OPPORTUNITIES IN EXPLORATION, PRODUCTION AND PROCESSING OF OIL AND GAS IN INDIA WITH SPECIAL EMPHASIS ON GAS PROCESSING

A Dissertation
By

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Submitted in partial fulfillment of the requirements for the award of the

MASTERS OF TECHNOLOGY IN REFINING & PETROCHEMICAL ENGINEERING

Of the University of Petroleum & Energy Studies,

Dehradun, (India).

Under the guidance of

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(Distinguished Professor)

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<u>**Certificate:**</u>

This is to certify that the project report on **"Opportunities in Exploration, Production and Processing Of Oil and Gas In India with Special Emphasis on Gas Processing"** submitted to university of petroleum and energy studies, Dehradun by Mr. Sai Krishna Jillepalli, in partial fulfillment of the requirement for the award of degree of Master of technology in Refining & Petrochemical engineering (Academic session 2004-06) is a bonafide work carried out by him under our supervision and guidance. This work has not been submitted anywhere else for any degree or diploma.

23.05.06

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Section I

INTRODUCTION

India- On Growth Path

India- The largest democracy in the world and an emerging global business giant.

It is also the fastest growing free market democracy in the World

The galvanization of this upcoming economy presents unique and unparalleled opportunities to entrepreneurs both within and outside India.

Liberalization being the motto of the Indian Government, all sectors of the economy including the capital markets are open to foreign investment. Also, India has the world's third largest pool of scientific and technical personnel, which serves as an important attraction for foreign investors.

Most managerial, technical people and many skilled workers speak English, and many have studied or worked abroad.

GDP Growth rate:

	In 2003-04: 8.1%
Achieved	In 2004-05: 7.5% &
	In 2005-06: 8.1%
Expected	In 2006-07: 8.1% ---- (ADB)

Per-capita energy consumption is bound to increase many folds due to the robust GDP growth

India is the fourth largest oil consumer in Asia Pacific region after Japan, China and Korea, and its consumption increasing at 7% per year

Oil and Gas Scenario in India

The Oil & Gas Industry plays a vital role in India's economy growth and is one of the largest contributors to central and state exchequer.

With a mammoth size of US$ 90 billion, the Indian oil & gas industry is now gearing up to meet the challenges of oil & gas security for India

Few statistics of Oil & Gas in India can be shown as:

Total crude oil requirement in India is (2005): 126 million. Tons, where almost 90 million tons of crude is imported

Domestic crude oil production in the years 2004 & 2005 are only 33.3 and 33.98 million tons, respectively

In the year 2005, Total O+OEG production (domestic & overseas equity) amounted to - 58.3 million Tons

Present Gas Production ≅ 100 million NM^3/day (SCMD)
Demand is ≅ 170 MMSCMD,
Growing @ 6-8% p. a

Total Indian refining capacity of 18 refineries is 127.4 million tons; and is projected to increase to 217 million. Tons by 2011

Petroleum products consumption in India is around 113.5 million tons

This is growing @ a CAGR of 3-3.5% per annum; to reach to 300 million tons by 2025

Section II

EXPLORATION & PRODUCTION OF

OIL & GAS IN INDIA

E&P Growth in India

The growth of Exploration & Production of Oil & Gas in India can be explained as:

Overall Prospects

India has total 26 sedimentary basins covering an area of 3.14 Million Sq. KM of which offshore area consists of 1.75 million Sq. Km while onshore area consists of 1.39 million Sq. Km

Of the whole sedimentary area almost 31% still remains untapped / unexplored and 20% is poorly explored

Hence, there is a huge Potential of business opportunities in the Indian E & P sector

Statistics:

India's Total hydrocarbon resource is estimated to be: 28 billion MTOE

The initial in-place reserves as on 1st April 2005 was estimated at: 8.24 billion MTOE of which "Proven Recoverable" reserves are: 3.16 billion MTOE

Almost Reserves of 640 millions MTOE have been discovered in the last two years

Sedimentary Basins in India

The classification of various sedimentary basins in India can be shown as:

CAT. I (PROVEN COMMERCIAL PRODUCTIVITY)

CAT. II (IDENTIFIED PROSPECTIVITY)

CAT. III (PROSPECTIVE BASINS)

CAT. IV (POTENTIALLY PROSPECTIVE)

DEEP WATER AREAS WITHIN EEZ

PRE-CAMBRIAN BASEMENT / TECTONISED SEDIMENTS

Source: Director General of Hydrocarbons (DGH)

Evolving Regulatory Regime

Since the initiation of economic reforms in India in 1991 there has been a growing acceptance of the need for deepening these reforms in several sectors of the economy which were essentially in the hands of the government for several decades.

The inadequate response of the private sector in investing in the energy sector over the last seven to eight years has led to the widespread recognition of the need for reforms by the government and the public at large.

Multi-pronged initiatives and actions have been taken by the Indian government to lend dynamism to the Oil and Gas industry in India.

The economic liberalization has resulted in radical restructuring of the oil & gas sector, and in-turn many new policies have been formulated.

To initiate the process of reform, the Government of India appointed a group, popularly known as the 'R' Group, which consisted of experts, oil industry professionals, government officials, and a select group of private sector leaders.

Its major recommendations included the dismantling of the APM and the institution of tariff reforms in the downstream sector.

In 1993, the government set up the Directorate General of Hydrocarbons (DGH) under the MoPNG. The DGH was set up as an agency to regulate and oversee the upstream activities in the petroleum and natural gas sector, and advice the government in these areas.

The objective of DGH is:

To promote sound management of the Indian petroleum and natural gas resources having a balanced regard to the environment, safety, technological and economic aspects of the petroleum activity.

The functions of the DGH are:

1. To provide technical advice to the MoPNG, on issues related to the exploration and optimal exploitation of hydrocarbons by national oil companies
2. To advice the government on the offering of acreage for exploitation to companies and the relinquishment of acreage by companies
3. To evaluate exploration and field development bidding rounds
4. To review the reservoir performance of the major fields
5. To reassess the hydrocarbon reserves discovered and estimated by the operating companies
6. To review development plans proposed by the operating companies for the commercial discoveries of hydrocarbon reserves
7. To advice government on the adequacy of such plans
8. To review and audit the management of petroleum reserves by the operating companies and to advice them on sound reservoir management practices.

Reforms were also initiated upstream with the Government of India liberalizing the terms of offer of exploration blocks by unveiling the NELP (New Exploration Licensing Policy).

The legal framework for regulation of exploration and production of oil and gas is enshrined in the Oil Fields Development & Regulation Act, and the Petroleum and Natural Gas Rules.

New Exploration Licensing Policy (NELP)

The New Exploration Licensing Policy (NELP) was formulated by the government in March 1997 to provide a level playing field in which all parties could compete on equal terms for the award of exploration acreage

Advantages of the NELP

1. Entire value chain privatized
2. Decontrol of Oil sector since April 2002
3. Allows 100% foreign participation
4. Awarding of licenses through international competitive bidding

Salient features of NELP

1. Fiscal stability provision in the contract- no customs duty, infrastructure status, variation of tax cost clause, etc
2. Finalization of contract on the basis of Model Production Sharing Contract- No payment of signature, discovery of production bonus
3. No minimum expenditure commitment during the exploration period
4. Freedom to sell crude oil and natural gas in domestic market at market related prices
5. Biddable cost recovery limit upto 100%
6. Sharing of profit petroleum based on pre-tax investment multiple achieved and is biddable
7. Royalty for offshore production payable at the rate of 12.5% on crude and 10% on gas on an ad valorem basis. Royalty for all offshore production payable at the rate of 10%. Royalty for all deepwater production chargeable at half the rate applicable to offshore areas in the first seven years of commercial

Draft petroleum & natural gas policy has been released

Draft Pipeline Policy

- The draft pipeline policy envisages that all trunk pipelines will be built by GAIL.
- Any gas producer wishing to service customers within 100 km of the landfall point can lay its own lines.

Now, the issue remains the access policy especially if the trunk pipeline network is envisaged as a monopoly. The government wishes to set up a regulator for access issues based on open access policy. The point of contention remains whether to go for a common carrier policy or a contract carriage policy.

A common carrier allows anyone to use the pipeline to transport gas for a fee. A contract carriage, on the other hand reserves capacity for specific buyers on a "take or pay" contract. World over gas pipelines operate under contract carriage because it ensures certainty of supplies. Moreover, it ensures a level playing field. In fact, it is widely acknowledged that contract carriage should be the guiding principle for gas pipelines. Private players feel that since GAIL is a buyer and seller of gas, there might arise a conflict in interest. The consensus is yet to happen.

Meanwhile, Reliance Industries & GSPC have drawn up plans for their network for bringing gas from KG fields to consumers.

