Chapter-3

NATURAL GAS

Natural gas has been the life line of the commercial energy source of Bangladesh for several decades. In 2010 natural gas share in power generation in the country was about 88%. The present move to increase the share of other source like coal in the energy mix is an inevitable result of the gas demand far outpacing the gas supply. The natural gas will remain a major player in meeting the commercial energy need of the country in the short to medium term future. In addition to power sector, the fertilizer producers, industrial units, commercial entities, domestic and transport sectors all record upward demands for natural gas. Increased level of exploration and exploitation of natural gas will form a primary part of Bangladesh's effort to address the challenge of energy crisis.

In a global context, natural gas is the fastest growing energy resource of the present century. Because natural gas is more environmentally friendly compared to oil and coal, it is preferred over the latter throughout the world today. Nations traditionally dependent on coal and oil has lately been trying to switch over their power generating and other installations to natural gas. Energy experts opine that use of natural gas will continue to grow worldwide, will exceed that of combined use coal and oil and will be the universal fuel by the middle of the present century.

3.1 What is natural gas

Natural gas refers to the naturally occurring hydrocarbon gas predominantly methane. Natural gas and crude oil are both hydrocarbons, but they differ in the weight and complexities of their component hydrocarbon molecules. While the main component of natural gas methane (CH_4) is the lightest and simplest hydrocarbon molecule, those of the crude oil are heavier and more complex. In fact, hydrocarbon molecules with 1 to 4 carbon atoms form the bulk of the natural gas, while those with 5 to 60 carbon atoms in their molecules form crude oil.

In many places natural gas and crude oil are found to be coexisting. This is because their origin and accumulation processes are similar in many accounts. However, while there are places rich in both oil and gas, some places are rich in gas

without significant oil. Petroleum geology offers explanation as to why rich oil and gas deposits occur together in some places while in other places only gas is abundant and not oil.

3.1.1 Composition, nature and properties

Methane (CH_4) is the predominant component of natural gas typically forming 70% to 99% of the bulk gas. In addition, it contains about 1-10% ethane (C_2H_6) and lower percentages of propane (C_3H_8), butane (C_4H_{10}) and higher hydrocarbons. Methane, the predominant component, is a colorless, odorless flammable gas. It is chemically non reactive, sparingly soluble in water and is lighter than air. In the 19th century, Europeans used to produce coal gas by destructive distillation of coal to use it in lightening streets and domestic purpose until it was replaced by natural gas.

Natural gas may contain trace to small amount of non hydrocarbon gases such as carbon dioxide, nitrogen, hydrogen sulfide, hydrogen, argon and helium. In exceptional cases, however, carbon dioxide may be present in significant amount and is produced commercially. The non-hydrocarbon gases reduce the purity and heating value of natural gas.

Sour gas refers to the natural gas that contains appreciable amount of hydrogen sulfide while sweet gas is one free from hydrogen sulfide. Hydrogen sulfide is poisonous, evil smelling, highly corrosive to steel and its presence can cause health and operational problem in gas and oil fields. A concentration of 0.1% of hydrogen sulfide in air can be fatal for human being in less than 30 minutes. Hydrogen sulfide is removed by chemical processing at the surface gas plant. Nitrogen is inert, but if present in appreciable amount, it reduces the heating value of natural gas. Most natural gas contains water vapor and this is removed by refrigeration, glycol absorption or dry desiccant at the surface gas plant.

Condensate refers to the portion which condenses and separates out from natural gas as liquid when the gas is produced at the surface. This liquid is composed of heavier hydrocarbons that exist as vapor dissolved in natural gas in underground pressure temperature condition but turned to liquid at the surface wellhead condition. Most condensates are composed of saturated hydrocarbons in the light gasoline range (butane, pentane and hexane). Condensate is a valuable product and is processed to

be used commercially as fuel. Depending upon the amount of condensate, natural gas is classified as dry gas and wet gas.

