
- operating pressure in the seam;

- outlet temperature and pressure of combustible gas;
- Distance of the reaction head from water aquifers.
- angle of drilling ;
- initial ignition mechanism;
- as a process may not be a continuous process during pilot and demonstration project, hence sealing and opening, and adjustment to accommodate the ever-varying conditions of gasification have to be taken care;
- drilling methods for inlet and outlet wells. The inlet well is inclined, and then horizontal. Design should incorporate retracting provision;
- Ash and slag removal strategy following reaction. The reservoir management should be such that any subsidence is prevented

There may be number of wells dug into seam to input reactant gas to form underground gasifiers. The locations of output of gasifiers have to be designed properly. The gas streams from different reactors can be mixed as required, to ensure consistency of overall gas quality.

Ergo Energy in their report has stated that UCG can be applied to coal in a wide range of geological conditions, coal seam having following preferred parameters:[39]

- Coal seam thickness from 0.5 to 30 m. Desired seam thickness is 2.5 meters with variation of 25%.
- Depth of the seam should be more than 300 meter. The process can be carried at depth between 100 and 300 meters.
- Dip of the seam should be between 0° to 70°.

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[39]http://www.ergoexergy.com/eucg.htm?gclid=CMGprqSXt58CFYMvpAodREeG1g

- Calorific value (LHV) of the seam should be from 8.0 to 30.0 MJ/kg (which includes low-quality lignite and bituminous coal).

4.4. Coal - Current and Historic Supply Demand Balance

Coal demand has been quite robust and has grown at an average of 7% per annum in the last five years accounting for increasing demand supply gap for coal in India. To fill this gap India has imported an increasing amount of coal. The percentage of imported coal consumption as a part of total coal consumption has grown to 10% in 2006-07 as compared to 6 % in 2003-04. The figure below shows the supply demand balance for the last five years.

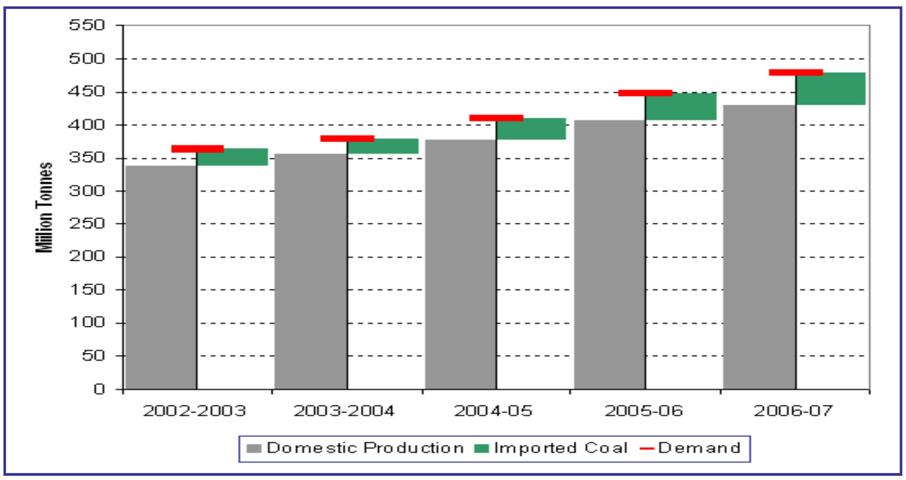

Figure 4.8: Historical Demand-Supply Balance

Burgeoning demand from industries like power and steel can be considered one of the main reasons for the growth in coal demand. On the coal supply side nationalized companies are not capable of increasing there production to meet this extra demand which has emerged as a result of strong economic growth in the recent past years. There are other reasons like infrastructure and transportation constraints on supplier and buyer ends leading to shortages but main reason is from the domestic production shortfalls.

Table 4.9[40]: Evolution of unit size and efficiency for coal based plants in India

Period	1950s	1960s	1970s	1977	1983	Under Constrn.
Unit size	30 MW to 50 MW	60 MW to 100 Mw	110 MW to 120 MW	200 MW to 250 MW	500 MW	660 MW
Turbine Inlet pressure/ Temperature	60 ata 490°C	70to 90 ata 490 to 535°C	130 ata 535°C	130 ata 537°C	170 ata 537°C	247 ata 537°C
Reheat Temperature	No Reheat	No Reheat	535°C	537°C	537°C	565°C
Turbine Cycle Heat rate (kCal/kW-hr)	2470	2370	2060 to 2190	1965	1945	1900
Gross Efficency (%)	29	30.5	33 to 35	37.2	37.6	38.5

4.5. Hydro Carbons- Petroleum and Natural Gas

4.5.1 Introduction

India has total reserves of 775 million metric tonnes of crude oil and 1074 billion cubic metres of natural gas as on 1.4.2009.

Table 4.10[41]:Oil andGas Reserves

AREA	2005	2006	2007	2008	2009
CRUDE OIL(Million Metric Tonnes)					
Onshore	376	387	357	403	405
Offshore	410	369	368	366	369

[40] NTPC

[41] *Theoilandnaturalgasreserves(provedandindicated)datarelateto1st Aprilofeachyear.Source:ONGC,OILandDGH.*

Total	786	756	725	769	775
NATURAL GAS(Billion Cubic Metres)					
Onshore	340	330	270	264	287
Offshore	761	745	785	786	787
Total	1101	1075	1055	1050	1074

The total number of exploratory and development wells and metreage drilled in onshore and offshore areas during 2008-09 was 381 and 888 thousand metres respectively. The Crude oil production during 2008-09 at 33.51 million metric tonnes is 1.79% lower than 34.12 million metric tonnes produced during 2007-08. Gross production of Natural Gas in the country at 32.85 billion cubic metres during 2008-09 is 1.33% higher than the production of 32.42 billion cubic metres during 2007-08.

The refining capacity in the country increased to 177.97 million tonnes per annum (MTPA) as on 1.4.2009 from 148.968 MTPA as on 1.4.2008. The total refinery crude throughput during 2008-09 at 160.77 million metric tonnes is 2.99% higher than 156.10 million metric tonnes crude processed in 2007-08 and the pro- rata capacity utilisation in 2008-09 was 107.9% as compared to 104.8% in 2007-08.

The production of petroleum products during 2008-09 was 152.678 million metric tonnes (including 2.162 million metric tonnes of LPG production from natural gas) registering an increase of 3.87% over last year's production at 146.990 million metric tonnes (including 2.060 million metric tonnes of LPG production from natural gas). The country exported 36.932 million metric tonnes of petroleum products against the imports of 18.285 million metric tonnes during 2008-09. The sales/consumption of petroleum products during 2008-09 were 133.400 million metric tonnes (including sales through private imports) which is 3.45% higher than the sales of 128.946 million metric tonnes during 2007-08.

4.5.2 Long term policy

The hydrocarbons sector plays vital role in the economic growth of the country. It is necessary to have a Long-term policy for the hydrocarbons sector, which would facilitate meeting the future needs of the country.

The Hydrocarbons Vision - 2025 lays down the framework which would guide the policies relating to the hydrocarbons sector for the next 25 years. Issues such as energy security, use of alternative fuels, and interchangeability of technology are vital to ensure that the mix of energy sources used in the economy is optimal and sustainable and that adequate quantities of economically priced clean and green fuels are made available to the Indian consumers. The estimated energy supply mix in India for a period up to 2025 is given in Table 4.10. Oil and gas continue to play a pre-eminent role in meeting the energy requirements of the country 45% of the total energy needs would be met by the oil and gas sector, though some amount of interchange between oil and gas is foreseen.

Table 4.11[42]: Share of future energy supply in India (%)

Year	Coal	Oil	Gas	Hydel#	Nuclear
1997-98	55	35	7	2	1
2001-02	50	32	15	2	1
2006-07	50	32	15	2	1
2010-11	53	30	14	2	1
2024-25	50	25	20		3

[42] *Source: Upto 2011 from Technical Note on Energy, Planning Commission, Govt. of India (1998-99). Beyond this period the figures have been extrapolated.*

 # Share of hydel energy remains constant considering the planned capacity addition upto 2012 and projected at the same level upto 2025.

- The current levels of per capita energy consumption in India are extremely low as compared to the rest of the world. In terms of comparison with the developed countries, the differentials are even more marked. The comparative figures of per capita energy consumption for India and rest of the world are in Table 4.11.

Table 4.12[43]: Per capita Total Primary energy supplied in million tonnes of oil equivalent (MTOE)

Country/Region	2002	2007
World	1.5	1.82
India	0.2	0.53
China	0.6	1.48
Latin America	5.8	1.19
OECD	3.1	4.64
Russian federation	4.7	4.75
Rest of the World	0.6	0.7

Growth of the economy would lead automatically to growth in energy consumption, as there is a direct correlation between the GDP and energy consumption. The per capita consumption of primary energy and hydrocarbons reveals that India is amongst the lowest in consumption of hydrocarbon in terms of kilograms of oil equivalent. Viewed from all angles, therefore, the hydrocarbon sector is most crucial for determining the energy, security for the country. The details are given in Table 4.12.

[43] *Key Statstics-2009 IEA*

Table 4.13[44]: Per capita consumption of Energy vis-à-vis Hydrocarbons (in Kg of oil equivalent)

Country/Region	Primary Energy	Hvdro-Carbons
World	1454	927
India	285	113
China	688	169
Pakistan	264	231
Bangladesh	81	80
Japan	3962	2520
U.K.	3856	2719
Germany	4102	2539

- The presence of the Public Sector Undertakings (PSUs) in exploration, production and marketing of petroleum products has been pre-dominant in the last four decades. The oil sector PSUs stand out in performance both in terms of operational efficiencies and profitability amongst all the PSUs in India. This pre-eminence of the PSUs in the oil sector is a matter of pride.

- The Vision. 2025 for the hydrocarbon sector has been prepared taking into account the above background. The action required to be taken in the medium term (3 to 5 years) and in the long term (beyond 5 years) to realise the Vision has also been brought out .

[44] *British Petroleum Statisitcs-1998*

4.5.3 Hydrocarbons Vision – 2025

- To assure *energy* security by achieving self-reliance through increased indigenous production and investment in equity oil abroad.
- To enhance *quality* of life *by* progressively improving product standards to ensure a cleaner and greener India. .
- To develop hydrocarbon sector as a globally competitive industry this could be benchmarked against the best in the world through technology up gradation and capacity building in all facets of the industry.
- To have a free market and promote healthy competition among players and improve the customer service.
- To ensure oil security for the country keeping in view strategic and defense considerations.

4.5.4 Exploration and Production Sector

The gap between supply and availability of crude oil, petroleum products as well as gas from indigenous sources is likely to increase over the years, details in Table 4.13 **.** The growing demand and supply gap would require increasing emphasis to be given to the exploration and production sector.

The objectives of the exploration policy would be as follows:-

Table 4.14[45]: Supply/Demand-Petroleum Products (in MMT)

Year	Demand (without meeting gas deficit)	Demand (with meeting gas deficit)	Estimated refining capacity	Estimated crude requirement
1998-1999	91	103	69	69
2001-2002	111	138	129	122
2006-2007	148	179*	167	173
2011-2012	195	195**	184	190
2024-2025	368	368	358	364

* *Assuming 15 MMTPA of LNG import by 2007.*

** *Assuming that by 2012, adequate gas is available through imports and domestic sources.*

As against this requirement the present domestic crude production is 33 MMT. The gap will have to be met through imports and increase in domestic production.

As against this requirement, the present domestic gas supply is 65 MMSCMD. The gap will have to be met from imports, increase in domestic production and by switching to liquid fuels.

[45] *Report of the Sub-Group on development of refining, marketing transportation and infrastructure requirements (1999).*

Table 4.15[46]: Supply/Demand-Natural Gas(in million standard cubic meters per day) (MMSCMD)

YEAR	DEMAND
1999-2000	110
2001-2002	151
2006-2007	231
2011-2012	313
2024-2025	391

4.5.4.1 Objectives

- To undertake a total appraisal of Indian sedimentary basins for tapping the hydrocarbon potential and to optimise production of crude oil and natural gas in the most efficient manner so as to have Reserve Replacement Ratio of more than 1.
- To keep pace with technological advancement and application and be at the technological forefront in the global exploration and production industry.
- To achieve as near as zero impact, as possible, on environment

To achieve the above objectives the following actions are required to be taken.

4.5.4.2 Medium term

i) Continue exploration in producing basins.

ii) Aggressively pursue extensive exploration in non-producing and frontier basins for knowledge building' and new discoveries, including in deep-sea offshore areas.

[46] *Report of the Sub-Group on development and utilization of natural gas (1999).*

iii) Finalize a programme for appraisal of the Indian sedimentary basins to the extent of 25% by 2005, 50% by 2010, 75% by 2015 and 100% by 2025. Sufficient resources to be made available for appraising the unexplored/party explored acreages through Oil industry Development Board (OIDB) cess and other innovative resource mobilization approaches including disinvestment and privatization.

iv) Provide internationally competitive fiscal terms, keeping in view the relative prospectively perception of Indian basins, in order to attract major oil and gas companies and through expeditious evaluation of bids and award of contracts on a time bound basis.

v) Optimize recovery from discovered/ future fields.

vi) Improve archival practices for data management.

vii) Continue technology acquisition and absorption along with development of indigenous Research & Development (R&D).

viii) Ensure adequacy of finances for R&D required for building knowledge infrastructure.

ix) Make Exploration and Production. (E&P) operations compatible with the environment and reduce discharges and emissions.

x) Support R&D efforts to reduce adverse impact on environment.

xi) Acquire acreages abroad for exploration as well as production.

4.5.4.3 Long term

i) 100% exploration coverage of the Indian sedimentary basins by 2025.

ii) Leapfrog to technological superiority.

iii) Put in place abandonment practices to restore the original base line.

iv) Conserve resources and adopt clean technologies.

4.5.5 External policy & Oil Security

4.5.5.1 Objectives

Supplement domestic availability of oil with a view to provide adequate, stable, assured and cost effective hydrocarbon energy to the Indian economy.

To achieve the above objective the following actions are required to be taken.

4.5.5.2 Medium term

i) Put in place a comprehensive policy to include total deregulation of overseas E&P business and empowering them to compete with international oil companies with provision of fiscal and tax benefits.

ii) Evolve a mechanism to leverage India's "Buyer Power" to obtain quality E&P projects abroad.

iii) Have focused approach for E&P projects and build strong relations in focus countries with high attractiveness like Russia, Iraq, Iran and North African countries.

4.5.6 Natural Gas

Natural gas is emerging as the preferred fuel of the future in view of it being an environmental friendly economically attractive fuel and also a desirable feedstock. Increased focus needs to be given to this potential sector.

4.5.6.1 Objectives

- To encourage use of natural gas, which is relatively a clean fuel.
- To ensure adequate availability by a mix of domestic gas imports through pipelines and import of LNG.

- To tap unconventional sources of natural gas like coal bed methane, natural gas hydrates, underground coal gasification etc.

To achieve the above objectives the following actions are required to be taken.

4.5.6.2 Medium term

i) Timely and continuous review of gas demand and supply options to facilitate policy interventions.

ii) Pursuing diplomatic and political initiatives for import of gas from neighboring and other countries with emphasis on transnational gas pipelines.

iii) Expediting setting up of a regulatory framework.

iv) Import LNG to supplement the domestic gas availability and encourage domestic companies to participate in the LNG chain.

v) Provide a level playing field for all the gas players and ensure reasonable transportation tariffs. .

vi) Rationalise customs duty on LNG and LNG projects.

vii) Put in place an effective organisational structure, which would facilitate progress in the National Gas Hydrates Programme.

viii) Opertionalise the Coal Bed Methane Policy with a time bound programme.

ix) Formulate National Policy on Underground Coal Gassification in a time bound manner.

x) Increase R&D efforts on conversion of gas to liquids.

4.5.6.3 Long term

i) Review of LNG option in the light of economic, political and energy security considerations.

ii) Exploit the gas hydrates reserves.

iii) Produce gas from Coal Bed Methane and through Underground Coal Gasification.

iv) Commercialize the production and use of alternate fuels like Di-Methyl Ether and use of Fuel Cells through increased R&P efforts.

4.5.7 Refining & Marketing

This is another important sector and its development is crucial for having self-sufficiency in petroleum products and in moving towards a consumer oriented competitive market.

4.5.7.1 Objectives

- To maintain around 90% self-sufficiency of middle distillates in the sector with an appropriate mix of national oil companies, foreign players and private Indian players.
- To develop a globally competitive industry.
- To have a free market and healthy competition amongst players. .
- To develop appropriate infrastructure such as ports, pipelines etc. for an efficient hydrocarbons industry.
- To improve customer services through better retailing practices.
- To make available un-adulterated quality products at reasonable prices.
- To achieve free pricing for products while continuing subsidized prices for

- Some products in certain remote areas, Which are to be identified and reviewed from time to time.

To achieve the above objectives, the following action is required to be taken:-

4.5.7.2 Medium term

i) Grant operational flexibility to refineries in crude sourcing and in respect of risk management through hedging.

ii) Set out a timetable for achieving product quality norms to conform to cleaner environmental standards and to global standards by 2010.

iii) Formulate a clear stable long-term fiscal policy to facilitate investment in refining, pipeline and marketing infrastructure.

iv) Grant full operational freedom to existing PSUs to establish and maintain marketing networks and allowing entry of new players into the marketing sector through a transparent and clear entry criteria and provide a level playing field for new entrants.

v) Make marketing rights for transportation fuels conditional to a company investing or proposing to invest Rs.2000 crores in E&P, refining, pipelines or terminals. Such investment should be towards additionality of assets and in the form of equity, equity like instruments or debt with recourse to the company.

vi) Set up mechanisms to enable new entrants to establish own distribution networks for marketing without encroaching on the retail networks of existing marketing companies.

vii) Set up a common regulatory mechanism for downstream sector and natural gas.

viii) To take up with the States for a uniform State level taxation on petroleum products.

ix) Provide for level tax rates for domestic products vis-a-vis imported products.

x) Increase the ceiling of Foreign Direct Investment (FDI) in refining sector from the present level of 49% to 100%.

xi) Provide a level playing field among all market participants.

4.5.7.3 Long term

i) Develop an optimal transportation mix keeping in view the existing rail and port infrastructure.

ii) Develop a policy for encouragement of transportation of crude through Indian flag vessels.

iii) Develop a policy for transportation of LNG preferably through Indian flag vessels.

iv) Provide for massive capacity expansion of the refining and marketing infrastructure to be taken up. The total investment in refining sector upto 2025 is estimated at Rs.2,50,000 crore while the same for the marketing infrastructure is estimated at Rs.1,35,000 crore.

4.5.8 Tariff and Pricing

A rational tariff and pricing policy is vital to ensure healthy growth of the hydrocarbon sector and to protect the consumers as well.

4.5.8.1 Objectives

- To provide incentives for cleaner, greener and quality fuels to promote environment friendly Hydrocarbon sector.
- To balance the need to boost Government revenue with need to align duties with Asia - Pacific countries and moving the prices to international levels.
- To promote new investments, by ensuring adequate protection to domestic producers.

- To remove subsidies and cross subsidies to promote efficient and optimal utilisation of scare resources and also to eliminate adulteration.

To achieve the above objectives the following actions are required to be taken.

4.5.8.2 Medium term

i) Phase out existing subsidies as early as possible.

ii) Set up a Group of Experts to determine appropriate levels of tariffs and duties for introduction in a phased manner as early as possible.

iii) Transfer freight subsidy on supplies to far flung areas and subsidies on products to fiscal Budget. Necessity for concession is to maintain the supply line to hilly and remote areas, after decontrol of marketing.

iv) Increase linkage of consumer price of natural gas from current level of 75% fuel oil (FO) import parity to near 100%.

4.5.9 Restructuring and Disinvestment

4.5.9.1 Objective

The core objective of industrial restructuring is to maintain long-term profitability and strengthen competitive edge of the concerned companies in the context of changes in market forces and also to ensure that the consumers benefit by the restructuring.

To achieve the above objectives the following actions are required to be taken.

4.5.9.2 Medium term

The following sequence needs to be followed:-

i) Announce policy in regard to specific public sector enterprises in alignment with the overall disinvestment policy of the Government.

ii) Complete the internal restructuring of oil PSUs, making full use of information technology.

iii) Implement proposals of mergers and alliances of oil PSUs with the objective of enhancing shareholder value.

iv) Disinvest in a phased manner in oil PSUs down to appropriate level to realise best shareholder value.

4.5.10 Conclusion

The Hydrocarbon Vision articulated in this report has to be converted into prioritized action agenda for implementation in the medium and long term. In brief, the main thrust of the activities would be:

a) Focus on oil security through intensification of, exploration efforts and achievement of 100% coverage of unexplored basins in a time bound manner to enhance domestic availability of oil and gas.

b) Secure acreages in identified countries having high attractiveness for ensuring sustainable long term supplies.

c) Pursue projects to meet the deficit in demand and supply of natural gas, and facilitate availability of LNG.

d) Maintain adequate levels of self-sufficiency in refining (90% of consumption of middle distillates).

e) Establish adequate strategic storage of crude and petroleum products in different locations.

f) Create additional infrastructure for distribution and marketing of oil and gas.

g) Open up the hydrocarbon market so that there is free and fair competition, between public sector enterprises, private companies and other international players.

h) Create a policy framework for cleaner and greener fuels.

i) Have a rational tariff and pricing policy, which would ensure the consumer getting the petroleum products at the most reasonable prices and requisite quality, eliminating adulteration.

j) Announce a long-term fiscal policy to attract required investments in the hydrocarbon sector.

k) Restructure the oil sector PSUs with the objective of enhancing shareholder value and disinvest in a phased manner in all the oil sector PSUs.

l) To develop regulatory and legislative framework for providing oil/gas security 'for the country.

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CHAPTER 5. LOW CARBON TECHNOLOGIES

5.1. Technology Development

The future technology trends are being driven by three main criteria viz. efficiency, environment and economics. Green House Gas (GHG) emission from thermal power stations has been drawing greater attention in the recent past. Any improvement in efficiency would result in lesser fuel being burnt and in corresponding economic and environmental benefits. Therefore, the conversion efficiency which is a function of turbine and boiler efficiency needs to be improved to reduce the GHG emissions. The steam turbine efficiency has been increasing with the increase in unit size accompanied by increase in steam parameters.

5.2. Super Critical Technology and Higher Unit Size

Constant efforts have been made in the past to improve the technology and efficiency of thermal generation, and units with higher steam parameters have been progressively introduced. Increase of steam parameters i.e. temperature and pressure is one of the effective measures to increase efficiency of power generation. The improvement in efficiency in respect of once-through super critical units varies from 1.7% to 5.1% as compared to sub critical boilers depending on steam parameters adopted. The supercritical units also have faster starting time & load changes and are thus more suitable for daily start up/ shut down operation and better efficiency at part load operation. Some stations with 660 MW unit size namely Sipat, North Karanpura and Barh etc. are already contemplated with supercritical parameters.

Inducting more efficient higher-size coal fired units rapidly is the most viable strategy to achieve the required capacity addition and therefore, the "Committee to Recommend Next Higher Unit Size of Coal Fired Thermal Power Stations " was set up by CEA with representatives from BHEL,NTPC, Planning Commission and other major Utilities in state and private sector. The Committee has recommended setting up of higher unit size of 800-1000 MW in view of their lower installation cost and marginally better efficiency as compared to 660 MW units. The steam parameters of 246-250 kg/cm^2, and higher steam temperatures of 568^{0}C to 593^{0}C depending upon site specific techno-economics has been recommended for deriving maximum efficiency gains from higher size units. However, in order to really achieve the benefits of higher efficiency of super critical units, it is essential that the operating practices and skills of the Utilities are considerably improved to enable achieving design performance of these units. Besides NTPC, APGENCO has planned to install large size units with super critical technology. In all Ultra Mega Projects being developed in the country on tariff based competitive bidding, it is mandatory to utilise super critical technology. In the 12th Plan, based on the experience gained by NTPC, other generating companies should also adopt super critical technologies so as to reduce green house gases emissions.

However, the approach of efficiency improvement would yield environmental benefit only to a limited extent and there is a need to look beyond for larger quantum of environmental benefits which is possible only by adopting new clean coal technologies.

5.3. Clean Coal Technologies

This group of technologies basically focuses on conversion process which, by virtue of either improved efficiency or better amenability to pollution control measures result in reduced environmental degradation. These technologies include fluidized bed combustion, integrated gasification combined cycle etc.

5.3.1 Fluidised Bed Combustion (FBC) technology

The main advantage of the FBC technology is its amenability to wide variety of fuels which cannot be burnt in the conventional pulverised coal fired boilers while at the same time maintaining NOx/ SOx emissions within limits. These fuels can be high ash coals, lignite, mill rejects, washery rejects and variety of other fuels like rice husk, baggasse etc. Circulating

Fluidised bed combustion boilers at present are available in capacities up to 250 MW. The adoption of FBC technology in the country, however, is presently for lignite-based power plants in Gujarat, Rajasthan & Tamil Nadu as the calorific value of lignite is very low as compared to non coking coal used in conventional thermal plants.

The technical details of the Fluidised Bed Combustion Technology are as under:

5.3.1.1 Introduction:

The quality of coal available in India is of low quality, high ash content and low calorific value. The traditional grate based fuel firing systems have got performance limitations and are techno-economically unviable to meet the rising demand and techno-economic challenges of future.

Many new technologies are being tried and implemented on experimental basis to meet the ever rising demand and environmental concerns.

Fluidized bed combustion has emerged as a viable alternative and has significant advantages over conventional firing system and offers multiple benefits –

1) Compact boiler design

2) Fuel flexibility;

3) Higher combustion efficiency; and

4) Reduced emission of noxious pollutants such as SOx and NOx.

The fuels burnt in these boilers include coal, washery rejects, rice husk, bagasse & other agricultural wastes. The fluidized bed boilers have a wide capacity range- 0.5 T/hr to over 100 T/hr.

5.3.1.2 Principle:

A fluidized bed may be defined as the bed of solid particles behaving as a fluid.

When an evenly distributed air or gas is passed upward through a finely divided bed of solid particles such as sand supported on a fine mesh, the particles are undisturbed at low velocity. As air velocity is gradually increased, a stage is reached when the individual particles are suspended in the air stream – the bed is called "fluidized".

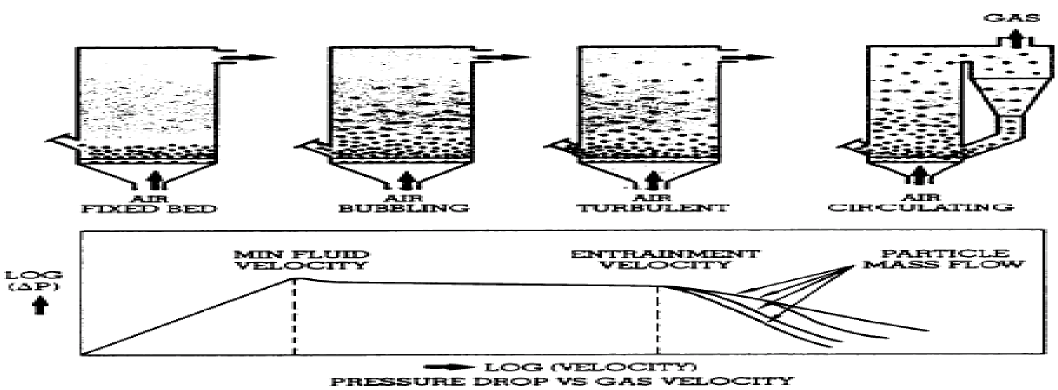

Figure 5.1[47]: Various stages of Fluidized coal bed combustion

With further increase in air velocity, there is bubble formation, vigorous turbulence, rapid mixing and formation of dense defined bed surface. The bed of solid particles exhibits the properties of a boiling liquid and assumes the appearance of a fluid – "bubbling fluidized bed".

[47] Chapter 6- FBC Boilers- Bureau of Energy Efficiency Guide Book

At higher velocities, bubbles disappear, and particles are blown out of the bed. Therefore, some amounts of particles have to be re circulated to maintain a stable system – “circulating fluidized bed”.

Fluidization depends largely on the particle size and the air velocity. The mean solids velocity increases at a slower rate than does the gas velocity.

The same principle is applied for the combustion of coal.

Combustion process requires the three “Ts” that is Time, Temperature and Turbulence. In Fluidized Bed Combustion, turbulence is promoted by fluidizations. Improved mixing generates evenly distributed heat at lower temperature. Residence time is many times greater than conventional grate firing. Thus an FBC system releases heat more efficiently at lower temperatures.

FBC reduces the amount of sulphur emitted in the form of SO_x emissions. Limestone is used to precipitate out sulphate during combustion, which also allows more efficient heat transfer from the boiler to the apparatus used to capture the heat energy (usually water tubes). The heated precipitate coming in direct contact with the tubes(heating by conduction) increases the efficiency. Since this allows coal plants to burn at cooler temperatures, less NOx is also emitted. FBC boilers can burn fuels other than coal, and the lower temperatures of combustion (800 °C / 1500 °F).

5.3.1.3 Types of Fluidized bed combustion systems:

FBC systems fit into essentially two major groups, atmospheric systems (FBC) and pressurized systems (PFBC):

5.3.1.3.(i) Atmospheric Fluidized Bed Combustion Systems:

Atmospheric fluidized beds use a shy limestone or dolomite to capture sulphur released by the combustion of coal. Jets of air suspend the mixture of absorbent and burning coal during combustion, converting the mixture into a suspension of red-hot particles that flow like a fluid. These boilers operate at atmospheric pressure.

5.3.1.3.(ii) Pressurized Fluidized Bed Combustion Systems (PFBC):

The PFBC system also uses absorbent and jets of air to suspend the mixture of absorbent and burning coal during combustion. However, these systems operate at elevated pressures and produce a high-pressure gas stream at temperatures that can drive a gas turbine. Steam generated from the heat in the fluidized bed is sent to a steam turbine, creating a highly efficient combined cycle system.

(a) Advantages:

1. FBC boilers can burn fuel with a combustion efficiency of over 95% irrespective of ash content.

2. FBC boilers can operate with overall efficiency of 84% (plus or minus 2%).

3. High heat transfer rate over a small heat transfer area immersed in the bed result in overall size reduction of the boiler.

4. FBC boilers can be operated efficiently with a variety of fuels. Even fuels like flotation slimes, washery rejects, agro waste can be burnt efficiently. These can be fed either independently or in combination with coal into the same furnace.

5. FBC boilers would give the rated output even with inferior quality fuel. The boilers can fire coals with ash content as high as 62% and having calorific value as low as 2,500 kcal/kg. Even carbon content of only 1% by weight can sustain the fluidized bed combustion.

6. Coal containing fines below 6 mm can be burnt efficiently in FBC boiler, which is very difficult to achieve in conventional firing system.

7. SO_x formation can be greatly minimized by addition of limestone or dolomite for high sulphur coals. 3% limestone is required for every 1% sulphur in the coal feed. Low combustion temperature eliminates NO_x formation.

8. The corrosion and erosion effects are less due to lower combustion temperature, softness of ash and low particle velocity (of the order of 1 m/sec).

9. Since the temperature of the furnace is in the range of 750 – 900 ^{o}C in FBC boilers, even coal of low ash fusion temperature can be burnt without clinker formation. Ash removal is easier as the ash flows like liquid from the combustion chamber. Hence less manpower is required for ash handling.

10. The CO_2 in the flue gases will be of the order of 14 – 15% at full load. Hence, the FBC boiler can operate at low excess air - only 20 – 25%.

11. High turbulence of the bed facilitates quick start up and shut down. Full automation of start up and operation using reliable equipment is possible.

12. Inherent high thermal storage characteristics can easily absorb fluctuation in fuel feed rates. Response to changing load is comparable to that of oil fired boilers.

13. In FBC boilers, volatilisation of alkali components in ash does not take place and the ash is non sticky. This means that there is no slagging or soot blowing.

14. Automatic systems for coal and ash handling can be incorporated, making the plant easy to operate comparable to oil or gas fired installation.

15. By operating the fluidized bed at elevated pressure, it can be used to generate hot pressurized gases to power a gas turbine. This can be combined with a conventional steam turbine to improve the efficiency of electricity generation and give a potential fuel savings of at least 4%.

5.3.2 Integrated Gasification Combined Cycle (IGCC)

Integrated Gasification Combined Cycle (IGCC) System is one of the clean coal technologies in which coal is converted into gaseous fuel, which after cleaning is used in CCGT plants. The IGCC systems which are commercially available have shown higher efficiencies and exceptionally good environmental performance in Sox removal, NOx reduction and particulate removal. IGCC, if commercially proven, will be one of the most attractive power generation technologies for the 21st century. Integrated Gasification Combined Cycle technology is also being considered in view of the development of advanced gas turbines with very high efficiencies. However, IGCC technology with high-ash domestic coal is still in the R&D stage. 100 MW Experimental project is proposed to be set up at NTPC Auraiya/ Sipat and Vijayawada TPS of APGENCO jointly with BHEL during 11th plan period.

The technical details of Integrated Gasification Combined Cycle are as under:

Integrated gasification combined cycle (IGCC) is a technology based on the conversion of coal into gas—synthesis gas (syngas) by destructive distillation process.

It then removes impurities from the coal gas before it is combusted. This results in lower emissions of sulphur dioxide, particulates and mercury. Excess heat from the primary combustion and generation is then passed to a steam cycle, similar to a combined cycle gas turbine. This result in improved efficiency compared to conventional pulverized coal firing process.

This process also provides flexibility of type of fuel to be used for the production of syngas as syngas can be produced from high-sulphur coal, heavy petroleum residues and biomass apart from coal.

In the process of Coal gasification the coal is converted into to a gaseous fuel through partial oxidation. The coal is fed into a high-temperature pressurized container along with steam and a limited amount of oxygen to produce synthesis gas (syngas). Syngas mainly consists of carbon monoxide and hydrogen. The gas is cooled and undesirable components, such as carbon dioxide and sulphur are removed. The gas can be used as a fuel or further processed and concentrated into a chemical or liquid fuel.

The essence of the process of coal gasification consists of the conversion of chemical energy of solid fuel into chemical energy of gaseous fuel. Gas produced in the process of coal gasification is not only the carrier of chemical energy, but also of the physical one. The following essential properties of coal gasification process differentiate this process from coal combustion:

1) Process of coal gasification is conducted with low gasifying medium (oxidizer) number to obtain high chemical efficiency in the process and low content of NOx in the gas.

2) About **99%** of sulphur is converted into **H_2S** and **COS,** and only a little into **SO_2;** these gases are removed from the gas in the cleaning process.

2) Ash is efficiently removed from the gas in melted form.

3) High pressure of the process of coal gasification allows the construction of a combined gas-steam power plant with high efficiency.

4) Gas is cleaned of sulphur compounds and of ash before burning.

The process of coal gasification, as a part of the technology used in generation of electric energy, allows producing "clean” gas fuel from "dirty" coal.

5.3.2.1 Process

Integrated gasification combined-cycle (IGCC) systems combine a coal gasification unit with a gas fired combined cycle power generation unit. The first stage is the coal gasification process where coal is fed into the high pressurized vessel along with steam and limited amount of oxygen to produce syngas. This syngas is then fed to cleaning chamber where contaminations are removed from it and clean syngas is obtained. This cleaned syngas is then fed into the conventional gas turbine where it is burned to produce electrical energy. The hot exhaust gas is recovered and used to heat water in a steam boiler, creating steam.

A part of the steam produced in the steam boiler is fed into the high pressure chamber for the syngas generation process and remaining part is fed into steam turbine to produce electrical energy. In typical plants, about 65% of the electrical energy is produced by the gas turbine and 35% by the steam turbine.