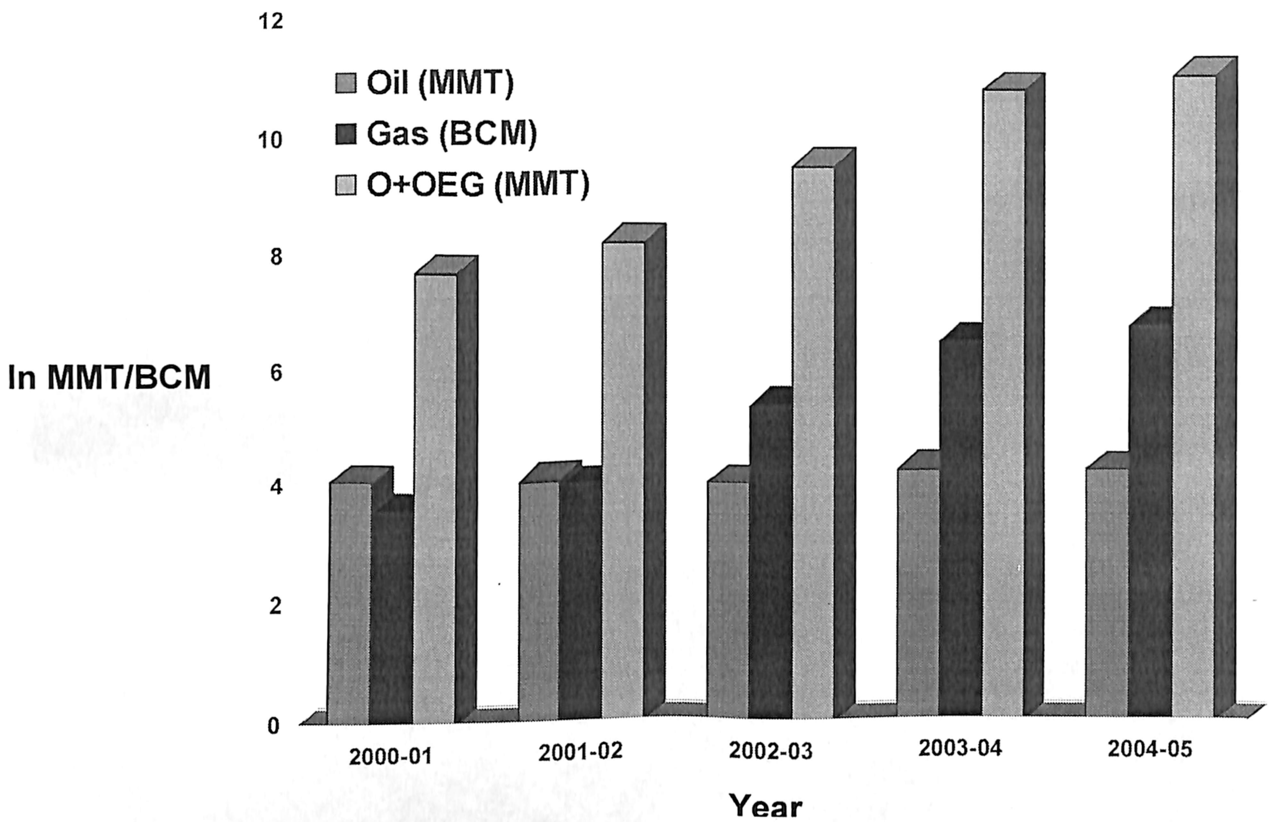
Indian Hydrocarbon Vision 2025- is a vision statement for Oil & Gas taken out by the Government of India. It acts as a framework for future policies in India upto 2025.

The **Common Carrier Pipeline Policy** for Product Pipelines- lays down that pipelines originating from refineries and ports will need to be built on a common user principle. The policy allows two or more companies to use a single pipeline

Benefits of NELP:

Due to the restructuring of oil & gas sector there was an increasing trend of oil & gas production in India, which can be shown as:

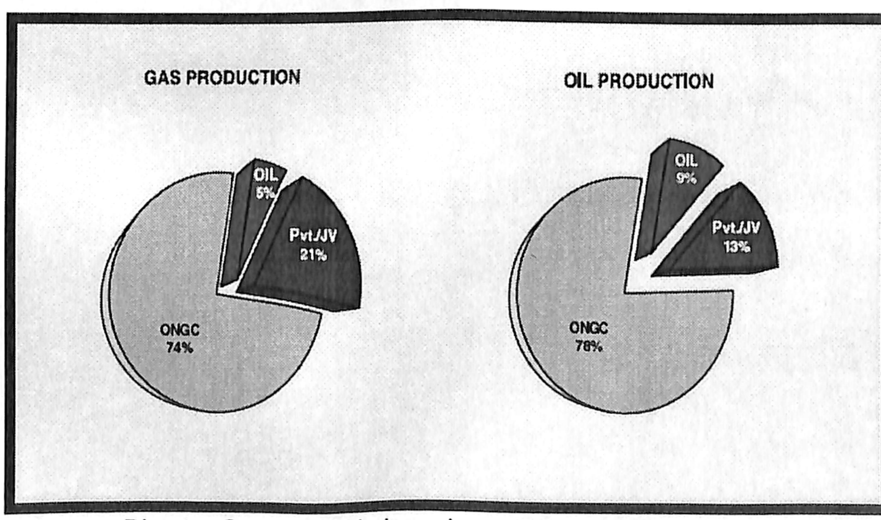
Increasing Trend of Oil & Gas Production:



Source: Director General of Hydrocarbons (DGH)

Oil & Gas Production in India:

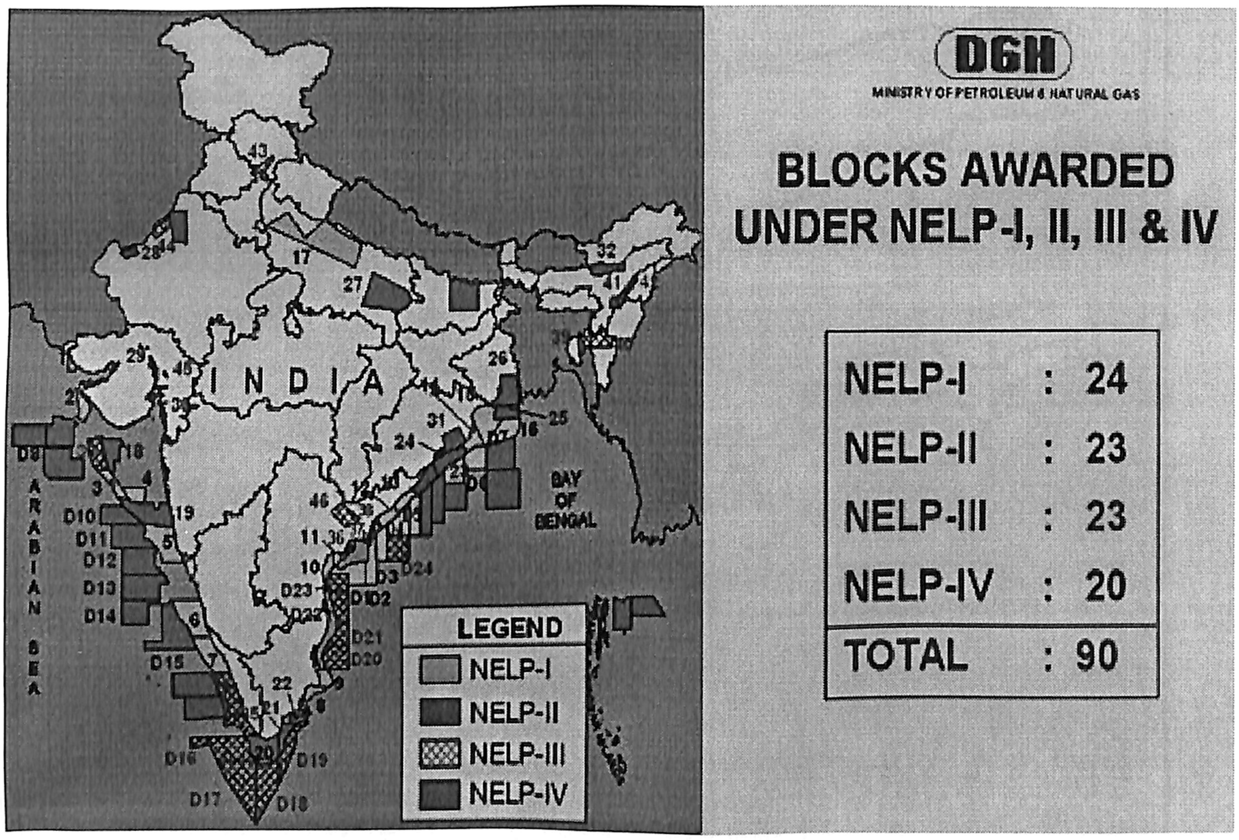
JV/Pvt. Share almost 13% of Oil & 21% Gas of National production.



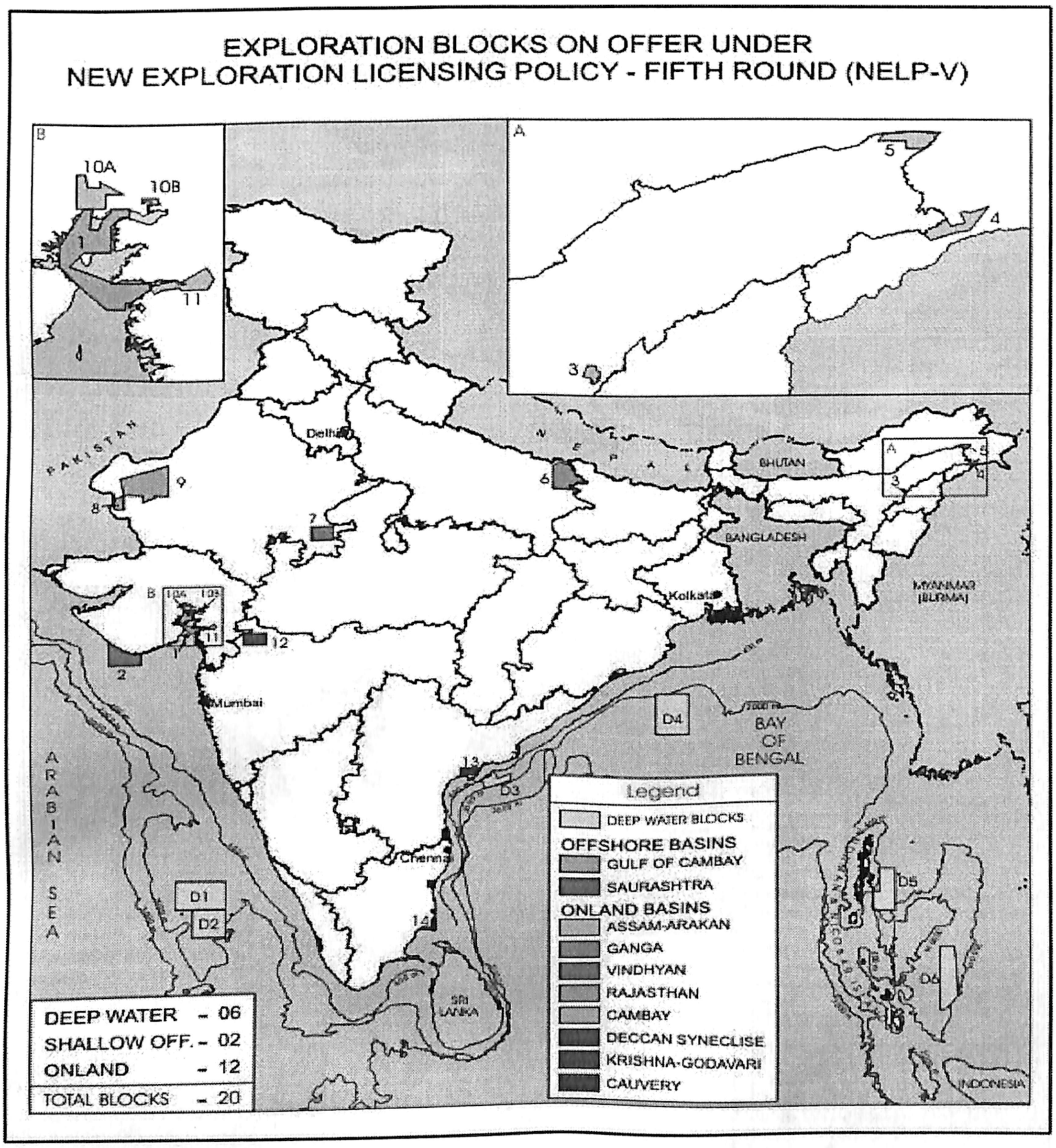
Source: Director General of Hydrocarbons (DGH), 2005.