Dry gas is defined as the natural gas which contains less than 0.1 gallon/1000 ft^3 of condensate and wet gas is defined as one which contains more than 0.3 gallon/1000 ft^3 of condensate (Selley 1998). A gas may be termed lean gas when condensate proportion lies between 0.1 and 0.3 gallon of condensate per 1000 ft^3 of gas. Composition of typical wet gas and dry gas are shown in Table 3.1.

Table 3.1 Hydrocarbons in typical 'wet gas' and 'dry gas'. (Source: Tiratsoo 1979)

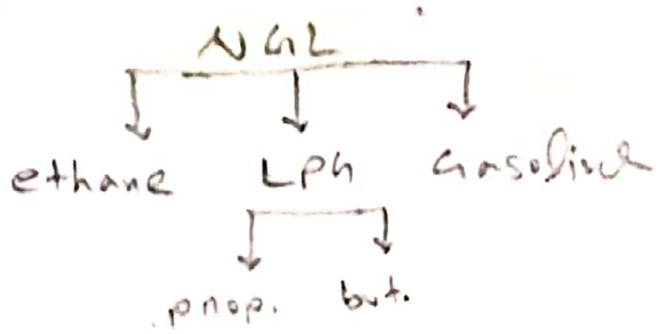
Gas component	Percentages by volume	
	Wet gas	Dry gas
Methane	84.6	96.0
Ethane	6.4	2.0
Propane	5.3	0.6
Butane	2.6	0.3
Pentane	0.4	0.1
Hexane	0.4	0.1
Heptain	0.1	0.08

Associated gas refers to the natural gas when it occurs in association with oil as gas cap or gas dissolved in oil. Non associated gas refers to the natural gas when it occur singly and is not associated with oil. It may be noted that all the discovered natural gas in Bangladesh are non- associated gas.

3.1.2 Products for uses

Natural gas is normally transported by pipeline to reach the end point for use. However there are some other ways natural gas products are used.

Natural gas liquid (NGL) refers to a mixture of all hydrocarbons except methane, which can be extracted by compression and cooling in separator. After extraction, NGL is distilled to be separated into ethane (most important for petrochemical feedstock), propane plus butane (LPG) and natural gasoline.



Liquefied petroleum Gas (LPG) refers to a mixture of essentially propane and butane which are extracted from wet natural gas. LPG is also available during refining of crude oil. It is liquefied under pressure at room temperature and is commercially sold in cylinder as a convenient and portable fuel for domestic uses where supplies of pipeline gas are not available. LPG can also be used in industrial and commercial establishments and to run automobiles.

Liquefied natural gas (LNG) refers to liquid form of natural gas that is produced by special liquefaction process in a plant at the surface. Production of LNG is a costly process and involves cooling the gas to minus 161 degrees centigrade. When produced, one ton of LNG is approximately equivalent to 50,000 cubic feet of natural gas. LNG is suitable for transportation by ship to far away places where gas transportation by pipelines is not possible. Importer requires LNG to be regasified before passing it through pipeline for use.

Compressed Natural gas (CNG) refers to the natural gas made available in compressed form for use as fuel in vehicles. Usually natural gas is compressed to 3000 pound per square inch gauge (psig) in refueling station and put in a cylinder for CNG run vehicles. CNG is a cleaner transport fuel and is preferred over the traditional petrol or diesel fuel from an environmental point of view.

3.2 Origin of natural gas

Natural gas or the hydrocarbon gas as it is also called may be originated from organic matter by several ways. The most commonly found are referred to as i) thermogenic gas, ii) bacterial (biogenic) gas, while less common are iii) gas from coal and iv) gas from oil cracking.

3.2.1 Thermogenic gas: The most important and common origin of natural gas is by the thermal conversion of dispersed organic matter called 'kerogen' in the rock. The two most important factors for significant gas to originate in a rock are the presence of sufficient organic matter in the rock (minimum of 0.5% TOC) and attaining thermal maturity by burial temperature. Such rock that generates natural gas is called 'source rock'. Natural gas originates in the source rock but migrates upward to be accumulated into suitable trap-reservoir condition.