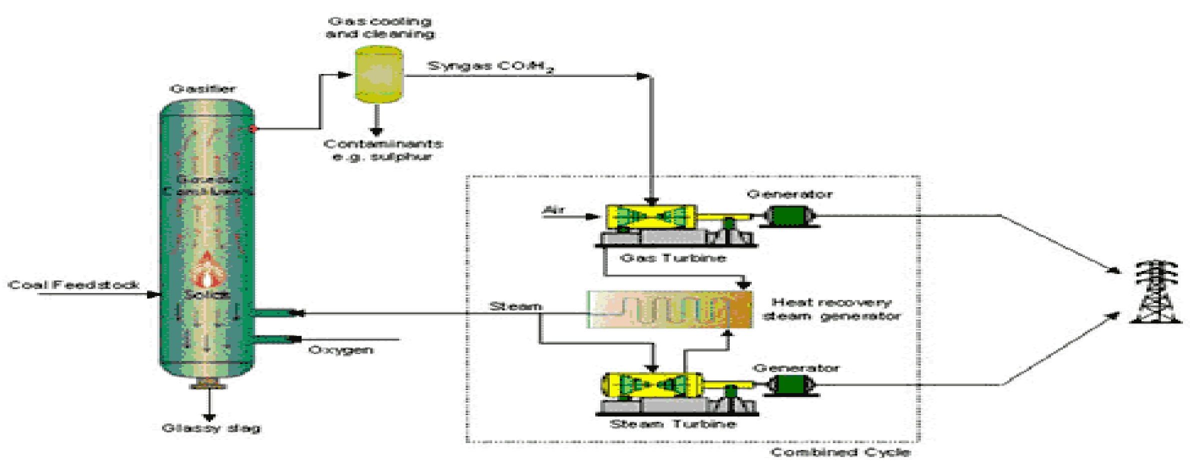

Figure 5.2[48]: Integrated Gasification combined cycle

[48]http://www.ccsd.biz/factsheets/igcc.cfm

5.3.2.2 Advantages

1. Thermal efficiency of 50% can be achieved using IGCC. This is a higher efficiency compared to conventional coal power plants
2. Less coal is consumed in this process to produce the same amount of energy, resulting in lower rates of carbon dioxide (CO_2) emissions
3. The volume of solid wastes produced in IGCC process is about half the volume produced in conventional coal power plant.
4. It uses 20-50% less water compared to a conventional coal power station.
5. It can utilise a variety of fuels, like heavy oils, petroleum cokes, and coals.
6. Up to 100% of the carbon dioxide can be captured from IGCC, making the technology suitable for carbon dioxide capture and storage.
7. carbon capture is easier and costs less than capture from a pulverised coal plant
8. Around 95% of the sulphur is removed
9. Nitrogen oxides (NO_x) emissions are below 50ppm..
10. The syngas produced from a gasifier unit can be used as a fuel in other applications, such as hydrogen-powered fuel cell vehicles

5.3.2.3 Disadvantages

1. The overall thermal efficiency of the IGCC power plant is less when compared with Natural Gas fired combined cycle plant
2. The start up times of IGCC will be more than Pulverized Coal fired power plant due to the large number of sub systems. This makes the IGCC suitable only for base load operation. .
3. Current cost of IGCC is higher than the Ultra supercritical pulverised coal fired plants without CO_2 capture.
4. More components, more heat exchangers increase maintenance costs and outage times.

5. Present IGCC technology is almost 25% expensive than conventional coal based thermal power plant technology.

5.3.3 Oxy –Fuel Technology:

5.3.3.1 Introduction

Oxy-fuel technology refers to technology where pure oxygen is mixed with fuel instead of air for the purpose of combustion.

Atmospheric air contains 20.95% oxygen, 78.08% nitrogen and rest part is occupied by the inert gases like Neon, Helium Xenon etc.

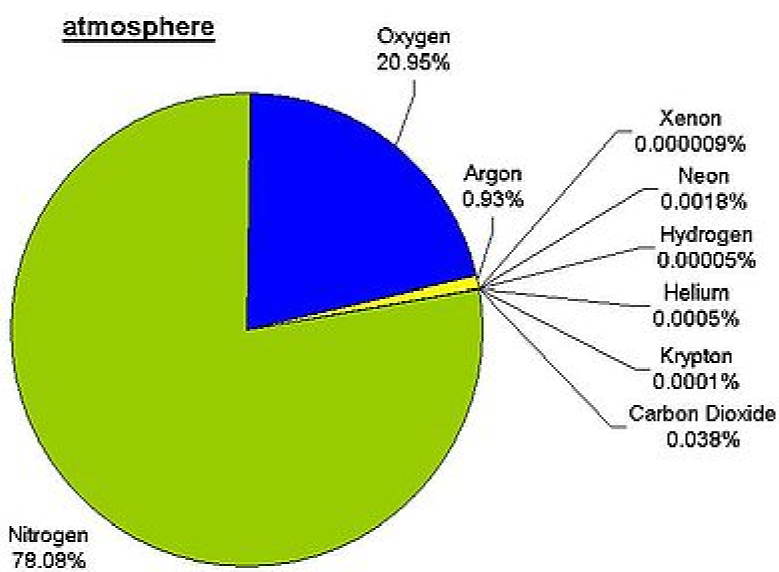

Figure 5.3[49]: Contents of atmospheric air

[49] Based upon information on http://www.uigi.com/air.html

Generally atmospheric air is used to form a mixture along with the fuel for combustion purposes but as the oxygen content in air is only 20.95%, higher temperature cannot be reached on account of energy used in diluting the inert gases.

Higher temperature can be reached if pure oxygen is mixed with the fuel and then that mixture is used for combustion. This negates any chance of energy being used for dilution of the inert gases.

Approximately the same total energy is produced when burning a fuel with oxygen as compared to with air; the difference is the lack of temperature diluting inert gases like nitrogen, Helium, Xenon etc.

Oxy-fuel combustion is the process of burning a fuel by making fuel-pure oxygen mixture using pure oxygen instead of mixing the fuel with air where air acts as the primary oxidant. In oxy-fuel combustion process, since there is no nitrogen component and only pure oxygen is mixed with the fuel to make oxygen- fuel mixture, the fuel consumption is reduced, and higher flame temperatures are possible, thereby increasing the efficiency of the process.

Historically, the primary use of oxy-fuel combustion has been in welding and cutting of metals, especially steel, since oxy-fuel allows for higher flame temperatures than can be achieved with an air-fuel flame.

Now this technology is introduced on pilot basis in fossil- fuel power plants with an oxygen enriched fuel mix instead of air.

5.3.3.2 Application of Oxy- Fuel Technology in Fossil Power Plants

Oxygen fired pulverized coal combustion (Oxy-Fuel), offers a low risk step development of existing power generation technology to enable carbon dioxide capture and storage. The justification for using oxy-fuel is to produce a CO_2 rich flue gas ready for sequestration.

Oxy-firing of pulverized fuel in boilers involves the combustion of pulverized coal in a mixture of oxygen i.e. combustion of oxygen-enriched gas mix instead of air. Almost all of the nitrogen is removed from input air, yielding a stream that is approximately 95% oxygen. Firing with pure oxygen would result in too high a flame temperature, so the mixture is diluted by mixing with recycled flue gas. Also, the flue gas is added to the oxygen-fuel mixture in order to reduce the net volume of flue gases from the process and to substantially increase the concentration of carbon dioxide (CO2) in the flue gases – compared to the normal pulverized coal combustion in air.

Oxy-fuel combustion produces approximately 75% less flue gas than air fueled combustion and produces exhaust consisting primarily of CO_2 and H_2O. Oxygen combustion combined with flue gas recycle increases the CO2 concentration of the off-gases from around 15% for pulverized coal up to a theoretical 95%.

5.3.3.3 Fossil Fuel Fired power Plant with oxy-fuel combustion process

There are a number of variants for the proposed oxy-firing of boilers, but in simple terms the technology involves modification to familiar technology to include oxygen separation; flue gas recycling; and CO2 compression, transport, and storage. Relatively pure oxygen is mixed with a proportion of either wet or dry flue gas taken down stream of the particulate cleaning plant (typically 70% of the total gas flow) and blown into the wind box of the boiler. Primary air to sweep the pulverising mills is substituted with dry flue gas. The net result of this combustion process is a concentrated stream of CO2, that enables the CO2 to be captured in a more cost effective manner compared to post combustion capture of CO2 from an air-fired boiler.

5.3.3.4 Process Explanation

Here, pulverized coal is sent into the boiler along with oxygen supplied form the air separation unit to the boiler where the combustion of the oxygen-coal takes place.

The steam is sent to the steam turbine for the process of electricity generation and then from turbine it is sent back to condenser and again fed back to the boiler.

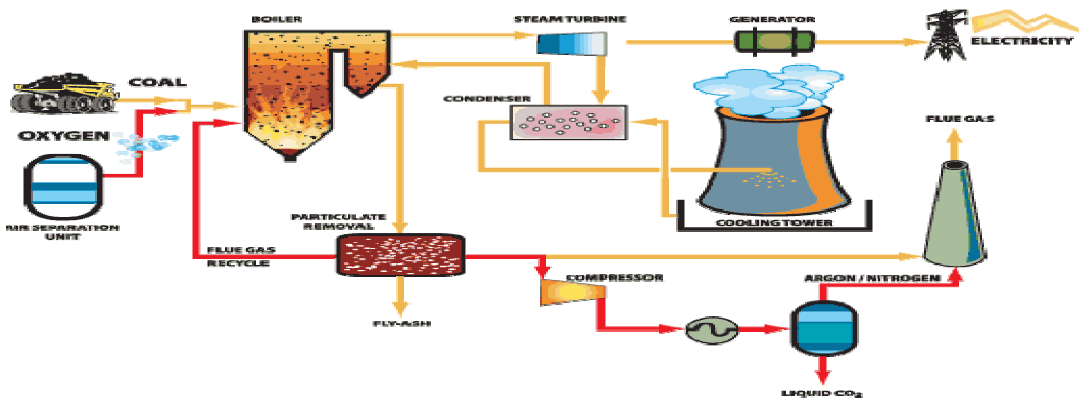

Figure 5.4[50]: Oxyfuel process

The flue gas leaving the boiler is sent to the particulate separator where fly ash and other particles are separated.

A part of flue gas is fed back to the boiler to control the temperature of the flame and to increase the CO_2 content in the flue gas. A part of flue gas which now majorly consists of CO_2 is fed to the compressor, where it is cooled and compressed and dried down to a dew point of -60°C.

This CO_2 is then further cooled down to the triple point of CO_2 where it is converted into liquid and uncondensed inert are separated. The inert gases are sent out through the stack and the liquid $CO_2$is transported for storage.

A part of flue gas which cannot be used in any way is also sent out through the stack.

[4] http://www.ccsd.biz/factsheets/igcc.cfm

5.3.3.5 Importance

Oxy-fuel technology is important for clean electricity generation using fossil fuel for the following reasons:

1. The potential for a medium- to long-term, lower cost and lower technology risk, option for achieving near zero emissions from coal-based electricity generation;
2. The potential to retrofit this technology to standard PF technology (sub-critical as well as super/ultra-super critical PF technology).
3. The prospect of applying the technology to new coal-fired plant with significant reductions in the capital and operating cost of flue gas cleaning equipment such as deNOx plant.
4. The mass and volume of the flue gas are reduced by approximately 75%.
5. Because the flue gas volume is reduced, less heat is lost in the flue gas.
6. The size of the flue gas treatment equipment can be reduced by 75%.
7. The flue gas is primarily CO_2, suitable for sequestration.
8. The concentration of pollutants in the flue gas is higher, making separation easier.
9. Most of the flue gases are condensable; this makes compression separation possible.
10. Heat of condensation can be captured and reused rather than lost in the flue gas.
11. Because nitrogen from air is not allowed in, nitrogen oxide production is greatly reduced.

5.3.3.6 Oxy-fuel Technology Drivers

The specific reasons for considering oxy-fuel as an option for clean coal technology development are as follows:

1. The existing capacity of PF plant worldwide (old and new) is very substantial, and there are plans for a significant number of new PF plants to be installed around the world.
2. The CO2 capture cost from oxy-fuel is potentially competitive with other emergent technologies.

3. The technical risks associated with oxy-fuel are potentially less than other clean coal technologies because the technology is less complex.
4. In particular countries, the potential for lower capital and operating costs of gas cleaning in oxy-fired PF boilers (deNO_x and deSO_x) could lead to commercial applications of the technology.

5.3.3.7 Oxy-fuel Technology Status

The full-scale application of oxy-fuel technology is still under development. However, laboratory and theoretical work has provided an initial understanding of design parameters and operational considerations. In addition there have been a number of investigations using pilot-scale facilities in the US, Europe, Japan, and Canada. Studies have also assessed the feasibility and economics of retrofits and new power plant. Some of the conclusions that can be drawn from the findings to date are as follows:

1. Pilot-scale studies have demonstrated that there are no significant technical barriers to O2/RFG firing of PF boilers
2. Typically, the optimum O2 concentration from the ASU for oxy-fuel applications is around 97 - 98%; and the optimum recirculation rate is generally around 70% which yields about 25 – 30% O2 (vol. %, wet) in the windbox of the boiler, and about 3 - 3.5% O2 (vol. %, wet) at the furnace exit/AH inlet. At these conditions, flame condition and heat transfer characteristics reasonably approximate those for air-fired PF boilers.
3. O2/RFG combustion yields significant reductions in NOx - typically 25 - 50% lower than for the air-fired case.
4. Preliminary cost evaluations indicate CO2 capture costs ($/tCO2 avoided) and electricity costs ($/MWh) comparable with other technologies and lower than conventional PF with amine-based post-combustion capture of CO2.
5. Technical challenges include investigation of flame stability, heat transfer, level of flue gas clean up necessary and acceptable level of nitrogen and other contaminants for CO2

compression, and corrosion due to elevated concentrations of SO2/SO3 and H2O in the flue gas.

5.3.3.8 Limitations of Oxy- Fuel Technology

However, because of the energy and economic costs of producing oxygen, an oxy-fuel power plant is less efficient than a traditional air-fired plant. In the absence of any need to reduce CO_2 emissions, oxy-fuel is not competitive. However, oxy-fuel is a viable alternative to removing CO_2 from the flue gas from a conventional air-fired fossil fuel.

5.4. Status of Clean Coal Technology in world and India

The following table summarizes the status of Clean Coal Technologies in India and Worldwide level as in year 2007

Table 5.1[51]: Status of clean coal Technology implementation in world and India

Technology	Worldwide Status	Indian Status
PC firing with SOx and NOx Control System	Commercialised	NOx control commercialised SOx control not in use
AFBC Power Plant	Commercialised upto 165 MWe (USA)	2 x 10 MWe units operating
CFBC Power Plant	Commercialised upto 250 MWe	1x30 MWe unit commissioned by BHEL- LURGU Maharashtra (1997)
PFBC Power Plant	Demonstration units upto 130 MWe(Sweden, Spain, USA, Japan)	Bench scale R&D at BHEl and IIT Madras
IGCC Power Plant	Demonstration units upto 250 MWe (USA, Netherlands)	6.2 MWe demo plant at BHEl, 600 MWe conceptual design at IICT Hyderabad, Gasifier pilot plants at BHEL and IICT

[5]www.energyalternatives.com

Technology	Worldwide Status	Indian Status
Hybrid IGCC Plant	Pilot Plant R & D (UK)	No activity
Fuel Cell Based PFBC Power Plant	Advanced R&D	On-going R&D on fel cells

5.5. Integrated Solar Combined Cycle (ISCC)

Our country is gifted with vast potential of solar energy which can be utilized to generate power. Direct solar insolations for over 10 months in a year are available in the Thar desert stretching over vast areas of Rajasthan and Gujarat. Even if 1% of it is used, it can generate about 6000 MW of electric power. Proposal to set up 140 MW ISCC project at Mathania, Rajasthan would have been the first of its kind in India, but for administrative hassles in MNRE could not fructify. However, due to high cost of generation, use of solar energy for commercial production of electrical energy is limited. Low cost technologies have to be developed to economically exploit the vast potential available in the country.

5.6. Fuel Cell Technology

Fuel cells are electro-chemical devices that convert energy from fuel directly into electricity through electro-chemical reactions. These cells normally use hydrogen directly as fuel or as derived from natural gas or other hydro carbons. About 4-5 major technologies for fuel cells are in various stages of development worldwide. A fuel cell development programme is under way in India under the aegis of Ministry of Non-conventional Energy Sources and several organisations like BHEL, SPIC, Indian Institute of Science, Bangalore, Central Glass and Ceramic Research Institute, Calcutta have undertaken research projects for development of various technologies of fuel cells indigenously. M/s BHEL are in the process of developing 25 kW fuel cell stack with Phosphoric Acid Fuel Cell (PAFC) technology. A study to observe performance of imported 200 kW fuel cells stack under Indian conditions is also in progress at BHEL. M/s SPIC are in the process of developing 5 KW solid polymer fuel cells stacks. M/s

Electrochemical Institute, are engaged in Molten Carbonate Fuel Cell (MCFC) technology. Project for development of direct methanol fuel cell is in progress at IISc., Bangalore under a UNDP research programme. Fuel cell applications include distributed generation in hospitals, airports, research institutes etc. Apart from power generation, variants of fuel cell also find applications for transport in electric-driven vehicles.

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CHAPTER 6. CARBON CAPTURE AND TRANSPORTATION

6.1. Introduction

The objective of carbon capture process is to separate CO_2 from the flue gas or process gas stream of a power plant. The separation process operates by absorbing or adsorbing CO_2 from gas stream preferentially under specific thermodynamic condition by a solvent, physical media, and followed by separation of CO_2 from the solvent, physical media in subsequent process. The other separation processes being developed are use of membrane, cryogenics. The tangible cost incurred in capture process is the maximum. All the research and development processes are focused on reducing cost of capture cycle. Carbon capture units have capacity to capture 85 to 95% of CO_2 emissions from the exhaust gases of coal- and gas-fired power plants, oil refineries and steel plants. The subsequent process after capture is it to transport carbon dioxide to appropriate geological site for storage. Equivalent capture and separation processes have been commercially applied in ammonia manufacturing in fertilizer (urea) industry. In USA the captures and separated CO_2 stream is being used for enhanced oil recovery. Their national standard institutions have set up norms and standards for the CO_2 purity for pipeline transportation. The existing capture technology replication in CCS components for power plant has following limitations:

- Scale of flue gas emission or gas stream in power plant process loop is very high in comparison to urea manufacturing units;

- Concentration of CO_2 in the flue gas stream (post combustion) is low. Hence pre-combustion process (IGCC) or oxy-fuel technology is being developed to obtain high concentration of CO_2 gas stream. The gas stream analysis of IGCC and conventional power units for carbon capture is shown in table 1. The projections for oxyfuel technology for CO_2 concentration in flue gases prepared for carbon capture are greater than 80% ;

- Pre-combustion processes have to be developed for removal of impurities, and extraction of coal by-product;
- Thermodynamic parameters i.e. temperature, concentration, pressure in flue gas is inadequate to ensure efficient extraction. Development of catalyst and contactors are needed

In order to cut cost of capture process, important requirement is to improve the yield of capturing medium used for capturing CO_2. That is media should first separate CO_2 from gas stream, and then separating CO_2 from the medium, with minimum degradation of media. The recycling of media should be feasible to maximum extent. The task is to transport separated CO_2 to geological site. Before transportation of CO_2, the CO_2 gas has to be dehydrated, and processed for removal of impurities, to obtain CO_2 gas stream according to norms and design standards. The CO_2 capture technologies have been applied at small scales in "gas and oil production" scheme to remove CO_2 to enhance characteristics of oil and gas. The streams of separated CO_2 are used to increase oil production of the reservoir, termed as enhanced oil recovery (EOR). The issues of research for establishing viability of CCS demonstration project should focus on efficient design of capture process, these are;

(1) Enhanced performance of capture technology at thermodynamic condition of gas stream. These include (a) technology selection absorption/ membrane (b) catalyst & contactor (c) optimum use of waste heat (d) recycling of capturing media

(2) Cost of capture in total CCS loop is very high. This includes both "Capital costs" and "operation & maintenance cost". There are concerns escalation of material prices used as capturing media.

(3) Compliance with regulatory scheme

(4) Cost of electricity will increase as additional fuel is needed[52] (directly & indirectly) to produce equivalent power (The cost impact of CCS on the cost of electricity is estimated at 30% in the case of coal fired power plants with CO_2 capture.)

(5) Scope of harnessing steam energy in the process line.

As per the present status of technology and development, in the total CCS value chain, the carbon capture and separation of CO_2 and for preparing interface for transport process accounts for 80% of the total cost of CCS value chain. The balance cost of 20% is due to transportation and sequestration. There are continuous operational cost of monitoring and verification, and compliance with regulatory requirements, which has not been considered. This does not include, database maintenance for future generation. Significant opportunity exist for reducing costs in the carbon capture cycle, and intensive R&D is needed to develop innovative scheme to enhance capture efficiency and reduce cost in capture cycle at emerging boundary conditions of processes following innovation and R&D.

Table 6.1[53]: Characteristics of gas-stream for carbon capture

Gas composition	Pre-combustion capture (after water gas shift) #	Post-combustion capture $
CO_2	35.50%	15 – 16 %
H2O	0.20%	5 – 7 %
H2	61.50%	-
O2	-	3 – 4 %

[52]The *IPCC Special Report: Carbon Dioxide: Capture and Storage* estimated that capture of 90 percent of CO_2 using current technologies would result in an increased fossil fuel consumption of 24–40 percent for new Super Critical Pulverized Coal plants, 11–2 percent for natural gas combined-cycle (NGCC) plants, and 14–25 percent for IGCC systems compared to similar plants without CO_2capture and compression

[53]*$ -Pennline (2000), Photochemical removal of mercury from flue gas, NETL*

CO	1.10%	20 ppm
N2	0.25%	70 – 75 %
SOx	-	< 800 ppm
NOx	-	500 ppm
H2S	1.10%	-
Thermodynamic Conditions		
Temperature	40 °C	50 – 75 °C
Pressure	50 – 60 bar	1 bar

Linde Rectisol, 7th European Gasification Conference;

The capture process as described here means, capture of CO_2 from flue gas/ gas stream by media such as MEA in a reactor, circulation of CO_2 rich MEA solution, then stripping CO_2 from rich MEA solution. Within the complete capture process, capture by absorbent accounts for approximately 34% of the total capture process cost (operational variable). The circulation of the solvent and gas through the columns by pumps and blowers, accounts for approximately 17% of the total operating cost. The maximum cost of CO_2 capture cycle is in solvent regeneration process occurring due to the energy requirement, enhanced yield of solvent regeneration. This phase accounts for 49% of the total capture cost. Improving design of the packed bed thereby minimizing pressure drop can facilitate the cost reduction in all reaction phases.

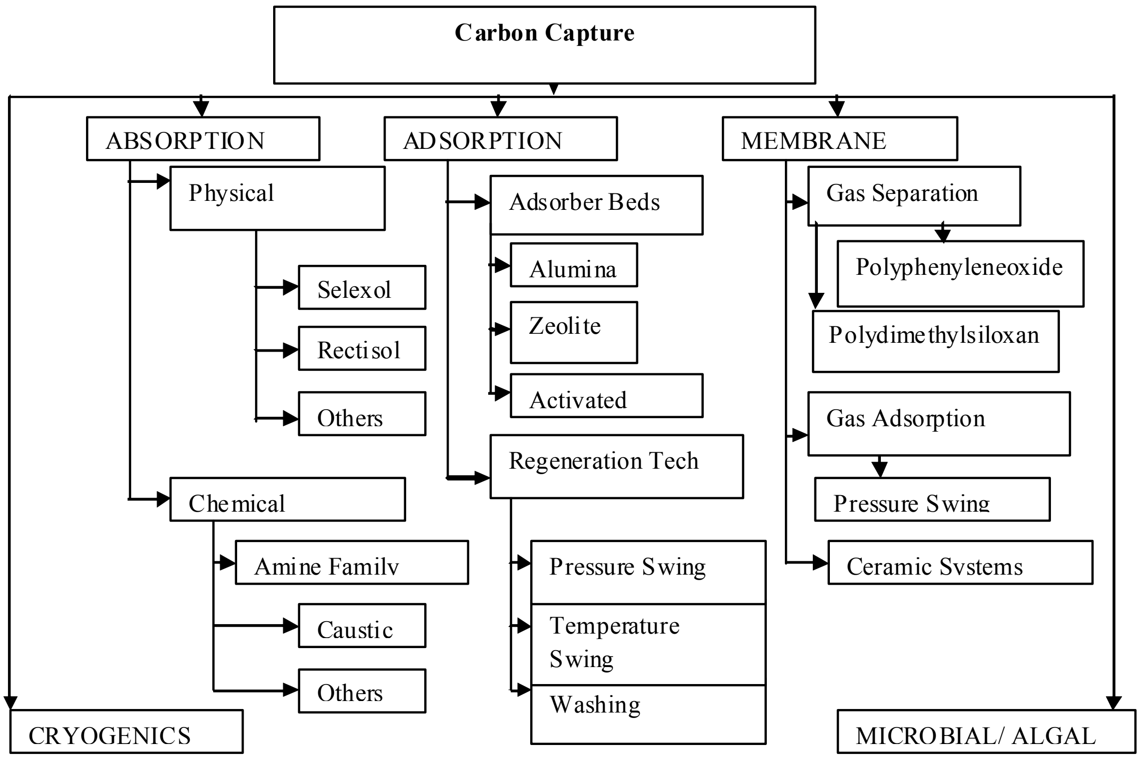

Figure 6.1: Carbon Capture process

Table 6.2[54]: Process conditions of various solvents

	Solvent name	Solvent type	Process conditions
Physical Solvent	Rectisol	Methanol	-10/-70°C, >2 MPa
	Purisol	n-2-methyl-2-pyrolidone	-20/+40°C, >2 MPa
	Selexol	Dimethyl ethers of polyethyleneglycol	-40°C, 2-3 MPa
	Fluor solvent	Propylene carbonate	Below ambient temperatures,3.1-6.9 MPa
Chemical solvents	MEA	2,5 n monoethanolamine and inhibitors	40°C, ambient-intermediate pressures
	Amine guard	5n monoethanolamine and inhibitors	40°C, ambient-intermediate pressures
	Econamine	6n diglycolamine	80-120°C, 6.3 MPa
	ADIP	2-4n diisopropanolamine 2n methyldiethanolamine	35-40°C, >0.1 MPa
	MDEA	2n methyldiethanolamine	
	Flexsorb,KS-1,KS-2,KS-3	Hindered amine	
	Glycol		
	Methanol		
	Ionic liquid		
	Benfield and versions	Potassium carbonate & catalysts.Lurgi & Catacarb processes with arsenic trioxide	70-120°C, 2.2-7 MPa
Physical/ Chemical Solvent	Sulfinol-D, Sulfinol-M	Mixture of DIPA or MDEA, water and tertahydrothiopene (DIPAM)or diethylamine	>0.5 MPa
	Amisol	Mixture of methanol and MEA, DEA, diisopropylamine (DIPAM) or	5/40°C, >1 MPa

http://www.iea.org/textbase/nppdf/free/2004/prospects.pdf *(Source: Gupta et al)*

		diethylamine	

6.2. Current Status of Technology and research needed:

6.2.1 Amine absorption for CO_2 capture and the challenges

Amine solvent based absorption processes of carbon capture have been widely practiced for many years from gas streams in natural gas processing, synthetic gas stream in ammonia production for urea fertilizer manufacturing, and refinery off-gas treatment. The gas streams in these industries are usually at a high pressure of about 30 to 70 atmosphere. The flue gas from a power plant mainly consists of N2, water vapor, oxygen from excess air of combustion and CO_2. The flue gas from thermal power plants also contains SOx and NOx. Nox is a greenhouse gas. During the process of amine scrubbing of flue gas, SOx and NOx are reaction retardant, which are known to form heat stable salts with the amines used for CO_2 capture. Following scrubbing and carbon capture the amine solution is reprocessed to separate out CO_2 and recover purer form of Amine for recycling again for carbon capture loop. The schematic process is shown in figure 6.2. The phenomenon of salt formation degrades the capturing medium (Amine in this case), and recovery of amine decreases. Since the flue gases also contain oxygen at appreciable partial pressures, it will be necessary to address and avoid the oxidative degradation of the solvent. There are other impurities such as HCl and fly ash. These will further complicate the application of capturing media and hence resulting in the existing flue gas treatment technology of CO_2 capture from coal-fired power plants, economically unviable. These constraints and processes increase the cost of capture significantly.

The present capture system uses 15-30-wt% MEA (mono-ethanol-amine) for scrubbing. The cost of the amine is relatively lower than other chemicals used for carbon capturing. . The amine reacts with the CO_2 to form carbamate. The kinetic parameters of the reaction are favorable. The carbon capture process constitute of first capturing the CO_2 of flue gas, and later stripping of CO_2 and regeneration of amine for re-circulation. The scrubbing solution should be loaded with optimum concentration of amine, because the free amine is converted to carbamate. The energy requirement of the reaction is high, because of a high heat of reaction to produce the carbamate. The MEA system requires additives to minimize degradation and corrosion.

Applied Research is needed for innovation of new solvents that can offset limitation of amine and are cost effective. The new solvents should also have low vapor pressure, highly resistant to degradation, display low corrosivity in the presence of oxygen. New solvents should comply with technical attributes of (i) higher equilibrium capacity for CO_2 (ii) high CO_2 reaction rates (iii) having low regeneration energy requirement (iv) having good capture efficiency at low partial pressure and (v) higher yield during regeneration process. The high reaction rate will in turn reduce the size of the absorption towers that will reduce capital and operating costs.

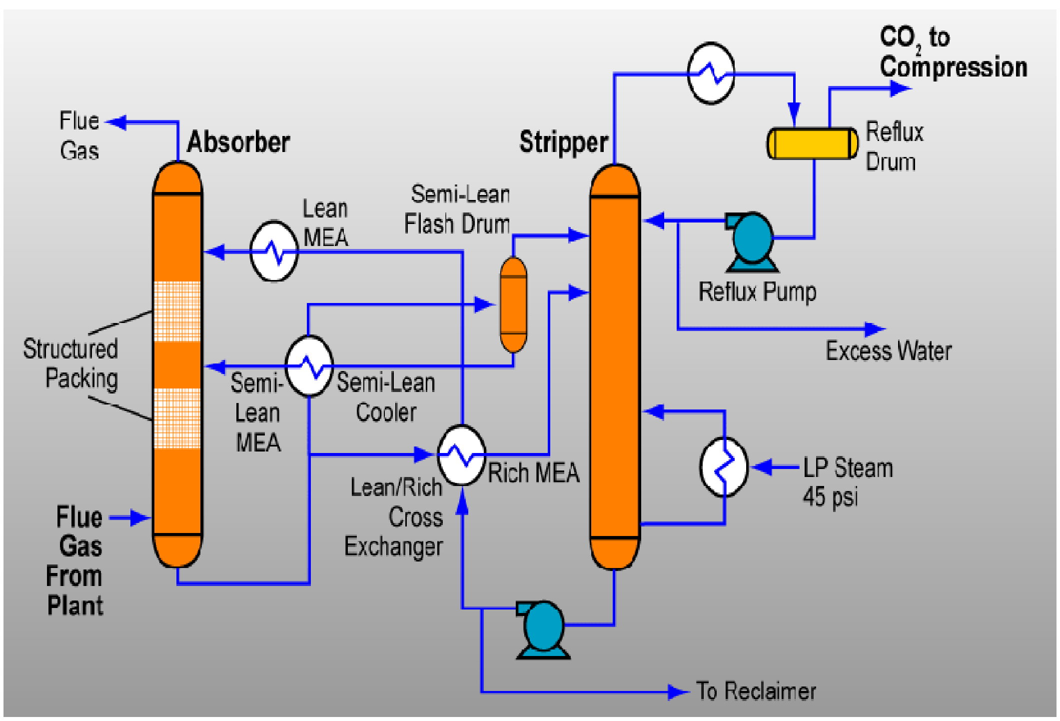

Figure 6.2[55]: Typical Amine Absorption Process--Schematic Diagram of an Amine CO_2 Capture Process for Post Combustion Process (Absorber parameter are 50 degree Centigrade, ~ 1atmosphere pressure; Stripper Parameter ~120 degree centigrade, ~ 2 atmosphere pressure; solution concentration ~ 30% MEA)A number of novel solvents based on (a) sterically hindered amines, (b) amine blends, and (c) activated amines, which can have higher equilibrium and kinetic selectivity for CO_2 and lower energy requirements for regeneration, by incorporating optimum blend, are being developed by few leading research groups in the world.

The reaction pattern of amines is as under

(1) Primary and secondary amines are limited in their capacity to absorb CO_2 because of the formation of a stable carbamate.

CO_2 + 2R2NH → R2NCOO- + RNH2+ (R stands for –C_2H_4OH)

Thus the stoichiometry of the reaction limits the amount of CO_2 that can be absorbed. The maximum possible is 0.5 mole CO_2 per mole of amine.Tertiary amines, on the other hand exhibit greater capacity to absorb CO_2 but have lower rates of absorption as compared to the primary and secondary amines. Because tertiary amines absorb CO_2 as bicarbonate rather than carbamate, the maximum stoichiometry is one mole of CO_2 per mole of amine:

$$CO_2 + R_3N \rightarrow HCO_3- + R_3NH+$$

Moderately hindered amines are characterized by forming carbamates of low to intermediate stability. The reaction with carbon dioxide proceeds mainly through the production of bicarbonate. Carbamate reversion to bicarbonate is also a significant reaction. Hence these moderately hindered amines have a high thermodynamic capacity that approaches 1.0 mole of CO_2 per mole of amine:

[55] http://www.netl.doe.gov/technologies/coalpower/ewr/CO_2/pubs/EPEC%20CO_2%20capture%20program%20overview%20feb09.pdf

$RNH_2 + CO_2 + H_2O \rightarrow RNH_3+ + HCO_3-$

At present, there are several update technological options available for capturing carbon dioxide (CO_2) from flue gas streams. The aqueous alkanolamine monoethanolamine (MEA) solution has been extensively used in many industries for removing CO_2 because it has a faster rate of reaction, which allows absorption process to take place in a smaller column. However, MEA solution is more corrosive than other amines and also requires excessive energy for regeneration. A sterically hindered amine AMP (2-amino-2-methyl-1-propanol) is less corrosive and requires less energy for solvent regeneration. This makes AMP an attractive solvent for gas treating industries today.

Recently, the use of blended-alkanolamines has been receiving a great deal of interest from practitioners because it combines the favorable features of different alkanolamines while suppressing the unfavorable. The common blended alkanolamines are MDEA (methyl-di-ethanol-amine)-based solvents, which are claimed to have low energy requirement, high absorption capacity, and excellent stability. However, the use of MDEA-based solvents may be limited by the low rate of CO_2 absorption. Compared to MDEA, AMP can absorb CO_2 with the similar capacity but at a much higher rate. Therefore, the AMP-based solvents, especially MEA-AMP blend, appear to be another alternative option for Carbon capture.The reaction between CO_2 and amine solutions is very complex. According to Astarita et al. (1983), the following three reactions need to be considered.

Carbamate formation[56]: $CO_2 + 2RR'NH \leftrightarrow RR'NH^+_2 + RR'NCOO^-$

Bicarbonate formation: $CO_2 + 2RR'NH + H2O \leftrightarrow RR'NH^+_2 + HCO^-_3$

[56]Where R stands for $–C_2H_4OH$, and R' represents –H and $–C_2H_4OH$ for primary and secondary amines, respectively.

Carbamate reversion: $CO_2 + RR'NCOO^- + 2H2O \leftrightarrow RR'NH^+_2 + 2\ HCO^-_3$

The carbamate formation is considered to be the main reaction of CO_2 with primary and secondary amines. The formation mechanism can be explained by using zwitterion mechanism, which involves the following two steps [6]:

$CO_2 + RR'NH \leftrightarrow RR'NH^+COO^-$

$RR'NH^+COO^- \,{}^+B \leftrightarrow BH^+ + RR'NCOO^-$

where B is a base that could be an amine, OH-, or H2O.