NELP ROUNDS:

The various blocks awarded in the IV NELP Rounds can be shown as:

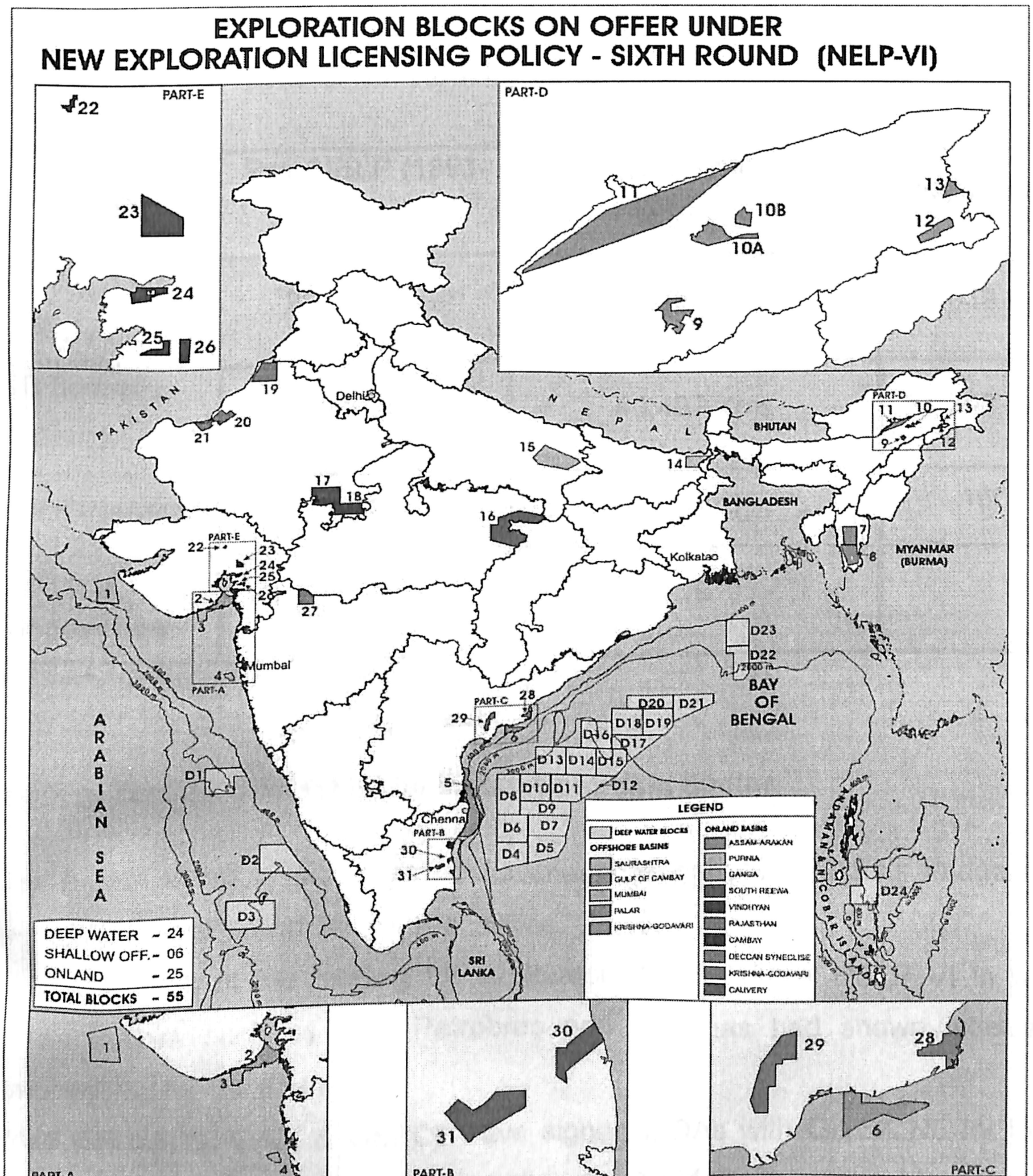


Under the NELP V Programme the blocks awarded can be shown as:



Source: Director General of Hydrocarbons (DGH)

The blocks to be awarded under the NELP VI programme are:



Source: Director General of Hydrocarbons (DGH)

Activity

- No: of Blocks awarded in V NELP rounds: 108
- To be awarded in NELP VI: 55
- Total area available for exploration under V NELP rounds: 8,64,533.11 Sq. Km
- Total area offered under NELP VI: 3,55,000 Sq. Km

Pre-NELP versus Post-NELP Exploration & Production activity can be summarized as:

Pre-NELP V/S Post-NELP E & P Activity

Activity	Pre- NELP (1993-2000), 7 years	Post- NELP (2000-2004), 4 years	2004-2005
2D Seismic Survey	22,502 Kms	78,650 Kms	24,939 Kms
3D Seismic Survey	4,399 Kms	40,407 Kms	31,798 Kms
Exploration Wells	66	57	165
No. Of Discoveries	11	19	

Source: Director General of Hydrocarbons (DGH)

Increasing Foreign Interest in the Indian Upstream Sector

1. The recent string of significant discoveries has enhanced India's image as a prospective destination for E & P activities.
2. This is evident in the bidding for exploratory blocks under NELP VI in which global majors such as ENI, Petrobras and Petronas had shown interest in participating for the first time.
3. Prize petroleum, GAIL & GSPCL have signed MOAs with OILEX NL for jointly exploring Oil & Gas in India & Australia with 2 bid for exploring blocks in NW Australia.
4. BG had entered into an agreement with ONGC.
5. ONGC has signed an agreement with Russia's GAZPROM for collaboration in oil and gas sector.
6. Russia's state-owned oil major Rosneft has offered India's ONGC Videsh Limited (OVL) stake in 11 oil and gas projects in Russia including Yuganskneftegaz.

7. ONGC signed an agreement with L.N. Mittal group to form two 51:49 % joint venture companies - OMEL (ONGC Mittal Energy Ltd) and OMESL (ONGC Mittal Energy Services Ltd) for exploration, production and shipping activities abroad.

Indian E & P Cos. Acquiring Oil & Gas Equity Overseas

1. ONGC formed ONGC Videsh (OVL); now doing E & P in 13 Countries- Russia (Sakhalin), Iran, Syria, Libya, Libya, Qatar, etc..
2. OVL acquired 10 fields in Sudan (Reserves 1 bn barrels)
3. OVL & GAIL have taken over Daewoo stake in Myanmar
4. Reliance has bagged a deep sea oil and gas block of 3000 Sq. Kms in the Gulf of Oman, and is looking for oil assets in Qatar, Iran and Saudi Arabia
5. Indian Oil Corp and its partner Oil India Ltd have won an oil block in Libya in the first ever joint foray in oil and gas exploration overseas.
6. Reliance Industries is pursuing talks to buy oil and gas fields in West Africa, South America and Middle East.
7. ONGC and CNPC (China National Petroleum Corporation) had jointly won 38 % stake of Petro-Canada in Al-Furat oil & gas fields in Syria
8. ROSENEFT, Russia offered PI for 11 blocks in Russia to ONGC Videsh Ltd (OVL)
9. Prize Petroleum along with Petronas is eyeing oil assets for E & P in Philippines, Iran & Oman
10. Reliance Industries has bagged a deep sea oil and gas block in the Gulf of Oman, and is looking for oil assets in Qatar, Iran and Saudi Arabia.

Major Local & International Oil Companies in E & P in India

Local

1. Oil & Natural Gas Corp. (ONGC)
2. Oil India Limited (OIL)
3. Reliance Petroleum Limited (RPL/RIL)
4. Gujarat State Petroleum Corp. (GSPCL)
5. Gas Authority of India (GAIL)
6. Hindustan Oil & Exploration (HOEC)
7. Essar Oil
8. Videocon
9. Prize Petroleum
10. Jubilant Energy

International

1. Cairn Energy, UK
2. British Gas, UK (JV with ONGC for 3 deepwater exploration blocks in KG basin)
3. Hardy Oil, UK
4. ENI Group, Italy (JV with ONGC for 3 deepwater exploration blocks)
5. Petrobras, Brazil (JV with ONGC for offshore)
6. Command Petroleum, Australia
7. Niko Resources, Canada
8. Geopetrol International, Canada

E & P Services

1. Schlumberger
2. BJ Services
3. Baker Hughes
4. Tata Petrodyne

New Actions to Enhance E & P

The various actions to be taken to enhance the growth of E & P sector in India are:

- Enhanced Oil Recovery (EOR)
- Offshore Deepwater Exploration
- Seismic Survey and Creation of Geo-Scientific Data
- Coal Bed Methane (CBM)
- Natural Gas Hydrates

Enhancement of Oil Recovery (EOR):

Enhancement of recovery of oil in the existing large and medium sized fields is one area on which rapid actions are to be taken.