The evolution of thermogenic gas (and oil) in the rock is directly linked to burial temperature in the subsurface. The evolution of petroleum from organic matter takes place through three subsurface zones - diagenesis, catagensis and metagenesis- occurring with progressively greater depth and higher temperature (Tissot and Welte 1984).

Diagenesis zone: As the organic matter is buried, it is converted to a complex insoluble material called 'kerogen' under shallow burial and low temperature in the zone of diagenesis (Figure 3.1). No thermal hydrocarbon gas of any significance is generated in this zone and this is referred to as thermally 'immature zone'. Temperature generally reaches upto 60 degree centigrade at the bottom of the zone.

Catagenesis zone: With further increase of burial depth and temperature the sediments enter into the zone of catagenesis where oil and gas are generated from kerogen. This zone generally lies within temperature range of 60 degree to 200 degree centigrade (Hunt 1996). Catagenesis is a thermally 'mature zone' of moderate to deep burial and it includes oil window and gas windows (Figure 3.2). This is also referred to as 'hydrocarbon kitchen'.

'Oil window' refers to the depth range where most intense generation of oil takes place. Most oil windows exist in temperature range from 60 degree centigrade to 160 degree centigrade. Overlapping the oil window and extending below it occurs the 'gas window' - as referred to the depth range where most intense generation of gas takes place. Most 'gas windows' are in the range of 100 degree to 200 degree centigrade (Hunt 1996).

Metagenesis zone: With further burial and increase of temperature, the zone of catagenesis gives way to the zone of metagenesis where only small amount of gas is produced as the methane generation diminishes and graphitic structure begin to form (Tissot and Welte 1984). This is a zone of deep burial and the temperature generally ranges from 200 degree to 250 degree centigrade. Beyond this zone further below, the higher burial temperature of metamorphic zone will destroy all gas and oil to produce only carbon residue i.e. graphite.

The transformation of organic matter to petroleum is a function both of temperature and time. Therefore, although general temperature ranges are mentioned