The research paper from University of Regina[57] have stated for MEA and AMP blend "The kinetics of CO2 absorption by blended MEA-AMP solution was investigated using a laboratory wetted wall column. The experiments were carried out at 298-308K with the molar MEA:AMP mixing ratio of 1:0, 4:1, 1:1, 1:4, and 0:1. The kinetic data were presented in terms of the overall rate constant as a function of mixing ratio and temperature. It was found that an increase in MEA concentration in the blended solution causes the rate constant to increase in a nonlinear manner. And also, the rate constant increases with the absolute temperature, which follows the Arrhenius' law." Hence the optimum blend of MEA and AMP have to be established with research.In regard to the energy penalty issue, there are several promising new solvents, including advanced and activated amines and ammonia, that have potential to significantly reduce the energy requirements compared to conventional amines. This reduces both the capital and operating cost of CO_2 capture plants.

[57] Reaction rate of CO_2 in aqueous MEA-AMP solution: Experiment and modeling; by Roongrat Sakwattanapong, Adisorn Aroonwilas *, Amornvadee Veawab; Science Direct-Elsevier; Energy Procedia 1 (2009) 217–224

Potassium Carbonate is another option for carbon capture. The absorption of CO_2 into aqueous K2CO3 is commonly represented by the overall reaction

$CO_3^{2-} + H_2O + CO_2\ (aq) \leftrightarrow 2HCO_3$-This reaction is much slower than that with aqueous amines. This limits its commercial viability and application. The reaction can be augmented with in-processes removal of reaction product. It is often advantageous to add a promoter with primary solvent to enhance the absorption rate. The energy required to reverse the reaction is less than that required for amine solvents.

Also, promoted potassium carbonate solutions offer the potential for the lowest heat of absorption (10-20 kcal/gmol). Because of low heat of absorption, temperature swing regeneration is not attractive. Isothermal operation at 40 to 70 degree C with stripping at reduced pressure is a possible configuration. **New solvents**

Potassium carbonate is a relatively cheap solvent, and, hence, a permissible fraction of degradation (generally it is not generally subject to degradation.) may be tolerable at demonstration stage. While comparing with other solvents it is economic to replace in the event of contamination.

There are concerns with respect to applications of amines and ammonia as solvent. The fraction of solvents may get entrapped in flue gas in small quantity. These gaseous solvents are corrosive in nature, which impair stack refractory and pipelines made of steel.

Research is in progress for application of alternate solution for capturing CO_2 is **Piperazine (PZ) reaction:**[58]

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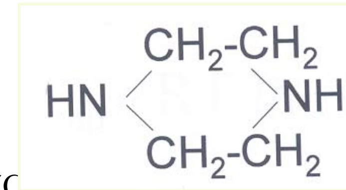
[58]Presentation in National Conference on Carbon Dioxide Capture – Challenges for Engineers, GCET, Gujarat, 6 March 2009Carbon Dioxide Capture and Sequestration: Perspectives and Research Need; Syamalendu S. Bandyopadhyay, Indian Institute of Technology, Kharagpur,

Piperazine (PZ) is a diamine



$CO_2 + PZ + H_2O \xrightleftharpoons[K_2,]{} PZCOO^- + H_3O^+$

$CO_2 + PZCOO^- + H_2O \longleftrightarrow PZ(COO^-)_2 + H_3O^+$

Table 6.3: Solvent Energy properties

	ΔH_{abs} kJ/gmol	k_2 at 25C $M^{-1}s^{-1}$	**Solvent** m
MEA	84	6e3	7
NH_3	60	0.35e3	10
PZ	84	100e3	2
MDEA	60	0.005e3	6
AMP	60	0.6e3	6
K_2CO_3	20	0.05e3	5

Based on reaction kinetics, VLE (vapour liquid equilibrium), and solvent energy properties activated MDEA, activated AMP, Chilled Ammonia and activated K2CO3 solutions have been considered appropriate for CO2 capture from power plant flue gas.

For Further work on developing new solvent formulations by research project, a bench scale and pilot plant test for new solvents is essential. A two side interaction for sharing results, between team conducting pilot project and team developing optimization and simulation models is necessary for development of process design and operation layout and flow chart. Cost-effective application of innovative amine systems will require quantitative modeling of system performance. The processes of absorption/ stripping that occur in these systems are fundamentally more complicated than in the conventional amines.

6.2.3 Advanced contactors

Blended amines have an additional degree of freedom. The chemical reaction characteristics of the blend will have non-linear relationship with varying composition. The specifications with varying composition have to establish with laboratory experimentation. More sophistication is needed in estimating equilibrium ratio and rate constants for different pressure and temperature equivalent to those occurring in thermal plant flue gas circuit.

As stated about research at University of Regina, blended amines have an additional degree of freedom i.e. blend composition specification. The reaction kinetics (equilibria and rate constants.) have to be developed with experimentation. The system design of absorption/stripping for CO2 capture will require careful tradeoffs and process optimization based on energy consumption, contactor efficiency, degradation, corrosion, and removal performance. During reaction in the reactor there are issues of gas/liquid contacting at ambient pressure, gas flow rate and high gas volumes of flue gas. The state-of-the-art technology relies upon common dumped packing as the primary means of gas/liquid contacting in a carbon steel absorber and stripper.

The advanced contactors are needed for enhanced mass transfer performance, augment reaction kinetics at a reduced capital costs. Different types of contactors and materials are used to achieve the desired pressure drop in the reactors. The limiting mechanism of mass transfer in the absorber will usually vary from diffusion with fast reaction to diffusion of reactants and products, requiring higher contact area.The stripper performance will be limited/ constrained by diffusion of reactants and products and ambient thermodynamic characteristics in the reactor. None of these stripping mechanisms has any strong dependence (transport phenomena) on gas film mass transfer. The usual reaction transport mechanism is of gas-liquid contactors interaction.The conventional contactors designed to maximize gas film mass transfer rates may not be ideal for application to CO2 capture. The Innovative dumped or structured packing designed specifically to maximize gas/liquid contact area and liquid film mass transfer coefficients at the expense of gas film mass transfer coefficients, should be good for the absorber.

Trays offer high values of the liquid film mass transfer coefficients. They may be most effective if used in the stripper where pressure drop is less critical.

6.2.4 Stripping

So far most studies in absorption/ stripping operations have been focused on absorption. There are very few studies on stripping operations. There is a need for more information in the open literature on stripping. Stripper modeling is required to quantify the performance of different solvents and process configurations under different operating conditions. Optimal stripper design is critical because the stripping energy requirement accounts for 49% of the operating cost for CO2 capture. The total energy requirement for CO2 capture and storage includes pumping of liquids (carbon dioxide) and compression of the gas to the final pressure for injection to the storage site.

These activities are the parasitic losses of the power plant. The energy required for running blowers, pumps and compressors for CCS scheme are taken from the power plant. . The steam recycling process can be optimized with simulation model. In current scheme of process flow it is condensed in the re-boiler. Stripper process modeling will provide a detailed understanding of the stripper operation and mass transfer with chemical reaction at stripper conditions. This task will assist in improved regeneration of solvent.

6.2.5 New stripper configuration

Vacuum stripper could be attractive for different solvent formulations and could help reduce the degradation of the amine and possible corrosion of equipment. The use of low-pressure steam could be advantageous in reducing energy requirements under vacuum operation.

The multi-pressure stripper, integrates the stripping and compression operations and makes use of the latent heat of the water vapor.

6.2.5.1 Ammonia process:

The system uses Ammonia as a CO2 absorber and is designed to operate with slurry. The cooled flue gas flows upwards in counter current to the slurry containing a mix of dissolved and suspended ammonium carbonate and ammonium bicarbonate. More than 90% of the CO2 from the flue gas is captured in the absorber. The clean flue gas, which now contains mainly nitrogen, excess oxygen and low concentration of CO2, flows to the stack. The process has the potential to be applied to capture CO2 from flue gases exhausted from coal-fired boilers and natural gas combined cycle (NGCC) systems, as well as a wide variety of industrial applications. ALSTOM is engaged in an extensive development ALSTOM is installing this cutting edge technology in the Pleasant Prairie Power Plant owned and operated by We Energies. The project will remain operational for at least one year during which the EPRI will conduct an extensive test program to collect data and evaluate technology performance.

6.2.5.2 Solid Sorbent

6.2.5.2.(i) Membrane Separation:

There are polymeric and ceramic porous membranes that selectively separate CO_2 in flue gas/ gas stream, using differences in the size or permeating rate of substances. The membrane separation process for separating carbon dioxide from the flue gas is designed with a polymeric membrane. The diffusion of CO2 through polymeric membranes is driven by pressure and concentration of CO2 across the membrane wall. The diffused CO2 is captured by flowing amine fluids. The main constraint is high cost of membranes, supporting structure of membrane, low CO_2 recovery rate, and high-pressure requirement for separation.

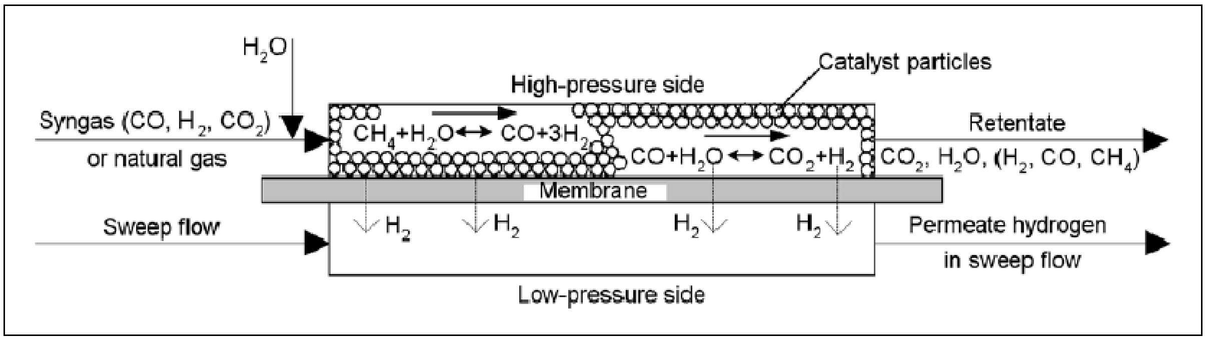


Figure 6.3: Membrane Use in IGCC Process

Figure 6.3 indicates the membrane use in IGCC process where H2 is being permeated through membrane pores. The diffused hydrogen is swept away for subsequent combustion**.** Separating CO_2 from H_2 in pre-combustion syngas has to take precaution as the gases are already hot and pressurized. Los Alamos National Laboratory (LANL), USA led team are developing polybenzimidazolebased membranes. There are progress in ion transport membranes, and these researches are focused on application in oxygen technology. The primary challenge of the technology is in choking of the membrane. Clean gas input to the membrane surface has to be ensured. Considering heavy duty environment R& D should focus on developing durable, high performing CO_2 selective membranes for flue gas applications

6.2.5.2.(ii) Physical Adsorption:[59]

Carbon dioxide can be separated from flue gas with a variety of non-reactive sorbents. Some materials, which have porous structure, are used for capture. They can be induced to retain CO_2,

[59]http://web.mit.edu/mitei/docs/reports/herzog-meldon-hatton.pdf

which can be recovered by changing pressure and/or temperature. These include zeolites, activated carbon and alumina; there are technical challenges of scalability, CO_2 adsorption and separation.

Activated carbon and charcoal have high porosity with CO2 capture capacities of 10-15% by weight. Their CO2/N2 selectivity are relatively low.

Zeolitic materials, on the other hand, offer CO2/N2 selectivities 5-10 times greater than activated carbon materials. Their CO2 capacities are 2-3 times lower. The zeolite performance is impaired in presence of water vapor.

There are three separate processes (a) Pressure Swing Adsorption (PSA), (b) Temperature Swing Adsorption (TSA), and (c) Pressure and Temperature Swing Adsorption (PTSA). These are a series of reactor packed with adsorbents. The gas stream is passed through these reactor alternately to facilitate adsorption and desorption (regeneration of adsorbent) by altering thermodynamic condition. Some of the reactive solids are (a) CaO (b) Na2CO3 (c) NaOH/CaO (d) Li2O/Li2ZrO3 (e) Li4SiO4.

Another process under development is isothermal Electrical Swing Adsorption (IESA) process. The adsorption media selected are to be electrically conductive such that when a power supply is applied across the matrix, a current passes through the matrix, with a resulting desorption of the adsorbed component.

R&D should focus on understanding behavioral characteristics of the materials such that current scheme can be scaled up to be incorporated in the large industrial unit. From the current observation the scheme will need large space.

6.2.5.2.(iii) Biomimetic sequestration of CO2

There have been several exploratory studies of the use of the enzyme carbonic anhydrase, which is one the most efficient catalyst of CO2 reaction with water, to produce carbonate ions to promote CO2 scrubbing from flue gases. The aims to mimic the reaction for fixation of anthropogenic CO_2 into calcium carbonate using carbonic anhydrase (CA) as a biocatalyst. NEERI, India team is doing R&D on biomimetics[60] to stabilize and immobilize the enzymes or alternately use a combination of both these approaches to achieve sequestration reaction at a satisfactory level.

They have studied nearly 36 materials belonging to the class of chitosan, mesoporous silicates/carbons. Bioceramic materials have been designed for immobilization of Bacillus Pumilus and CA. PNA assay has been used as diagnostic tool for assessing/estimating activity of immobilsed microbes/CA. The materials were also screened for immobilization of pure and crude extract of CA. Based on the esterase activity, 13 materials have been selected for further studies, out of which four materials belonging to the category of bioceramics are being investigated, considering the novelty of their properties and very promising results. In addition, new hierarchical mesoporous materials are also showing very promising results.

A unique protocol for the synthesis of single enzyme nanoparticles (SENs) has been developed for CA to stabilize the enzyme activity by encapsulating each enzyme molecule with a hybrid organic/inorganic polymer network.

Department of Science and Technology has sponsored R&D on Microalgae systems. The micro-algae are especially attractive because they consume CO2 in surrounding by photosynthesis. The micro-algae can provide bio-fuel (carbon-neutral fuel). The algae biomass can serve as animal feed.

6.2.5.2.(iv) Cryogenic Distillation:

The conventional process is of compression and cooling gas separated by distillation. This will be economic, provided concentration of CO2 is high as envisaged in oxy-fuel combustion. The CO2 under normal condition liquefies at -50 degree centigrade, and LNG process liquefaction

[60] Dr. Sadhana Rayulu; Molecularly Engineered Materials for Carbon Sequestration; NEERI, Nagpur

takes place at -162 degree centigrade. LNG (-160°C) during re-gasification phase is a potential cryogenic medium for liquefaction of CO2. These can be used in coast based power plants having proximity to re-gasification plant. These researches are being pursued.

6.3. Carbon Transport

Transport is that stage of carbon capture and storage that links sources and storage sites. The beginning and end of 'transport' may be defined administratively. 'Transport' is covered by the regulatory framework concerned for public safety that governs pipelines and shipping. CO_2 is transported in three states: gas, liquid and solid. Commercial-scale liquid transport scheme uses tankers, pipelines and ships for gaseous and liquid carbon dioxide. Gas transported at close to atmospheric pressure occupies such a large volume that very large facilities are needed. Gas occupies less volume if it is compressed, and compressed gas is transported by pipeline. Volume can be further reduced by liquefaction, solidification or hydration. Liquefaction is an established technology for gas transport by ship similar to LNG. Solidification needs much more energy compared with other options, and is inferior from a cost and energy viewpoint. Each of the commercially viable technologies is currently used to transport carbon dioxide.

Research and development on a natural gas hydrate carrying system intended to replace LNG systems is in progress, and the results might be applied to CO_2 ship transport in the future. In pipeline transportation, the volume is reduced by transporting at a high pressure: this is routinely done in gas pipelines, where operating pressures are between 10 and 20 MPa.

A transportation infrastructure that carries carbon dioxide in large enough quantities to make a significant contribution to climate change mitigation will require a large network of pipelines. As growth continues it may become more difficult in the context of long-distance movement of large quantities of carbon dioxide, pipeline transport is part of current practice. Pipelines routinely carry large volumes of natural gas, oil, condensate and water over distances of thousands of kilometres, both on land and in the sea. Pipelines are laid in deserts, mountain ranges, heavily- populated areas, farmland and the open range, in the Arctic and sub-Arctic, and in seas and oceans up to 2200 m deep.

The most preferred way of transportation of CO2 from capture points to storage location is by pipeline. There is uncertainty around future pathways for CO2 pipeline locating / laying of pipeline. The research should pertain to optimize CO2 transport costs through clustering sources and sinks; planning and developing pipeline networks similar to natural gas; and introducing new, lighter pipeline materials and advanced CO2 compression technologies. Critical issues are:

(1) Design of network;

(2) Pipeline material and segment connectivity;

(3) Compressor at the source and booster station;

(4) Leak remediation techniques;

(5) Purity of CO2 stream;

(6) Interstate transport of CO2;

(7) Environment impact assessment;

(8) Infrastructure design if it is to be transported by ship.

As there is interstate transport, loading in ship, storing at geological site, the Regulatory frameworks also need to be adapted to existing legal and regulatory scheme. Currently India has expertise on natural gas transport; GAIL and RIL have their gas network. In the natural gas network the booster station works with natural gas energy. The CO2 pipeline also needs booster station to compensate pressure drop in the pipeline. The compressors of booster station will need electrical power for drive. Hence the CO2 pipeline may preferably be aligned with power transmission line. IEA has projected CO2 pipeline requirement world wide for CCS which is indicated in Table 6.4.

It is a accepted fact that the transportation of CO_2 via pipeline can be done efficiently in supercritical fluid state by compressing and cooling the CO2. At supercritical state, where the density resembles liquid but it expands to fill space like a gas. Supercritical CO2 fluid in USA is also identified as a commodity, for use in many industrial processes. The technology has been developed in United States, and has large network of CO2 transport pipelines. Transportation at gaseous state is inefficient and large diameter pipeline will be needed. The supercritical fluid state for CO2 occurs at conditions greater than the supercritical pressure and temperature- 7.38 MPa (73.8 bar) and approximately 31°Centigrade.

Table 6.4[61] Requirement of CO_2 Pipelines

Region	Total CO2 pipeline 2020	Total Length in 2020 (km)	Total Pipeline investments 2010-2020 (US$ bn)	Total CO2 pipeline 2050	Total Length in 2050 (km)	Total Pipeline investments 2010-2050 (US$ bn)
OECD NA	25 -30	2800 - 3500	5.5	250 -450	38000 - 65000	160
OECD Europe	10-15	1200-1600	1.8	125 -220	20000 - 35000	70
OECD Pacific	5-7	700-850	0.8	110 -200	20000 - 35000	70
China & India	17-20	2100-2700	3	360-660	55000-10000	275
Other Non - OECD	20-25	3900-3700	3.8	460-840	70000-130000	250
World	77-97	10700 - 12350	14.9	1305-2370	20000 - 361000	825

[61]Technology Roadmap; Carbon capture and storage, IEA document

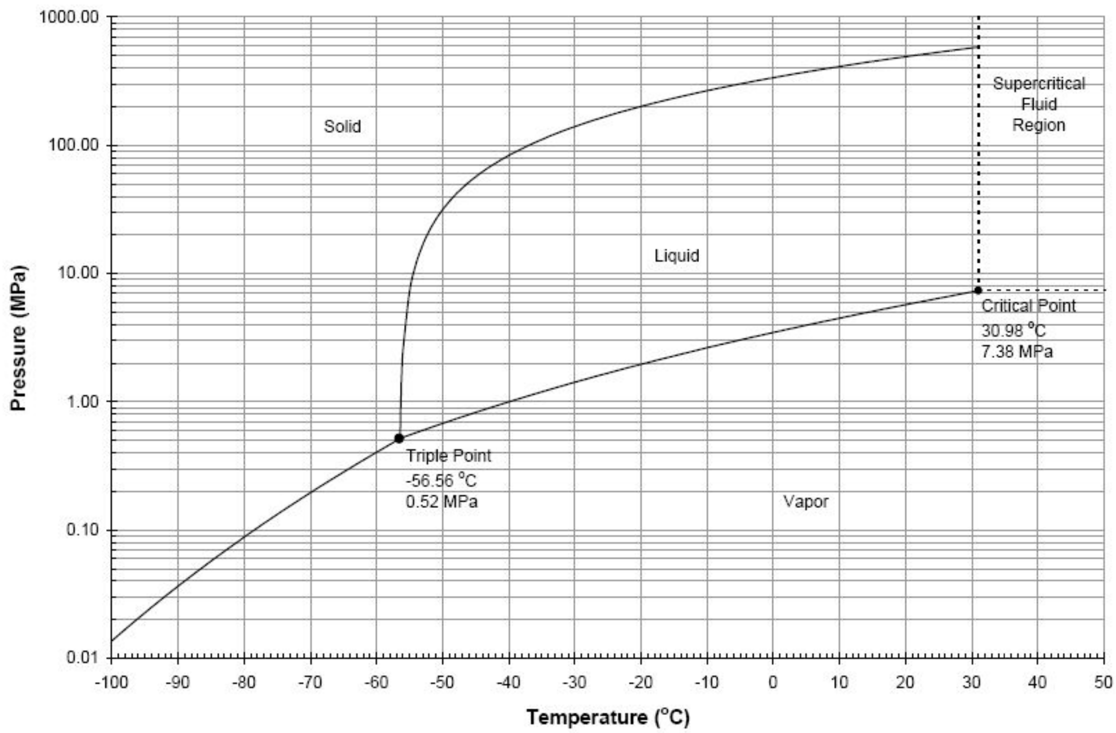
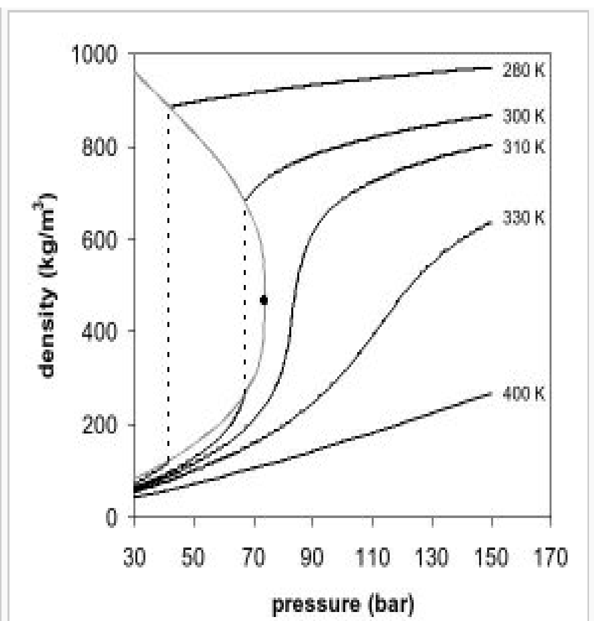
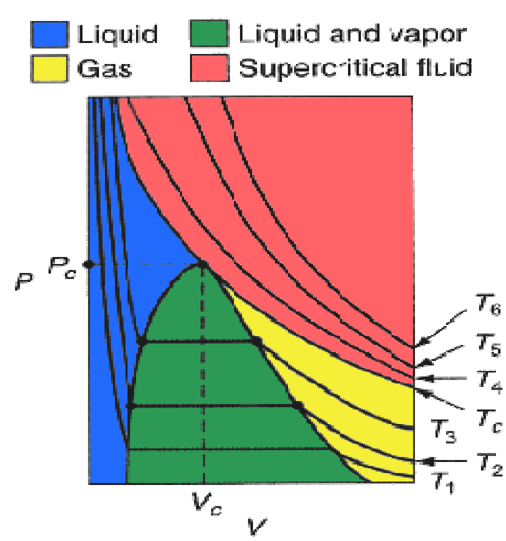


Figure 6.4: Temperature and pressure requirement for CO_2 transport by Pipelines





The compressed Carbon dioxide can be transported to geologic formations such as depleted oil and gas fields and deep saline aquifers efficiently. For engineering of pipeline for transport of CO2 supercritical state, pipeline operators recommend that the CO2 pressure not to be allowed to drop below 10.3 MPa at the outlet (near geological site and booster station) of the pipeline to avoid risk of two phase flow (Gas & liquid). At this state the fluid have an improved combination of vapor and liquid properties that is low viscosities and high diffusivities associated with supercritical fluids. The characteristics of CO2 supercritical fluid is (i) Critical Temperature in Kelvin, 304.2 (ii) critical Pressure in bar (atmosphere) 73.8 (iii) Vapor Pressure at 20 degree C in bar 57.258 (iv) CO2 gas Density Kg/m^3 (at 0 degree C) 1.9767 (v) Critical Density is 468 Kg/ m^3. The 304 degree Kelvin is equivalent to 31 degrees centigrade, which is approximately room temperature. The fluids CO2 are compressible and homogeneous. Their solvating strength of fluid can range from ideal gas to almost pure liquid that is more than in liquid state. There are issues of purity of CO2 used for transport. Some stakeholders have advocated for setting a CO2 purity standard of more than 90 percent, but many feel that there is enough uncertainty regarding the precise composition of the CO2 stream, therefore it is best to simply design projects with materials and procedures that account for any co-constituents in the gas stream.[62] The similar characteristics are preferable for underground storage, and due to these, the lower probabilities of risks are envisaged according to current state of knowledge.

Captured CO2 may contain impurities like water vapor, H2S, N2, methane (CH4), O2, mercury, and hydrocarbons that may require specific processing. Before transport, the CO2 is dehydrated to levels below 50 ppm of water. CO2 reacts with water to form carbonic acid, which corrodes the pipeline. H2S is toxic gas. Dehydration is particularly important in these cases, because H2S reacts with water to form sulfuric acid, which is highly corrosive and may also result in pipeline

[62] *Guidelines for Carbon Dioxide Capture, Transport, and Storage, WRI Report*

cracking, increasing the potential for leaks. CCS facilities in Canada have been storing H2S with CO2 through injection in geologic formations since 1989. The presence of CH4 affects the exhibited vapor pressure of CO2 and complicates the accurate prediction of flow. In EOR applications, in particular where organic materials are present for bacteria, oxygen is tolerable only in minute quantities (10 ppm). Even in deep saline formations organics elements may be present, and significant quantities of oxygen in the gas stream could allow for formation of bacterial colonies, affecting the injection operations. For pipeline design purposes, purity desired of captured gases is defined. USA pipeline standards are defined based on purity standard of CO2 stream. The purity standard for enhanced oil recovery may be different. Hence pipeline design should consider purity of gas, and nature of storage site. CO2 pipelines in USA operate at higher pressure than Natural gas transport. CO2 pipelines are constructed specifically for transporting CO2 and are normally listed as either Type II or Type III pipelines. Acceptable CO2 and co-constituent concentrations for both pipeline types are shown in the table 6.5

Table 6.5[63]: Acceptable CO2 and co-constituent concentrations

Parameter	Type I	Type II	Type III
CO2—% by volume	>95%	>95%	>96%
H2S—ppmbw	<10	<20	<10,000
Sulphur—ppmbw	<35	<30	-
Total hydrocarbons—% by volume	<5	<5	-
CH4—% by volume	-	-	<0.7
C2 + hydrocarbons—% by volume	-	-	<23,000
N2—% by volume/weight	<4	<4	<300
CO—% by volume	-	-	<1,000
O2—ppm by weight/volume	<10	<10	<50

[63] *Source: WRI Report*

H_2O—#/mmcf* or ppm by volume**	<25*	<30*	<20**
C_2 = carbon; CH_4 = methane; CO = carbon monoxide; CO_2 = carbon dioxide; H_2O = water; H_2S = hydrogen sulfide; mmcf = millions of cubic feet; N_2 = nitrogen; ppm = parts per million; O_2 = oxygen; ppmbw = ppm by weight			

The majority of the CO2 pipelines in North America can be listed as Type II pipelines, which serve multiple sources and user lines and have a strictly limited composition. Less common Type III pipelines have relaxed composition standards when compared to Type II pipelines.

The potential storage sinks of CO2 have to be matched with the large emission point sources. It has to be ascertained whether the implementation of this technology is feasible by creating

TheProductdeliveredbySellerorSeller'srepresentativetoBuyerattheCanyonReefCarriersDeliveryMetershallmeetthe following specifications, which herein are collectively called 'Quality Specifications'

6.3.1 Specimen CO_2 quality specifications:

(a) **Carbon Dioxide**. Product shall contain at least ninety-five mole percent (95%) of Carbon Dioxide as measured at the SACROC delivery meter.

(b) **Water.** Product shall contain no free water, and shall not contain more than 0.48 9 m^{-3} in the vapour phase.

(c) **Hydrogen Sulphide.** Product shall not contain more than fifteen hundred (1500) parts per million, by weight, of hydrogen sulphide.

(d) **Total Sulphur.** Product shall not contain more than fourteen hundred and fifty(1450) parts per million, by weight, of total sulphur.

(e) **Temperature.** Product shall not exceed a temperature of 48.9^{o}C.

(f) **Nitrogen.** Product shall not contain more than four mole percent (4%) of nitrogen.

(g) **Hydrocarbons.** Product shall not contain more than five mole percent (5%) of hydrocarbons and the dew point of Product (with respect to such hydrocarbons) shall not exceed –28.9^{o}C.

(h) **Oxygen.** Product shall not contain more than ten (10) parts per million, by weight, of oxygen.

(i) **Glycol.** Product shall not contain more than 4 x 10^{-5} Lm^{-3} of glycol and at no time shall such glycol be present in a liquid state at the pressure and temperature conditions of the pipeline.

The captured CO2 would have to be transported from the power plant to a storage injection site. The initial activity is to identify potential CO2 storage site, their capacities and distances from the capture plant. The preferred storage site in the pilot and demonstration stage should be depleted oil and gas fields, so that some revenue can be earned and project can be self sustaining. The next stage would be to identify how the CO2 could be transported to the storage sites. Economically feasible techniques for large scale transportation of CO2 could include pipelines and ships. For laying pipelines, technically feasible and safe routes should be identified and barriers to obtaining rights of way and public acceptance should be considered. Pipelines have large economies of scale, so the proximity to other potential sources of captured CO2 should be reviewed. For ships, the feasibility, safety and acceptability of on-shore CO2 buffer storage and ship loading and unloading facilities should be assessed. The engineering and design of transport infrastructure has to be developed with model based analysis. Some of the preliminary factors of consideration are

- Capacity of carbon capture and separation units at power station
- Location of storage site.

- Optimum linkage path between emission site and storage site aligned with power grid and natural gas grid.
- Booster Pump to compensate pressure loss.
- Safety system for transportation scheme for (i) discontinuous operation of pipeline during pilot and demonstration phase (ii) CO2 storage tank at emission and storage site.

Assessment on health and safety issues related to CO2 compression and high pressure CO2 transportation is essential. IEA report indicate CO2 compression plant for compressing CO2 to a pressure of about 110 bar for transport via pipelines.

Another key element in determining the cost of CCS is the cost of transport of CO2 once captured, to a suitable sink (aquifer, oil-field, gas field or coal-field), and bye product recovered from total technical scheme.

The pipeline length have to be computed in segments to align with booster pump, geographical profile, and design capacity of CO2 mass flow will be used to compute pipe diameter. The pipeline is modelled as a series of pipe segments located between booster pumping stations. Based on the input information to the transport model, the required pipeline diameter for each segment is calculated. The pipeline segment diameter is calculated from a mechanical energy balance on the flowing CO2. The energy balance is simplified by approximating supercritical CO2 as an incompressible fluid and the pipeline flow and pumping processes as isothermal. Booster pumping stations may be required for longer pipeline distances or for pipelines in mountainous or hilly regions. Additionally, the use of booster pumping stations may allow a smaller pipe diameter to be used, reducing the cost of CO2 transport. The pumping station size is also developed from an energy balance on the flowing CO2 in a manner similar to the calculation of the pipe segment diameter. Both the pumping station size and pipeline diameter are calculated on the basis of the design mass flow rate of CO2.

The pumping station size is required to determine the capital cost of the pump, while the pumping station annual power requirement is required to calculate the variable operating and maintenance cost. The capital cost of a CO2 pumping station has been estimated by the IEA for a study involving the pipeline transmission of CO2 .CO2 transport via pipelines to the storage location, including safe transportability and considerations on shared CO2 pipelines (or) ship transport for coastal sites.

Table 6.6[64]: Existing long-distance CO_2 pipelines (Gale and Davison, 2002) and CO_2 pipelines in North America

Pipeline	Location	Operator	Capacity	Length	Year finished	Origin of CO_2
Cortez	USA	Kinder Morgan	19.3	808	1984	McElmo Dome
Sheep Mountain	USA	BP Amoco	9.5	660	-	Sheep Mountain
Bravo	USA	BP Amoco	7.3	350	1984	Bravo Dome
Canyon Reef Carriers	USA	Kinder Morgan	5.2	225	1972	Gasification plants
Val Verde	USA	Petrosource	2.5	130	1998	Val Verde Gas Plants
Bati Raman	Turkey	Turkish Petroleum	1.1	90	1983	Dodan Field
Weyburn	USA &Canada	North Dakota	5	328	2000	Gasification Plant
Total			49.9	2591		

In view of above observations following data for pipelines and transmissions lines are needed for adapting a possible infrastructure of CO2-pipelines to the existing infrastructure (i) Major oil pipeline (ii) Major natural gas pipeline (iii) High voltage transmission line with a voltage of at least 220 Kilovolt (kV) and a carrying capacity of at least 200 MVA

[64]*Source: (CourtesyofOilandGas Journal).*

Table 6.7: Data for pipelines and transmissions

Planning Transportation Network	
Engineering and Design Inputs	Max CO2 Flow Rate
	CO2 pressure at Inlet
	CO2 Volume at Inlet
	Environment Temperature
	Temperature of Super - critical Liquid
	Elevation Change
	Roughness of Pipe material
	CO2 Density
	CO2 Liquid viscosity
	Pressure Drop in pipeline per unit length
	Reynolds Number
	Friction Factor
	CO2 outlet pressure
	Pipeline Length
Equipment Planning	Pump Size
	Pipeline Segmentation
	Number of Pumps required
	Pump Pressure Ratio
	Pump Efficiency curve
	Capacity Factor
	Pumping power required
	CO2 Storage Tank specification
Economic Analysis	Total Capital Cost

	Total Operation & Maintenance Cost
	Total Annual Cost
	Cost of Transportation (per ton of CO_2
	Energy Cost
	Capital Charge Rate

Handling of supercritical CO_2 presents engineering issues. Available pipeline gaskets lose their elastic properties, and hydrocarbon lubricants become infective when subjected to supercritical CO_2. CO_2 in the presence of moisture can produce carbonic acid, which can corrode carbon steel used in oil and natural gas pipelines. Thus, the CO_2 should be relatively dry before transport, and appropriate design measures must be taken to ensure that the pipeline and compressor materials are suited to handling supercritical CO_2.

The preliminary task of transportation is compression of CO_2 in gaseous phase to super-critical state. This is one of the areas where a significant amount of energy is consumed, and R&D is needed to optimize energy consumption of primary compressor at the source and subsequent booster station. There is a need of compression enabling technology to compress CO_2 from a Pulverized Coal fired (PC) , Oxy-Fuel, or IGCC power plant, cost-effectively minimizing the financial impact of CO_2 sequestration.[65] The research on compression and transmission was conducted by Southwest Research Institute, San Antonio, TX. Their observation was

(i) Identified that up to 35% power savings can be achieved over a conventional CO_2 compression solution;

[65] *http://ww0w.nist.gov/eeel/high_megawatt/upload/6_1-Approved-Moore.pdf Research and Development Needs for Advanced Compression of Large Volumes of Carbon Dioxide , J. Jeffrey Moore, et al ; Southwest Research Institute, San Antonio, TX*

(ii) The thermodynamic process is more important than compressor efficiency;

(iii) The internally-cooled compressor concept should result in significant capital savings over an integrally geared compressor;

(iv) Liquefaction and pumping equipment will add some additional capital expense, but some is offset by lower cost pump compared to high-pressure compressor.