These projects for enhanced oil recovery (EOR)/ improved oil recovery (IOR) are implemented through ONGC and OIL.

This includes development of new wells and additional development of existing wells in the existing fields.

Specialized schemes involving new technologies such as extended reach drilling, horizontal drilling and drain hole drilling are implemented for these projects.

This also includes projects for maintenance of the reservoir health in the oil fields involving seismic surveys for better delineation, work over operations and pressure maintenance methods.

These projects involve an estimated investment of- US$ 2 billion in the next 2 years

Exploration Initiatives in Deepwater and Frontier Areas

Exploration initiatives have been given a thrust in the deepwater and frontier areas which till now have remained unexplored or poorly explored.

ONGC's Sagar Samridhi project is one of the biggest ever deepwater exploration initiative in the world by a single operator, is currently underway in its operation.

ONGC is spending a huge amount of almost 1 million US$ daily on this project under which it plans to drill 47 deep and ultra deep water wells in the next three years in east and west coast of India (Depth 2000 upto 6000 m).

The company has employed three ships and planned to employ more on the project

Exploration activities particularly in the deepwater and frontier blocks require significant capital investments and involve significant business risks

Seismic Surveys and creation of Geo Scientific Data:

The quality of geo-scientific data available on the exploration blocks for the prospective bidders is one of the biggest challenges in the upstream sector.

A survey by Ernst & Young concluded, Seismic Surveys and creation of Geo Scientific Data with proper mechanism for data access and exchange as the most critical factor for the development of upstream sector.

If almost 38% of sedimentary basins remain unexplored, Surveys and data acquisition is a pre-requisite to interest more foreign E & P giants to undertake exploration in India

Government of India is taking the initiatives to setup the mechanism for accessing quality data and blocks through geo-scientific data repositories. This setup is to avoid any risk for the players involved in exploration of deepwater areas and frontier blocks

DGH is enhancing seismic surveys and data creation activity in India

Various factors important for the Development of Indian Upstream Sector can be shown as:

Factors Important for the Development of Indian Upstream Sector	Rank
Creation of a Geo Scientific data repository & data access and exchange	1
Bringing advanced technology for E & P activities in deep water and frontier areas	2
Establishment of an independent regulator	3
Proper categorization / differentiation of blocks with separate contracts and licensing norms	4

Source: Oceantex, 2006

Coal Bed Methane (CBM)

Exploration & Recovery

In order to meet the growing energy requirements in the future, and to reduce the dependence on oil imports various alternative non-conventional hydrocarbon sources should be developed

- One of the top sectors for foreign direct investment in India is Coal Bed Methane exploration and recovery.
- India is world's third largest coal producer, fulfilling India's 60 % energy needs
- India has vast deposits of coal and lignite in the country and these coal and lignite fields hold vast deposits of CBM.
- CBM can serve as a clean source of fuel for power generation and for supplementing the conventional gas supply.
- Total numbers of 16 blocks were awarded under CBM I & II covering 7800 Sq. Kms of area.
- 11 Blocks under the III round of CBM have been announced for E&P.

The studies for delineation of blocks for prospecting / exploitation of Coal bed Methane (CBM) have been carried out for Jharia, Raniganj, East Bokaro, West Bokaro, North Karanpura and Sohagpur coalfields by Central Mine Planning & Design Institute (CMPDI) at the instance of Ministry of Coal and Directorate General of Hydrocarbons (Ministry of Petroleum & Natural Gas).

- Total Estimated methane resources (CBE I, II, III) - 1670 BCM.
- Production potential from CBM I & II blocks is - 23 MMSCMD.
- Essar and Grades Services, USA have formed a 50:50 JV to offer technology and allied services for drilling & exploration for CBM/ Oil & Gas.
- Investment of US$ 45 million has been already committed.
- Partial production commenced from CBM I & II; expected full commercial Production by 2007.

Natural Gas Hydrates

Gas Hydrates, generally found in deep sea, are basically methane molecules trapped in ice.

Pilot studies for exploration & production of gas from the gas hydrates are being initiated by DGH, ONGC & GAIL. The total prognosticated gas resource from the gas hydrates in the country is -1894 TCM.

Surveys conducted in the East coast & Andaman Deepwater's @ 1300-1500 m water depths proved to be the most promising areas for gas hydrates. Commercialization (subject to viability) is expected in the next 3-4 years.

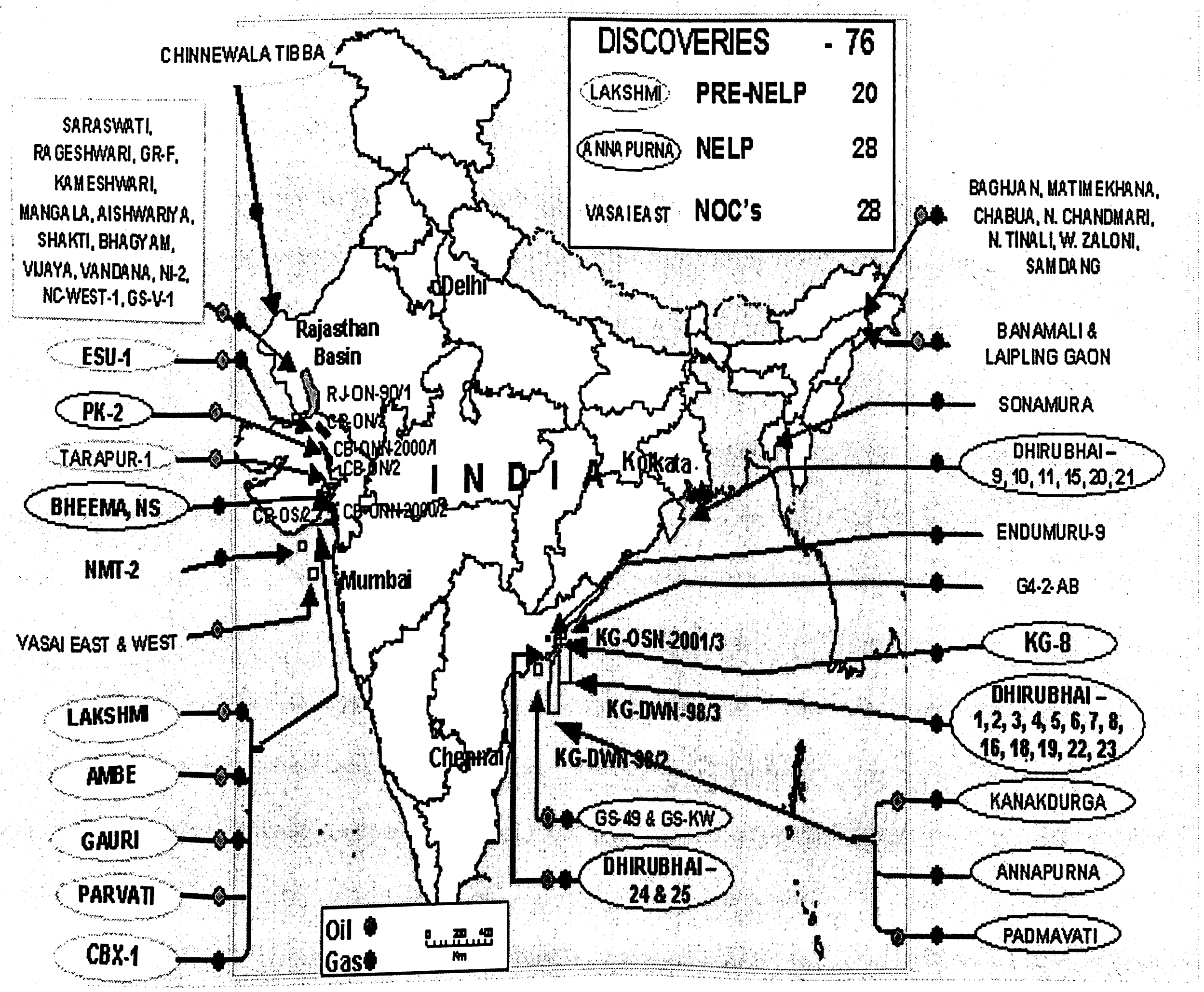
Recent Oil & Gas Discoveries

Oil & Gas Discoveries

1. Total 57 significant hydrocarbon discoveries were made under NELP I–V Rounds, amounting to hydrocarbon reserves of over 600 million tons OEG
2. Six large discoveries in last 2 years including; THREE of world's largest gas discoveries- potential of over 40 Tcf of gas
3. India's largest ever gas discovery of 20 Tcf was reported by GSPCL in June 2005
4. Reliance's gas discovery of 14 Tcf in K-G deep offshore well is likely to start producing 40 MMSCMD of gas by 2008
5. In 2004-05, ONGC made 10 offshore discoveries: 6 in Kutch/ Mumbai basins and 4 in KG basin
6. Cairn Energy: 3.5 billion bbls of oil discovery in Rajasthan; Production commenced
7. GSPCs PK-2 Structure- production started
8. Reliance discoveries- in KG basin- producing 3012 bopd and 2700 bopd respectively
9. ONGC has reported significant discovery of 4 Tcf of gas in the KG basin
10. RIL+ NIKO consortium gas discovery in Mahanadi offshore block has proven reserves of 2.3 Tcf.
11. ONGC's field in Myanmar is estimated to have 4-6 Tcf gas
12. Reliance's discovery of 3.76 Tcf in place reserves of CBM gas in sohagpur east and west blocks in Madhya Pradesh
13. ONGC is presently testing 2 wells for CBM gas. Commercial production is planned for early 2007
14. Great Eastern Energy Corp. Ltd (GEECL), 1.385 Tcf discovery in Raniganj block in west Bengal is in line for production