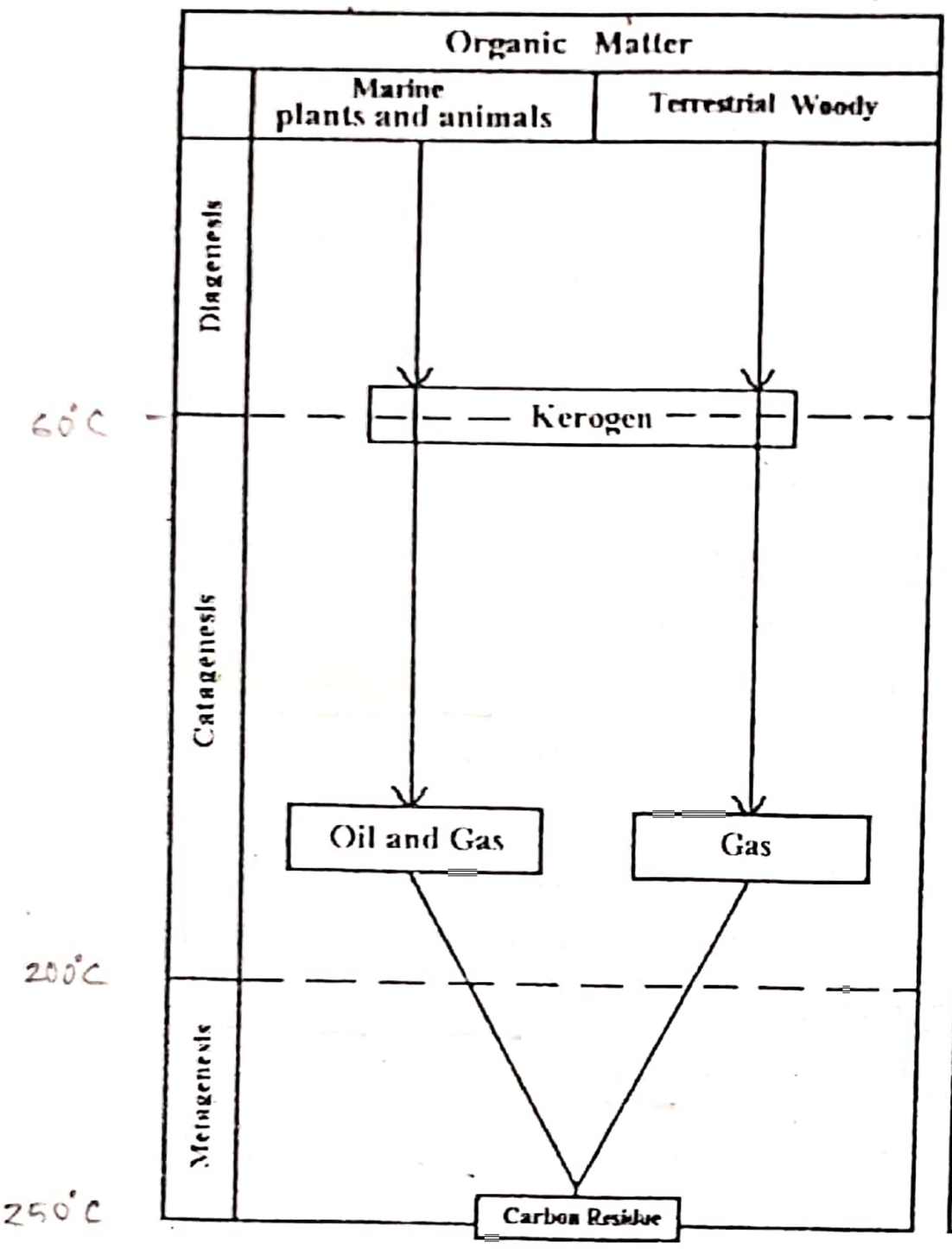


Figure 3.1 Transformation of organic matter to petroleum.