6.3.2 Design of a pipeline

The physical, environmental and social factors that determine the design of a pipeline are summarized in a design basis, which then forms the input for the conceptual design. This includes a system definition for the preliminary route and design aspects for cost-estimating and concept-definition purposes. It is also necessary to consider the process data defining the physical characteristics of product mixture transported, the optimal sizing and pressures for the pipeline, and the mechanical design, such as operating, valves, pumps, compressors, seals, etc. The topography of the pipeline right-of-way must be examined. Topography may include mountains, deserts, river and stream crossings, and for offshore pipelines, the differing challenges of very deep or shallow water, and uneven seabed. It is also important to include geotechnical considerations. For example, is this pipeline to be constructed on thin soil over laying granite? The local environmental data needs to be included, as well as the annual variation in temperature during operation and during construction, potentially unstable slopes, frost heave and seismic activity. Also included are water depth, sea currents, permafrost, ice gouging in Arctic seas, biological growth, aquifers, and other environmental considerations such as protected habitats. The extent of challenges is how the pipeline will accommodate existing and future infrastructure – road, rail, pipeline crossings, military/governmental restrictions and the possible impact of other activities– as well as shipping lanes, rural or urban settings, fishing restrictions, and conflicting uses such as dredging. Finally, this integrated study will serve as the basis for a safety review.

6.3.2.1 Conceptual design

The conceptual design includes the following components:

- Mechanical design: follows standard procedures, described in detail in (Palmer et al., 2004).
- Stability design: standard method sand software are used to perform stability calculations, offshore (Veritec, 1988) or onshore, though the offshore methods have been questioned. New guidelines for stability will be published in 2005 by DetNorskeVeritasandwillbedesignatedDNV-RP-F109 On-Bottom Stability;
- Protection against corrosion: a well-understood subject of which the application to CO_2 pipelines is described below.

Trenching and backfilling: onshore lines are usually buried to depth of 1m. Offshore lines are almost always buried in shallow water. In deeper waters pipelines narrower than 400 mm are trenched and sometimes buried to protect them against damage by fishing gear.

- CO_2 pipelines may be more subject to longitudinal running fracture than hydrocarbon gas pipelines. Fracture arresters are installed at intervals of about 500 m.

In the design of the SACROC CO_2pipeline the transportation options examined were:

(i) Allow pressure CO_2 gas pipeline operating at a maximum pressure of 4.8 MPa;

(ii) A high-pressure CO_2 gas pipeline operating at a minimum pressureof9.6 MPa, so that the gas would remaining dense phase state at all temperatures;

(iii) A refrigerated liquid CO_2pipeline;

(iv) Road tank trucks;

(v) Rail tankers, possibly in combination with road tank trucks.

The tank truck and rail options cost more than twice as much as a pipeline. The refrigerated pipeline was rejected because of cost and technical difficulties with liquefaction. The dense phase (Option ii) was 20% cheaper than a low-pressure CO_2 gas pipeline (Option). The intermediate 4.8 to 9.6 MPa pressure range was avoided so that two-phase flow would not occur. An added advantage of dense-phase transport was that high delivery pressures were required for CO_2 injection.

The final design conforms to the ANSIB31.8 code for gas pipelines and to the DOT regulations applicable at the time. The main 290 km section is 406.4 mm (16 inch) outside diameter and 9.53 mm wall thickness made from grade X65 pipe (specified minimum yield stress of 448 MPa). A shorter 60km section is 323.85 mm (12.75 inch) outside diameter, 8.74 mm wall thickness, grade X65. Tests showed that dry CO_2 would notcorrodethepipelinesteel;304L corrosion-resistant alloy was used for short sections upstream of the glycol dehydrator. The line is buried to a minimum of 0.9 m, and any point on the line is within 16 km of a block valve.

There are six compressor stations, totalling 60MW, including a station at the SACROC delivery point. The compressor stations are not equally spaced and the longest distance between two stations is about 160km. This is consistent with general practice, but some long pipelines have 400km or more between compressor stations.

Significant nitrogen and oxygen components in CO_2would shift the boundary of the two-phase region towards higher pressures, and would require a higher operating pressure to avoid two-phase flow.

6.3.2.2 Construction of land pipelines

Construction planning can begin either before or after rights of way are secured, but a decision to construct will not come before a legal right to construct a pipeline is secured and all governmental regulations met. Onshore and underwater CO_2 pipelines are constructed in the same way as hydrocarbon pipelines, and for both there is an established and well- understood base of engineering experience. Subsection 6.3.5 describes underwater construction.

The construction phases of a land pipeline are outlined below. Some of the operations can take place concurrently.

Environmental and social factors may influence the season of the year in which construction takes place. The land is cleared and the trench excavated. The longest lead items come first: urban areas, river and road crossings. Pipe is received into the pipe yard and welded into double joints (24 m long); transported to staging areas for placement along the pipe route, welded, tested, coated and wrapped, and then lowered into the trench. A hydro static test is carried out, and the line is dried. The trench is then back filled, and the land and the vegetation restored.

6.3.2.3 Underwater pipelines

Most under water pipelines are constructed by the lay-barge method, in which 12 or 24 m lengths of pipe are brought to a dynamically positioned or anchored barge, and welded one by one to the end of the pipeline. The barge moves slowly forward, and the pipeline leaves the barge over the stern, and passes first over a support structure ('stinger') and then down through the water in a suspended span, until it reaches the seabed. Some lines upto 450 mm diameter are constructed by the reel method, in which the pipeline is welded together on shore, wound onto a reel on a ship, and then unwound from the reel into its final position. Some short lines and lines for shore crossings in shallow water are constructed by various tow and pull methods, in which the line is welded together onshore and then pulled into its final location.

If the design requires that the pipeline be trenched, that is usually done after it has been laid on the seabed, by a jetting sled, a plough or a mechanical cutting device that is pulled along the line. On the other hand, inshore crossings and in very shallow water the trench is often excavated before the pipeline is laid, and that is done by dredgers, back hoes or draglines in soft sediments, or in rock by blasting followed by clamshell excavators. Many shore crossings are drilled horizontally from the shore; this procedure eliminates many uncertainties associated with the surf zone, and reduces the environmental impact of construction.

Underwater connections are made by various kinds of mechanical connection systems, by hyperbaric welding (in air under the local hydrostatic pressure) or by lifting the pipe end above the surface, welding them together and lowering the connected line to the bottom. These technologies are established and understood (Palmer and King, 2004). Underwater pipelines up to 1422 mm in diameter have been constructed in many different environments, and pipelines have been laid in depths upto 2200m. Figure 6.2 plots the diameters and maximum depths of major deepwater pipelines constructed up to 2004.The difficulty of construction is roughly proportional to the depth multiplied by the diameter, and the maximum value of that product has multiplied four fold since 1980. Still larger and deeper pipelines are technically feasible with today's technology.

6.3.2.4 Operations

Operational aspects of pipelines are divided into three areas: daily operations, maintenance, and health, safety and environment. Operations of a CO_2 pipeline in the USA, for instance, must follow federal operations guidelines (49CFR195). Overall operational considerations include training, inspections, safety integration, signs and pipeline markers, public education, damage prevention programmes, communication, facility security and leak detection. Pipelines outside the USA generally have similar regulatory operational requirements.

Personnel form a central part of operations and must be qualified. Personnel are required to be continuously trained and updated on safety procedures, including safety procedures that apply to contractors working on or near the pipeline, as well as to the public.

Operations include daily maintenance scheduled planning and policies for inspecting, maintaining and repairing all equipment on the line and the pipeline itself, as well as supporting the line and pipeline. This equipment and support includes valves, compressors, pumps, tanks, rights of way, public signs and line markers as well as periodic pipeline flyovers.

Long-distance pipelines are instrumented at intervals so that the flow can be monitored. The monitoring points, compressor stations and block valves are tied back to a central operations centre. Computers control much of the operation, and manual intervention is necessary only in unusual upsets or emergency conditions. The system has in built redundancies to prevent loss of operational capability if a component fails.

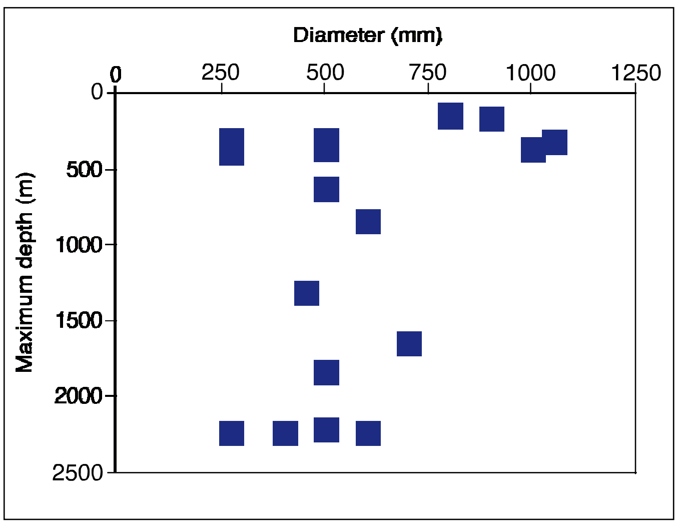


Figure 6.5: Preferred pipeline diameter at various depth

Pipelines are cleaned and inspected by ‘pigs’, piston-like devices driven along the line by the gas pressure. Pigs have reached a high level of sophistication, and can measure internal corrosion, mechanical deformation, external corrosion, the precise position of the line, and the development of spans in underwater lines. Further functionality will develop as pig technology evolves, and there is no reason why pigs used for hydrocarbon pipelines should not be used for carbon dioxide.

Pipelines are also monitored externally. Land pipelines are inspected from the air, at intervals agreed between the operator and the regulatory authorities. Inspection from the air detects unauthorized excavation or construction before damage occurs. Currently, underwater pipelines are monitored by remotely operated vehicles, small unmanned submersibles that move along the line and make video records, and in the future, by autonomous underwater vehicles that do not need to be connected to a mother ship by a cable. Some pipelines have independent leak detection systems that find leaks acoustically or by measuring chemical releases, or by picking up pressure changes or small changes in mass balance. This technology is available and routine.

6.3.3 Ships for CO2 transportation

6.3.3.1 Marine transportation system

Carbon dioxide is continuously capture dat the plant on land, but the cycle of ship transport is discrete, and so a marine transportation system includes temporary storage on land and a loading facility. The capacity, service speed, number of ships and shipping schedule will be planned, taking into consideration, the capture rate of CO_2 transport distance, and social and technical restrictions. This issue is, ofcourse, not specific to the case of CO_2 transport; CO_2 transportation by ship has a number of similarities to liquefied petroleum gas(LPG) transportation by ship.

What happens at the delivery point depends on the CO_2 storage system. If the delivery point is onshore, the $CO_2$is unloaded from the ships into temporary storage tanks. If the delivery point is offshore–as in the ocean storage option–ships might unload to a platform, to a floating storage facility (similar to a floating production and storage facility routinely applied to offshore petroleum production), to a single-buoy mooring or directly to a storage system.

6.3.3.2 Existing experience

The use of ships for transporting CO_2 across the sea is today in an embryonic stage. Worldwide there are only four small ships used for this purpose. These ships transport liquefied food- grade CO_2 from large point sources of concentrated carbon dioxide such as ammonia plants in northern Europe to coastal distribution terminals in the consuming regions. From these distribution terminals CO_2 is transported to the customers either by tanker trucks or in pressurized cylinders. Design work is ongoing in Norway and Japan for larger CO_2 ships and their associated liquefaction and intermediate storage facilities.

6.3.3.3 Design

For the design of hull and tank structure of liquid gas transport ships, such as LPG carriers and LNG carriers, the International Maritime Organization adopted the International Gas Carrier Code in order to prevent the significant secondary damage from accidental damage to ships. CO_2 tankers are designed and constructed under this code.

There are three types of tank structure for liquid gas transport ships:

- Pressure type;
- Low temperature type; and
- Semi-refrigerated type.

The pressure type is designed to prevent the cargo gas from boiling under ambient air conditions. On the other hand, the low temperature type is designed to operate at a sufficiently low temperature to keep cargo gas as a liquid under the atmospheric pressure. Most small gas carriers are pressure type, and large LPG and LNG carriers are of the low temperature type.

The low temperature type is suitable form as transport because the tank size restriction is not severe. The semi-refrigerated type, including the existing CO_2 carriers, is designed taking into consideration the combined conditions of temperature and pressure necessary for cargo gas to be kept as a liquid.

Some tankers such as semi-refrigerated LPG carriers are designed for applicability to the range of cargo conditions between normal temperature/high pressure and low temperature/atmospheric pressure.

At atmospheric pressure, CO_2 is in gas or solid phase, depending on the temperature. Lowering the temperature at atmospheric pressure cannot by itself cause CO_2 to liquefy, but only to make so-called 'dry ice' or solid CO_2. Liquid CO_2 can only exist at a combination of low temperature and pressures well above atmospheric pressure. Hence, a CO_2 cargo tank should be of the pressure-type or semi-refrigerated. The semi-refrigerated type is preferred by ship designers, and the design point of the cargo tankwouldbearound–54ºC per 6 barto–50ºC per7bar,which is near the point of CO_2.In a standard design, semi-refrigerated type LPG carriers operate at a design point of –50°C and 7 bar, when transporting a volume of 22,000 m^3.

Carbon dioxide could leak into the atmosphere during transportation. The total loss to the atmosphere from ships is between 3 and 4% per 1000 km, counting both boil-off and exhaust from the ship's engines; both components could be reduced by capture and liquefaction, and recapture on shore would reduce the loss to 1 to 2% per 1000 km.

6.3.3.4 Construction

Carbon dioxide tankers are constructed using the same technology as existing liquefied gas carriers. The latest LNG carriers reach more than 200,000m^3capacity. (Such a vessel couldcarry230ktofliquidCO_2).The same type of yards that today build LPG and LNG ship scan carry out the construction of a CO_2 tanker. The actual building time will be from one to two years, depending on considerations such as the ship's size.

6.3.4 Operation

6.3.4.1 Loading

Liquid CO_2 is charged from the temporary storage tank to the cargo tank with pumps adapted for high pressure and low temperature CO_2 service. The cargo tanks are first filled and pressurized with gaseous CO_2 to prevent contamination by humid air and the formation of dry ice.

6.3.4.2 Transport to the site

Heat transfer from the environment through the wall of the cargo tank will boil CO_2 and raise the pressure in the tank. It is not dangerous to discharge the CO_2 boil-off gas together with the exhaust gas from the ship's engines, but doing so does, ofcourse, release CO_2 to the air. The objective of zero CO_2 emissions during the process of capture and storage can be achieved by using a refrigeration unit to capture and liquefy boil-off and exhaust CO_2.

6.3.4.3 Unloading

Liquid CO_2 is unloaded at the destination site. The volume occupied by liquid CO_2 in the cargo tanks is replaced with dry gaseous CO_2, so that humid air does not contaminate the tanks. This CO_2 could be recycled and re liquefied when the tankis refilled.

6.3.4.4 Risk, safety and monitoring

There are calculable and perceivable risks for any transportation option. We are not considering perceivable risks because this is beyond the scope of the document. Risks in special cases such as military conflicts and terrorist actions have now been investigated. Atleast two conference son pipeline safety and security have taken place, and additional conferences and workshops are planned. However, it is unlikely that these will lead to peer-reviewed journal articles because of the sensitivity of the issue.

Pipelines and marine transportation systems have an established and good safety record. Comparison of CO_2 systems with these existing systems for long-distance pipeline transportation of gas and oil or with marine transportation of oil, yields that risks should be comparable in term so failure and accident rates. For the existing transport system these incidents seem to be perceived by the broad community as acceptable in spite of occasional serious pollution incidents such as the *Exxon Valde s*and *Torre y Canyon* disasters (van Bernemand Lubbe, 1997).Because the *consequences* of CO_2 pipeline accidents potentially are of significant concern, stricter regulations for CO_2 pipelines than those for natural gas pipelines currently are in force in the USA.

6.3.5 Legal issues, codes and standards

Transportation of CO_2 by ships and sub-sea pipelines, and across national boundaries, is governed by various international legal conventions. Many jurisdictions/ states have environmental impact assessment and strategic environmental assessment legislation that will come into consideration in pipeline building. If a pipeline is constructed across another country's territory (e.g. land locked states), or if the pipeline is laid in certain zones of the sea, other countries may have the right to participate in the environmental assessment decision-making process or challenge another state's project

6.3.5.1 International conventions

Various international conventions could have implications for storage of CO_2, the most significant being the UN Law of the Sea Convention, the London Convention, the Convention on Environmental Impact Assessment in a Trans boundary Context (Espoo Convention) and OSPAR. The Espoo convention covers environmental assessment, a procedure that seeks to ensure the acquisition of adequate and early information on likely environmental consequences of development projects or activities, and on measures to mitigate harm. Pipelines are subject to environmental assessment. The most significant aspect of the Convention is that it lays down the general obligation of states to notify and consult each other if a project under consideration is likely to have a significant environmental impact across boundaries. In some cases the acceptability of CO_2 storage under these conventions could depend on the method of transportation to the storage site.

The Basel Convention on the Control of Trans-boundary Movements of Hazardous Wastes and their Disposal came into force in 1992 (UNEP, 2000). The Basel Convention was conceived partly on the basis that enhanced control of trans-boundary movement of wastes will act as an incentive for their environmentally sound management and for the reduction of the volume of movement. However, there is no indication that CO_2 will be defined as a hazardous waste under the convention except in relation to the presence of impurities such as heavy metal sand some organic compounds that may been trained during the capture of CO_2. Adoption of schemes where emissions of SO_2 and NO_x would be included with the CO_2 may require such a review. Accordingly, the Basel Convention does not appear to directly impose any restriction on the transportation of CO_2 (IEAGHG, 2003a).

In addition to the provisions of the Basel Convention, any transport of CO_2 would have to comply with international transport regulations. There are numerous specific agreements, some of which are conventions and others protocols of other conventions that apply depending on the mode of transport. There are also a variety of regional agreements dealing with transport of goods. International transport codes and agreements adhere to the UN recommendations on the Transport of Dangerous Goods: Model Regulations published by the United Nations(2001).CO_2 in gaseous and refrigerated liquid forms is classified as a non-flammable, non-toxic gas; while solid CO_2 (dry ice) is classified under the heading of miscellaneous dangerous substances and articles. Any transportation of CO_2 adhering to the Recommendations on the Transport of Dangerous Goods: Model Regulations can be expected to meet all relevant agreements and conventions covering transportation by whatever means. Nothing in these recommendations would imply that transportation of CO_2 would be prevented by international transport agreements and conventions (IEAGHG, 2003a) as part of their function. A full review of relevant standards categorized by issues is presented in IEAGHG, 2003b. Public concern could highlight the issue of leakage of CO_2 from transportation systems, either by rupture or minor leaks. It is possible that standards may be changed in future to address specific public concerns. Odorants are often added to domestic low-pressure gas distribution systems, but not to gas in long-distance pipelines; they could, in principle, be added to CO_2 in pipelines. Mercaptans, naturally present in the Weyburn pipeline system, are the most effective odorants but are not generally suitable for this application because they are degraded by O_2, even at very low concentrations (Katz 1959). Disulphides, thio ethers and ring compounds containing sulphur are alternatives. The value and impact of odorization could be established by a quantitative risk assessment.

6.3.6 Costs

6.3.6.1 Costs of pipeline transport

The costs of pipelines can be categorized into three items

- Construction costs
  - Material/equipment costs (pipe, pipe coating, cathodic protection, telecommunication equipment; possible booster stations)
  - Installation costs (labour)

- Operation and maintenance costs
  - Monitoring costs
  - Maintenance costs
  - (Possible) energy costs
- Other costs (design, project management, regulatory filing fees, insurances costs, right-of-way costs, contingencies allowances)

The pipeline material costs depend on the length of the pipeline, the diameter, the amount of CO_2 to be transported and the quality of the carbon dioxide. For costs it is assumed that $CO_2$is delivered from the capture system at 10 MPa.

Figure 6.3 shows capital investment costs for pipelines. Investments are higher when compressor station(s) are required to compensate for pressure loss along the pipeline, or for longer pipelines or for hilly terrain. Compressor stations may be avoided by increasing the pipeline diameter and reducing theflowvelocity.Reportedtransportvelocityvariesfrom1 to 5 m per second. The actual design will be optimized with regard to pipeline diameter, pressure loss (required compressor stations and power) and pipeline wall thickness.

Costs depend on the terrain. Onshore pipeline costs may increase by 50 to 100% or more when the pipeline route is congested and heavily populated. Costs also increase in mountains, in nature reserve areas, in areas with obstacles such as rivers and freeways, and in heavily urbanized areas because of accessibility to construction and additional required safety measures. Offshore pipelines generally operate at higher pressures and lower temperatures than onshore pipelines, and are often, but not always, 40 to 70% more expensive.

It is cheaper to collect CO_2 from several sources into a single pipeline than to transport smaller amounts separately. Early and smaller projects will face relatively high transport costs, and therefore be sensitive to transport distance, where as an evolution towards higher capacities (large and wide-spread application) may result in a decrease in transport costs. Implementation of a 'backbone' transport structure may facilitate access to large remote storage reservoirs, but infrastructure of this kind will require large initial upfront investment decisions. Further study is required to determine the possible advantages of such pipeline system.

Figure 6.4 presents onshore and offshore transport costs versus pipeline diameter; where costs are based on investment cost information from various sources. Figure 6.5 gives a cost window for specific transport as function of the flow. Steel is a cost component for both pipelines and ships, and steel prices doubled in the two years up to 2005: this may be temporary.

6.3.6.2 Costs of marine transportation systems

Costs of a marine transport system comprise many cost elements. Besides investments for ships, investments are required for loading and unloading facilities, intermediate storage and liquefaction units. Further costs are for operation (e.g. labour, ship fuel costs, electricity costs, harbour fees), and maintenance. An optimal use of installations and ships in the transport cycle is crucial. Extra facilities (e.g. an expanded storage requirement) have to be created to be able to anticipate on possible disruptions in the transport system.

The cost of marine transport systems is not known in detail at present, since no system has been implemented on a scale required for CCS projects (i.e. in the range of several million tonnes of carbon dioxide handling per year). Designs have been submitted for tender, so a reasonable amount of knowledge is available. Nevertheless, cost estimates vary widely, because CO_2 shipping chains of this size have never been built at pressures and lower temperatures than onshore pipelines, and are often, but not always, 40 to 70% more expensive.

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A detailed study (Statoil, 2004) considered a marine transportation system for 5.5 Mt per year. The base case had 20 kt tankers with a speed of 35 km per hour, sailing 7600 km on each trip; 17 tankers were required. The annual cost was estimated at US$ 188 million, excluding liquefaction and US$ 300 million, including liquefaction, decreasing to US$ 232 million if compression is allowed (to avoid double counting). The corresponding specific transport costs are 34, 55, and 42 US$ per ton. The study also considered sensitivity to distance for the case excluding liquefaction, the specific costs were 20 US$ per ton for 500 km, 22 US$ per ton for 1500 km, and 28 US$ per ton for 4500 km.

A study on a comparable ship transportation system carried out for the IEA shows lower costs. For a distance of 7600 km using 30 kt ships, the costs are estimated at 35 US$ per ton. These costs are reduced to 30 US$ per ton for 50 kt ships. The IEA study also showed a stronger cost dependency on distance than the Statoil (2004) study.

It should be noted that marine transport induces more associated CO_2 transport emissions than pipelines due to additional energy use for liquefaction and fuel use in ships.IEA GHG (2004) estimated 2.5% extra CO_2 emissions for a transport distance of 200 km and about 18% for 12,000 km. The extra CO_2 emissions for each 1000 km pipelines come to about 1 to 2%. Ship transport becomes cost-competitive with pipeline transport over larger distances. Figure 6.6 shows an estimate of the costs for transporting 6 Mt per year by offshore pipeline and by ship. The break-even distance, i.e. the distance for which the costs per transport mode are the same, is about 1000 km for this example. Transport of larger quantities will shift the break-even distance towards larger distances. However, the cross-over point beyond which ship transportation becomes cheaper than pipeline transportation is not simply a matter of distance alone. It involves many other factors, including loading terminals, pipeline shore crossings, water depth, seabed stability, fuel cost, construction costs, different operating costs in different locations, security, and interaction between land and marine transportation routes.

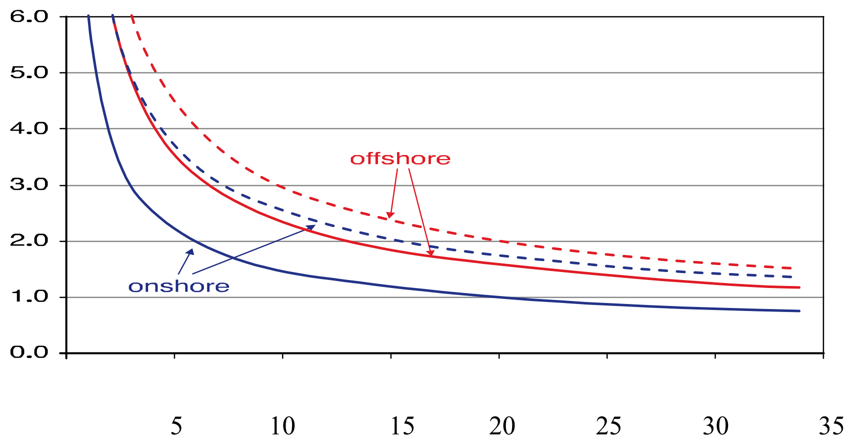

Figure 6.6: Transport costs for onshore and offshore pipelines per 250 km. High (broken lines) and low range (continuous lines) are indicated.

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CHAPTER 7. CARBON STORAGE

7.1. Introduction:

The carbon storage is the critical component of the CCS technology. At this stage CO_2 emission to the atmosphere are finally restricted by storing the captured gas in the selected geological site. The concept emerged as the subsurface of the Earth is large carbon reservoir, where the coals, oil, gas organic-rich shales exists. Consumption of these carbonaceous materials as energy source has resulted in rapid increase of GHG gas. For millions of years, crude oil and natural gas (in fluid form) have been stored naturally underground, where it is trapped in deep reservoirs or sedimentary basins protected by cap rock. CCS technology duplicates this process by safely storing CO_2 within similar geologic formations. The best sites for CO_2 storage from economic point of view are deep geological formations, such as depleted petroleum fields or deep natural gas reservoirs.

7.2. Sequestration of CO_2 :

Sequestration of CO_2 has been a natural process in the upper surface of the earth since the origin of life. Carbon dioxide derived from biological activity, igneous activity and chemical reactions between rocks and fluids accumulates in the natural subsurface environment as carbonate minerals, in solution or in a gaseous form, or bio-mass, living organism or as pure CO_2

The nature has well defined carbon cycle, which has provision of carbon sequestration mechanism with the green environment and ocean. The carbon storage in geological sites has its logic from replacing carbon extracted from geological sites as fossil fuel and restoring them with CO_2 wherever feasible. The stored CO_2 in geological sites have to be protected from subsequent release to atmosphere with proper capping. In the process of escaping from stored sites (defined as seepage, leakage, migration) they should not foul the underground water table used for human consumption.

The CO_2 is injected and stored into geological "storage reservoirs" using standard techniques that have been used in the oil and gas industry for many decades. During the storage process conceived in CCS, CO_2 is injected at least 1,000m (1km) deep into rock formations in the subsurface. For storing CO_2 the identification of secure storage site is essential. Each geological site must contain trapping mechanisms such as cap-rock (dense rock) that is impermeable to CO_2, which surrounds the storage area and acts as a seal to stop any upward movement of CO_2. It is also desired that CO_2 react with the porous surface of the rock to form stable compound, but in the process of reaction it should not weaken the rock structure. The storage site should have a stable geological environment to avoid disruption in storage on a long term. The basin characteristics such as tectonic activity, sediment type, previous drilling activity, geothermal and hydrology regimes of the storage site should be analyzed prior to site selection.

There have been many applications in various forms to restrict the CO_2 emission to atmosphere. Some of the ways to reduce CO_2 emission to atmosphere being suggested in the context of CCS that includes CCS are given in Table 7.1.

Table 7.1: Options of CO2 emission Mitigation

Ways of reducing CO2 emission		Potential
Avoidance and Carbon Neutral	Technology change (innovation) to avoid or reduce use of fossil fuel with renewable	Big
Control	All new emission reduction technologies	Big
Recovery	Beverages	Limited and Little Application. In fertilizer CO2 is released to atmosphere once the fertilizer is applied on fields.
	Fertilizer	
	Extinguisher	
	Solvent	
	Methanol Synthesis	
Biological sequestration	Afforestation	These are not permanent reliable solution. For
	Seaweed	

Ways of reducing CO_2 emission		Potential
	Greenhouses	algae more research are needed
	Algal Bio-diesel	
Ocean storage	Gas solution at 1000 m depth	Permanent storage may not be feasible, There are legal constraints of Biological environment
	Gas Hydrates	
	Deep-water injection	
Geological storage	Depleted Fields-Secondary EOR/ EGR	large, can be taken up now for pilot and demonstration
	Depleted Fields-Tertiary EOR/ EGR	
	Saline aquifers	
	Coal	Not Fully Explored
	Mineralization	
	Salt deposits	
	Basalt	

Figure 7.1 indicates various inland geological storage options being analyzed for CCS. The Enhanced oil and gas recovery is currently the viable option of CCS. The technology of deep coal mining is in preliminary stage. Underground coal gasification is one of the technology option that is in demonstration project stage

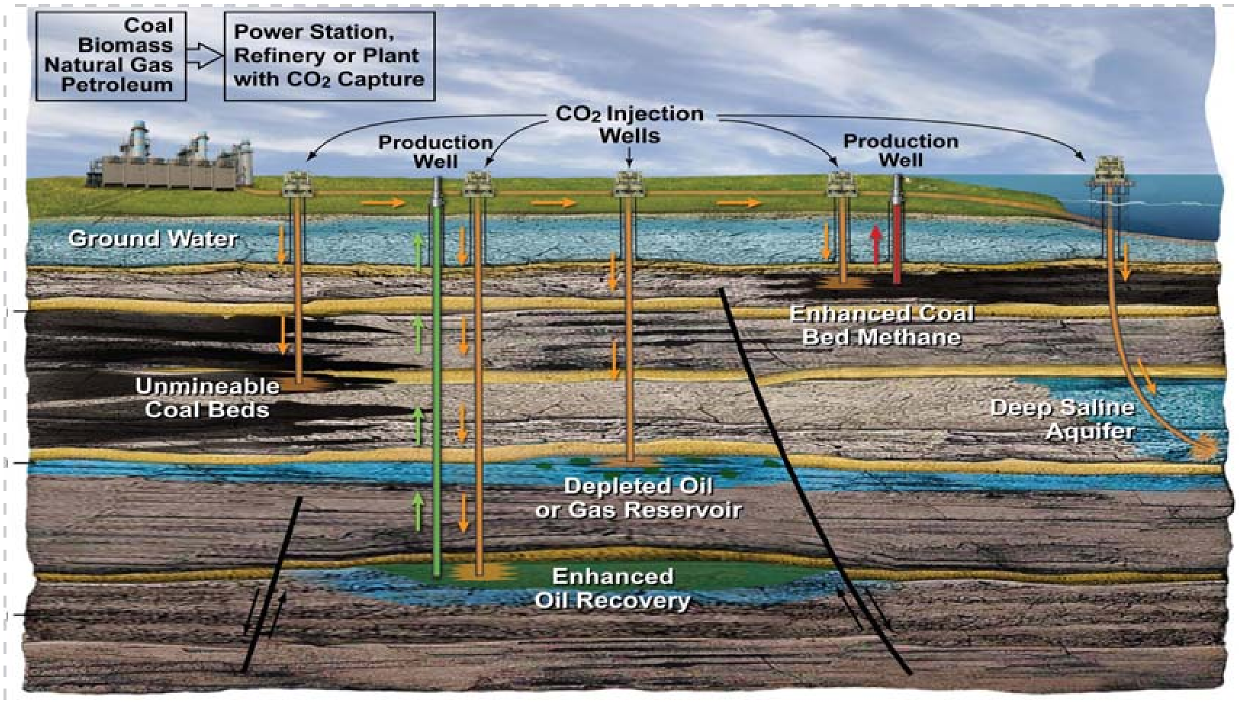

Figure 7.1: Inland CO2 Storage[66]

Geological (Sedimentary) formation in the subsurface are composed of transported rock-grains, mineral and organic material of varied composition and different chemistry, forms. The pore space (porosity) available in these rocks depends upon the degree of compaction and cementations due to depth of burial and environment of deposition. Storage of carbon dioxide in saline aquifers can be in both "confined" and "unconfined" aquifers. Storage in confined aquifers relies on tapping of the buoyant carbon dioxide by structural and stratigraphic trapping. The trapping mechanisms are:

- Physical trapping of CO2 beneath a seal (cap rock)
- Dissolution of CO2 into aqueous phase (saline water)

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[66] http://www.exxonmobil.com/Corporate/Files/news_pub_Carbon_Capture_Storage_brochure.pdf

- Geochemical reaction and formation of mineral in the pour space

The storage reservoir should have adequate porosity and dimension (area and thickness) to have commercially viable storage capacity), permeability to facilitate injectivity and flow of CO2 in the reservoir. The reservoir porosity usually decreases with depth. The pressure and flow regimes of formation waters in a sedimentary basin are important factors in selecting sites for CO2 storage (Bachu *et al.*, 1994). Every reservoir has a reservoir pressure. Injection of CO2 into these reservoir should not result into increasing reservoir pressure. Higher storage pressure above previous reservoir pressure may cause leakages.

Storage of CO2 in deep saline formations with fluids having long residence times (millions of years) is conducive to hydrodynamic and mineral trapping.

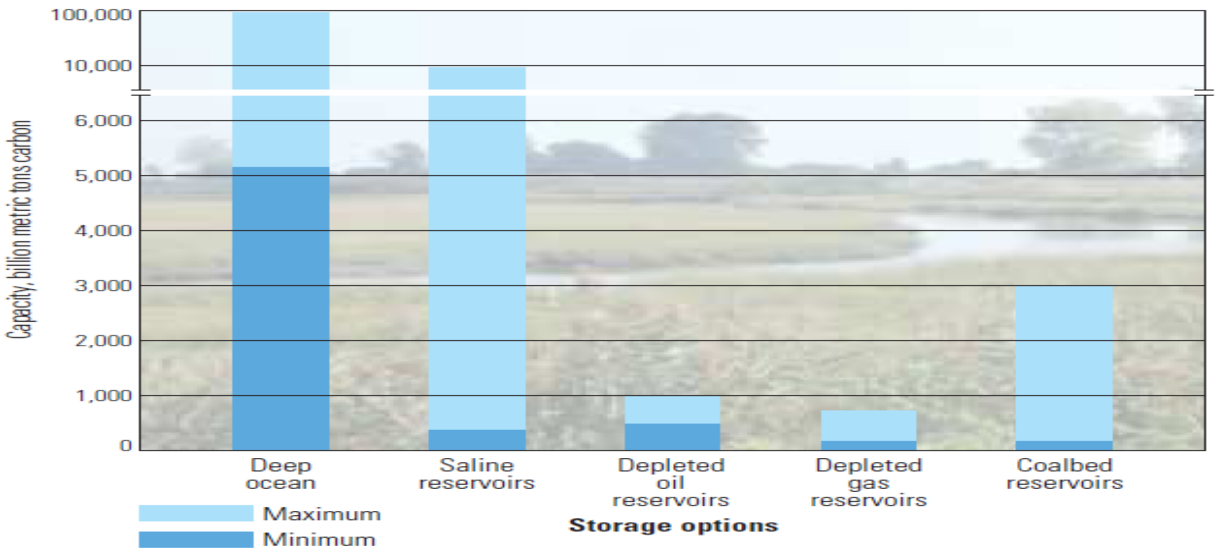

Figure 7.2: Global CO2 storage capacity (Maximum & Minimum)[67]

7.2.1 Saline Aquifers:

Global studies indicate that saline aquifers are present in onshore and offshore sedimentary basins. Saline aquifers have been identified as the inland storage site having maximum CO2 storage capacity. In Indian context following study is needed.