The recent discoveries in India can be shown as:

New Significant Discoveries by NOC's and Pvt./JV Companies (2000-2005)



Source: Director General of Hydrocarbons (DGH), 2005

Section III

SCOPE & PROSPECTS

Projects & Investments

Various undergoing Projects & their estimated Investments in Upstream Sector can be shown as:

Investments in the next 5 years	Approx. US$ 15-20 billion
Value of Projects announced in last 2 years	US$ 9.3 billion
Planned Investment for blocks under NELP I-IV	US$ 4.4 billion
Investment for blocks under NELP V	US$ 1 billion
Investment for blocks under NELP VI	US$ 7 billion
Mumbai High restructuring plan (ONGC)	US$ 1.8 billion
KG basin RIL deepwater block	US$ 2.5 billion
Enhanced/Improved Oil Recovery (ONGC/OIL)	US$ 2 billion
ONGC spending daily on Deepwater	US$ 1 mn/day
Investments in the next 25 years	Approx. US$ 120 billion

Scope and Prospects

There is huge upcoming opportunity to provide & supply Specialized Services & Equipment/Packages plants to the upstream exploration & production sector in India. The major areas of opportunities are as follows:

1. Seismic Surveys, Aerogravity & Aeromagnetic Surveys
2. Survey Vessels & Stimulation Vessels (90 Off-shore Supply Vessels required as per one estimate)
3. Subsea pipeline, Cabling and Telecom network
4. Production Platforms
5. Floating Production Storage Offshore Units
6. Subsea Equipments and Services
7. Oil Field Equipment
8. Specialty Chemicals/Technologies/services for improved production
9. Helicopters (almost 50 nos.) required to service offshore facilities
10. Gas Processing Technologies/Plants and Onshore Gas Processing Terminals
11. Gas Gathering, separation and Compressor Stations
12. Systems/Packages on platforms

Section IV

GAS PROCESSING TECHNOLOGIES

Gas Processing Technoloies

Natural gas Processing:

Natural Gas is one of the principle sources of energy for many of our day-to-day needs and activities.

Natural gas, as it exists underground, is not exactly the same as the natural gas that comes through the pipelines to our homes and businesses. Natural gas contains almost entirely methane as we use it.

Natural gas as we find it underground, however, can come associated with a variety of other compounds and gases, as well as oil and water, which must be removed. Natural gas transported through pipelines must meet purity specifications to be allowed in, so most natural gas processing occurs near the well.

Processing of natural gas is less complicated than the processing and refining of crude oil and also it is equally as necessary before its use by end users.

Raw natural gas comes from three types of wells: oil wells, gas wells, and condensate wells. Natural gas that comes from oil wells is typically termed 'associated gas'. This gas can exist separate from oil in the formation (free gas), or dissolved in the crude oil (dissolved gas). Natural gas from gas and condensate wells, in which there is little or no crude oil, is termed 'non-associated gas'. Gas wells typically produce raw natural gas by itself, while condensate wells produce free natural gas along with a semi-liquid hydrocarbon condensate. Natural gas once separated from crude oil (if present) it commonly exists in mixtures with other hydrocarbons; principally ethane, propane, butane, and pentanes. In addition, raw natural gas contains water vapor, hydrogen sulfide (H_2S), carbon dioxide, helium, nitrogen, and other compounds.

Natural gas processing consists of separating all of the various hydrocarbons and fluids from the pure natural gas, to produce 'pipeline quality' dry natural gas. While the ethane, propane, butane, and pentanes known as 'natural gas liquids' (NGLs) must be removed from natural gas & can be very valuable by-products of natural gas processing. NGLs include ethane, propane, butane, iso-butane, and natural gasoline. These NGLs are sold separately and have a variety of different uses; including enhancing oil recovery in oil wells, providing raw materials for oil refineries or petrochemical plants, and as sources of energy.

The extracted natural gas is processed at the well head itself or transported to the processing plants through a network of gathering pipelines, which are small-diameter, low pressure pipes. A complex gathering system can consist of thousands of miles of pipes, interconnecting the processing plant to upwards of 100 wells in the area.

Natural gas processing usually involves four main processes to remove the various impurities:

- Oil and Condensate Removal
- Water Removal
- Separation of Natural Gas Liquids
- Sulfur and Carbon Dioxide Removal

In addition to the four processes above, heaters and scrubbers are installed, usually at or near the wellhead. The scrubbers serve primarily to remove sand and other large-particle impurities. The heaters ensure that the temperature of the gas does not drop too low. With the presence of minimal quantities of water in natural gas, natural gas hydrates have a tendency to form when temperatures drop. These hydrates are solid or semi-solid compounds, resembling ice like crystals. These hydrates accumulate & impede the passage of natural gas through valves and gathering systems. To reduce the occurrence of hydrates, small natural gas-fired heating units are typically installed along the gathering pipe wherever it is likely that hydrates may form.

Oil and Condensate Removal

In order to process and transport associated dissolved natural gas, it must be separated from the oil in which it is dissolved. This separation of natural gas from oil is most often done using equipment installed at or near the wellhead.

The actual process used to separate oil from natural gas, as well as the equipment that is used, can vary widely. Usually raw natural gas from different regions may have different compositions and separation requirements. Natural gas is dissolved in oil underground primarily due to the pressure that the formation is under. When this natural gas and oil is produced, it is possible that it will separate on its own, due to the decreased pressure.

The most basic type of separator is known as a conventional separator. It consists of a simple closed tank, where the force of gravity serves to separate the heavier liquids like oil, and the lighter gases, like natural gas.

Usually some specialized equipment, Low-Temperature Separator (LTX), may also be necessary to separate oil and natural gas. These are most often used for wells producing high pressure gas along with light crude oil or condensate. These separators use pressure differentials to cool the wet natural gas and separate the oil and condensate. Wet gas enters the separator, being cooled slightly by a heat exchanger. The gas then travels through a high pressure liquid 'knockout', which serves to remove any liquids into a low-temperature separator. The gas then flows into this low-temperature separator through a choke mechanism, which expands the gas as it enters the separator. This rapid expansion of the gas allows for the lowering of the temperature in the separator. After liquid removal, the dry gas then travels back through the heat exchanger and is warmed by the incoming wet gas. By varying the pressure of the gas in various sections of the separator, it is possible to vary the temperature, which causes the oil and some water to be condensed out of the wet gas stream. This basic pressure-temperature relationship can work in reverse as well, to extract gas from a liquid oil stream.

Water Removal

In addition to separating oil and some condensate from the wet gas stream, it is necessary to remove most of the associated water. Most of the liquid, free water associated with extracted natural gas is removed by simple separation methods at or near the wellhead. The removal of the water vapor that exists in solution in natural gas requires a more complex treatment. This treatment consists of 'dehydrating' the natural gas, usually involves one of two processes: either absorption, or adsorption.

Absorption occurs when the water vapor is taken out by a dehydrating agent. Adsorption occurs when the water vapor is condensed and collected on the surface.

Separation of Natural Gas Liquids

Natural gas coming directly from a well contains many natural gas liquids that are commonly removed. Natural gas liquids (NGLs) have a higher value as separate products, and it is thus economical to remove them from the gas stream. The removal of natural gas liquids usually takes place in a relatively centralized processing plant, and uses techniques similar to those used to dehydrate natural gas.

There are two basic steps to the treatment of natural gas liquids in the natural gas stream. First, the liquids must be extracted from the natural gas. Second, these natural gas liquids must be separated themselves, down to their base components.

NGL Extraction

There are two principle techniques for removing NGLs from the natural gas stream: the absorption method and the cryogenic expander process.

The extraction of NGLs from the natural gas stream produces both cleaner, purer natural gas, as well as the valuable hydrocarbons that are the NGLs themselves.

Natural Gas Liquid Fractionation

Once NGLs have been removed from the natural gas stream, they must be broken down into their base components to be useful. i.e, the mixed stream of different NGLs must be separated out. This process used is known as fractionation. Fractionation works based on the different boiling points of the different hydrocarbons in the NGL stream. Essentially, fractionation occurs in stages consisting of the boiling off of hydrocarbons one by one. The name of a particular fractionator gives an idea as to its purpose, as it is conventionally named for the hydrocarbon that is boiled off. The entire fractionation process is broken down into steps, starting with the removal of the lighter NGLs from the stream. These are:

- Demethanizer – this step separates Methane from the rest NGL stream
- **Deethanizer** - this step separates the ethane from the remaining higher hydrocarbons in the NGL stream.
- **Depropanizer** - the next step separates the propane.
- **Debutanizer** - this step boils off the butanes, leaving the pentanes and heavier hydrocarbons in the NGL stream.
- **Butane Splitter or Deisobutanizer** - this step separates the iso and normal butanes.

By proceeding from the lightest hydrocarbons to the heaviest, it is possible to separate the different NGLs reasonably easily.

Sulfur and Carbon Dioxide Removal

In addition to water, oil, and NGL removal, one of the most important parts of gas processing involves the removal of sulfur and carbon dioxide. Natural gas from some wells contains significant amounts of sulfur and carbon dioxide. Natural gas containing sulfur content is commonly called 'sour gas'. Sour gas is undesirable because the sulfur compounds it contains can be extremely harmful & even lethal to breathe. Sour gas can also be extremely corrosive. The harmful sulfur that exists in the natural gas stream can be extracted and marketed on its own.

Sulfur exists in natural gas as hydrogen sulfide (H_2S), and the gas is usually considered sour if the hydrogen sulfide content exceeds 5.7 mg of H_2S per cubic meter of natural gas. The process for removing hydrogen sulfide from sour gas is commonly referred to as 'sweetening' the gas.