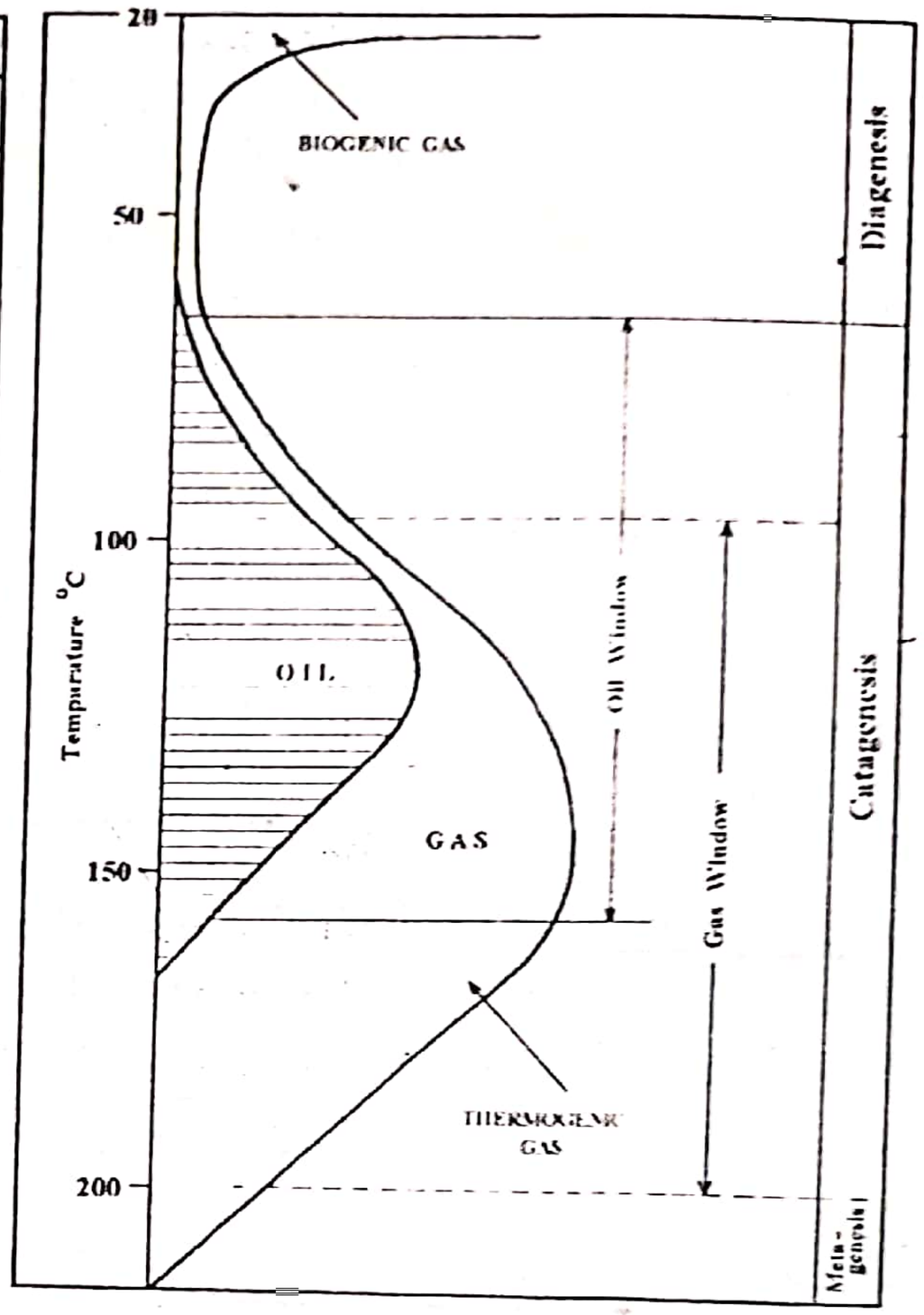


Figure 3.2 Evolution of oil and gas through oil and gas windows (After Hunt 1996).

above, the beginning of the oil and gas windows occur at higher temperature in the younger sediments compared to older ones. For example, oil window begins at 60 degree centigrade in Early Jurassic rocks (180 million years) of the Paris Basin, but it begins at 77 degree C in Early Tertiary rocks (35 million years) of the US Gulf coast basin, and at 115 degree C in Late Tertiary (10 million years) rocks of Los Angels Basin (Tissot and Welte 1984).

A further point is that the type of hydrocarbons produced will depend on the type of initial organic matter as well as the degree of temperature. A marine derived sapropelic type organic matter will produce both oil and gas in significant quantity whereas terrestrially derived woody-humic type organic matter will produce only significant gas (Figure 3.1).

The thermal evolution of oil and natural gas from organic matter, therefore, follows a path whereby different subsurface zones (diagenesis, catagenesis and metagenesis) are defined with successive increase of burial temperature. Most of the commercial gas reserves throughout the world, including those of Bangladesh, are of thermogenic in origin generated within the catagenesis zone.

3.2.2 Bacterial gas: Also known as biogenic gas or marsh gas in the literature, this is the methane gas produced by bacterial decomposition of organic matter in the surface or shallowly buried sediments. Burial temperature does not play a part in the process. Bacterial gas is dry and is generated under anoxic (reducing) condition by bacterial decomposition of organic matter at low temperature. In other words, it is formed in the zone of diagenesis (Figure 3.2). As the burial depth and temperature increases the bacterial population decreases and the process of biogenic gas generation ends.

Bacterial methane gas is far less common than thermogenic gas. It forms commercial accumulations in some places in relatively shallow and younger sediments. According to one estimate about 20% of natural gas in conventional reservoirs are of bacterial origin (Rice and Claypool 1981). It is argued that far larger amounts were formed through geologic time, but because shallow reservoirs generally lack seal, most of these gases are lost (Rice 1993).