- To estimated storage capacity of the saline formation to evaluate commercial viability.
- Proximity of thermal power stations to saline aquifer.
- Thickness of impervious (clay / sandstone) cap rock to ensure storage integrity.
- The reservoir pressure to estimate the storage capacity. Location of geological faults in the adjacent area.
- Use of water of saline aquifers, in case they can be extracted from reservoir.

[67] http://www.slb.com/~/media/Files/resources/oilfield_review/ors04/aut04/05_co2_capture_and_storage.ashx

The saline aquifers content do not have any commercial value; it has not been adequately studied. In view of CCS the saline aquifers should be studied extensively. The study should include physical, chemical, and geological analysis. The analysis is needed to evaluate the nature and composition of the rock, porosity & permeability of the reservoir, and surrounding rock formation. The information obtained can be superimposed on GIS environment.

Figure 7.3 indicate that for injecting CO2 at storage site, the pressure of inject-ant and temperature conditions should be greater than the existing occupant of pores. The hydrostatic pressure gradient is about 10 MPa / km at normal temperature gradient. The supercritical CO2 becomes stable from depths of 800 m and below the earth surface. At the depth more than 800 m, the fluid CO2 pressure and density is approximately equivalent as density of saline water. For stable CO2 storage the pressure of CO2 should be above the saline water pressure to push the saline water up, in the void capillaries. There is another aspect if the proposed reservoir pressure, is above the initial reservoir pressure, there is a risk that in long-term gas can migrate upwards by locating seepage site, or puncturing cap rock

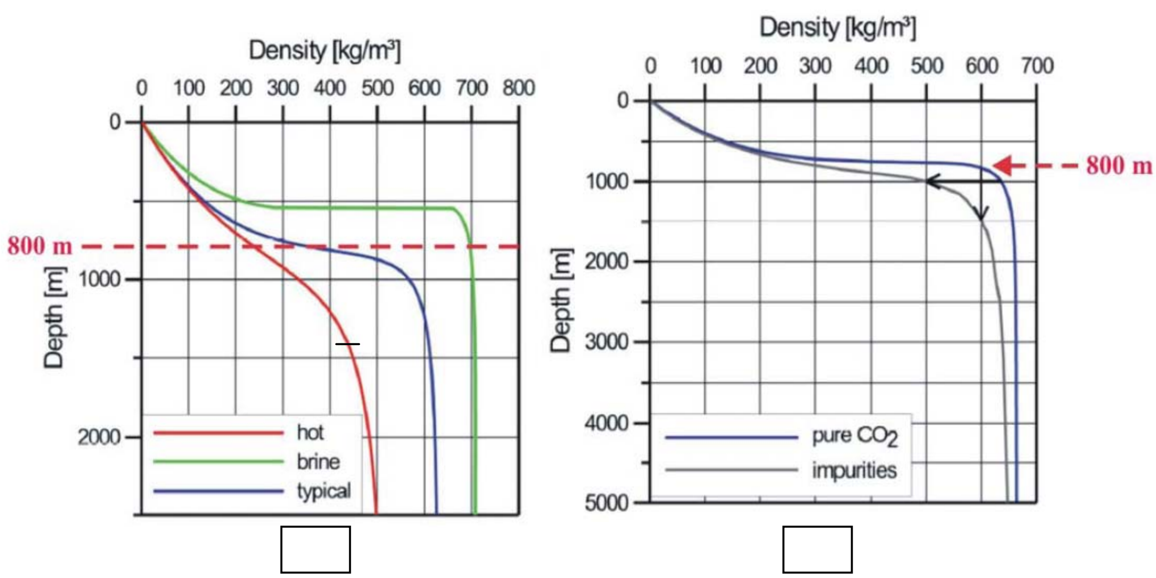

Figure 7.3: CO2 density variation with depth.

Graph A: assuming hydrostatic pressure and typical temperature gradient in sedimentary basin (blue/ middle); elevated geothermal gradient (45 degree centigrade per kilo-meter (red/ bottom) and hydrostatic pressure gradient of highly concentrated brines (12.5 M Pa per Kilometre, green/ top).

Graph B: Effect of impurities e.g. 2.75% O2 and other components

Therefore, characteristics of cap-rock should be analysed for sustainable buffer pressure to mitigate the risk. The maximum and minimum storage pressure will be caused by the mechanical material properties of the surrounding rocks of the reservoir. The applied storage load by injection at greater depth can increase the porosity of the rocks. This is where the science of rock mechanics (lithology) is important to understand the underground storage behaviour.

After certain depth all the voids beneath the earth surface are usually filled with water. The solubility characteristics of CO2 in underground water is it

(1) Increases with increasing pH

(2) Increases with increasing pressure

(3) Decreases with increasing salinity

(4) Decreases with increasing temperature.

The hydrostatic pressure gradient of water increases with depth, and is about 10 MPa / km. At a depth of 800 m below the earth, due to high proportion of dissolved ions (Salinity) in groundwater, the solubility of CO2 reduces. In case of contamination of the captured CO2 from power plants, and high geothermal gradients can shift achieving Density of CO2 of value of 600 kg / m^3 at significantly greater depth.

M/S Schlumberger had made an elaborate seismic and stratigraphic analysis of the Utsira formation in Norway, where CO2 storage is being done. The reservoir has good cap rock formation, and thin shale layer. Because of buoyancy CO2 migrates laterally beneath the shale layers. Their modelling indicated that "as brine becomes enriched with CO2, the mixture gets denser than the water below, forming current and enhancing dissolution." The nature of dissolution, mixing, and segregation of CO2 depends upon characteristics of reservoir. Storage mechanism with dissolution mechanism from convective mixing of CO2 is a long term process. Periodic seismic observation and geophysicist analysis is required to ensure storage security. The distribution of CO2 can be calculated by mapping saturation to the residual push down. The storage simulation with periodic feedback from seismic study can be done by superimposing seismic data with initial reservoir profile.

Saline aquifers at depths of ≥ 800 m also provide viable options for the storage of CO_2 which can be stored in the miscible and/or mineral phase. The potential storage capacity is vast and is estimated to be ~ $1x11^{13}$ tons of CO_2.The high porosity and permeability of the aquifer sands along with low porosity cap rock such as shales provides suitable conditions for CO_2 storage. Over the time, CO_2 gets dissolved in the brines and also reacts with the pore fluids/ minerals to form geologically stable carbonates.

Mineral trapping is a long term storage mechanism. CO2 reacts with non-carbonate, calcium, iron, magnesium rich mineral to form carbonate precipitates.

The most accurate knowledge of the geological construction is essential. The reservoir properties and the safety of geological CO2 storage conditions are of the surface do not depend on predictable factors. The storage efficiency does not depend only on the underground structures, but also the choice of storage strategies, and the purity of the captured CO2. Storage efficiency is defined as the proportion of the CO2 filled volume of the total pore volume of the store. The void volumes of the respective rocks have to be established with basic research.

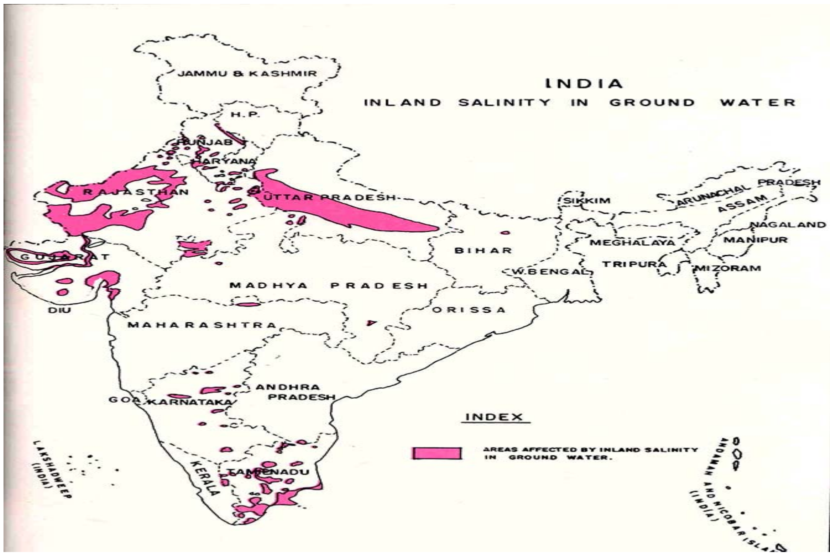

Figure 7.4: Areas affected by Inland salinity in India

The saline aquifers are present in India different geological formations as revealed by exploratory drillings for the delineation of aquifer zones by Central Ground Water Board.

No systematic study have been undertaken to map the deep saline aquifer zone in different basins as these are of no commercial use. The presence of saline aquifers in different geological formations is outcome of exploratory drilling for the delineation of aquifer zones for water development projects by the CGWB and exploratory deep drilling and geophysical surveys for oil and gas by ONGC and other agencies. The distribution of inland salinity/saline aquifers is given in figure.

Maximum saline areas fall in parts of Rajasthan, Haryana, Punjab, Uttar Pradesh, Gujarat and Tamil Nadu. Some of the mega thermal power plants are also coming up in these areas. In India, the deep saline aquifers may prove out to be a very efficient option for carbon sequestration.

In Gujarat, an area of 28, 000 Sq. Km. is affected by salinity. Exploration for deep saline aquifers was carried out upto 621m below ground level (bgl). The exploration indicated the presence of thick saline aquifers in the Basalt and Precambrian shale formations, the aquifers are under free flowing artesian conditions. In the Kutch region (coastal Gujarat, the saline aquifers were encountered at different depths and continue upto 458m bgl

In Southern coastal areas of Tamil Nadu, the deep saline aquifers occur in the Tertiary sandstone and alluvial formations over an area of 3, 750 Sq Km.

In the arid areas of Rajasthan, the exploration shows the presence of saline aquifers in about 100000 Sq Km. The exploration up to 610 m indicated the presence of granular zones with high salinity in Bikaner-Jaisalmer area.

In the Ganga Basin, exploratory drilling and geophysical logging shows the presence of deep saline aquifers. The saline aquifers are present in its western extension almost running for 342 Km from Meerut to Rasalpur in Uttar Pradesh. The geophysical logs of 172 boreholes in the study area show the thickness of saline aquifers ranging from 30 to 300 m indicating the presence of thick granular zones within the Ganga basin sediments.

Central Ground Water Board and Geological Survey of India have established the presence of saline aquifers upto depths of 300m below ground level in the Ganga basin. Deep Resistivity studies carried out at 9 sites around New Delhi have also shown the presence of saline aquifers at depths of 800m and beyond, around Palwal and Tumsara.

There are insufficient public domain data available to estimate accurately the storage capacity of saline aquifers. In order to study deep saline aquifers, the sedimentary Basins have to be short-listed with adequate storage capacity estimates. Resistivity surveys for Deep aquifers are needed for delineating Rock type and the aquifers. The reference to saline aquifers we can provide guess-estimates. This can be followed by deep drilling for knowing the characteristics of the sinks and cap rocks.

7.2.2 CO2 Storage potential in India:

The CO2 storage potential in India have been studied as a part of International Energy Agency (IEA) greenhouse gas programme (GHG), Halloway et. al (2008). They carried out Regional Assessment of the potential geological CO2 storage sites in Indian Sub-Continent Figure. The CO2 storage potential of India's sedimentary basin, and their classification of basin into good, fair and limited, is based on their expert judgment, and have to be established with field test using stratigraphic methodology.

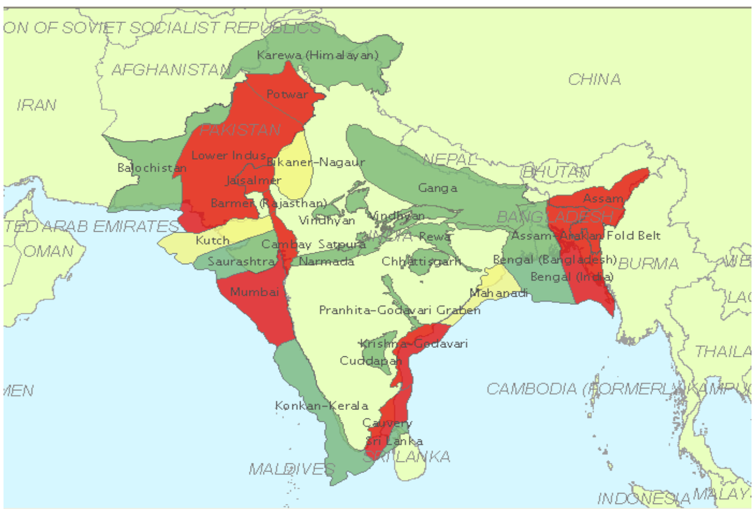

Figure 7.5: Potential CO_2 storage sites in India

In Figure 7.5, the red colour areas depict the hydrocarbon field and have good CO2 storage potential. The sea-green regions are the sedimentary basins with potential saline aquifers (including some of the marked in yellow), coal mines. The researchers have characterized the region having fair storage capacity. The rest of country has to be studies separately, as deccan area have basalt regions. Their capability has to be analyzed with research.

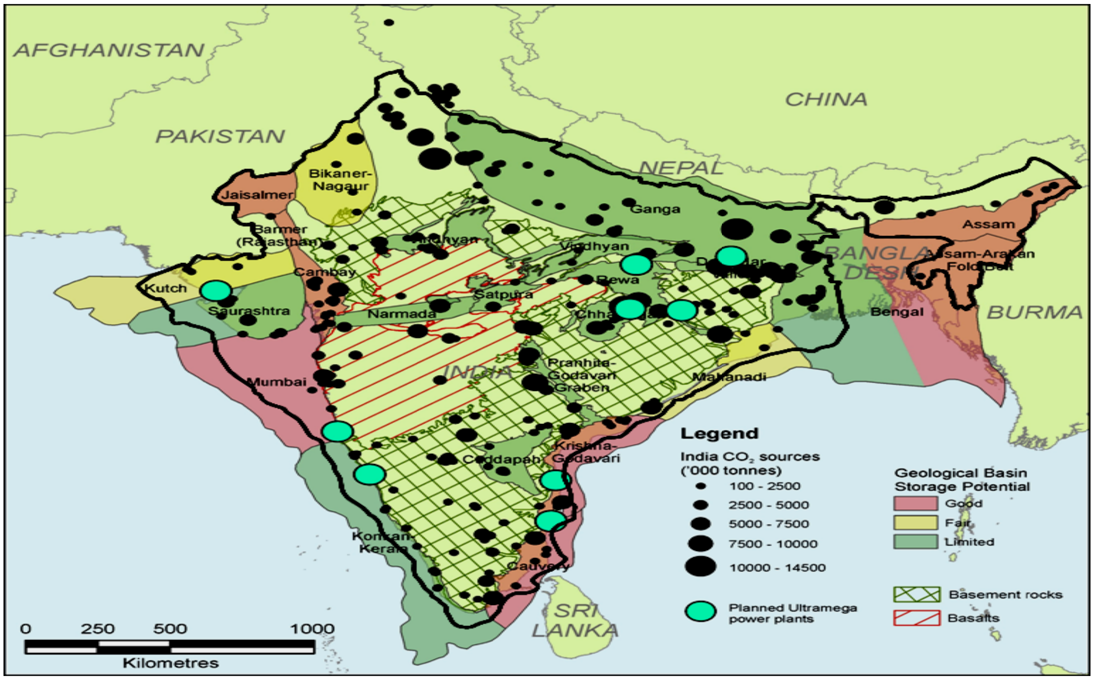

Figure 7.6: The intensive carbon emitting sites (primarily power plants) & (Blue circle indicates upcoming ultra-mega power plant)

The diagram has been updated with geographical boundaries and location of major power plants in the country by various researchers to establish linkage between CO2 emitting site and the storage area. These maps can be further upgraded on a GIS environment. Some additional information on power transmission line, gas pipeline can be incorporated to facilitate CO2 transportation planning.

India has hydrocarbon field in Barmer basin, Cambay basin, Mumbai Off-shore basin, Bombay High fields, off-shore Krishna Godavari basin, and oil field in upper Assam. The Directorate General of Hydrocarbon is the authority for monitoring status of fields. The major corporate in the exploration and production of Hydrocarbon business are ONGC India, Cairn India, OIL India, Reliance Industries. The inventories of the oil-fields are accounted for.

7.2.3 Enhanced Coal Bed Methane Recovery (ECBM)

CO_2 sequestration in the unmineable coal seams serves the dual purpose i.e. CO_2 storage and enhanced coal bed methane recovery. Coal beds typically contain large amounts of methane rich gas which is adsorbed onto the surface of the coal. The injected CO_2 efficiently displaces methane as it has greater affinity to the coal than methane in the proportion of 2:1 and is preferentially adsorbed displacing the methane absorbed in the internal surface of coal layers.

India has vast coal bed methane potential (1000 bcm.) The unmineable coal seams in India occur in many Gondwana and Tertiary coal fields. The CO_2-ECBM can be advantageously used for exploiting the coal bed methane resources of India. The development and application of this technology is still at an early stage in the country. Directorate General of Hydrocarbons (DGH), New Delhi has planned to initiate CO_2-ECBM technology in some selected Gondwana coal fields.

7.2.4 Basalt formations

The Basalt Formations are most viable options for environmentally safe and irreversible long time storage of CO_2. The basalts are attractive storage media as they provide solid cap rocks and have favourable chemical compositions for the geochemical reactions to take place between the CO_2 and the formation minerals, rendering high level of storage security. The Deccan trap has a vast basalt formation. The Intertrappeans[68] between basalt flows also provide major porosity and permeability for injection.

Large Igneous Provinces like the Columbia River Basalt Group (CRBG) of USA and the Deccan Traps of India are the potential host mediums for the geologic storage of CO_2. The lab study of

[68]http://geoweb.princeton.edu/people/keller/deccan/deccan.html

the in site reaction of CO_2 with basalt at Battelle Pacific Northwest National Laboratory(PNNL), Richland, USA have shown fast mineralization reactions in terms of geological time scale (≤ 1000 days). Basalts are rich in Calcium, Magnesium and iron Silicates (may be aluminosilicates).

Table 7.2: In site reaction of CO2

Depth, (m)	T, °C	tp, d
800	35	964
900	38	822
1000	42	678
1100	48	534
1200	56	397
1300	67	275
Geo-chemical modelling studies by PNNL, USA		

The mineralization reaction is controlled by mixing behaviour of CO2 with the rock and kinetics have secondary role. The reaction equations are

$$CO_2\,(g) \longrightarrow CO_2\,(Aq)$$

$$CO_2\,(Aq) + H_2O \longrightarrow HCO_3^- + H^+$$

$$(Ca,Mg,Fe)_X Si_Y\,O_{X+2Y} + 2xH^+ + (2y-x)H_2O \longrightarrow x(Ca,Mg,Fe)^{2+} + yH_4SiO_4\;(Aq)$$

$$(Ca,Mg,Fe)^{2+} + HCO_3^- \longrightarrow (Ca,Mg,Fe)CO_3 + H^+$$

The reaction produces stable minerals, which can exist over long geological time (million years). Mg-silicates (eg olivine Mg2SiO4 (Forsterite)) is the reactive component, and the reaction is exothermic, so that this additional energy is obtained. Quartz sandstone, have good porosities and permeability but are poor as reactive minerals.

For fixing of 1 tonne of CO2, theoretically 1.6 Tons of basalt is needed, but in practice requires it needs up to 10 tonnes of olivine.

7.3. Deccan Traps, India:

The Deccan volcanic province is one of the largest volcanic eruptions in Earth's history and today covers an area of 500,000 km2. The original size prior to erosion is estimated to have been at least twice as large. The volume of lava extruded is estimated to have been about 1.2 million km3. Deccan Basalts (The most common flow type of the Deccan Trap is the Pahoeho sheet flows, due to the lesser viscosity and less strain. It forms large horizontal sheets. Deccan Flood Basalts is tholeiitic (cinopyroxene and plagioclase) in nature and the eruptions are of fissure type,)cover an area of 500x103 sq. km. It is composed of typically 48 flows. The thickness of basalts varies from few hundreds of meters to > 1.5 km. The largest lava flows of 1500 km across India from Deccan trap took place in the direction of Rajamundry and into the Gulf of Bengal

The basalts provide solid cap rocks and thus can ensure high level of integrity for CO2 storage. The intertrappeans between basalt flows provide significant porosity and permeability along with vescicular, brecciated zones within the flows. Tectonically the traps are considered to be stable.

Geophysical studies[69] have revealed presence of thick Mesozoic and Gondwana sediments below the Deccan Traps. A pilot study for the evaluation of Basalt Formations of India for

[69]Evaluation of Basalt Formation in India for Storage of CO2; S.N. Charan, B. Kumar and Ravi Shekhar Singh: presentation

environmentally safe and irreversible long time storage of CO_2 has been initiated by National Geophysical Research Institute, Hyderabad jointly with Department of Science &Technology, New Delhi, National Thermal Power Cooperation, India and Battelle

Deccan Traps are partly continental Basalt. The basaltic flows have covered 300 to 500 km from their sources. Chemical composition of Deccan Basalt is around SiO2- 59.07, Al2O3- 15.22, FeO -6.45, CaO -6.10, MgO- 3.45, Na2O -3.71, K2O- 3.11, P2O5- 0.30, TiO -2 1.03, MnO - 0.11.

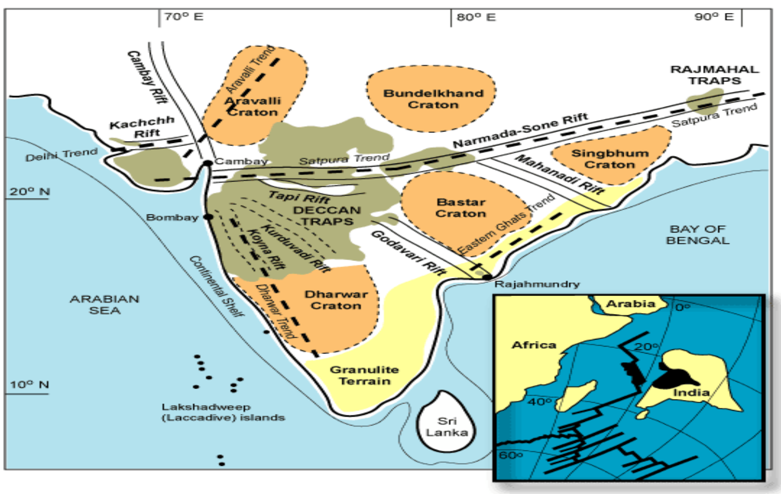

Figure 7.7: Blasaltic flows of deccan traps

Sedimentary basins are depression in the earth's crust formed by movement of tectonic plates where sediments have accumulated over geological time frame to form sedimentary rocks. Hydrocarbons/ fossil fuel commonly occur in sedimentary basins. Almost two-third parts of the country is occupied by the Archean igneous and metamorphic rocks which have negligible porosity .In the Deccan basalts only secondary porosity is preserved within the fractured zones and weathered layers. The porous formations are confined to semi-consolidated and consolidated sedimentary rocks occurring in the Ganga basin, Gondwanas, Cuddalore sandstone and their equivalents, in Rajasthan basin, Vindhyan basin etc.

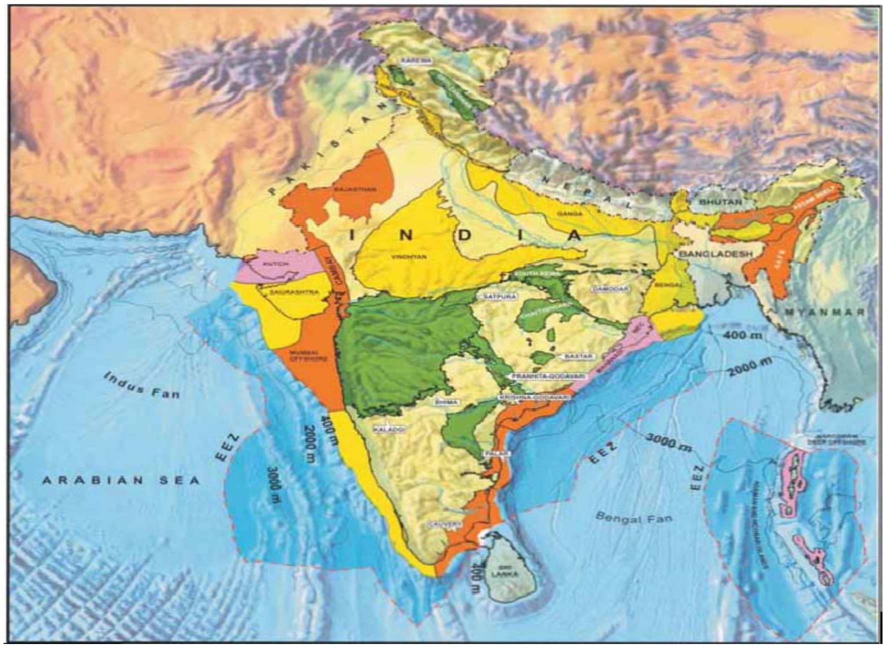

Figure 7.8: Sedimentary basins of India

Table 7.3: Legend

COLOUR	Basin
Orange	Category 1 basin (proven commercial productivity)
Pink	Category 2 basin (identified prospectivity)
Yellow colour	Category 3 basin (prospective basin)
Green colour	Category 4 basin (potentially prospective)
Off-white colour	Pre-cambrian basemant/ tectonised sediments
Blue colour	Deep water areas within eez

Table 7.4: Sedimentary Basins in India

Category	**Basin**	**Basinal Area (Sq. Km.)**		**Total**
UPTO 200M	**ISOBATH**	**On land**	**Offshore**	
I	**Cambay**	**51,000**	**2,500**	**53,500**
	Assam Shelf	56,000	- - - -	56,000
	Bombay offshore	- - - -	116,000	116,000
	Krishna Godavari	28,000	24,000	52,000
	Cauvery	25,000	30,000	55,000
	Assam-Arakan Fold Belt	60,000	- - - -	60,000
	Rajasthan	126,000	- - - -	126,000
	SUB. TOTAL	**346,000**	**172,500**	**518,500**
II	**Kutch**	**35,000**	**13,000**	**48,000**
	Mahanadi-NEC	55,000	14,000	69,000
	Andaman-Nicobar	6,000	41,000	47,000
	SUB. TOTAL	**96,000**	**68,000**	**164,000**
III	**Himalayan Foreland**	**30,000**	**- - - -**	**30,000**
	Ganga	186,000	- - - -	186,000
	Vindhyan	162,000	- - - -	162,000
	Saurashtra	52,000	20,000	80,000
	Kerala-Konkan-Lakshadweep	- - - -	94,000	94,000
	Bengal	57,000	32,000	89,000
	SUB. TOTAL	**542,000**	**168,000**	**710,000**
IV	**Karewa**	**3,700**	**- - - -**	**3,700**
	Spiti-Zanskar	22,000	- - - -	22,000
	Satpura-South Rewa-Damodar	46,000	- - - -	46,000

	Narmada	17,000	- - - -	17,000
	Decan Syneclise	273,000	- - - -	273,000
	Bhima-Kaladgi	8,500	- - - -	8,500
	Cuddapah	39,000	- - - -	39,000
	Pranhita-Godavari	15,000	- - - -	15,000
	Bastar	5,000	- - - -	5,000
	Chhattisgarh	32,000	- - - -	32,000
	SUB. TOTAL	**461,200**	**- - - -**	**461,200**
	TOTAL	**1,390,200**	**394,500**	**1,784, 700**
DEEP WATERS				
	Kori-Comorin J			
	85° E	- - - -	- - - -	1,350,000
	Narcodam			
	GRAND TOTAL	**- - - -**	**- - - -**	**3,134, 700**

Considering the depleted oil fields and saline aquifers being the most suitable storage site; following information should be compiled to estimate storage capacity.

The following data should be collected for every hydrocarbon field;

1. Name and location of the field and operating company (GPS-coordinates)
2. Total amount of production per field (m^3 gas or barrel oil)
3. Estimation of reserves (m^3 gas or barrel oil)
4. Depth of hydrocarbon field (m)
5. Starting year of operation

6. Date of depletion (when would a hydrocarbon field be available for CO2 injection)
7. Secondary or tertiary recovery methods in progress to increase production (EOR - enhanced oil recovery or EGR -enhanced gas recovery):
   - Already injected and produced water (m^3)
   - Planned water injection and recovery (m^3)
   - Already injected and produced CO2 (m^3)
   - Planned CO2 injection and recovery (m^3)

7.4. Other parameters for CO2 storage capacity calculation for each hydrocarbon field

The formula applied to calculate CO2 storage capacity is m^3

$CO2 = V \cdot Bg/FVF \cdot \rho CO2 \cdot E.$

Thus the parameters beside cumulative recovery (V) should be known. If site-by-site values are confidential or unavailable, general values can be used.

The following data should be collected for every hydrocarbon field:

1. Gas expansion factor (Bg) or formation volume factor for oil (FVF)
2. Density of CO2 (ρCO2) (kg/m3)
3. Driving mechanism (depletion-drive or water-drive)
4. Sweep efficiency E (how much of the recovered hydrocarbons can be substituted by CO2? E.g. 75% or 100%?)

Following information on Deep saline aquifers needs to be collected:

7.4.1 Primary properties of aquifers to select suitable structures

The following data should be collected for every deep saline aquifer:

1. Name and location (GPS-coordinates)
2. Volume of aquifer: thickness h (m), areal extent A (m2), bulk volume V = h * A (m^3)
3. Sediment types
4. Geological stratigraphy
5. Porosity (%) and permeability (mD) of sediments
6. Depth of aquifer (m)
7. Exclusion criteria: Existence of faults, seismic activity?
8. Existence of cap rock above the potential structure and sealing capacity (thickness, porosity, permeability)?

Based on this list of structures, additional data will be needed to calculate the amount of possible CO2 storage capacity.

The following data should be derived from geologic measurement data or from expert knowledge estimates for every selected deep saline aquifer:

1. CO2 density (kg/m3)
2. Percentage of trap structures in the bulk volume to store safely CO2
3. Efficiency factor (how much of saline water can be displaced?), controlled via maximal pressure increase in the reservoir and compressibility of water and rock

4. Usable fraction of the geological structures
5. Permeability -->possible injection rate

CO2 Storage in the oceans is one of the option to reduce emission to the atmosphere. The options is being actively researched in the U.S., Japan and Norway since last few decades.

"The ocean represents the largest potential sink for anthropogenic CO_2. It contains an estimated 40,000 billion metric tons of carbon compared with only 750 billion metric tons of carbon in the atmosphere and 2200 in billion metric tons of carbon in the terrestrial biosphere. Apart from the surface layer, deep ocean water is unsaturated with respect to CO_2. It is estimated that if all the anthropogenic CO_2 that would double the atmospheric concentration were injected into the deep ocean, it would change the ocean carbon concentration by less than 2%, and lower its pH by less than 0.15 units.[70]"

CO2 dissolves in sea water as a liquid in sea at a depth of approximately 1,000 meters. The resulting increase in density of CO2 at greater depth it sinks to great depths and gets collected at seabed. The permanent storage of CO2 at seabed is doubtful due to circulations, currents and in extreme case tsunami. This methodology can be taken as a short-term storage measures.

The impact of this scheme on marine environment and other geochemical reactions not well established. With ocean current flow systems, this scheme can impact on the climate

[70] http://sequestration.mit.edu/pdf/enclyclopedia_of_energy_article.pdf

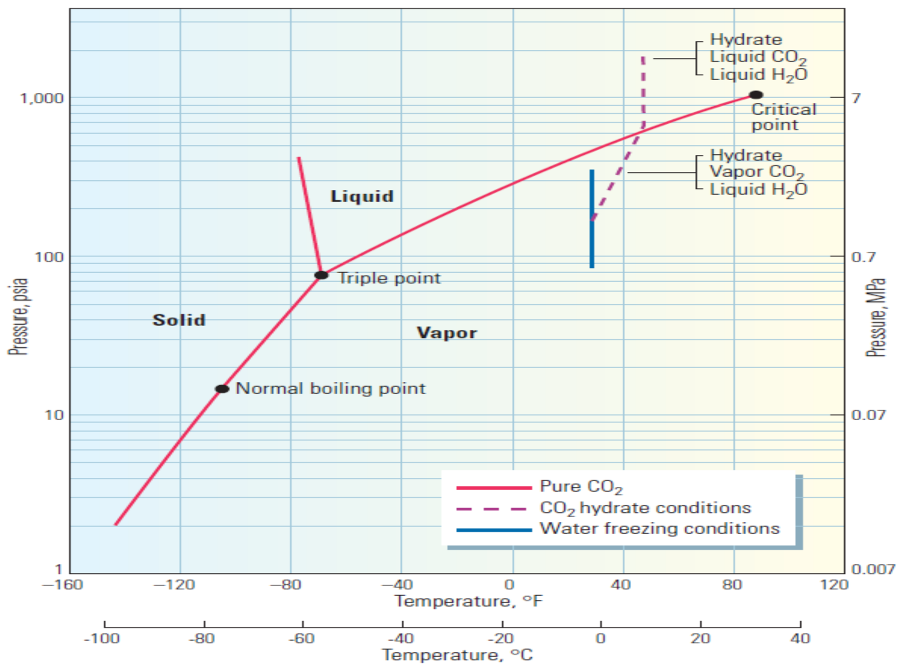

Figure 7.9: Triple point of CO_2

When liquid CO_2 is in contact with water at temperatures less than 10 ^{o}C and pressures greater than 44.4 atm (4.44 MPa, 440 meter depth), a solid hydrate is formed in which a CO_2 molecule occupies the center of a cage surrounded by water molecules. For droplets injected into seawater, only a thin film of hydrate forms around the droplets.

For longer-term solution hydrate technology can be used. The retention period of CO2 in sea-is more of guess-estimates. The retention period can be enhanced by additional artificial nutrient input in the form of phosphates and nitrates.