The primary process for sweetening sour natural gas is quite similar to the processes of glycol dehydration and NGL absorption. In this case, however, amine solutions are used to remove the hydrogen sulfide. This process is known simply as the 'amine process', or alternatively as the Girdler process, in which the sour gas is run through a tower, which contains the amine solution. This solution has an affinity for sulfur, and absorbs it much like glycol absorbing water. There are two principle amine solutions used, monoethanolamine (MEA) and diethanolamine (DEA). Either of these compounds, in liquid form, will absorb sulfur compounds from natural gas as it passes through. The effluent gas is virtually free of sulfur compounds, and thus loses its sour gas status. Like the process for NGL extraction and glycol dehydration, the amine solution used can be regenerated (that is, the absorbed sulfur is removed), allowing it to be reused to treat more sour gas.

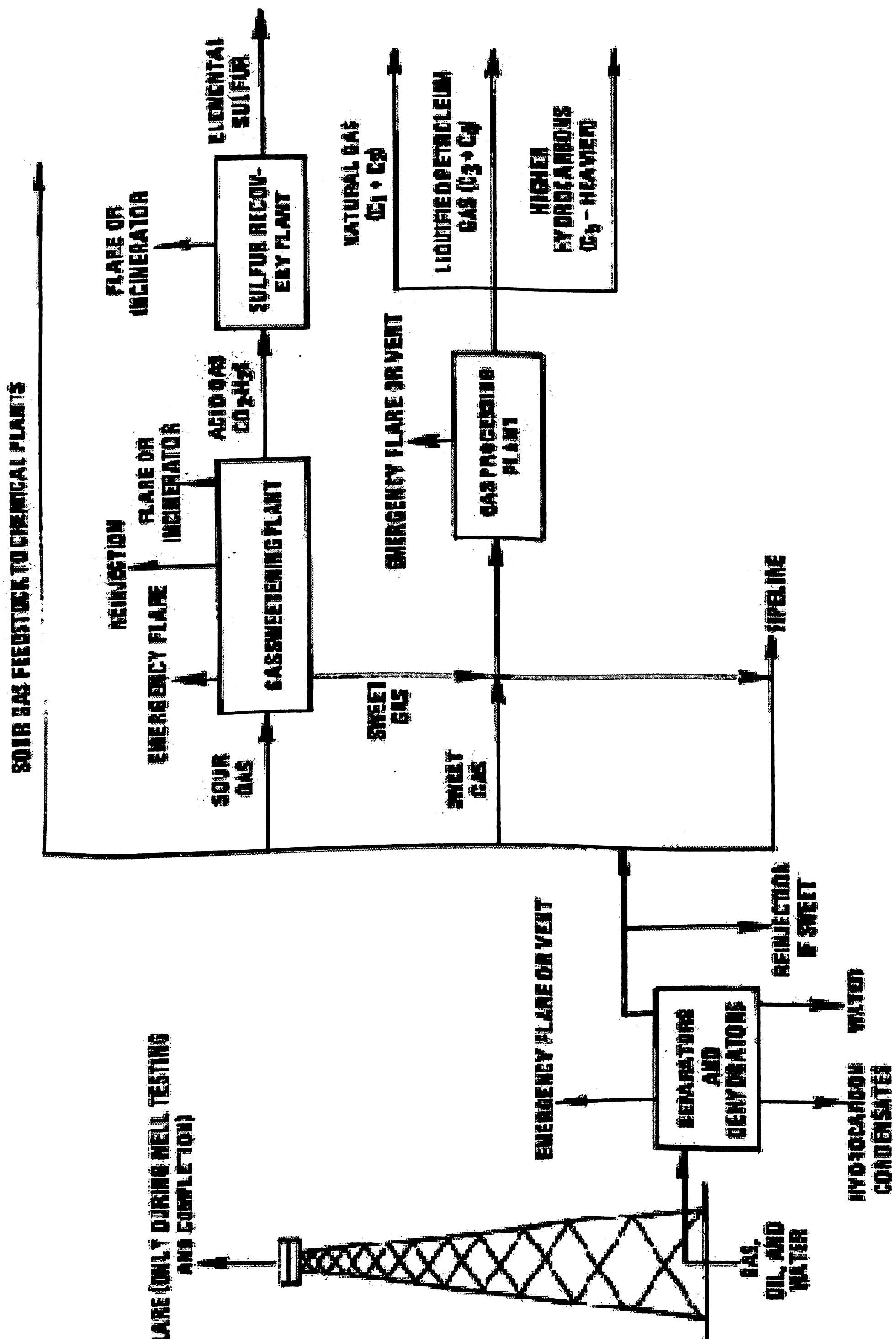
Although most sour gas sweetening involves the amine absorption process, it is also possible to use solid desiccants like iron sponges to remove the sulfide and carbon dioxide.

Sulfur can be sold and used if reduced to its elemental form. Elemental sulfur is a bright yellow powder like material, and can often be seen in large piles near gas treatment plants. In order to recover elemental sulfur from the gas processing plant, the sulfur containing discharge from a gas sweetening process must be further treated. The process used to recover sulfur is known as the Claus process, and involves using thermal and catalytic reactions to extract the elemental sulfur from the hydrogen sulfide solution.

The Claus process recovers 97 percent of the sulfur that has been removed from the natural gas stream. Since it is such a polluting and harmful substance, further filtering, incineration, and 'tail gas' clean up efforts ensure that well over 98 percent of the sulfur is recovered.

Gas processing is an instrumental piece of the natural gas value chain. Once the natural gas has been fully processed, and is ready to be consumed, it must be transported from those areas that produce natural gas, to those areas that require it.

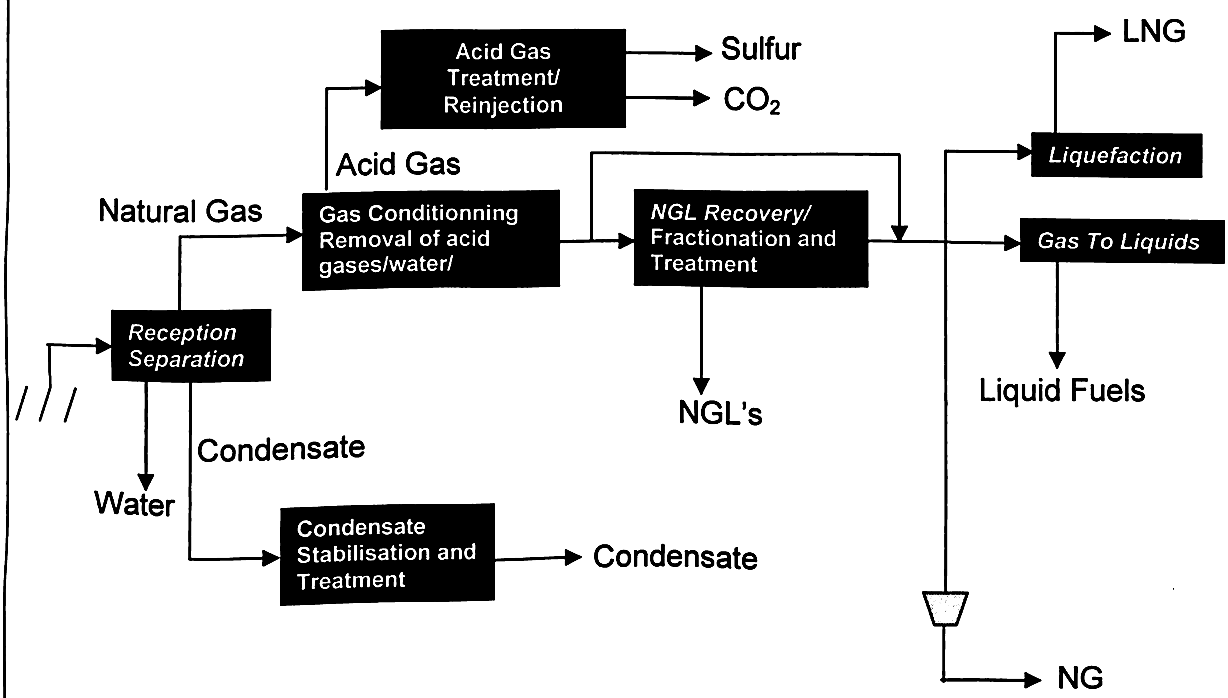
General flow diagram of Natural gas industry:



Source: Naturalgas.org

Gas Processing Chain:

Alternatively, gas processing chain can be shown as:



Source: Axens, 2006.

Section V

MODELING OF NGL FRACTIONATION TRAIN USING ASPEN HYSYS

Modeling of a NGL fractionation Train using Aspen HYSYS:

Recovery of Natural gas Liquids (NGL) from natural gas is usually done to:

1. Produce transportable gas (free from heavier hydrocarbons which may condense in the pipeline)
2. Meet a sales gas specification
3. Maximize liquid recovery (when liquids products are more valuable than gas)

Natural Gas Liquid Fractionation

Once NGLs have been removed from the natural gas stream, they must be broken down into their base components to be useful. i.e, the mixed stream of different NGLs must be separated out. This process used is known as fractionation. Fractionation works based on the different boiling points of the different hydrocarbons in the NGL stream. Essentially, fractionation occurs in stages consisting of the boiling off of hydrocarbons one by one. The name of a particular fractionator gives an idea as to its purpose, as it is conventionally named for the hydrocarbon that is boiled off. The entire fractionation process is broken down into steps, starting with the removal of the lighter NGLs from the stream. These are:

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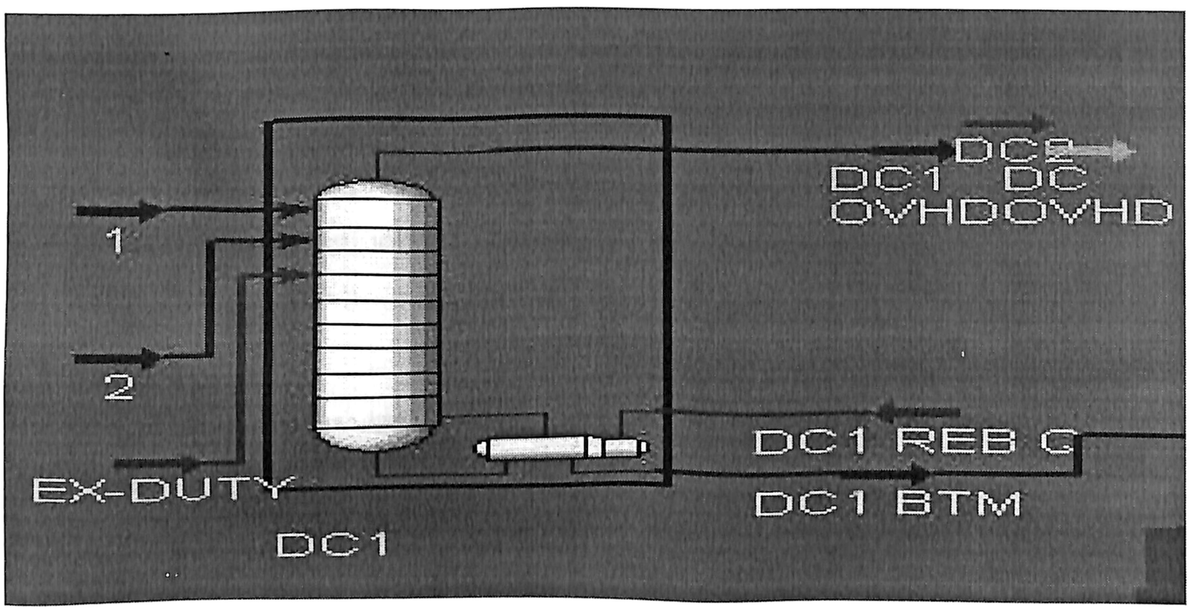
- **Debutanizer** - this step boils off the butanes, leaving the pentanes and heavier hydrocarbons in the NGL stream.
- **Butane Splitter or Deisobutanizer** - this step separates the iso and normal butanes.

By proceeding from the lightest hydrocarbons to the heaviest, it is possible to separate the different NGLs reasonably easily.

HYSYS can model a wide range of different column configurations. In this simulation a demethaniser column is constructed, which is operated and modeled as a Reboiled Absorber Column.

In the simulation process we consider Peng-Robinson Equation of States for the Thermodynamic Equilibrium calculation of the variables.

The De-Methanizer column is modeled as a reboiled absorber operation, with two feed streams and an energy stream feed, which represents a side heater on the column.



Mathematical Model Development:

The mathematical model will be developed by rigorous method, which converts the column into a group variables and equations. These equations are referred to MESH equations.

As the columns have many stages and fewer components, Naphthali Sandholm method will be used. Newton Raphson equation can be used to solve the equations and variables together

Naphthali Sandholm Method:

l_{ij} - Molar flow rate of component i, leaving j^{th} tray in liquid phase

v_{ij} – Molar flow rate of component i, leaving j^{th} tray in vapor phase

V_j, L_j – Total flow rate of vapor and liquid leaving j^{th} tray

j – No. of trays j - 1…13

i – Components i – 1…50

H_j, h_j – Molar enthalpy of vapor and liquid streams leaving the stage

$f^L_{i,j}$, $f^V_{i,j}$ – Molar flow rate of j^{th} component in the feed entering the i^{th} tray

Independent variables l_{ij}, v_{ij}, T_j

General Tray equations:

Mass balance:

$$M_{i,j} = l_{i,j-1} + V_{i,j-1} - l_{i,j} - v_{i,j} + f^L_{i,j} + f^V_{i,j}$$

Where j – 1…13

i – 2…49

M_{ij} – Discrepancy factor, which is assigned a value at the start of simulation and will be close to zero at the end of simulation.

Equilibrium:

$$y_{i,j} = K_{i,j} * x_{i,j} \quad (\eta_{i,j} = 1)$$

Where j – 1…13

i – 2…49

$$y_{i,j} = v_{i,j} / \Sigma\, v_{i,j}$$

$$x_{i,j} = l_{i,j} / \Sigma\, l_{i,j}$$

Enthalpy Balance:

$H_i = L_{i-1,} \times h_{i-1} + V_{i+1} \times H_{i+1} - L_i \times h_i - V_i \times H_i + f_i^L \times h_i^F + f_i^V \times H_i^F - Q_i = 0$

Where, $j - 1 \ldots 13$

$i - 1 \ldots 50$

Partial Reboiler:

Component material balance:

$M_{50} = l_{49,j} - v_{50,j} - l_{50,j}$

Where, $j\text{-}1 \ldots 13$

Equilibrium balance:

$V_{50,j} = K_{50,j} \times L_{50,j}$

Where, $j\text{-}1 \ldots 13$

Specification equations:

$H_{50} = L_{50} - L_{50}^S$

Where, L_N^S = Total bottom product withdrawn

These mathematical model equations can be solved in an iterative process to improve upon such that results match the real system. They are conceptual and in dimensionless form which can be solved by using mathematical software's like Matlab.

Simulation by Aspen Hysys:

Aspen HYSYS is a software solution for the process industry. This is the basic concept necessary for creating simulation in Aspen HYSYS. Hysys gives direction how to determine properties of these streams by using the phase and the property table utilities.

1. Define fluid package (property package, library components, hypothetical components)
2. Add streams
3. Understand flash calculations
4. Attach stream utilities
5. Customize the work book

Simulation Basis Manager:

HYSYS uses the concept of fluid package to contain all necessary information for performing flash and physical property calculations. This approach allows us to define all information (property package, components, hypothetical components, interaction parameters, reactants, tubular data, etc.) inside a single entity.

1. All associated information is defined in a single location, allowing for easy creation and modification of information.
2. Fluid packages can be stored as completely defined entities for use in any simulation.
3. Components list can be stored out separately from the fluid package as completely defined entities for use in any simulation.
4. Multiple fluid packages can be used in the same simulation.

The simulation basis manager is a property view that allows us to create and manipulate multiple fluid package or component lists in simulation.

Steps involved in Simulation by Aspen HYSYS:

1. Start a new case by selecting the new case icon.
2. Create a fluid package by clicking the add button.
3. Choose the fluid package (Peng-Robinson Equation)
4. Adding the component list by clicking view button.
5. Select the hypothetical menu item in the add components box to add a hypothetical components in the fluid package. A hypothetical component can be used to model non-library components of defined or undefined mixtures. Hypothetical component is used to model the components heavier than that component.
6. When hypothetical component has been defined, return to the fluid package and add the hypothetical component in the selected component.
7. Adding material streams:- In HYSYS, there are two types of streams such as material and energy. Material streams have a composition and parameter such as temperature, pressure and flow rate. These represent the process stream

8. Adding the Unit Operation to DC1:

   The DC1 column is modeled as a multi-component, multi-stage, simple distillation column with 10 stages in the column plus the reboiler. The objective of the column is to produce a methane (>90%) in the column.

9. Click on the distillation column bottom and enter the necessary information. After entering click the run button to run the column. Once the column has converged, then check the product quality

Once the system has converged, then compare the product quality we are getting from HYSYS and actual data from industry. If product quality is varying then change the assigned parameters.

Design Case:

The liquid feeds composition has been taken from existing case in Aspen. The composition is as follows:

Table: (Feed 1 Mole fractions)

Feed-1	Mole fraction
Nitrogen	0.0025
CO_2	0.0048
Methane	0.7041
Ethane	0.1921
Propane	0.0706
i-Butane	0.0112
n-Butane	0.0085
i-Pentane	0.0036
n-Pentane	0.0020
n-Hexane	0.0003
n-Heptane	0.0002
n-Octane	0.0001

Feed 2 Mole Fractions:

Feed-1	Mole fraction
Nitrogen	0.0057
CO_2	0.0029
Methane	0.7227
Ethane	0.1176
Propane	0.0750
i-Butane	0.0204
n-Butane	0.0197
i-Pentane	0.0147
n-Pentane	0.0102
n-Hexane	0.0037
n-Heptane	0.0047
n-Octane	0.0027

The molar flow rate of feeds 1 & 2 to DC1 are 1620 Kgmole/Hr & 215 Kgmole/hr. The amount of Methane present in feed has been recovered by 99.98% at top of the DC1. Under this high recovery of methane condition, we maximized CO_2 recovery at the top of the DC1.

Simulation Results for Design Case:

The simulation process was done using Aspen Hysys version 2004 and the results obtained are as follows:

DC1 column:

The specifications under which the column was converged:

a) Methane recovery 99.98 %

b) CO_2 Recovery 96.99 %

c) Reboil Ratio 2.105

The specification should be selected such that the degree of freedom is zero, which is a basic condition for simulation process.

<u>Table:</u> (Material balance design case DC1 column)

Molar flow rate to DC1 is 1620 & 215 Kg mole/hr.

Parameter	Value
Column top pressure	2275 KPa
Column top temperature	-87.15 C
Column bottom pressure	2310 KPa
Column bottom temperature	20 C
Reboiler O/L temperature	21 C

Table: Product composition and rates (Composition in mole fraction basis)

Component	Calculated DC1 OVHD(1350 Kgmoles/hr)	Calculated DC1 Btm (485 Kgmoles/hr)
Nitrogen	3.91E-03	4.91E-10
CO_2	6.03E-03	5.21E-04
Methane	0.96000002	4.96E-05
Ethane	2.89E-02	0.613432782
Propane	1.13E-03	0.26592811
i-Butane	4.29E-05	4.63E-02
n-Butane	1.84E-05	3.71E-02
i-Pentane	1.97E-06	1.85E-02
n-Pentane	6.41E-07	1.12E-02
n-Hexane	1.57E-08	2.64E-03
n-Heptane	1.79E-09	2.75E-03
n-Octane	1.55E-10	1.53E-03

RESULTS AND DISCUSSION

The simulation result obtained from Aspen HYSYS 2004 version and the resulting analysis has been studied under different condition. Following flexibilities are available with respect to column simulation and operation.