Although most biogenic gas is generated and occur at depths less than 1 km, it can be subsequently buried as deep as thermally originated gas, often mixing with the latter. In the US Gulf coast biogenic gas accumulations are found in Pleistocene sediments at depths of 460 to 2800 m, in the USA Rocky mountain area biogenic gas in Cretaceous to Tertiary sediments occur at depths of 120 to 840m, in Siberia giant gas fields of biogenic origin occur in Cretaceous rocks at depth of 700 to 1300 meter (Rice and Claypool 1981). Occurrence and emission of bacterial methane gas in shallow water wells are commonly reported from various part of alluvial plain of Bangladesh although these are not proved large enough to be considered commercial yet.

3.2.3 Gas from coal: Methane gas can also be formed from coal. Thermal maturation of the humic coal in the subsurface may generate major quantities of

methane gas. The generated methane may migrate up to be accumulated in suitable reservoir-trap condition. The gas fields of the southern North Sea in Europe have their gas originated in the carboniferous coals. The gas migrated up into the overlying Permian sandstone reservoir sand and formed large accumulation in block faulted anticlines (Selley 1998).

Coal bed methane (CBM) refers to the methane gas that remains within coal mostly in adsorbed state. This will be discussed as one of the unconventional gas resource later in this chapter.

absorb vs. adsorb

3.3 Prospects and reserves - Fundamentals

3.3.1 Prospect analysis

Natural gas does not remain in the rock within which it originates, but migrates upward. A commercial gas pool is formed if the gas reaches suitable reservoir rock and is barred from further migration by any kind of geologic trap. The same principle applies for oil as well.

Therefore, the prospect of finding an accumulation of natural gas or oil in an area depends on satisfactory coexistence of several factors in the subsurface (Selley 1998). These include a) source rock in which gas is generated, b) reservoir rock that has porosity and permeability to store the gas and c) trap and d) seal- which would bar the gas from further migration and confine it to reservoir rock (Figure 3.3). A fifth factor (e) is the timing of gas migration, i.e. gas migration must take place after the formation of trap. Otherwise, if the gas is migrated before development of the trap, it would be lost to the surface and will not be accumulated.

The probability of finding petroleum in an area ranges from 1.0 (100% probability) to 0.0 (no probability). Instead of subjectively rating the probability of finding oil or gas on a scale of 1.0 to 0.0, the probability of each of the above parameters may be assessed and the overall probability of petroleum success may be found from their product (Selley 1998; Hunt 1996). This can very well be expressed by the formula:

Probability of success = P1 x P2 x P3 x P4 x P5

adsorb- (of a solid) hold (molecules of a gas or liquid or solute) as a thin film on the outside surface or on internal surfaces within the material.

where,

P1 is the probability of finding source rock,

P2 is the probability of finding reservoir rock,

P3 is the probability of finding trap,

P4 is the probability of finding seal

P5 is the probability of timely migration of gas.