The additional CO2 concentration due to assimilation and subsequent sedimentation binding, can enhance biomass e.g. plankton. This requires increased research projects. Some of the research has been conducted by National Institute of Oceanography. There are chances of accompanying production of methane gas. There is an increased need for research in relation to the changes of sea water and their effects

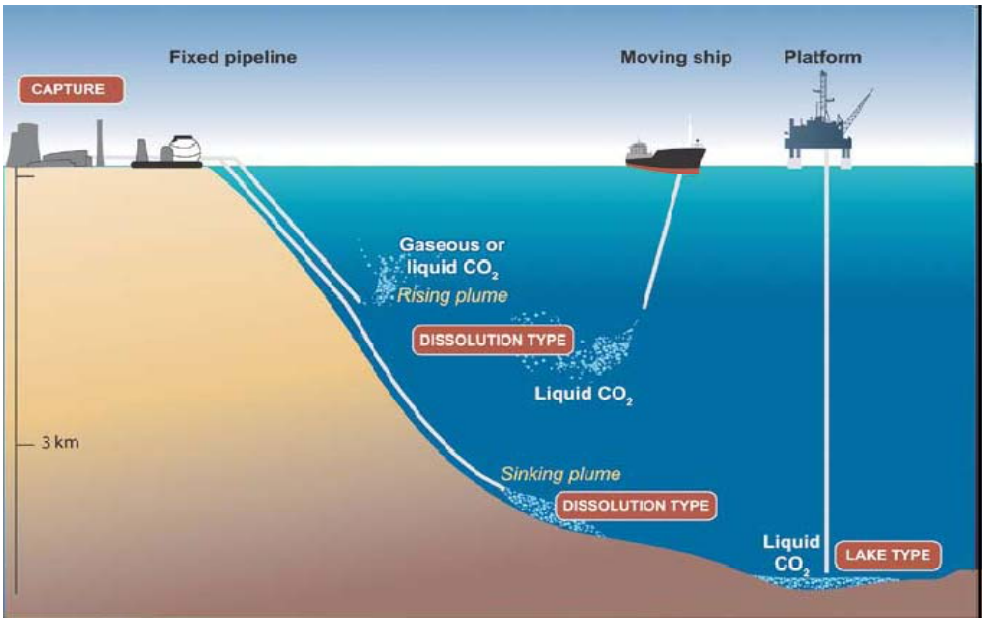

Figure 7.10: Various options for ocean storage

The effectiveness and integrity of geological storage on a long time frame of hundreds of years depends on a combination of physical and geochemical trapping mechanisms. The potential of CO2 to escape from geological site is high if stored CO2 exist in a separate phase. The most effective storage sites are those where CO2 is trapped permanently under a thick, low-permeability cap rock seal, and CO2 reacts with formation water and surrounding rock mass.

7.5. Physical trapping: Stratigraphic, structural, and hydrodynamic

Physical trapping of CO2 for CO2 storage is designed to be injected below low-permeability seals/ caprocks. These cap rocks are part of geological formation. The Sedimentary basins that have cap rock and porous and permeable rocks beneath it are potential storage site. The stretch of porous and permeable rocks (reservoir) may contain saline water, oil and gas. The boundary of reservoir are formed by structural traps that are formed by folded or fractured rocks and geological faults. Faults can act as permeability barriers in some circumstances, can facilitate fluid flow in other circumstances, and can also provided seepage path to atmosphere. Stratigraphic traps can be formed by changes in rock type. Both of these types of traps are suitable for CO2 storage. Care must be taken not to exceed reservoir pressure or sustaining pressure of the cap rock and fault boundary.

*"*Hydrodynamic trapping can occur in saline formations that do not have a closed trap, but where fluids migrate very slowly over long distances. When CO2 is injected into a formation, it displaces saline formation water and then migrates buoyantly upwards, because it is less dense than the water. When it reaches the top of the formation, it continues to migrate as a separate phase until it is trapped as residual CO2 saturation as plumes in local structural or stratigraphic traps within the sealing formation."

7.6. Geochemical trapping

Carbon dioxide in the storage site can undergo a sequence of geochemical interactions with the rock (mineral trapping) and formation water that will further increase storage capacity and effectiveness. When CO2 dissolves in formation water, a process commonly called solubility trapping occurs. The primary benefit of solubility trapping is that once CO2 is dissolved, it no longer exists as a separate phase, thereby eliminating the buoyant forces that drive it upwards. In the rocky environment, the H2CO3 forms ions, as the rock dissolves. This will alter pH of the water.

Several minerals in the reservoir rock surface react with CO_2 with the formation of carbonates, and thus permanently storing the CO_2. Such minerals are calcium and magnesium silicates etc. The reaction occurring with serpentine, a magnesium silicate is shown below. Some fraction of the stored CO2 may be converted to stable carbonate minerals (mineral trapping). These are the permanent form of geological storage. Mineral trapping reaction is slow, occurring in the geological timescale of thousand years or longer.

Chemical Reaction of CO2 in geological storage can be represented as flows:

$CO2\ (g) + H2O \leftrightarrows H2CO3$ (Solubility Trapping)

$H2CO3 \leftrightarrows HCO3^{-} + H^{+}$ (Ionic Trapping)

$HCO3^{-} + H^{+} \leftrightarrows CO3^{2-} + 2H^{+}$ (Ionic Trapping)

$Mg_3Si_2O_5(OH)_4 + 3CO_2(g) = 3MgCO_3 + 2SiO_2 + 2H_2O(l)$ (Mineral Trapping)

The CO2 solubility in formation water decreases as temperature and salinity increase.

Dissolution is rapid when formation water and CO2 share the same pore space, but once the formation fluid is saturated with CO2, the rate slows and is controlled by diffusion and convection rates.

CO2 dissolved in water produces a weak acid, which reacts with the sodium and potassium basic silicate or calcium, magnesium and iron carbonate or silicate minerals in the reservoir or formation to form bicarbonate ions by chemical reactions approximating to:

3 K-feldspar + 2H2O + 2CO2 _ Muscovite + 6 Quartz + 2K+ + 2HCO3 −

There are possibilities that the cap rock and overlying rock formations have affinity for mineralization.

7.7. Research Opportunities in Carbon Storage

1. Mineral/ Physical Trapping of CO2
2. Enhanced oil and Gas Recovery

3. Microbial – Biogeochemical Transformation of CO_2
4. Geophysical site selection and Monitoring
5. Chemical/ Kinetic Behavior in real time
6. Well integrity CO_2 resistant cement / steel
7. Numerical Simulation
8. Risk Assessment (FEP – Procedure)
9. Hydrodynamic models of Aquifers. 15/04/2010
10. Geo-mechanical rock behaviour.

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3 ttp://geoweb.princeton.edu/people/keller/deccan/deccan.htmttp://geoweb.princeton.edu/people/keller/deccan/deccan.htm

4 Evaluation of Basalt Formation in India for Storage of CO_2; S.N. Charan, B. Kumar and Ravi Shekhar Singh: presentation

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6 Geo-chemical modelling studies by PNNL, USA

CHAPTER 8. ECONOMIC CONSIDERATIONS OF CARBON CAPTURE AND STORAGE

8.1. Introduction

CCS is in relatively early phase of development in respect of its costs, timings and relative attractiveness versus other low carbon opportunities. Public understanding of CCS is low and there is some confusion around its true economics. There is high degree of uncertainty in estimating the cost of CCS because of significant variations between project's technical characteristics, scale and application. There is also uncertainty over how costs will develop with time and variability of input costs such as steel, engineering and fuel development.

8.2. Approach to determining cost of CCS:

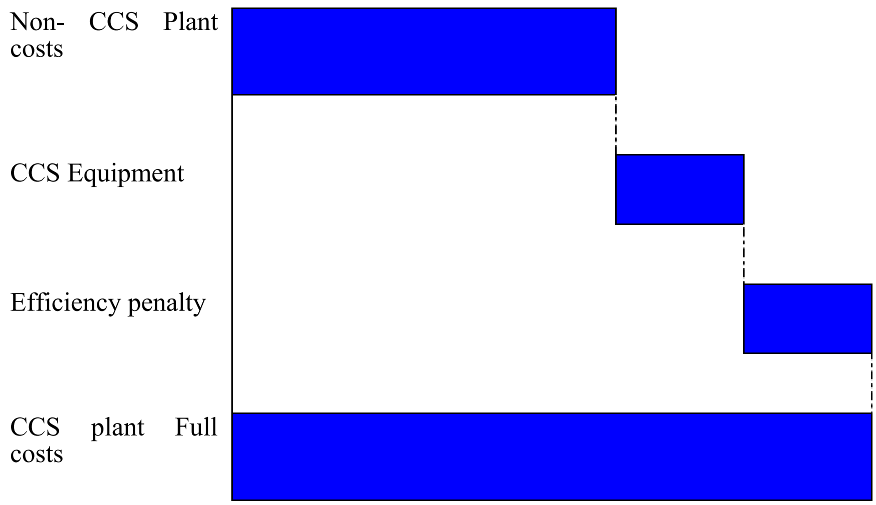
The cost of CCS is defined as additional full cost i.e. initial investments (capital costs) and ongoing operational expenditure of a CCS ready power plant compared to cost of state of the art non- CCS power plants with the same net electricity output and using the same fuel. The cost to include all components of value chain: CO2 capture at the power plant, its transport and permanent storage.

The cost of CCS is expressed in real term in US $ per tonne of net CO2 emission reduction, to allow comparison with other abatement technologies

- The capture costs also includes the initial compression of CO2 to a level that would not require additional compression or pumping if the storage site were closer than 300 km;
- Transport cost to include any boosting requirements beyond 300 km;
- For storage only geographical storage options such as depleted oil or gas fields and saline aquifers.

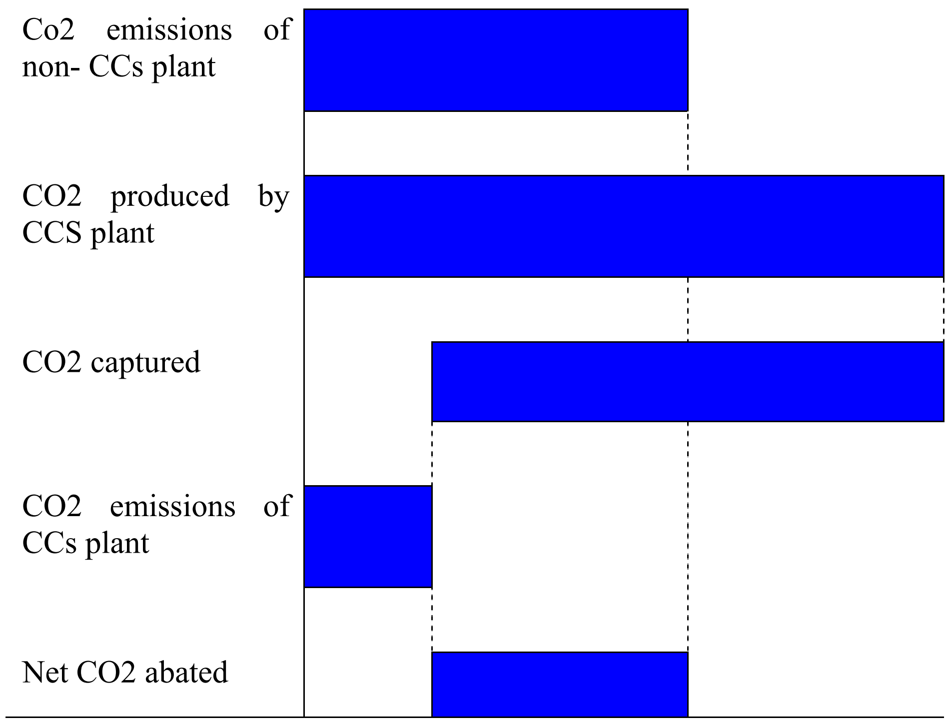
The cost estimation also indicates the likely cost level of CCS at different stages of development to early commercial and eventually mature commercial projects.

Table 8.1[71]: Additional CCS cost defined as additional full cost vs. state of art non CCS plant



[71] *Source: Carbon capture& storage: Assessing the economics McKinsey&Company*

Table 8.2[72]: CCS cost expressed as cost per tonne of net CO2 abated



The estimation of CCS costs is based on the following parameters:

1. Demonstration phase: Sub commercial scale to validate CCS as an integrated technology at scale and start learning curve- 300 MW capacity coal fired plant- by 2015 in Europe.

2. Early commercial phase: first full scale projects to start ramp up of CO2 abatement potential 900 MW coal fired thermal unit – by 2020

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72 *Source: Carbon capture& storage: Assessing the economics McKinsey&Company*

3. Mature commercial phase: wide spread roll out of full scale projects: significant abatement is realised – by 2030.

Table 8.3[73]: Estimation of CCS costs

	Demonstration Phase	Early commercial phase	Mature commercial phase
Definition	**Sub-commercial scale projects to validate CCs as an integrated technology at scale and start learning Curve**	**First Full scale projects to start ramp up of abatement potential**	**Wide spread European rollout of full scale projects. Significant abatement is realized.**
Key Assumptions			
Size	300 MW	900 MW	900 MW
Efficiency penalty	~ 10%	~ 10 %	~ 9%
Utilization**	80%	86%	86%
Economic life	25 years	40 years	40 years
WACC	8%	8%	8%
Transport distance	Onshore: 100 km Offshore: 200 km	Onshore: 200 km Offshore: 300 km	Onshore: 300 km Offshore:400 km (with booster)
Onshore/offshore split	80%/20%	50%/50%	20%/80%
Earliest start date	2015	2020	2030

* Assuming no technological breakthrough

[73] *Source: Carbon capture& storage: Assessing the economics McKinsey&Company-Team Analysis*

** A non- CCS plant is assumed to have utilization of 86%

8.2.1 Cost of installation of CCS demonstration projects:

The studies have indicated that given their smaller scale and focus on proving

technologies rather than optimal commercial operations, would cost between \$ 80-120 per ton CO_2 abated, the variation in cost ranges may be on account of variation in individual project costs.

8.2.2 Early commercial CCS projects:

The cost of CCs abatement may come down to in the range of US \$ 50-70 per ton for full scale projects likely to be operational by 2020. The cost could comprise of amount of US\$54 for capture phase, \$ 7-10 for transport and \$10-15 for permanent geological storage.

8.2.3 CCS costs beyond early commercial storage:

The later CCS costs would depend on several factors including learning effect on development of the technology, economies of scale, availability of favourable storage locations and actual roll out realised. Assuming a commissioning of about 80-120 projects by 2030, the total cost of CCS abatement of US\$ 40-65 per ton of CO_2 could be achievable. In case of higher roll out of 500-550 projects costs can further reduce to about \$ 35-50 per ton of CO_2 with the introduction of new process currently been researched.

8.3. Analysis of CCs cost components for early commercial phase:

8.3.1 CO2 capture phase:

This is the main cost block representing about 2/3rd of total CCS costs. The main cost drivers are the addition of capture specific equipments and efficiency penalty caused by the energy absorbed in the capture process and the additional capture specific equipment like air separation unit in the oxy- fuel technology or the CO2 scrubber for post combustion – increase in the initial capital expenditure and O&M costs.

The absolute efficiency penalty of about 10% (meaning plant efficiency reduces from around 50% to 40%) drives an increase in fuel consumption and requires over sizing of the plant to ensure the same net electricity output. Additional capital cost would contribute more than half of the CO2 capture cost i.e. $ 20-28 per tonne of CO2, while fixed and variable operational expenditure and fuel cost would represent the remaining $ 7 to 10 per tonne CO2 and $3 to 8 per tonne respectively.

At the present level of development, the choice of specific technology (pre combustion, post combustion, oxy-fuel) does not significantly affect the total cost of capture. However, relative shares of capital expenditure, operational expenditure and fuel cost may vary.

It is expected that after the first demonstration phase it would be possible to assess in much greater detail the technical and economic performance differences among the processes; allowing a prioritization depending on the specific application.

Table 8.4: Details of CO_2 Capture Costs

	Capture costs US$/ tonne of CO2 abated	Assumptions

Capital expenditure (CAPEX)	20-28	900MW plant US$ 3800-4500 per KW
Operating Expenditure (OPEX)	7-10	$ 1.4-3 per MWh- opex cost 2.5% of Capex for fixed opex cost
Fuel	3-8	Hard coal at US$ 90 per tonne
Total	30-46	

8.3.2 CO2 Transport Cost:

It assumes about 20-25 CCS projects in Europe, which is sufficient to form a small local transport networks and would achieve some economies of scale. Transport would be through pipelines and two main onshore (200km) and offshore (300km) storages respectively and of which 100-200 km would be a backbone line sufficient to support three plants. The estimated costs work out to be about $ 5 to 6 per tonnes of CO2 for on shore and $ 8 to 9 per tonne CO2 for offshore. More than 95% of this cost is initial capex.

8.3.3 CO_2 Storage Costs:

The total CO2 storage costs are calculated taking into account the initial exploration, site assessment phase and site preparation (drilling etc.) and operations over a period of 40 years and the likely costs associated with site closure and monitoring for further 40 years, a period sufficient to confirm permanent storage. The storage options include on shore, offshore, depleted oil and gas fields and deep saline aquifers. The storage cost is highly dependent on onshore versus offshore locations due to overall increase in equipment, exploration and site setup/closure costs in offshore cases. It is estimated that deep saline aquifers initially are likely to be more expensive than DOGF due to higher exploration and site mapping costs. The comparative costs are as following:

Table 8.5[74]: Comparative Costs according to type of Storage

Type of Storage	Comparative Costs
On shore	US$ 5-6 per tonne of CO2 DOGF US $ 7 per tonne of CO2- saline aquifers
Off Shore	US$ 15-17 per tonne of CO2

8.4. Conclusions: The way forward

8.4.1 Demonstration phase (2015)

In the early demonstration projects which are likely to roll out by 2015, the CCS costs are roughly double than those for the early commercial plants, at around US $ 70-90 per tonne of CO2, mainly due to smaller scale (300 MW), lower utilization rate (80%) and shorter life (25 yrs.) In general the demonstration projects are first of their kind and incur costs for the learning experience they are designed to deliver.

The transportation costs are comparable to the early commercial phase at around US$ 7 per tonne of CO2 primarily on account of cherry pick projects with favourable storage locations in

[74] *Source: Carbon capture& storage: Assessing the economics McKinsey&Company- Team Analysis*

order to minimize transport distances(around 100km). The long distance transport to storage locations could increase the cost of transportation considerably.

8.4.2 Early Commercial Phase :(2020 +)

The costly demonstration phase is fundamental step to reach the commercial stage of integrated CCS plants. In order to reduce the costs from the demonstration phase to the levels of early commercial stages, it is presumed that about 20-25 plants are implemented with integrated CCS.

8.4.3 Beyond Early Commercial Phase:(2030+)

Beyond early commercial development, the cost of CCS is expected to evolve differently at each stage of value chain and according to different driving factors, and effective cost reductions in capex of capture equipment, combustion technology efficiencies, source sink matching i.e. onshore and offshore mix etc. The overall impact of these factors on CCS costs would depend on the roll out scenario after the early commercial phase.

The introduction of new 'breakthrough' technologies, currently in the early stages of development phase such as chemical looping or membranes, could potentially lead to a step like reduction in cost of CO2 capture.

The estimates of long term CCS costs are structurally more uncertain and are highly dependent on the assumptions such as:

- Learning rates on currently non operational processes
- Possible new technologies
- Storage locations and availability
- Roll out hypothesis

- Costs may come down faster with broader roll out, so global introduction of CCS would increase the overall cost efficiency

8.4.4 Cost variations between CCS applications:

CCS has four main categories of applications

- New power plants (coal, gas, bio diesels)
- Existing power plants
- New CO2 intensive industrial operations such as refining, production of steel, cement

The cost economics of CCS ready power plants have been discussed in earlier paragraphs, the cost economics of CCS applications in the other three will be discussed here, primarily the CO2 capture phase because transportation and storage costs would not change.

8.5. Retrofitting of old coal power plants:

In general the retrofitting an existing power plant would lead to a higher CCS costs and are highly dependent on site specific characteristics including plant specification, remaining life and overall site layout.

There are four main factors which drive the cost increase of retrofits

i. Higher capex of capture plant-(existing plant configuration and space constraints)

ii. Shorter lifespan for capture installation

iii. Higher efficiency penalty leading to higher fuel costs

iv. ‘Opportunity cost’ of lost generating time(plant to be taken out of operation for retrofitting capture equipment)

It is estimated that the capture costs may be 30% higher as compared to a new CCS ready plant, but these will be plant specific and will vary from plant to plant and cannot be generalised.

8.6. Other Fossil fuel plants:

In case of biomass power plants scale and process characteristics are the main considerations. The higher cost of per ton CO2 abated in biomass plants could be linked to the relatively small scale of these plants (100 MW or less), higher penalty and lower efficiency.

In case of gas plants main reason for higher costs of CCS in the characteristic of flue gases which is produced in much higher volumes with 25-30% less CO2 concentrations as compared to coal plants. Thus much of the CCS equipment would have to be significantly larger with higher additional costs. Similarly, fuel cost is higher than coal. So efficiency penalty to run capture process would be higher.

8.7. Industrial Applications:

Refineries, steel and cement plants are also high emitters of CO2, accounting for about 25% of stationary source emissions in Europe and making them potential target of CCS. A large scale steel plant using integrated iron ore power plant blast furnace could produce 5-10 million tonnes of CO2 per year- more than 1000 MW coal fired power plant.

The specific industrial applications are very different in terms of process, scale, CO2 concentrations and gas stream characteristics; the available costs study show a very broad image. The resulting CCS cost would depend on specifics of situation. In general the need for retrofitting CCS facilities would increase the cost similar to a power plant. The application of CCS to processes in which the concentration of CO2 is already separated as a part of the production process (hydrogen production in refineries), cold lead to lower capture cost.

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REFERENCES:

Source: Carbon capture& storage: Assessing the economics McKinsey&Company

CHAPTER 9. CCS IN INDIA: STAKEHOLDERS SURVEY

9.1. Introduction of the survey on CCS Technology

The survey of stakeholders' perception on Carbon Capture and Storage technology has been undertaken by IRADe to support the research project under the National programme assigned by DST, GoI titled "Analysis of Carbon Capture and Storage (CCS) Technology in the context of Indian power sector".

The survey was intended to elicit viewpoints from the top-level experts and stakeholders related to Indian Energy and Power sector, their perception on the following matters:-

i. Their understanding about the importance of CCS technology in restricting the concentration of CO_2 (as a GHG) in the atmosphere.

ii. Importance of the CO_2 emissions from Power Plants as a threat to global warming.

iii. Chances of developing efficient CO_2 capture technologies with low marginal energy consumption after R&D.

iv. Difficulties in reaching energy efficient and safety technology components of CCS.

v. Whether India can benefit due to the business opportunities offered by R&D needed to develop energy efficient CCS technology.

vi. Time horizon perceived for use of CCS technology in view of high-energy consumption in developing world.

vii. Key barriers affecting progress in R&D in developing CCS technology.

viii. The barrier to use CCS which can be overcome by undertaking R&D

ix. Specific ideas on the necessity of utilizing CCS technology in the context of Indian Power sector to arrest climate change.

The questionnaire was designed to conduct the survey in June-July 2008, enclosed at Annexure-9.1.

This questionnaire was sent to about one hundred experts from different groups of stakeholders during July-September'08, through e-mail route, inviting response. Only two (2) experts responded. Five more replies were received through personal interviews.

Learning from this experience, a questionnaire focused on the responses needed from the stakeholders was designed in January 2009. This questionnaire (Annexure-2) was brief and focused. About one hundred (100) copies were distributed among the participants during the Energy and Climate Summit-09 held at Le-Meridien New Delhi- on 3-4th February 2009.

Responses were received from twenty seven (27) top-level professionals/ experts through persuasion and personal contacts.

The questionnaire was restructured in February 2009, to seek elaborate answers on same issues, needed to analyze the CCS technology in the context of Indian power sector. This questionnaire is placed at annexure 3. About 80 copies of this questionnaire were distributed during the conferences on CCS and low carbon technology at Anand, Gujarat and at Delhi during March and April 2009 respectively. The questionnaires were also emailed to experts for response. Twenty (20) responses were received on this questionnaire.

Therefore in all responses were received from professionals/Experts with the following breakup.

	Distributed Nos.	Responses received Nos.
Questionnaire 1	100	07
Questionnaire 2	100	27
Questionnaire 3	80	20
Total	**280**	**54**

9.2. Methodology used for the survey

The study was to identify the possible stakeholders and to conduct a survey with the help of questionnaire to gather information about the level of understanding, views and suggestion from the stakeholders on relevance and development of CCS technology in India. The perceptions and responses thus obtained will help in understanding the viewpoint of the stakeholders and will help in research and analysis of Carbon Capture and Storage in India with respect to Indian power plants.

Data gathering was done through well-defined and structured questionnaire covering key concerns. Key stakeholders were identified and were targeted for the response through e-mail, personal interview or by distributing the set of questionnaire in the conferences, summits, workshops etc. The respondents consisted of top officials from public sector utilities such as BHEL, NTPC, Coal India ltd, HPCL, ONGC etc, experts from key consultancies, private sector industries such as Arcelor-Mittal Steel, L&T, Shell, financial institutions, banks, government officials, academics, regulators, and researchers etc.

Enquiries were targeted to understand the awareness, views and suggestion of stakeholders i.e. power/energy experts. The analysis in this report uses the survey responses to draw conclusions.

9.3. Brief on the questionnaire used for the survey

Well-defined questionnaire was formed in consultation with the full team, keeping in view the requirement of the study and to get the maximum feedback from the stakeholders. The questionnaire covered questions on various issues associated with the project. The feedback on general awareness, views and suggestions, institutions of the stakeholders was necessary to determine the way forward.

The questionnaire was formed in a sequential way to get the truthful and maximum output from the respondents. The focus of questionnaires were (a) Overall role of CCS globally for mitigation of CO2 emission; (b) Overall Indian participation in the CCS development context; (c) Role of developed countries on technology development; (d) Scope of CCS demonstration project planning; (e) Capacity building for CCS demonstration project; (f) Large-scale deployment of CCS globally and in India; (g) R&D requirement leading to planning for demonstration project

The respondents were approached through various means and were interviewed at various forums.

9.4. Analysis of the respondents to questionnaire

The interviews reflected the participant's views, ideas and concerns related to the concept of CCS. Wide arrays of comments were collected from environmentalists, academics, journalists, activists, consultants, policy makers, public and private sector companies and government officials. Comments undertook issues such as safety, cost and economics, funding, demonstration plant etc., issues in light of certain concepts, and concept can be operationalized (e.g. policy space). The reply showed the interpretations of concept by different groups, which often mean different ideas on CCS.

The responses from the foreign experts (though obtained) were not included in the analysis so as to bring the clear picture of the survey.

A total of 54 interviews were collected from the respondents who are the key players from the target groups at various venues and locations. The team tried to gather the information from the experts in the fields throughout the country. The graph below shows the profile of the respondent

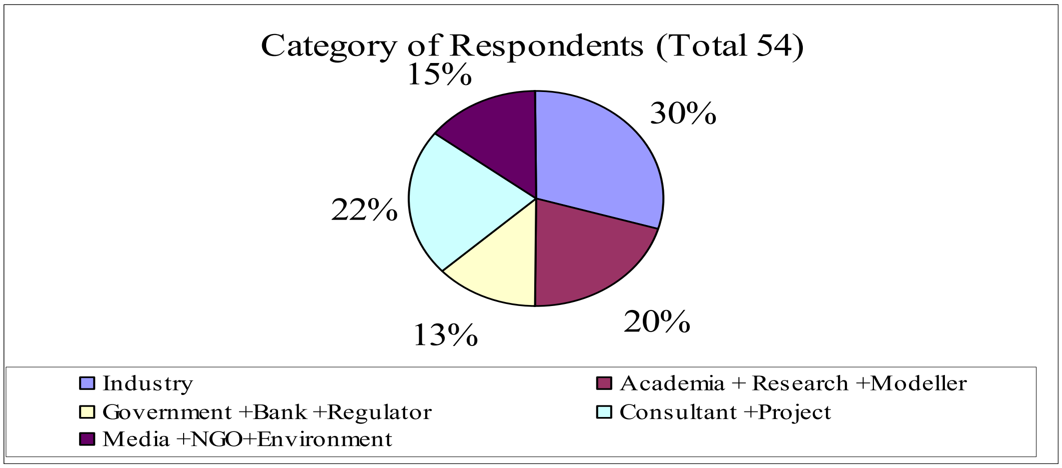

Figure 9.1: Category of Respondents

9.5. Categories of the respondents

The key stakeholders and decision makers were identified on the basis of there occupation and influential capabilities. The respondents were then divided into five broad categories. The categories being

vi. Industry

vii. Academic + Research + Modeler

viii. Government + Bank + Regulators

ix. Consultant + Project

x. Media + NGO + Environment

9.5.1 Industry

This category consists of Private and Public sector establishments. The private sector respondents consists of oil companies, steel manufacturer etc., on the other side the public sector companies consists of plant equipment manufacturers, oil companies, power producers, coal suppliers, fertilizer manufacturers etc.

9.5.2 Academic + Research + Modeler

This group consists of researchers, experts and faculties from various research institutions either directly or indirectly involved with Carbon Capture and Storage but have a role to play in the future development of CCS. The respondent targeted in this category consists of professors, academicians from best institutes and research establishment countrywide. The researchers and modelers response was obtained. The responses of technical researchers present in the National Conference on Carbon Capture and Sequestration: Challenges for Engineers-09, in the state of Gujarat was also collected.

9.5.3 Government + Bank + Regulators

This group of respondents consists of heads, key team members and decision makers from various government departments, regulatory commission, financial institutions, planning commission of India etc.

9.5.4 Consultant and Project consultants

The consultants and project consultants include consultants from key consultancy firms. This includes various scientific, engineering, regulatory consultancy groups actively involved in the projects and plays an important role in decision-making.

9.5.5 Media+ NGO+ Environmentalist

This category includes the opinion of environment and energy sector journalists, NGOs' and Environmentalist. This category plays a vital role in creating awareness, forming public perception and encouraging new technologies.

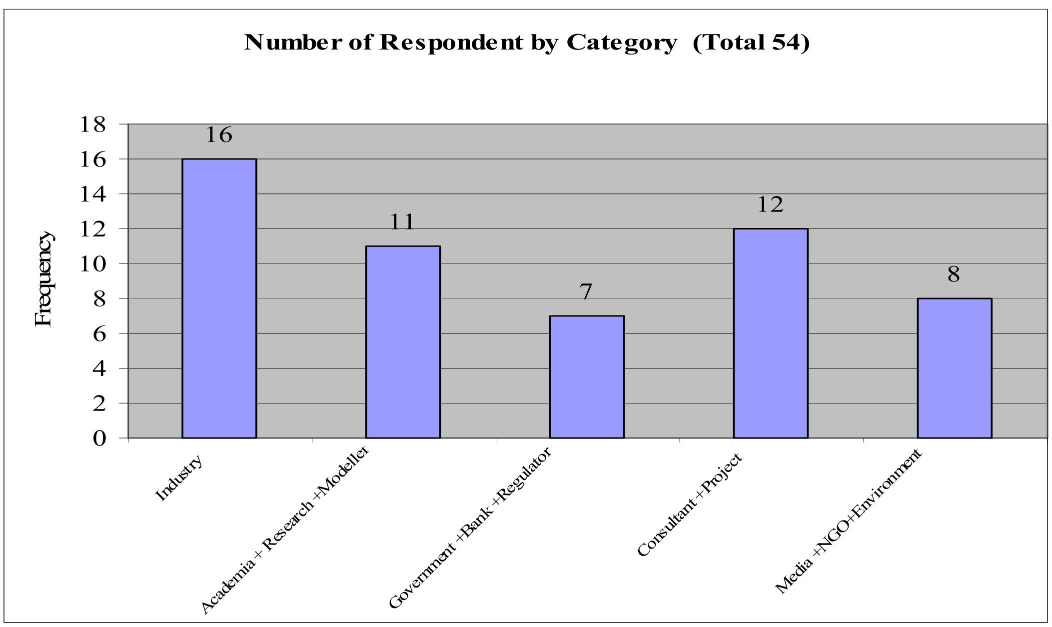

Figure 9.2: Sub Categories of Respondents

9.6. Survey Analysis:

9.6.1 Their understanding about the importance of CCS technology in restricting the concentration of CO_2 as a GHG in the atmosphere

Almost all the respondents from different categories take CCS as a very transformational technology for the Indian power sector.

Most of the **academicians, researchers, and modelers** agree that fossil fuels meet 80% of the energy demand today in the world, and will serve as major part in the future too, making CO_2 emissions from coal fired plants as a major problem in the future, this highlights the importance of emission control technologies like CCS to address climate change.

The professionals from **the government, bankers and the regulators** had similar views, they felt that coal will continue to be prime energy resource for the coming few decades and cutting emissions in the short term will mean using CCS; they added that in addition to renewable, India should also analyze all other options of available energy.

However, the **government professionals** also feel that for successful adoption of CCS and for it to becomea transformational technology: R&D effort must lead to lowering of cost of production, it should enable scale-ability, and it must be cost-effective. An improved version of the CCS process should be available (in this case – treatment), and it should be easy to use with additional features with new way of functioning.

CCS in India presently, fulfills none of these conditions and hence there are many barriers before it is actually implemented.

9.6.2 Importance of CO_2 emissions in power plants as a threat to global warming

Almost all the respondents surveyed agreed to CO_2 emissions from power plants to be a serious threat.

However noteworthy here, is the response of professionals from the **government bankers and regulators** who listed the **long term, short term** and **medium term** activities that needed to be carried out to deal with this problem of GHG emissions from power plants that lead to global warming.

(a) Long-term: On a long-term basisstrategic policy & regulations need to be focused on in the fields of R&D, Environmental Taxes etc. Reforms need to be made in regulatory frameworks for enablers to make alternative power solutions as a business choice, and lastly state's environmentally competitive indices for Green Budgets need to be revised.

(b) Medium-term: On a medium term basis,technology transfer options need to be considered, and capabilities need to be developed for technologies like IGCC etc with in India, improvement of grid infrastructure for off take as well as T&D is needed; and lastly the respondents added that up gradation of the existing power plants with efficient technologies or processes is needed.

(c.) Short-term: Immediate actions, the respondents added, were needed to - Upgrade the existing power plants with efficient technologies or processes & also quick action was required in gearing up all stakeholders for future consensus.

9.6.3 What are the chances of developing efficient CO_2 Capture technologies with low marginal energy consumption after R&D?

As a response to this question, amongst the **industrialists** most feel positively and feel that, their chances are very bright to develop efficient CCS technologies, however very few also disagree. The **academicians, researchers and modelers** similarly have the same opinion as industrialists and here to a large number agree to this notion. Amongst the consultants and project implementers roughly half of them agree to this notion

Amongst the media persons, NGO s and environmentalists too a large amount agree.

9.6.4 Difficulties in reaching energy efficient and safe technology components of CCS.

The **government professionals, bankers and regulators responded** to this issue in the following manner they feel that environmental & Safety Integrity in case of leakage is a major concern, especially since India has Marine National Parks listed in red data book, one of Mega Biodiversity centers, any leakage could augment the climate change impacts as well as affect the livelihoods of fisherman.

Others also add that trans-boundary issues and dispute Resolution will be a major barrier under which National & international law for (off-shore & onshore CCS project) will have to be revised according to the stakeholder involved.

9.6.5 Whether India can benefit due to the business opportunities offered by R&D needed to develop energy efficient CCS technology?

Most of the **industrialists** feel that business opportunities lie in Production of CH_3OH, useful fertilizer products and alcohols

The **academicians, researchers and modelers** also add that once CCS importance is realized by the developed countries new players and new technologies will come into the picture.

Amongst the **government bankers and regulators** most agree that, business opportunities lie in terms of carbon credit and trading; also awareness through R&D is required for development of CO_2 conversion to usable value added products which will partially offset cost of CO_2 capture.

The **consultants and project implementers** feel that business opportunities lie in technologies like: EOR (Enhanced Oil Recovery) where CO_2 injection enhances oil recovery and in reduction in gas of flaring

Large business opportunities others added also lie in carbon market in terms of issuing (reduction certificate); and in power Sector EPC opportunities in future; other power sector opportunities

9.6.6 Time horizons perceived to necessarily use CCS technology in view of high-energy consumption in developing world?

Approximately half of the **industrial professionals** take the time horizon as 2015, and few take it as medium term that is by 2020.

Amongst the **academicians –modelers and researchers** most take it as near term aim that can be achieved by 2015. Amongst The **government professionals and regulators** more than half take the time horizon as 2015, but still a considerable amount of them also take it as 2020. Amongst the **Media persons** and the environmentalists roughly half of them take the time horizon to be2015.