(i) Two feed streams

(ii) Specification and Operating conditions

All these consideration have been taken into account in the sensitivity analysis. In addition to computational calculation, the mathematical model has done by Naphthali-Sandholm method.

Sensitivity Study:

Sensitivity analysis signifies, how the product qualities changed by changing the parameter once at a time and other parameter remains unchanged.

Table: (Design case)

The composition and recovery for the original design case are as follows:

D=1350,B=485, F1=1620, F2 = 215 kgmoles/hr, R=2.5					
Components	**Ovhd Pdt of CD1 (Mole fraction)**	**Bottom of CD1 (Mole fraction)**		**Ovhd pdt of CD1 (Recovery)**	**Bottom of CD1 (Recovery)**
Nitrogen	3.91E-03	4.91E-10		99.99999549	4.51E-06
CO2	6.03E-03	5.21E-04		96.98952641	3.010473589
Methane	0.96000002	4.96E-05		99.99814388	1.86E-03
Ethane	2.89E-02	0.613432782		11.58148924	88.41851076
Propane	1.13E-03	0.26592811		1.165872485	98.83412752
i-Butane	4.29E-05	4.63E-02		0.257105011	99.74289499
n-Butane	1.84E-05	3.71E-02		0.137631891	99.86236811
i-Pentane	1.97E-06	1.85E-02		2.96E-02	99.97044573
n-Pentane	6.41E-07	1.12E-02		1.59E-02	99.98406607
n-Hexane	1.57E-08	2.64E-03		1.65E-03	99.99834954
n-Heptane	1.79E-09	2.75E-03		1.81E-04	99.99981855
n-Octane	1.55E-10	1.53E-03		2.81E-05	99.9999719

FLOW RATE:

Table: Increased feed flow rate by 30%:

For 30 % increase in feed flow rate from 1620 kgmoles/hr to 2106 kgmoles/hr, the composition and recovery are:

30% increase in feed flow rate (2106 Kgmoles/hr)					
Components	**Ovhd Pdt of CD1 (Mole fraction)**	**Bottom of CD1 (Mole fraction)**		**Ovhd pdt of CD1 (Recovery)**	**Bottom of CD1 (Recovery)**
Nitrogen	3.80E-03	3.36E-10		99.99999682	3.18E-06
CO2	6.12E-03	4.73E-04		97.29181663	2.708183367
Methane	0.9600003	3.53E-05		99.9986746	1.33E-03
Ethane	2.89E-02	0.619241037		11.46748164	88.53251836
Propane	1.13E-03	0.265047801		1.167240839	98.83275916
i-Butane	4.29E-05	4.54E-02		0.261854215	99.73814579
n-Butane	1.84E-05	3.60E-02		0.141568156	99.85843184
i-Pentane	1.97E-06	1.75E-02		3.13E-02	99.96871028
n-Pentane	6.42E-07	1.04E-02		1.71E-02	99.98290538
n-Hexane	1.57E-08	2.32E-03		1.87E-03	99.99812544
n-Heptane	1.80E-09	2.33E-03		2.14E-04	99.99978601
n-Octane	1.55E-10	1.29E-03		3.34E-05	99.99996663

If the feed flow rate is increased by 30%, then the recovery of Methane remains same but the recovery of CO_2 has increased by 1%. Increasing feed flow rate does not affect the product quality much. Decrease in flow rate also does not affect much the product recovery of the streams.

Also variation in the feed 2 flow rates has not much effect on the final product properties.

Hence this condition may be applicable for increasing the overhead product flow rate without the change in the quality (within 10-30% of feed rate).

Excessive increase in the feed flow rate further causes increased load on the column.

Pressure

This table signifies the role of pressure on the compositions and recoveries of the products.

Table: Increase in Pressure (P- 4000 Kpa):

	Mole Fractions			Recovery %	
	DC1 OVHD	DC1 BTM		DC1 OVHD	DC1 BTM
Component					
Nitrogen	3.91E-03	4.35E-10		99.999996	4.00E-06
CO2	6.05E-03	4.80E-04		97.23028385	2.769716155
Methane	0.95999486	4.42E-05		99.99834466	1.66E-03
Ethane	2.89E-02	0.613473224		11.57747759	88.42252241
Propane	1.13E-03	0.265932321		1.16633898	98.83366102
i-Butane	4.29E-05	4.63E-02		0.257211308	99.74278869
n-Butane	1.84E-05	3.71E-02		0.137683052	99.86231695
i-Pentane	1.97E-06	1.85E-02		2.96E-02	99.97043608
n-Pentane	6.41E-07	1.12E-02		1.59E-02	99.98406164
n-Hexane	1.57E-08	2.64E-03		1.65E-03	99.99834924
n-Heptane	1.79E-09	2.75E-03		1.81E-04	99.99981853
n-Octane	1.55E-10	1.53E-03		2.81E-05	99.9999719

Table: Decrease in Pressure (P-2000 Kpa):

	Composition			Recovery %	
	DC1 OVHD	DC1 BTM		DC1 OVHD	DC1 BTM
Nitrogen	3.91E-03	6.51E-10		99.99999401	5.99E-06
CO2	5.82E-03	1.12E-03		93.55366449	6.446335515
Methane	0.95999983	7.38E-05		99.99723824	2.76E-03
Ethane	2.89E-02	0.61320886		11.61158423	88.38841577
Propane	1.26E-03	0.265557943		1.301012987	98.69898701
i-Butane	4.83E-05	4.63E-02		0.289179271	99.71082073
n-Butane	2.06E-05	3.71E-02		0.15472137	99.84527863
i-Pentane	2.22E-06	1.85E-02		3.33E-02	99.96672933
n-Pentane	7.21E-07	1.12E-02		1.79E-02	99.98208408
n-Hexane	1.76E-08	2.64E-03		1.85E-03	99.99814578
n-Heptane	2.01E-09	2.75E-03		2.04E-04	99.99979623
n-Octane	1.73E-10	1.53E-03		3.15E-05	99.99996846

With increase in the pressure of the system there is increase in the CO_2 recovery by 1 % when compared to the design case.

With decrease in the pressure from 3000 Kpa to 2000 Kpa there was significant decrease in the CO_2 recovery from 97% to 93%, which is not desirable.

So, with the decrease in the pressure, recovery of CO_2 decreases.

Temperature:

Increase in temperature (T1- -115 C)

	Composition			Recovery %	
	DC1 OVHD	DC1 BTM		DC1 OVHD	DC1 BTM
Nitrogen	3.91E-03	3.13E-10		99.99999712	2.88E-06
CO2	6.13E-03	2.60E-04		98.49774957	1.502250428
Methane	0.96000001	2.98E-05		99.99888516	1.11E-03
Ethane	2.89E-02	0.613299381		11.60258866	88.39741134
Propane	9.89E-04	0.266317058		1.023362855	98.97663715
i-Butane	3.74E-05	4.64E-02		0.223845969	99.77615403
n-Butane	1.60E-05	3.71E-02		0.119925741	99.88007426
i-Pentane	1.71E-06	1.85E-02		2.57E-02	99.97427531
n-Pentane	5.59E-07	1.12E-02		1.39E-02	99.98610869
n-Hexane	1.37E-08	2.64E-03		1.44E-03	99.99855881
n-Heptane	1.57E-09	2.75E-03		1.59E-04	99.99984135
n-Octane	1.35E-10	1.53E-03		2.46E-05	99.9999754

With the increase in temperature of the feed stream 1 by 20 C there is a significant increase of recovery of CO_2 by 2%.

So, increase in the temperature of the streams by 20 C is favorable.

Decrease in Temperature (-79 C):

	Composition			Recovery %	
	DC1 OVHD	DC1 BTM		DC1 OVHD	DC1 BTM
Nitrogen	3.91E-03	1.86E-09		99.9999829	1.71E-05
CO2	3.63E-03	7.22E-03		58.28154573	41.71845427
Methane	0.95999999	3.56E-04		99.986671	1.33E-02
Ethane	3.09E-02	0.607727482		12.37586803	87.62413197
Propane	1.53E-03	0.26473253		1.578804726	98.42119527
i-Butane	5.95E-05	4.63E-02		3.56E-01	99.64372674
n-Butane	2.54E-05	3.70E-02		1.91E-01	99.80939115
i-Pentane	2.75E-06	1.85E-02		4.12E-02	99.95876134
n-Pentane	8.93E-07	1.12E-02		2.22E-02	99.97780637
n-Hexane	2.19E-08	2.64E-03		2.31E-03	99.99769452
n-Heptane	2.52E-09	2.75E-03		2.55E-04	99.99974522
n-Octane	2.18E-10	1.53E-03		3.97E-05	99.99996032

By the decrease in temperature by 6 C, there is a drastic decrease in the recovery of CO_2 by 38%, which is not favorable.

So, decrease in the temperature of the feed streams in not applicable.

Section VI

CONCLUSIONS & RECOMMENDATIONS

Section VI

Conclusions & Recommendations

In the present work, a mathematical model has been developed for Reboiled Absorber column. Modeling and simulation has been done by using Aspen HYSYS 2004 version. It has given flexibility in product quality, duties, temperature, pressure, etc. We have undergone the detailed sensitivity analysis, which signified the product qualities of different operating conditions.

Few Recommendations from the results obtained are:

1. Temperature is the most critical factor in the process, with a decrease in the temperature of the feed stream by 6 C, there is a drastic decrease of 38% of CO_2 recovery in the overhead product stream.
2. This causes the increase in the work load of downstream units.
3. By increasing the temperature of feed 1, there is increase of 2% of CO_2 recovery for 20 C raise in temperature.
4. Increase or Decrease of flow rates of feed streams does not affect the properties of the product streams.
5. Pressure has a direct relation to the product properties of the system.
6. Increase in pressure of the system causes increased recovery of CO_2.

Similarly modeling of Gas Sweetening process, Gas Dehydration Process, etc for varying capacities and varying compositions can also prove helpful in understanding the processes better and help in exploring more opportunities.

Section VII

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Section VII
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