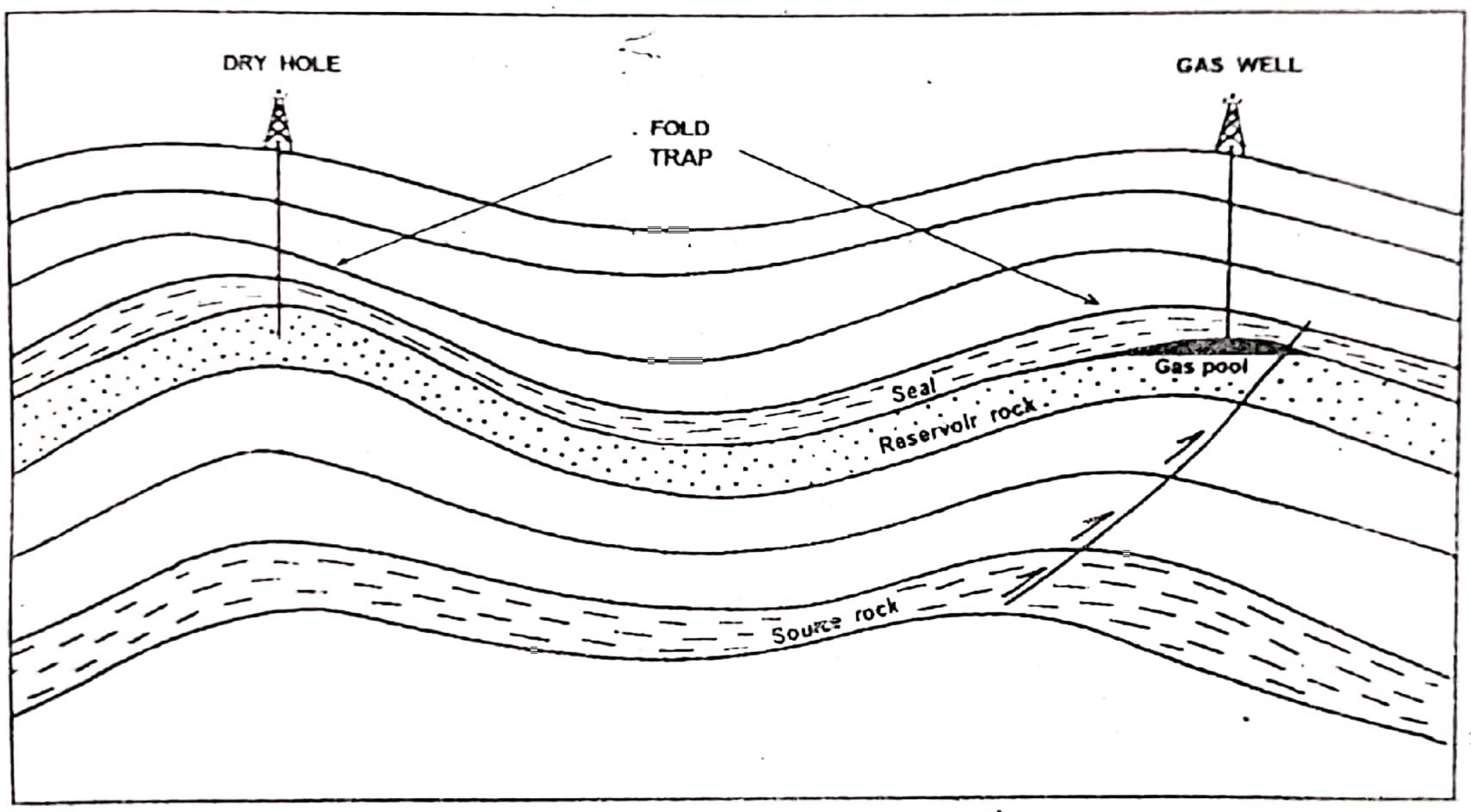


Figure 3.3 Basic parameters required for formation of petroleum pool.

Table 3.2 gives a hypothetical survey result, for example, for hydrocarbon prospect evaluation of three areas, A, B and C with varying probabilities of occurrence of the above parameters. The probability of success decreases from 64% in area A to 46% in area B. It is important to note that if any one of the above parameter has 0 probability, it will result in a dry hole, no matter how favorable are the other factors. For example, although area C has excellent probabilities of having source rock, reservoir rock and trap, it's success probability is 0 because of absence of seal.

3.3.2 Gas reserves–Definitions: The quantity of gas that is available underground and the quantity we can extract from it are vitally important issues. In reality, we cannot extract all the gas that a gas field holds underground.

Box 3.1 Natural Gas - Prime Fuel of 21st Century

Natural gas is the fastest growing fuel in the present world. While the total consumption of natural gas in the world in 1970 was 36 trillion cubic feet (Tcf), it increased to 87 Tcf in 2000 and 111 Tcf in 2010. Natural gas demand worldwide is expected to reach 153 Tcf in 2020 and 176 Tcf in 2025 (BP statistical review of world energy 2003). This implies a worldwide annual growth rate of 2.8% from 2001 to 2025, compared with 1.8% for oil and 1.5% for coal. The most robust growth of natural gas use is expected to occur in the developing nations including south Asian countries. There are several reasons why natural gas is preferred over other fuels :

i) Natural gas is a cleaner and environmentally friendly fuel. For same energy output, it burns to give at least 40% less carbon dioxide (the main greenhouse gas) than coal and 25% less than oil. Unlike coal or oil, most natural gas contains virtually no sulfur and therefore it produces little or no sulfur dioxide, the main contributor of acid rain. Furthermore, natural gas has no combustion residue as dust or ash and no radioactive waste to dispose of.