9.6.7 Key barriers affecting progress in R&D in developing CCS technology

The **researchers and modelers** feel that the major challenge lies in the development of new efficient solvents, which absorb CO_2 efficiently at the same time, which consume less power. Others add that insufficiency in data regarding gro-physical modeling and simulation is also a major barrier.

The response of **the government professionals and regulators** is given below they consider the following barriers that affect the progress in R&D.

- Cost Barriers: Costly technology as well as CCS components.
- Location barriers: Little proximity between stationary point of sources and prospective areas in sedimentary basins. Thus making the chances of deployment CCS India low.
- Lack of incentives for CCS – Regulatory or Environmental (CDM).
- Environmental & Safety Integrity in case of leakage is a concern, especially since India has Marine National Parks listed in red Data Book, one of Mega Biodiversity centers, any leakage could augment the climate change impacts as well as affect the livelihoods of fisherman.

Amongst the **consultants and project implementers** most feel that political red tape at the bureaucratic and ministerial level is a major challenge before implementing this technology. Other barriers were also identified as EIA clearances and stakeholder's reluctance.

9.6.8 The barrier to use of CCS, which can be overcome by undertaking R&D

The survey findings show that undertaking R&D will help overcome the following barriers, the category wise responses have been given below:

The **industrialists** reason, that though CCS is a matured technology for CO2 capture but it needs continuous development to address the key issues like economy and contractor design of the CO2 capture process, as far is sequestration is concerned mainly storage is done below sea level, and major sequestration sites have yet to be mapped.

The professionals of **government, bankers and regulators** have identified the following barriers:

Location barriers due to little proximity between stationary point of sources and prospective areas in sedimentary basins. Therefore, making likelihood of CCS deployment India low.

Some here have also identified, various **unresolved regulatory Issues** like:

(1) CO_2 Injection & Storage phase: Storage (Definition and Well Design), Property Rights, and Intellectual property Rights.

(2) Long-term Stewardship: Monitoring and Verification, and Liability

The **consultants and project implementers** add that effective R&D work will help to overcome barriers like high cost of CCS and its impact on efficiency of generating electricity on per unit of fuel used by power plants.

Inadequate understanding of risks, and burden of costs on developing countries are other such barriers that can be foregone with effective R&D

9.6.9 Ideas on necessity of utilizing CCS technology in the context of Indian power sector to arrest climate change.

Most of the **Industrialists** feel that CCS technology becomes necessary in Indian scenario as almost (3/4th or may be 2/3rd) power generated in India is through coal-, which are heavy CO_2 emitter.

Amongst the consultants and project implementers most feel that fossil fuels and power plants play major role in electricity production so CCS technology is the best solution. Professionals here added that if power production is done by IGCC & Coal Gasification route, CO_2 emission may be restricted and CCS is possible but production cost of power will go up.

Some responses obtained by this group also discouraged the utility of CCS in the Indian power sector the reasons given for this were:

- CCS opportunities in India are very limited due to non-availability of natural cavities near open cast mines.

- **That there exists a need to look into technologies and economics of emission reduction at stacks, efficiency measures, and storage options for carbon, and alternate use of carbon. So CCS can be an option.**

The **government professionals and bankers** seem to understand and state that for India, the adoption of CCS is an inevitable option to address climate change issues; they reasoned this with the points mentioned below:

Firstly they added that, Coal would always remain a major component mix of energy use:

- Existing coal-based power plants will continue to operate (and not scraped).
- New coal-based power plants will need to focus on better technological and/or operational efficiencies.

Secondly, presently the renewable energy contribution is still very low, for us to be fully dependent on it; this is owing to variable reasons, such as poor grid infrastructure, location specific, tariff structure, low plant efficiencies.

Lastly, Climate change impacts are already being felt, irrespective of developing (S & SE Asia) or developed countries (France, etc.).

Finally the respondents add that faster actions need to be taken into in emission reductions, and currently CCS despite its limitations seems to be one such option.

9.7. Conclusion drawn from the survey

The survey covers 54 individuals' professionals/ experts covering the whole spectrum of stakeholders without depending on the industry associations such as FICCI, ASSOCHAM, and CII. There are a number of respondents who are involved from various stakeholders in CCS

R&D projects. These respondents are working on development of clean technologies, carbon capture technologies and carbon storage technologies.

The group 3 and 5 among the respondents were of the view that developed countries should lead by example by establishing successful demonstration CCS. Projects ongoing R&D work to make CCS technologies techno-economic viable was indicated by the survey. Few respondents suggested that global R&D center on CCS be established in India. There could be business opportunities for India because we are in a position to establish manufacturing base. Referring to regulatory issues, the emerging suggestion appears that a body in India may compile development in regulatory aspect in developed countries and its tuning to Indian scenario may be worked out. Responding to funding issue respondent referred to the need of specific financial support. The CDM may be applicable only after demonstration projects have reached cost effective deployment. Except for international support for the project no other suggestion emerged from the survey.

Annexure 9.1

Questionnaire for Carbon Capture & Storage (CCS)

Send by e-mails to 100 experts- 2 replies received Personal interview: 5 replies received

Organization Name	
Name: (optional)	
Nature of your Company (Gov, PSU, Energy, Power, Education, R&D, Cons, Bank, others (Please specify)	
Address: Email Add Telephone	
Nature of Activities of your organization (Regulatory, Banking, Finance & Insurance,	

Environment, R&D, Manufacturing, Power & Energy, Academics, consultancy, NGO, Others)	

Q.1 Please rank in order of importance, the Environmental issues facing the world and India in Particular today.

Water Pollution

Toxic Waste.

Degrading Eco-systems.

Urban sprawl

Climate Change or Global Warming

Ozone depletion

Q.2 Give some options of mitigation of GHG emissions to atmosphere enhancing energy efficiency

Carbon Capture and Storage technology.

Fuels shift to natural gas and renewable energy

Co-generation

More efficient vehicles (hybrid cars)

Alternative fuels (ethanol, gas, biodiesel, hydrogen)

End-use savings/ energy conservation

Afforestation/ re-forestation

Others (Please specify)

Q.3 Are you aware of CCS

Yes

No – Please refer to the attached article.

Q.4 What is the R&D opportunities and priorities for mitigation of carbon dioxide from the industries?

Oxy-fuel

Fuel switching

Fuel efficiency

Others (Kindly specify)

Q.5 The Scientists and technologists in Developed countries are working on development & demonstration of CCS technology for mitigating GHG emission from power sector. What are the issues needs to be considered in the Context of Indian Power?

Increasing efficiency of the Boiler units.

Capture of Carbon dioxide from flue gas.

Development of IGCC / Oxy-fuel for use with Indian Coal.

Nuclear

Others (Specify).

Q.6 What do you think are the key barriers to be addressed in acceptance for demonstration of CCS Technology?

Public and worker safety?

Environmental protection?

Cost and economic factors?

Technological Know-how?

Land Use?

Others (Please specify)

Q.7 the expected year of commercialization of CCS in power sector is beyond year 2015. What should be R&D priorities in Indian context?

Capturing Carbon dioxide from the flue gas and regeneration of capturing medium.

Suitable geological sites including saline aquifers.

Storage in coal bed and coal bed methane.

Transporting CO_2

Others (Please specify)

Q.7 Is your organization involved in development of the Carbon Capture and Storage (CCS) project? Please specify your sector of Interest.

No

Yes (Please specify)

Development of clean coal technologies

Capture

Transportation

Storage

Monitoring

Q.8 Are there any particular issues that need to be taken into account with regard to CCS when considering the use of policy mechanisms to reduce CO_2 emissions

To ensure safety of storage sites

To provide clarity for project developer

Mining, drinking water and environmental laws

Liability: local and global risks

UN Convention on the Law of the Sea

London Convention and its Protocol

Preliminary guidance on OSPAR: CCS for CO_2 from offshore installations not prohibited

Others (Please specify)

Q.10 India will have business opportunity in CCS, if one makes a beginning with R&D projects. Do you agree?

Yes

No

Kindly explain (briefly) your views

Q.A What are the major issues needs to be addressed urgently on mitigation of greenhouse gas emission specific to Power sector? At what stage India may consider CCS technology to mitigate CO_2 emission.

Q.B what do think are the key factors affecting progress in R&D in CCS?(Tick mark your choice)

Commercial

Technical

Regulatory

Safety

Others (please specify)

Q.C How do you visualize progress in CCS in the future?

Q.D What type of policy instruments, policies and Processes development would make CCS more acceptable?

Q.E What are the likely public reactions to concerns about CCS, and how could concerns be addressed?

Q.F If CCS technology can mitigate the problems associated with Climate Change, then what quantum of commercial cost of incorporation of technology can be considered reasonable?

Q.G Indian economy is in growth trajectory, hence total GHG emission will continue to increase. What indicators will guide effective control anthropogenic emission?

Energy consumption against GDP Growth.

Per Capita GHG emission

Sectoral Approach – energy efficiency parameter in each sector of Industry.

Q.H what level of international coordination exists between developed countries and India? What is the balance between Public sector and private sector RDD&D in Industries and power sector in particular?

Q. I What technical target will the technologies need to achieve in order to succeed and Over what time frame?

Q.J What are the key elements of government policies needed to help achieve technology targets, and to achieve deployment/ commercialization as technical targets are achieved?

Q.K What is the current status of government policies for CCS? What is needed in order to promote active participation of PSU and private power generating industry to support R& D in CCS?

Q.L What stakeholder groups are important to engage?

Annexure 9.2

Questionnaire to Top-level Professionals & Experts of Energy & Power Sector

Distributed to experts during Energy & climate summit Delhi (Feburary'09)

Distributed 100- 27 responses received

Note: The survey will report the results anonymously.

(Analysis of Carbon Capture and Storage (CCS) technology in the context of India)

IRADe has been assigned a research (study) project to analyze possibility of using CCS technology in India esp. power Sector by Department of Science and Technology. The Questionnaire here intends to solicit the opinion of the 'Top Professionals and Experts' in the area to help analyze the issues involved.

Introduction: CCS technology consists of

Capture (separation) of CO_2 from flue gases (gas stream) after combustion.

Transporting CO_2 underground storage.

Storing CO_2 underground in saline aquifers, sedimentary basins and depleted oil/gas/coal reservoirs.

CCS technology is considered useful to stabilize GHG concentration in the atmosphere below dangerous levels to prevent anthropogenic interference and climate change even though it consumes energy. Concentration of CO2 is already reaching dangerous levels due to large growth in energy consumption all over the developing world.

Kindly fill up the brief Questionnaire and leave it with the organizer or on your seat.

Questionnaire:

Name:………………………………………………………………………………

Designation & Organization:………………………………………………

Contact No. (Ph)………………(M)……………… E-mail Id…………………

Area of your Expertise:……………………………………………………

(Note: Ranking 1(Least) to 5 (highest))

How serious is the threat of global Warming. 1 2 3 4 5

There is an increase in emission of CO2 per unit of electricity generated when using CCS technology, but almost entire CO2 produced is buried under ground and reduces CO2 Concentration. How do you rank importance of using CCS technology to prevent disaster from climate change or till the time we develop a sustainable energy consumption pattern in the world?

1 2 3 4 5

What are the chances of developing efficient CO2 Capture technologies with low marginal energy consumption after R&D?

1 2 3 4 5

During Research and development phase to apply CCS technology in Indian power sector; how difficult are the following components of CCS technology to reach energy economy and safety

CO2 Capture from flue gases. 1 2 3 4 5

Transportation of CO2 to storage sites 1 2 3 4 5

Storage of CO2 under ground for long period. 1 2 3 4 5

India will have business opportunity in CCS, if one makes a beginning with R&D projects. Do you agree?

YES NO

What types of business opportunities?

What is the time horizon you would suggest to induce CCS technology as a compulsory action to arrest CO2 concentration levels considering the high rate of growth in energy consumption throughout the developing world?

5 10 15 20 25

What are the key barriers affecting progress in R&D in CCS? (Please rank 1-6)

Technical feasibility and know how 1 2 3 4 5

Safety 1 2 3 4 5

Cost and Economic 1 2 3 4 5

Storage 1 2 3 4 5

Monitoring 1 2 3 4 5

Regulatory 1 2 3 4 5

Which of these barriers could be overcome with R&D?

Technical feasibility 1 2 3 4 5

Safety 1 2 3 4 5

Cost and Economic 1 2 3 4 5

Storage 1 2 3 4 5

Monitoring 1 2 3 4 5

Regulatory 1 2 3 4 5

Your specific comments if any, on the necessity of utilizing CCS technology for arresting climate change and use of CCS technology in the context of Indian Power Sector?

Annexure 9.3:

Survey on Carbon Capture & Storage & R & D Priorities

Distributed during Conference on CCS at Anand, Gujrat (March'2009) and during Workshop on Low Carbon technologies at Delhi (April'2009) Distributed 80 Copies- 20 responses received

Questionnaire for Carbon Capture & Storage (CCS)

Your Detail

Note: The survey will report the results anonymously.

1	Organization Name	
2	Name: (optional)	
3	Nature of your Company (Government, PSU, Energy, Power, Academic, R&D, Consultant, Bank, others (Please specify)	

4	Address: Email Add Telephone	
5*	Nature of Activities of your organization (Regulatory, Banking, Finance & Insurance, Environment, R&D, Manufacturing, Power & Energy, Academics, consultancy, NGO, Others)	

* Essential

<u>The key follow up questions are: Q6,7,8,9,10,11,12</u>

Overall role of CCS globally

Q1. Do you think it is possible for the world to address climate change effectively without CCS technology?

Yes – renewable and energy efficiency will mean we can stop using coal

No – coal will continue to be part of our energy mix, so we must address coal emissions

Please explain

Overview

Q2. What are your overall hopes and fears regarding CCS technology? Please explain your reasoning

Overall Indian CCS context

Q3. Do you think that greenhouse gas emissions from Power Plants are a serious problem that needs to be dealt with in the short/medium/ longer term ?

Serious – Yes / No

If Yes, then Short / Medium / Long term?

Q4. Do you perceive Carbon Capture and Storage (CCS) as a transformational technology that has the potential to complement other CO2 mitigation options from Indian power plants?

Scale of 0-10 (0 being no, 10 being yes – very transformational)

Please comment to explain reasoning

Q5. Overall, what role do you think India can play in the development of CCS technology?

Role of developed countries

Q6. What do you think industrially developed countries should do on CCS technology, to lead by example?

Q7. What kind of financial support should industrially developed countries make available to countries such as India, to help with CCS?

Q8 In your view, what type of policy instruments – whether international instruments (e.g. CDM) or domestic policy instruments – would make CCS technology more acceptable in India?

International policy instruments – please describe

Domestic policy instruments – please describe

Both international and domestic policy instruments – please describe

CCS demonstration

Q9. Do you think it would be helpful for India to demonstrate CCS technology on its soil in the near term / medium term / long term – or never?

Near term – by 2015

Medium term – by 2020

Long term – beyond 2020

Never

Q10. If the developed world did more to lead by example on CCS, then when do you think it would be helpful for India to demonstrate CCS technology on its soil?

Near term – by 2015

Medium term – by 2020

Long term – beyond 2020

Never

Q11. If so, what kind of barriers do you think need to be overcome in order for CCS demonstration in India to be attractive? Do you see any opportunities to overcome some of these barriers?

Please list barriers

Opportunities – yes / no

If yes, please describe

Capacity building for CCS demonstration

Q12 Do you feel that enough expertise exists in India to assess and calculate the technical and social benefits of adopting CCS technology in the longer term?

Yes / No

If no, would you like to suggest any specific capacity building activities for the demonstration of CCS technology in India where industrially developed countries could potentially play a helpful role? What kind of technical support should industrially developed countries make available to countries such as India?

Please describe:

(i) Specific capacity building activities

(ii) Technical support from industrially developed countries

Large-scale deployment of CCS

Q13 In your opinion what are the key barriers to be addressed in order for *large-scale deployment* of CCS technology in the Indian Power Sector to become viable? Please elaborate specifically in relation to public/ worker safety, environmental protection, cost/ economic factors/ maturity of the technology / stakeholder acceptability/ land usage. Pick top 3

Public/ workmen safety,

Environmental protection,

Cost/ economic factors

Maturity of the technology

Acceptability by stakeholder

Land usage

Q14 Under what conditions should India start considering *large-scale deployment* of CCS technology for its new build power plants?

R&D

Q15 Commercially viable CCS solutions for the power sector will be available post 2016. With reference to this and your response to Q3, what should be the focus of CCS R&D in the Indian context?

Q16 Do you think that CCS R&D will give India new business opportunities?

Yes / No

Your organization

Q17 Is your organization involved in development of a CCS project (e.g. an R&D project)?

Yes / No

If yes - please specify your interest in CCS technology:

Development of clean coal technologies

Carbon capture

Transportation of carbon dioxide

Carbon storage

Monitoring of CO2 in Geological storage site and adjacent to it.

IT , Instrumentation & Automation

CHAPTER 10. ROADMAP OF CARBON CAPTURE AND STORAGE (CCS) TECHNOLOGY IN INDIA

10.1. Introduction

. Current trends in energy supply and use are patently unsustainable – economically, environmentally and socially. Without decisive action, energy-related emissions of CO2 will more than double by 2050 and increased oil demand will heighten concerns over the security of supplies. We can and must change our current path, but this will take an energy revolution and low-carbon energy technologies will have a crucial role to play. Energy efficiency, many types of renewable energy, carbon capture and storage (CCS), nuclear power and new transport technologies will all require widespread deployment if we are to reach our greenhouse gase mission goals. Every major country and sector of the economy must be involved. The climatologists based on results of General Circulation Model (GCM) recommend that emission mitigation effort to be undertaken to stabilize CO_2 concentration in atmosphere at 450 ppm

Figure 10.1 exhibit that in a baseline scenario, the global cumulative CO_2 emission per year grows from 27 Giga Ton (Gt) in 2005 to 42 Gt in 2030, and 62 Gt in 2050. In order to stabilize at 450 ppm the cumulative CO_2 emission per year has to be brought down to 23 Gt in 2030, and 14 GT in 2050. The goal of mitigation effort should be to reduce carbon dioxide emission by technological, management, and administration means by 19 Gt by 2030, and 48 Gt by 2050.

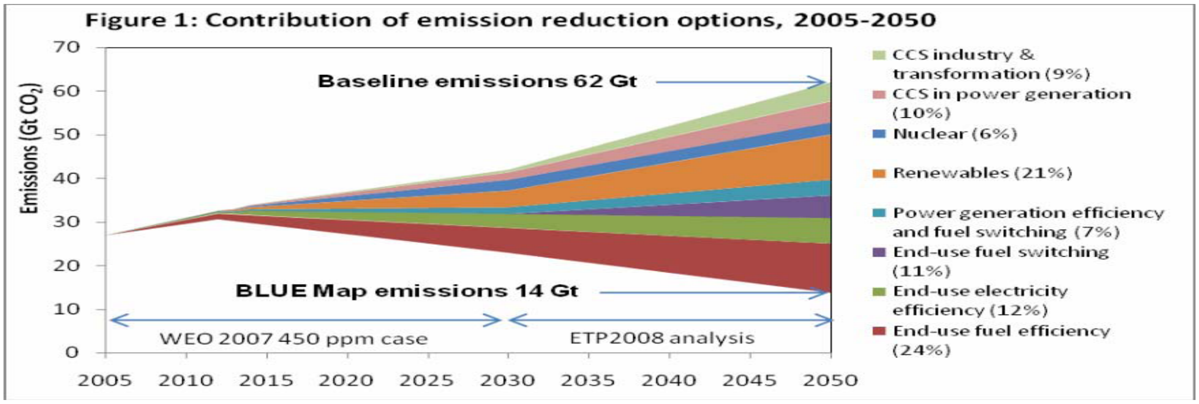

Figure 10.1: Cumulative global CO_2 emissions and technology share in energy reduction Time frame 2005-2050

Figure 10.1 also indicates the strategy of mitigation and evaluation of impact of each strategy in cumulative global mitigation action. These are:

- End use fuel efficiency by all economic sector;
- end use electricity efficiency – by using energy efficient equipments, and cut down on consumption ;
- End use fuel switching with focus on renewable and clean energy ;
- Power generation efficiency and fuel switching – super-critical, ultra super-critical, IGCC, oxyfuel etc;
- Renewable as replacement of fossil fuel;
- Nuclear as alternate source of energy and resolving issues connected with nuclear energy application;
- CCS in power generation; and
- CCS in Industry and process transformation.

Similar analysis has been done by researchers at Bellona Foundation, Norway.[75] The results are indicated pictorially in Figure 10.2. and indicates that how global CO_2 emissions can be reduced by 71 percent in 2050 compared to emissions today by using a combination of Energy efficiency, Renewable Energy and CCS technologies.

The analysis of results presented in both the Figure 10.1 and Figure 10.2 indicate the greater emphasis on energy efficiency measures and CCS technology between 2030 and 2050 for global CO_2 emissions reduction. Thus the technology development of CCS and energy efficiency in industries should be complemented. The renewable technology development can have separate development strategy, but R&D is needed to substitute renewable in place of fossil fuel, to the maximum extent feasible.

[75]Source: Why CO2 Capture and Storage (CCS) is an Important Strategy to Reduce Global CO2 Emissions, Dr. Aage Stangeland, The Bellona Foundation, June 1, 2007)

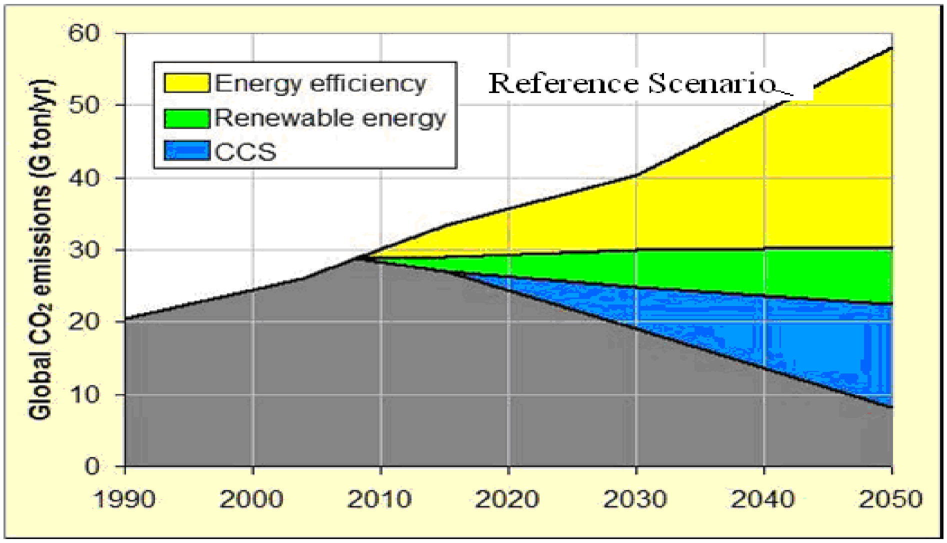

Figure 10.2: Reduction of Global CO_2 emissions by 2050

10.2. Thermal Power plants as source of GHG:

The analyses of anthropogenic GHG emissions indicate that maximum cumulative GHG emissions are from thermal power plants. The technology development is focused on enhancing efficiency of thermal power plant with development and deployment of innovative technologies like IGCC, Super/ Ultra-super critical boilers, Oxy-fuel combustion etc. The CCS technology features in curtailing subsequent CO_2 emission to atmosphere by capturing CO_2 from flue gas and storing CO_2 in the sub-surface of earth. The benefits of mitigation of CO_2 emissions will be visible in long term as it has long life in atmosphere, and hence it is difficult to quantify.

The current developments in India connected with CO_2 emissions mitigation in practice are as follows;

- Preparation of CO_2 and GHG Emissions Inventory at the national level (Central Electricity Authority)

- Improvement in efficiency of existing (old, inefficient plants) thermal plant by Renovation and Modernization.Mapping of thermal power station for higher energy efficiency is being carried by Central Electricity Authority, Bureau of Energy Efficiency in collaboration with GTZ. Use of automation, communication, and IT are being applied for enhancing process, logistics and management efficiency.

- The new Greenfield plants are having the state of art technology ensuring higher efficiency technologies (Super/ Ultra super critical technology are being incorporated in UMPP). Most of these units are being located near mines (pit head power plant); and units will practice best mining practices. The UMPP at Krishnapatnam, Mundra, Tadri, Girye, Cheyyur are coastal power plants and they plan to use of imported coal.
- R&D on Oxyfuel, ultra-super critical (steam temperature above 700 degree centigrade and 300 ata) and IGCC pilot plant are being developed by BHEL and NTPC
- Use of renewable energy, use of biomass, carbonaceous waste in the existing heating scheme of the boilers.
- Alternate energy source can be used, where the opportunity exists.
- Optimum harnessing of waste heat energy in the industrial process loop.
- The research and academic institution are working on development of Carbon Capture and Storage technology (CCS) and its component.

The planning of research for development of indigenous CCS technology for a demonstration project has different phase of advancement. Indigenous developments of the mitigation process require active participation of the government bodies, scientific community (academics & research institutions), design bureaus and consultants, manufacturing technologists. Each has a defined role. These design development leading to successful execution of demonstration project have to be established with :

(a) Basic and applied research on each component of CCS technology;

(b) Gap analysis between indigenous capability and off the shelf-technology availability in developed countries will guide scope of technology transfer;

(c) Analysis of technology of each component for their maturity for pilot project;

(d) Planning for capture ready plant. Define profile of capture ready plant;

(e) Project design for an integrated CCS pilot /demonstration project;

(f) Approval and permission of competent authority for regulatory checks and land use;

(g) Execution of demonstration projects; and

(h) Lessons learnt for subsequent project up-gradation, and scalability.

Figure 10.3 exhibits flow diagram of CCS scheme development phases commencing from scientific and technological development globally, and the efforts of different researchers. The conceptual process design is distributed into separate components for conducting basic and applied research for identifying suitable indigenous technology. Pilot projects are to synthesize suitable technology for engineering of higher level of components. The pilot projects are further integrated to design demonstration project.

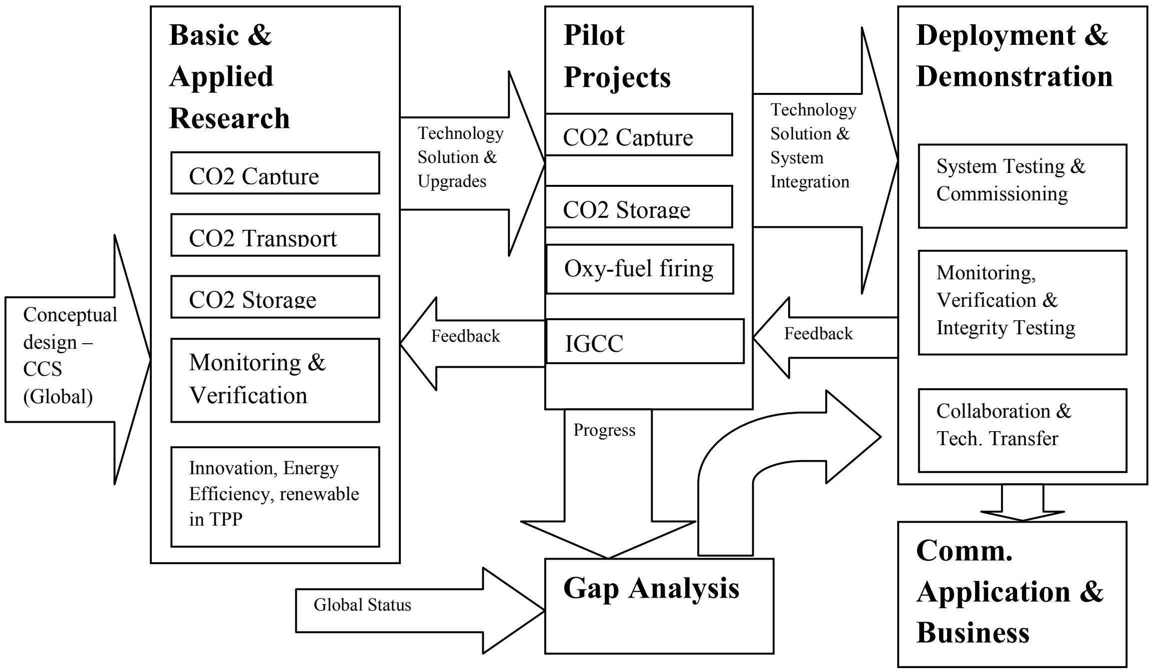

Figure 10.3: CCS component development through R&D and Demonstration project

India is the member of Carbon Sequestration Leadership Forum (CSLF), and FutureGen project. The state owned leading Indian exploration company 'Oil and Natural Gas Corporation' (ONGC,) is establishing a carbon sequestration pilot project for EOR at Ankleshwar. The participation of India in the FutureGen[76] project had the sanction of the government. Clearance of MoEF is essential for Environment Impact assessment (EIA). The state governments and the states sharing boundaries with the plant location where project will be implemented have permit issuance authority on the project, in context of state and national regulatory framework, health & safety, and land use. Without resolving risk factors associated with geological storage & transport, and pollution at capture stage, it will be difficult to obtain EIA approval.

[76]The American Clean Energy and Security Act of 2009 (ACESA) provides a number of important provisions that will facilitate the demonstration and deployment of carbon dioxide capture and storage (CCS) technologies.

Analyzing the current scenario of power sector development, it appears that earliest testing of CCS demonstration project can be feasible in the thirteenth five year plan i.e. 2017-2022. The eleventh five year plan is nearing its end. The large number of power plants to be commissioned during 12^{th} plan are under construction or are in the process of placing orders for equipment and starting construction. The innovative concept for capture ready units can be thought of for thermal power plants to be commissioned in 13^{th} plan and beyond.

Table 10.1 indicates the key parameters associated with GHG emissions in India. The annual per capita emission in India was 1.13 tons of CO_2, against global average 4.28 tons of CO_2. In the year 2006 per capita electricity consumption was 503 kWh. The government under its commitment of Power for all (The government will provide minimum power lifeline consumption of 1 unit/ household/ day by 2012, ensuring accessibility of electricity to all households) by 2012 will result in the Per capita consumption of power increase to 1000 kWh by 2012. There will be corresponding increase cumulative CO_2 emission.

Table 10.1: Key GHG Emission Indicators- India[77]

Key GHG Emission Indicators	
Population (Million)	1,109.81
GDP (billion 2000 US$)	703.33
GDP (PPP) (billion 2000 US$)	3671.2
Energy Production (Mtoe)	435.64
Net Imports (Mtoe)	134.83
TPES (Mtoe)	565.82
Electricity Consumption (TWh)	557.97
CO_2 Emission (Mt of CO_2)	1249.74
Electricity Consumption per capita (KWh/capita)	503
CO_2 Emission per capita (t of CO_2/ capita)	1.13
Global Average- CO_2 Emission per capita (t of CO_2/ capita)	4.28

10.3. A Recommendation of IEA on CCS Roadmap:[78]

IEA has made an elaborate study on the role of CCS technology in mitigation of global carbon dioxide emission and documented a roadmap for development and implementation of the CCS scheme in power sector[79]. Each developed country has a road-map for implementation of CCS technology. The IEA report covers all options of CO_2 emission mitigation as projected in Figure

[77] www.wri.org

[78] http://www.iea.org/Textbase/techno/etp/roadmap.pdf , and http://www.iea.org/Textbase/subjectqueries/ccs/technology_status.asp

[79] Energy Technology Map, IEA report

10.1. The IEA studies have projected that end-use energy efficiency will account for 36% to 44% of emissions reductions, exhibited in ACT (accelerated technology map) and BLUE line under alternative policy scenario, compared to the baseline. In the BLUE scenario, renewable represent 21%, CCS represents 19% of reductions, power generation efficiency and fuel switching 7%, and nuclear 6%. In the BLUE map scenario, the share of coal in power generation declines from 52% in the baseline scenario to 13%. The share of gas declines from 21% to 17%, reflecting the fact that CCS – applied to virtually all coal-fired power plants in this scenario – is significantly more expensive per ton of CO_2saved for gas than coal. About 76% of gas-fired power is generated from plants equipped with CCS. The technologies included in the ACT map are energy efficient buildings, CCS, bio-fuels, electricity production from nuclear sources, renewable and natural gas. IEA has also established another scenario where new technologies are deployed faster than ACT; called TECH. By TECH option global CO_2 emission can be lower by 27% by year 2050 reference to year 2007. Table 10.2, indicates projection of IEA on CCS technology Deployment, RDD & D and envisaged Commercial Cost. While, Table 10.3, indicates the timeline of progress in CCS Technology as indicated in IEA document.

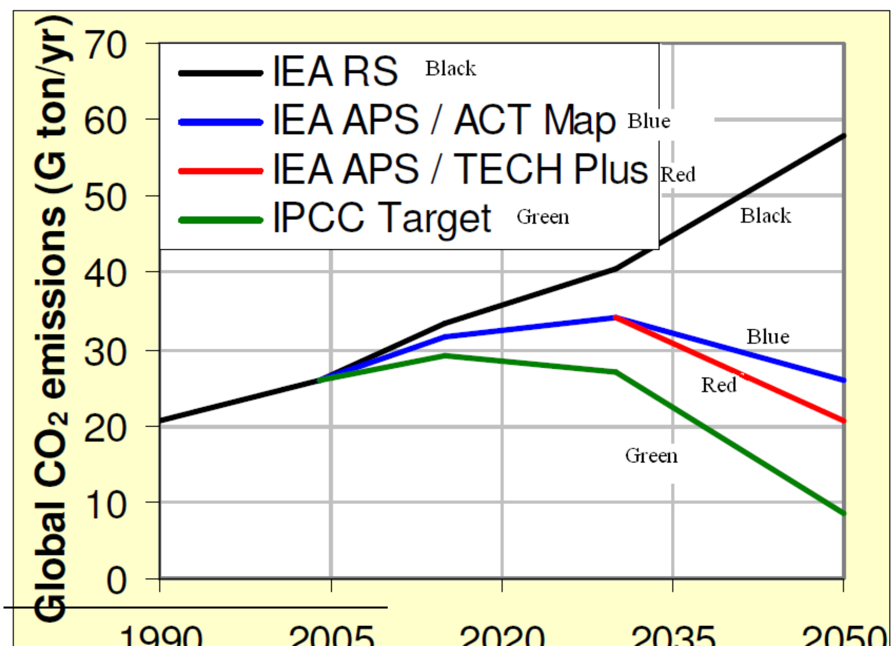

Figure 10.4[80] Global CO_2 emissions based on IEA scenarios

[80] http://www.bellona.org/position_papers/WhyCCS_1.07/#1b

Black line: the Reference Scenario (RS).

Blue line: the Alternative Policy Scenario (APS).

Red line: extrapolation from APS in 2030 to the TECH Plus scenario in 2050.

Green line represents the IPCC target of 50 to 80 percent reduction in global CO_2 emissions by 2050

Table 10.2: Progress in CCS Technology Timeline

<table>
<tr><td colspan="7">TECHNOLOGY TIMELINE</td></tr>
<tr><td></td><td>2005</td><td>2010</td><td>2020</td><td>2030</td><td>2040</td><td>2050</td></tr>
<tr><td rowspan="2">Baseline</td><td colspan="2">10 demo plants 2008-2020: USD 12 bn</td><td colspan="2" rowspan="2">Progress continued</td><td colspan="2" rowspan="2">CCS Technology limited to enhanced hydrocarbon recovery and storage in depleted reservoir</td></tr>
<tr><td colspan="2">Storage R&D 2008-2030: USD 1 bn</td></tr>
<tr><td rowspan="3">ACT</td><td colspan="2">20 demo plants 2008-2020: USD 25 bn</td><td rowspan="3">Development of regional transport infrastructure 2015-30</td><td rowspan="3">9% of Power generation by 2030</td><td rowspan="3">Progress continued</td><td rowspan="3">16% of Power generation with CCS 2050</td></tr>
<tr><td colspan="2">Storage R&D 2008-2030: USD 2 bn</td></tr>
<tr><td colspan="2">Basin capacity estimates 2008-2012</td></tr>
<tr><td rowspan="3">BLUE</td><td colspan="2">10 demo plants 2008-2015: USD 15 bn</td><td rowspan="2">20 full-scale demo plants 2015-2030: USD 30 bn</td><td rowspan="3">12% of Power generation by 2030</td><td rowspan="3">Progress continued</td><td rowspan="3">30% of Power generation With CCS 2050</td></tr>
<tr><td colspan="2">Major DSF storage validated 2008-2012</td></tr>
<tr><td></td><td colspan="2">Development of transport infrastructure 2010-2020</td></tr>
<tr><td colspan="7">In this roadmap, commercialization assumes an incentive of USD 50/t CO_2 saved. ACT--Represents Emission Stabilization & BLUE represents 50% emission reduction</td></tr>
</table>

Table 10.3: Technology Deployment Projection of IEA, RDD & D and Commercial Cost

	ACT 2.9 GT CO2 savings by 2050			BLUE 2.9 GT CO2 savings by 2050		
	Global Deployment Share 2030	RDD&D Inv. Cost* USD Billion (2005-2030)	Commercial Inv. Cost* USD Billion (2005-2030)	Global Deployment Share 2030	RDD&D Inv. Cost* USD Billion (2005-2030)	Commercial Inv. Cost* USD Billion (2005-2030)
OECD NA	35%	25-30	160-180	35%	30-35	350-400
OECD Europe	35%	25-30	100-120	35%	30-35	150-200
OECD Pacific	10%	7-8	30-40	10%	10-12	70-80
China & India	15%	10-12	280-300	15%	12-14	400-450
Others	5%	3-4	60-70	5%	4-5	250-300

Leaders of G8 countries have shown commitment to establish twenty fully integrated CCS demonstration projects. They envision industrial scale commercial projects execution by the year 2020. The industrially developed countries have established Global Carbon Capture and storage institute, Australia. Similar institution in UK, Germany, Canada, USA are working towards early deployment of CCS demonstration projects, while sharing knowledge with International Energy Agency (IEA), Carbon Sequestration Leadership Forum (CSLF).

10.3.1 Key actions needed as recommended by IEA[81]

- Develop and enable legal and regulatory frameworks for CCS at the national and international levels, including long-term liability regimes and classification of CO_2 for storage.
- Incorporate CCS into emission trading schemes and in post-Kyoto instruments.
- RD&D to reduce carbon capture cost including development of innovative technology, and improve overall system efficiencies in power generation, also including innovative technologies such as IGCC, oxy-fuel, chemical looping to enhance CO_2 concentration in flue gas to enhance efficiency of carbon capture process.
- RD&D for storage integrity and monitoring, Validation of major storage sites, Monitor and valuation methods for site review, injection & closure periods. Define ownership issues of storage site for defining short term responsibilities.
- Raise public awareness and education on CCS.
- Assessment of storage capacity using Carbon Sequestration Leadership Forum methodology at the national, basin, and field levels.
- Governments and private sector should address the financial gaps for early CCS projects to enable widespread deployment of CCS for 2020.
- New power plants to include capture/storage readiness considerations within design by 2015.

[81] http://www.iea.org/Textbase/techno/etp/roadmap.pdf

10.3.2 Key areas for international collaboration

- Development and sharing of national and global legal and regulatory frameworks.
- Develop international, regional and national instruments for CO_2 pricing, including CDM and ETS.
- Global participation in development and execution of demonstration projects similar to schemes proposed by Organizations: CSLF, IEA GHG, IEA CCC, IPCC.
- Sharing best practices and lessons learnt from demonstration projects (pilot and large-scale).
- Joint funding of large-scale plants in developing countries by multi-lateral lending institutions, industry and governments.
- Route identification for CO_2 pipelines.
- Development of standards for national and basin storage estimates and their application.

10.4. Feasibility of CCS technology development and deployment in India

There is a lack of assigning priority to development of CCS technology in India. The public awareness of this technology is highly limited. Thus, development procedure for CCS and CO_2 emission mitigation is recommended as shown in Figure10.5.

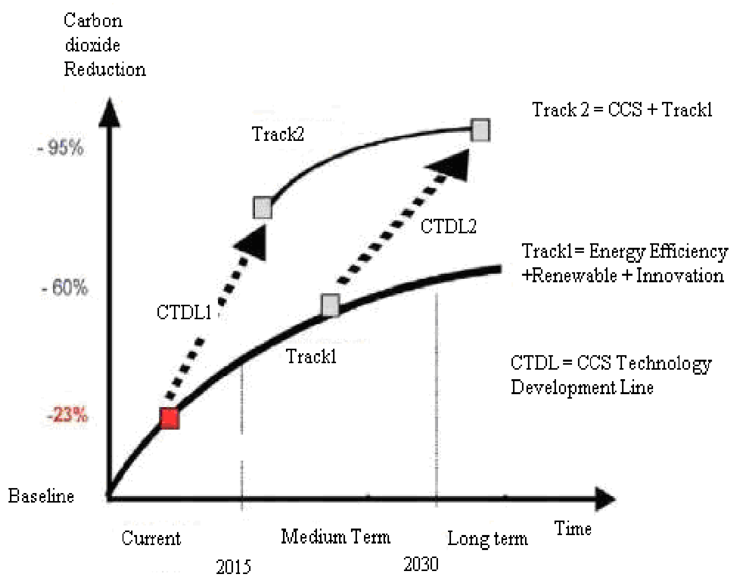

Figure 10.5: Carbon dioxide emission reduction strategy

Figure10.5 suggests R&D procedure of CCS that has relevance to Indian power sector. The current status of power sector is dominated by old power plants that have low efficiency. Indian power sector is upgrading the power plants with appropriate technology, re-engineering, improved fuel handling system etc. The green field thermal power plants are using super-critical technology. The government of India is planning to develop indigenous ultra-super-critical technology. Track 1 indicates the path of performance enhancement of carbon dioxide emission reduction per mega-watt with enhanced energy efficiency measures, use of natural gas as fuel, partial substitution of fossil fuel with renewable, incorporating innovative technology with re-engineering etc. By following track1, approximately 60% reduction in GHG emission can be achieved. Track 2 indicates emission mitigation by CCS technology superimposition on the strategy and development followed in Track1. The dotted line CTDL (CCS technology development line) indicate paradigm shift in power plant generation unit from Track 1 to Track 2 by incorporating capture ready provision and downstream linkages, by following CTDL1 &

CTDL2. It is possible that after achieving a level of technical maturity in CCS technology and power plant, design of capture ready power plant can be taken up. Another interpretation of CTDL lines can be CTDL1 is for demonstration project, and line CTDL2 is for commercialization of CCS scheme.

10.5. Basic Research Work in field of CCs in India:

The government institutions are pursuing basic research on CCS technology independently. For transition to applied research stage few research groups have to come together to form collaboration for pilot projects. The government will have to approve few pilot projects separately for carbon capture, carbon storage, and monitoring verification for validation of conceptual technology emerging from basic research. The transportation process design may be according to the existing standards of ASTM. The governments in principal approval will be needed for demonstration of CCS technology by integrating technology component at a future date. They are aware of the administrative issues such as

(a) regulatory framework on health, safety, protection scheme

(b) financing of the project

(c) environment impact assessment clearance

(d) technology transfer

(e) land use

(f) compliance with existing legal provisions.

They are reviewing the global development periodically, and in absence of any positive feedback they are keeping their decision of active support for the technology in abeyance. The Government is supporting basic research on carbon sequestration, carbon capture through department of science and technology. The government's support on clean coal technologies, IGCC, underground coal gasification, enhanced oil recovery; scheme related to enhance energy efficiency is being pursued with participation of public sector units BHEL, NTPC, ONGC etc. The R&D on CCS being capital intensive, the private sector participation will be needed. The approval and fiscal incentives from the government will encourage execution also through public private partnership.

CCS Being a complex process will require efforts of experts from multiple discipline and organizations. The progresses made in developed countries are very significant. The challenge is in integrating different indigenous engineering modules, technology transfer, and subsequent analysis of operation data. The formation of multi-disciplinary taskforce is needed to kick-start the project at pilot and then at Demonstration. One of the options of initiating integrated effort is to have at least one Indian institution as knowledge center of CCS. The expected function of knowledge center could be:

- Develop a global network with international stakeholders associated with development of the technology for commercial application, and compile information on scientific, technological, regulatory developments;
- To bring together Indian stakeholders, especially business investors, and government, academic and others also who are interested in this area;
- To identify key questions & concerns with regard to CCS technology;
- To develop study projects to address the questions and issues, particularly which are of relevance to India;
- To study the cost of CCS and to suggest financing and cost-reduction measures;
- To study technology gaps in CCS and to suggest ways of bridging the technology gap;

- To make policy recommendations;
- To propose projects, including pilot and demonstration projects, to stakeholders;
- To interact with similar institutions and bodies overseas and to make available the latest information and insights to Indian stakeholders;
- To disseminate reliable and usable information ; and
- To promote study and research in this area & facilitate capacity building.

The important institutions and researchers working on CCS scheme in India are as follows:

a. The Government Organizations – such as Ministries of Power, Coal, Water resources and Mines, Department of Science and Technology, Geological Survey of India, CSIR institutions (NEERI, NIO, NGRI, CMRI, CMMS etc.)

b. Public Sector Units – BHEL, NTPC, GAIL, CIL

c. Private sector units – Tata Power, Reliance Power, L&T, PunjLloyd, Tata Bluescope, Shiv Vani oil etc.

d. Others such as Iron and steel Units, Instrumentation and Control system manufacturer for monitoring and safety

e. Regulators and government authorities and advisors.

10.6. Identification of Storage Sites:

The identification of storage sites is the foremost issue. The characteristics of Indian sedimentary basin that includes saline aquifers and hydrocarbon fields, deccan basalt for sequestration are not evaluated for CCS potential. The characteristics have to be established by statigraphy, seismic analysis, R&D of reservoir rock characteristics, and pilot projects. This will establish suitability of the site. These will establish ground work for monitoring and verification system.

10.7. Legal and Regulatory Framework:

The initial legal and regulatory framework conducive to CCS research is needed in the context of health, risk, safety, and existing government policies and acts. The regulatory clarity for land use, social health and safety, and liability policies is essential to guide dos and don't's for project planning and subsequent designing. Some of the global regulatory frameworks are OSPAR, UNCLOS, London Convention & Protocol, Doha Declaration of Environmental Goods, & BASEL Convention on Hazardous Waste etc.

2. The group of CCS technologies should have compliance with the eight missions of National Action Plan of Climate Change.

3. The scope of requisite features of instrumentation, automation, control, & IT needed for monitoring, carbon storage accounting, and safety of the project sites have to be identified and indigenous development of hardware and software may be initiated.

10.8. Technical Barriers

The main technical barriers envisaged could be summarized as following:

(a) There is inadequate understanding on the efficiency of the capturing technology and driving media in actual operation. The capture and separation of CO_2 from flue gas process will be conducted at near atmospheric pressure and flue gas temperature, where driving mechanism of reaction and diffusion are low;

(b) The cost of capturing and then stripping of CO_2 from media is high and may enhance cost of electricity by 30% and also increase consumption of energy resource. The appropriate process selection based on energy consumption, and cost in the capture process ;

(c) Purity of CO_2 obtained during capture process and its impact during transport and storage process are important for maintenance of the infrastructure;

(d) Each geological site are unique, the sites would have to be evaluated for capacity, storage rate, geological performance;

(e) Monitoring and Verification process have to be appropriate to obtain regulatory compliance.

These barriers have to be surmounted, and the challenges are as follows.

- Key R&D challenges in decreasing order of technical complexity for cost reduction have been identified as

  a) Capture of CO_2 from flue gas.

  b) Storage of CO_2. (R&D on storage options for storage mapping and its cost analysis.)

  c) Transportation of CO_2.

- CCS will require lot of IT infrastructure for modeling of CO_2 storage at geological site, and maintaining database for CO_2 inventory in storage site for long period.

- Analytical Research on data modeling and simulation is needed to evaluate field test data and optimize cost function.

- Development of new solvents for CO_2 capture (ionic fluids and amines) and new processes for absorption and separation (membrane separation), which can withstand temperature of gas stream.

- Development of IGCC technology for Indian thermal power plants, and oxy-fuel technology for post-combustion capturing. These will reduce load on capturing process and reduce amine requirement.
- CCS R&D should focus on building test centers to carry out pilot studies.

10.9. Research and Development

The progress towards developing CCS demonstration project requires inputs from series of research and development tasks of each technology component of CCS. Basic researches are essential to find out the unknown process design parameters of scheme, and applied research is needed to enhance the performance and reliability of the scheme evolving from basic research. Applied researches provide basic inputs to the designers and project consultants for site engineering and detailed engineering for the projects. The developments needs which have to be backed with intensive R&D are:

10.9.1 Enhanced energy efficiency of Coal Based Thermal Power Plant.

Efficient power generation technologies are needed to maximize the efficiency of carbon capture process of CCS. The innovative technologies being developed for thermal Power plants are (a) Integrated gasification and combined cycle (b) Oxy-fuel combustion (c) Supercritical heating system (d) Tuning of Turbine and boiler synchronization (e) ERP of power plant management (f) Waste heat of ash utilization. Of these IGCC and oxy-fuel technology increases CO_2 percentage in gas stream significantly, thereby facilitating higher rate of CO_2 separation. Other technologies are beneficial for maximize use of heat rate for power generation. These reduce CO_2 emission per mega-watt of energy.

The enhanced energy efficiency is the priority of action in thermal power plants. The enhanced energy efficiency will yield greater electrical power from a unit energy input. The efficient energy to power conversion system reduces CO_2 emission in tones per mega watt-hours. The developments of super-critical technologies for boilers are major development in last two decades. The current research on coal is focused on clean coal technologies through gasification, and the combustion of synthetic gas so obtained be used efficiently. The advanced clean coal technologies are composite of two processes

a. Integrated gasification combined cycle (IGCC), during gasification a mixture of hydrogen, carbon mono-oxide, and carbon dioxide is generated as synthetic gas from coal. The synthetic gas can be processed to get mix of hydrogen and carbon dioxide. Carbon dioxide can be separated during capture process. BHEL is developing a pilot project at Vijaywada. The IGCC process can have upstream de-sulphurizing process depending upon Sulphur content of coal. The chemicals released during gasification process can be separated for commercial use

b. In Oxy-fuel combustion, the oxygen is separated from air and is used for combustion of pulverized coal in a reducing atmosphere. During combustion CO_2 is generated as flue gas. Part of flue gas is re-circulated and mixed with oxygen to maintain consistent flame temperature inside the boiler burner. In this process the probability of NOx formation is minimized except for initial burning period, and high concentration of CO_2 in flue gas can be ensured. In both process the CO_2 content in flue gas/ synthetic gas is high providing better efficiency during capture phase. M/S Vattenfall has successfully commissioned demonstration project in Germany. M/S Doosan Babcock is also working on demonstration project for Oxy-fuel combustion.

10.9.2 The R&D opportunities on Oxy-fuel technology:

The R&D opportunities in Oxy-fuel technology are:

1. Fuel (Indian coal has high ash) selection, preparation and firing scheme for injecting fuel in the firing zone.

2. Addition of renewable (biomass, waste) in firing scheme

3. Air separation unit for separating pure oxygen from air (This is standard process. Issue is scalability.

4. Feedback loop of flue gas in firing system and flame stabilization (Temperature, length)

5. Burner design for diffused flame and furnace design to maximize heat transfer to the boilers. Coal Burners to be designed to suit introduction of the burning media with higher oxygen concentration to the boiler in two separate streams (1) media used for feeding fuel to the burners and (2) media for ensuring complete combustion of fuel.

6. Optimum furnace temperature control with the addition of flue gas loop. Heat flow optimization

7. Aerodynamics of Burner has to be redesigned for optimum combustion, because of the higher concentration of CO_2 gas in the burner field. This is media is denser than air- fuel air mixing. Recycle flows of flue gas has to be adjusted to establish stable flame and temperature regime in the furnace.

8. Gas cleaning system for removing particulates of ash, SOx and NOx. Recycling has to be adjusted because of recycled NOx. Proper burner design ensuring Flame staging design will reduce CO formation from fuel burning

9. To obtain stable and controlled oxy coal combustion at low O2 concentrations in the CO_2 / O2 mixture is the research objective in burner development / modifications

10.9.3 Boiler Technology:

Boiler technology has a long history. The R&D on Boiler technology development is an on-going process. In last two decades it has gained special importance due to design of super-critical and ultra super-critical boilers and metallurgy of boiler material development both for boiler tubes and high pressure welding.

1. Design Practices pre-processing of coal as fuel prior to injection into furnace

   (a) Tilting Tangential Dry Bottom Pulverized Coal Fired Boilers

   (b) Bubbling Fluidized Bed Boilers

   (c) Circulating Fluid Bed boilers

2. Operational Aspects of furnace section of boilers, where raw coal or washed coal containing volatile matter are used (a) They are designed mostly for base load, but they operate at full load or above full load (b) The furnaces use raw coals that deposit soot at the refractory wall. They need soot blowing (c) most of the boilers have less deposits in convection pass, and these furnaces need lesser soot blowing

3. The furnaces need scanners for flame detection (To ensure positive detection and stability of flame with suitable flame scanners so that conditions that might cause furnace explosions / implosions are avoided)

4. Furnace input logistics need dynamic and continuous response. A rugged Fuel feeding and conveying is needed. There are scope development with appropriate research and development

5. Indian coal has high ash and they are abrasive in characteristics. Deposit Chemistry, slagging and Ash behaviour including fate of trace elements needs to be analyzed.

Carbon rich (Volatile matter) combustion media will form resultant chemical compounds that would tend to deposit on furnace wall and increase fouling. The chemical may cause ash to slag that will deposit at downstream location. This would lead to break down maintenance

6. Re-engineering of boiler, tube layout of suitable boiler during modification and Renovation. (Suitable Furnace auto control to be engineered (Eg Furnace Safe Guard Supervisory System-FSSSTM)
7. Corrosion Studies and boiler leakages.
8. Regulatory needs to be met (e.g. National Fire Protection Agency NFPA/US)

10.9.4 Carbon Capture technologies

These technologies can be classified as chemical absorption, membrane separation, physical adsorption, physical absorption and cryogenic separation. Each technology has limitation due to pressure, temperature, and concentration of CO_2. At the applied research and system design stage; the process of absorption/ separation for CO_2 capture scheme development will require careful tradeoffs of energy consumption, contactor efficiency, degradation of solvent, corrosion of infrastructure, and removal performance etc for establishing design parameters, and design of optimal Carbon capture process.

Research and Development is needed in the Carbon capture process to ensure efficient absorption/ adsorption/ separation of CO_2 from the gas stream. The solvent used for absorption should be able to capture CO_2 of the gas stream followed with easy separation of CO_2 and regeneration of solvent. During the process there should be minimum loss and degradation of solvent to facilitate recycling of solvent. The solvent should have enhanced rate of chemical reaction and perform at low pressure. The solvent should be non-corrosive. To ensure development of good solvent for carbon capture both for post and pre-combustion cycle, following R&D efforts are needed to ensure performance and scalability

One of research area is of reactor design and incorporation of advanced contactors. The separation activities are the parasitic losses of the power plant. The energy required for running blowers, pumps and compressors for CCS scheme are taken from the power plant. . The steam recycling process can be optimized with simulation model. Separation process modeling will provide a detailed understanding of the separation operation and mass transfer with chemical reaction at stripper conditions. This task will assist in improved regeneration of solvent. The Major carbon capture technologies are as under

10.9.4.1 Chemical Absorption

i. **Amine Process-**Amine solvent based absorption processes have been widelypracticed for many years for CO_2 capture from gas streams in natural gas processing, synthetic gas stream ammonia production and urea fertilizer manufacturing, and refinery off-gas treatment. The gas streams in these industries are usually at a high pressure of about 30 to 70 atm. The major scope of research for CO_2 capture from the flue gas stream of a fossil fuel fired power plant are the large volumetric flow rates of flue gas at essentially atmospheric pressure with CO_2 available at low partial pressures. Few leading research groups in the world are developing a numberof novel solvents based on sterically hindered amines, amine blends, and activated amines, which have higher equilibrium and kinetic selectivity for CO_2 and lower energy requirements for regeneration. Piperazine (PZ) is a di-amine has good capture characteristics. The amine based capture and separation of CO_2 is being practiced in Urea fertilizer plant. **ii. Ammonia process:** The system uses Ammonia as a CO_2 absorber and is designed to operate with slurry. The cooled flue gas flows upwards in counter current to the slurry containing a mix of dissolved and suspended ammonium carbonate and ammonium bicarbonate. More than 90% of the CO_2 from the flue gas is captured in the absorber. The clean flue gas, which now contains mainly nitrogen, excess oxygen and low concentration of CO_2, flows to the stack. The process has the potential to be applied to capture CO_2 from flue gases exhausted from coal-fired boilers and natural gas combined cycle (NGCC) systems, as well as a wide variety of industrial applications. ALSTOM is engaged in an extensive development ALSTOM is installing this cutting edge technology in the Pleasant Prairie Power Plant owned and operated by We Energies. The project will remain operational for at least one year during which the EPRI will conduct an extensive test program to collect data and evaluate technology performance.

10.9.4.2 Solid Sorbent

i. Membrane Separation

There are polymeric and ceramic porous membranes selectively separate CO_2in gas, using differences in the size or permeating rate of substances. The main constraint is high cost of membranes, supporting structure of membrane, low CO_2recovery rate, and high-pressure requirement for separation.

ii. Physical Adsorption:

Some materials, which have porous structure, are used for capture. They can be induced to retain CO_2, which can be recovered by changing pressure and/or temperature. These include zeolites, activated carbon and alumina; there are technical challenges of scalability, CO_2adsorption and separation. There are three separate processes Pressure Swing Adsorption (PSA), Temperature Swing Adsorption (TSA), and Pressure and Temperature Swing Adsorption (PTSA).

iii. Cryogenic Distillation

The conventional process is of compression and cooling gas separated by distillation. This will be economic provided concentration of **CO_2** is high as envisaged in oxy-fuel combustion. LNG (-160°C) during re-gasification phase is a potential cryogenic medium. These can be used in coast based power plants having proximity to re-gasification plant. These researches are being pursued.

The carbon separation from flue gas or gas stream (IGCC process) consumes 80% of resources and hence is cost intensive process. Considering scalability, temperature of gas stream, partial pressure of CO_2; absorption and membrane technology are viable option for separation of CO_2 from gas stream. There are major researches in progress in membrane technology but obtaining a technological solution from membrane basket appears to be difficult in near future. The current challenge is to select best absorption solution that is cost effective, have high yield, high recycling potential for capturing $CO_2$from gas stream and subsequent separation.

Some of potential applied research opportunities exist in:

1. Determination of CO_2 absorption capacity of different physical solvents (Propylene carbonate, polyethylene glycol dialkyl ether, N-methylpyrolidone, chilled methanol, chilled ammonia, selexol) ;
2. Evaluation of Thermodynamic Data related to gas separation process at flue gas, gas stream pressure, partial pressure and temperature;
3. CO_2 absorption kinetics in various chemical solvents (sodium hydroxide, potassium carbonate, Monoethanolamine, piperzine, chilled ammonia, Diisopropanolamine, DEA, TEA, and blend with AMP);
4. Searching for high performance absorber and subsequent regeneration of the used solvent;
5. Studies of membrane for gas separation process in IGCC following shift reaction to separate hydrogen from syn gas constituting of (H2, CO, CO_2, N2);

6. Studies of corrosion and corrosion control in the reactor in CO_2 and solvent environments;

7. Studies of solvent degradation in CO_2 absorption process;

8. Modeling and simulation of CO_2 gas separation process (capture, separation, regeneration of solvent) for selection of solvent;

9. Optimization and cost studies of co-generation –based CO_2 capture;

10. Knowledge based system for solvent selection in CO_2 separation process;

11. Intelligent monitoring and control of CO_2 generating systems.

10.9.4.3 Carbon Storage

The potential sites of storage are depleted oil and gas field, saline aquifers, basalts and ocean. The EOR scheme has distinct financial advantages as additional oil and gas is obtained with sequestration. Hence research cost can be supplemented by addition crude accrued. ONGC is implementing a demonstration project of Carbon sequestration for EOR project at Ankleshwar. Participation of Indian institutions in development of EOR technology with carbon sequestration is generating interest among stakeholders in the power sector. The applied research of carbon capture and carbon storage with EOR or other site can be tested with pilot projects[82]. At this state of carbon storage tankers can transport the CO_2. The pilot projects should be planned to be facilitator of designing demonstration projects. There are many old and matured oil fields in Assam where EOR can be effectively implemented. The exhausted reservoir can be used for carbon storage. The storage site R&D has following opportunities:

11. Stratigraphic and seismic analysis of the reservoir and the cap-rock profile.

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[82] The CO2 free Power Plant From vision to reality (presentation) by Mr. Lars Strömberg, VattenfallAB

12. The study of rock characteristics to understand rock mechanics.
13. Analysis of Porosity and permeability of reservoir and reservoir pressure, and structure of cap-rock.
14. Mechanism of Mineral/ Physical Trapping of CO_2 at the storage site.
15. Reservoir pressures are the primary constraint of Enhanced oil and Gas Recovery. The pressure generated following CO_2 storage should not be greater than original reservoir pressure.
16. Potential of Microbial – Biogeochemical Transformation of CO_2
17. Geophysical site selection for drilling bore-holes for CO_2 injection and Monitoring strategy during CO_2 injection phase to study spread of CO_2
18. Chemical/ Kinetic trapping behavior at storage site
19. Well integrity CO_2 resistant cement / steel
20. Numerical Simulation of CO_2 spread in the reservoir, probability of seepage, leakage and migration.
21. Risk Assessment (FEP – Procedure)
22. Hydrodynamic models of Aquifers
23. Geo-mechanical rock behavior.

The geological modelling is one of the challenging tasks. The task can be categorized as

(1) Simulation study of depleted oil field

(2) Reservoir simulation of saline formation

(3) Reservoir simulation of sedimentary basins

(4) Reservoir simulation of basalts.

The modelling work on the first two has been done conclusively at institutes of developed countries. The modelling project in (3) & (4) are progressing and their outcome is not known. Detailed geological models are needed understanding by reservoir simulations of the injection and storage of carbon dioxide over several thousand years. There are projected strong tendency on the migration of carbon dioxide during the injection period. Carbon dioxide dissolved in the formation water on a scale of thousands of years, with convective mixing being a key mechanism. The effects of relative permeability, stratigraphic complexity are subject of research.

Ocean sequestration is one the good opportunities available for shore based thermal power plant for carbon sequestration. The Indian shore line has different characteristics. Bay of Bengal is turbulent and has history of tsunami. The west coast has continental shelf, and is moderately calm. India will have to rely on hydrate technology for ocean sequestration, or go for deep sea sequestration.

10.9.4.4 Long distance transport of CO_2:

The volumes of CO_2 generated at high capacity power plant are very high. The pipelines for transportation of the gas will be of large diameter involving high cost, laying problem, and pressure boosting problem for transport from power plant to geological site for storage. Alternately scheme for high pressure dense phase (super-critical) CO_2 transportation has been developed. The CO_2 in dense phase is kept at sufficiently high pressure and temperature above super critical point to maintain dense phase. The booster stations are installed at designed location, which will be operating with electricity. The hydraulics of transportation is sensitive to the composition of super-critical fluid. The purity of fluid is dictated by the cost of capture + separation, material composition of pipelines and environmental considerations applying at the sink. The high pressure is maintained up to storage site. The pressure required for storage is higher than the transportation pressure. Hence a storage tank may be needed at the storage site. The technology challenges are design of compressor for converting gas to super-critical fluid, compressor/ pump at booster station, and preparing standards for pipelines according to purity of the fluids. R&D on Compressor used for compressing CO_2 gas stream to super-critical fluid. The compressor technology will be similar to process CO_2 from a Pulverized Coal, Oxy-Fuel, or IGCC thermal power plant. The compressor will be consuming significant quantum of electric energy, which can be reduced with better compressor design.

1. Optimize on power consumption of compressor by leveraging existing compressor technology.
2. Compressor design should be scalable and compliant with various capture schemes (1) amine (2) membranes.
3. The input parameter of gas stream for the compressor and liquefaction process (high pressure ratio, heat of compression) in the compressor cycle has to be analyzed
4. Thermodynamic cycle analysis to identify optimal compression scheme.
5. The internal cooling system of the compressor is needed for protection scheme.
6. Perform qualification testing of a refrigerated liquid CO_2 pump
7. Perform optimization of pipeline booster stations pumps, booster station spacing, pressure drop compensation, (it is assumed that pipeline layout will be along power grid to provide power for booster station)
8. Instrumentation and automation to measure the fluid flow in the pipeline without leakage.
9. Perform more gas properties measurements of CO_2 mixtures
10. Jointing methodology of pipeline, as super-critical fluid is corrosive.

11. Locating crack arrestor to suppress spread of ductile fracture and block valve to switch of transportation loop in case of rupture.

10.9.5 Timeline for demonstration:

The documents in the website of Global Carbon Capture and Storage Institute, Australia, specifies the target year 2020 for commercialisation of CCS technology. The report assumes active participation of India in development of CCS technology to accrue business benefits. This is feasible if the country develops its capability in CCS technology in tandem with the developments in industrially advanced countries. Indian policy makers have their apprehension about the technology, and they have to be ensured of technological viability of the scheme by successful operation of Demonstration project in developed countries. The industrially developed countries are projecting to conduct test run of CCS demonstration project by 2012.

The G8 countries are also planning for multiple demonstration projects. UK is hopeful to execute a technically relevant demonstration project by year 2014. India can avail the opportunity of active participation in demonstration projects in developed countries and UK for capacity building. This will ensure synchronous capability development with their counterparts in developed countries.

India needs to undertake a demonstration project at indigenous site for following rationale,

- Every sequestration site has unique characteristics; hence there should be indigenous capability
- The CCS is emerging technology, and future power plants are of large capacity. Thus there will be scalability issue. Existing scheme of carbon capture are capturing carbon is lesser scale then power plant.
- There are risk perceptions of leakages, fouling with underground water table. There are multiple agencies associated with the process.

- The maintenance of the process (high capacity power plant, capture unit, pipeline operating at a high pressure, capping of leakage sites.) is complex.
- The storage sites have variable trapping mechanism. The monitoring and verification task have to be done assiduously. The participation
- The power plants technologies have a history of 100 years and are evolving and innovating regularly. They have established and are functioning in a regulatory frame work. The CCS is emerging technology, and their regulatory system will evolve from in-house research. Hence its development in India should follow the path of demonstration instead of turnkey CCS project.

The CSLF (Carbon Sequestration Leadership Forum)[83] is a voluntary climate institution of developed and developing nations. The members of CSLF are Australia, Brazil, Canada, China, Colombia, Denmark, the European Commission, France, Germany, Greece, **India**, Italy, Japan, Mexico, the Netherlands, New Zealand, Norway, Poland, Russia, Saudi Arabia, South Africa, South Korea, the United Kingdom and the United States. The members are engage in cooperative CCS technology development. The Carbon Sequestration Leadership Forum has added in October 2009, 10 new carbon capture and storage (CCS) projects to its existing R&D portfolio.

The aim of CSLF is to compile and share knowledge and experience required initiating applied R&D on carbon capture, establishing procedure for safe, secure geologic storage in the order of thousands of years. The current initiative of forum can be categorized under (a) technical development (capture, identify storage locations, monitoring and verification for safety and risk mitigation) and (b) Policy and regulatory framework development. The CSLF task portfolio also includes cutting the costs of CO_2 capture technology and cross cutting issues. The technical tasks also include enhanced oil recovery and methane recovery from un-mineable coal seams.

[83] http://www.cslforum.org/pressroom/publications/pr_projects_101209.pdf

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ABBREVIATIONS

ASSOCHAM	Associated Chamber of Commerce and Industry of India
ASTM	ASTM International is American Institute for specifying Standards
bgl	Below Ground Level
BHEL	Bharat Heavy Electricals Limited
bn	billion
BU	Billion Units
CA	carbonic anhydrase
CAGR	Compounded Annual Growth Rate
Capex	Capital Expenditure
CBM	Coal Bed Methane
CCGT	Combined Cycle Gas Turbine
CCS	Carbon capture and storage
CDM	Clean Development Mechanism
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commision
CII	Confederation of Indian Industries
Cmt	Cubic Meter
CO2	Carbon dioxide
CRBG	Columbia River Basalt Group(USA)
CSLF	Carbon Sequestration Leadership Forum
DGH	Directorate General of Hydrocarbons
DPR	Detailed Project Report
DSM	Demand Side Management
DVC	Damodar Valley Corporation
EGR	Enhanced Gas Recovery
EIA	Environment Impact Assessment
EOR	Enhanced Oil Recovery
EPRI	Electric Power Research Institute, USA
EPS	Electric Power Survey
EU	European Union
FBCT	Fluidised Bed Combustion Technology
FICCI	Federation of Indian Chambers of Commerce and Industry
GAIL	Gas Authority India Limited

GCM	Genaral Circulation Model
GDP	Gross Domestic product
GHG	Green House Gas
Gt	Giga tonnes
GT	Gas Turbine
GW	Giga Watt
GWh	Giga Watt hour
H2S	Hydrogen Sulphide
HBJ	Hazira Bijaipur Jagdishpur; Gas Pipeline
HSD	High Speed Diesel
HT	High Tension
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IPCC	Inter-governmental Panel on Climate Change
IPPs	Independent Power Producers
IRADe	Integrated Research and Action for Development, New Delhi
IS	Indian Standard
KG	Krishna Godavari
Km	Kilometer
KW	Kilo Watt
LDC	Load Duration Curve
LE	Life Extension
LNG	Liquefied Natural Gas
LPS	large point sources
LT	Low Tension
MEA	mono-ethanol-amine
MMSCMD	Million Metric Standard Cubic Meter per day
mn	million
MNRE	Ministry of New and Renewable Energy
MoC	Ministry of Coal
MoEF	Ministry of Power
MoP	Ministry of Environment and Forests
MoPNG	Ministry of Petroleum & Natural Gas
Mpa	Mega Pascal
MT	Million Tonnes

MW	Mega Watt
MWh	Mega Watt hour
NELP	New Exploration Licence Policy
NEP	National Electricity Policy
NGCC	Natural Gas Combined Cycle
NGL	Natural Gas Liquids
NGO	Non Government Organization
NHPC	National Hydro-electric Power Corporation Limited
NLC	Neyveli Lignite Corporation
NOX	Nitrous Oxide GHG
NTPC	National Thermal Power Corporation Limited
OIL	Oil India Ltd.
ONGC	Oil & Natural Gas Corporation Ltd.
Opex	Operating Expenditure
PFBCT	Pressurized Fluidised Bed Combustion Technology
PFC	Power Finance Corporation Limited
PGCIL	Power Grid Corporation of India Limited
PLF	Plant Load Factor
PPM	Parts per Million
PPMv	Parts per Million by Volume
PSA	Pressure Swing Adsorption
R&D	Research and Development
R&M	Renovation & Modernisation
RD&D	Research Development and Demonstration
REC	Rural Electrification Corporation Limited
RLA	Residual Life Assesment
ROR	Rate of Return
S&T	Science and Technology
SERC	State Electricity Regulatory Commision
SOX	Sulphur Oxides
SWOT	Strength, Weakness, Opportunities & Threats
T	Tonnes
ToD	Time of the Day
TSA	Temperature Swing Adsorption
TWh	Tera Watt hour

UCG	Underground Coal Gasification
UMPP	Ultra Mega Power Projects
UNEP	United Nation Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
USA	United States of America
USD	United States Dollar
VCBM	Virgin Coal Bed Methane

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