ii) Compared with nuclear energy and oil, affect of an accident involving natural gas is immediate and local rather than long term and widespread.

iii) Natural gas has greater efficiency and lower cost in generating electricity in combined cycle gas turbine (CCGT). Many fold increase in the demand for electricity throughout the world has made this point a the prime factor for the increase in demand for natural gas,

iv) Production, processing and transportation of natural gas are relatively easy in comparison to oil and coal.

The possibility of natural gas losing its value or being replaced by new alternating energy source specially solar energy in near future, has been rejected by energy experts. Professor Peter Odell, in an study in 1999 for the International Atomic Energy Association, has hinted the way the different energy resources will play in fuelling the world in the 21st century. He has pointed out that the take off point for solar energy or other renewable as a means of large scale and widely used energy source will be delayed and will not start to happen before 2060. He has suggested that consumption of both oil and gas will continue to dominate the world market till 2040, after which natural gas will be the near unlversal fuel. Natural gas use in the world will peak at about 2050 following which the use of natural gas will exceed that of oil and coal together. However the competition between gas and renewable energy will begin in earnest in about 2060 and the battle will swing in favor of renewable including solar energy after 2070 because of cost reduction which will be achieved by then.

Multinational oil giant Shell Oil Company, recently published a similar report providing forecast of how the significance of natural gas in the world energy supply may grow in the longer term. The report showed that the world's natural gas use is foreseen to expand from 1.4 trillion cubic meter (about 50 Tcf) in 1984 to around 3.5 trillion cubic meter (about 123 Tcf) by 2020 and thereafter to sustain this level for the following 40 years to 2060.

The role of nuclear energy in the future world energy scenario will continue to reduce because of the negative experiences of environmental disaster with nuclear plant accidents and lack of an environmentally safe solution to nuclear waste disposal problem.

Energy experts opine that as coal was the fuel of 19th century and oil of the 20th century, so will the natural gas be the fuel of the 21st century.

Table 3.2 Rating success probabilities for petroleum in three areas based on five parameters. (fter Selley 1998)

	Area A	Area B	Area C
Probability of source rock (P_1)	0.90	0.85	0.95
Probability of reservoir rock (P_2)	1.00	0.90	0.99
Probability of trap (P_3)	0.95.	0.85	0.97
Probability of seal (P_4)	0.95	0.90	0
Probability of timely migration (P_5)	0.80	0.80	0.90
Probability of success	**0.64**	**0.46**	**0**

Reserve is the quantity of gas that is commercially recoverable from known underground gas deposit.

To determine gas reserve, we therefore need to know what is the gas recovery factor (recovery percentage) in addition to knowing how much gas is there in the underground initially. Complexities in reservoir parameters dictate that reserve determination of gas field involve a degree of uncertainty. Because the degree of uncertainty is inherent or embedded in the reserve assessment, the gas reserves are 'estimated' rather than 'measured' and reserves are defined in different categories (proved, probable and possible) on the basis of uncertainty level (Martnez and McMichael 1999).

3.3.2.1 Gas Initially In Place (GIIP): This refers to the total amount of gas present initially in the gas field underground. As mentioned above, part of the GIIP in a discovered gas field can be recovered. The gas recovery efficiencies depend on number of factors including porosity-permeability of the reservoir, fluid properties, reservoir drive mechanism, abandonment pressure etc. Generally, recovery of gas from the GIIP in typical gas fields range from a low of 60% to a high of 90%.

3.3.2.2 Reserves: Reserves are defined as those quantities of natural gas (or oil) that are estimated to be commercially recoverable from known accumulation under the current economic and operating conditions. It is important to note that reserves are 'estimated', not 'measured' and all reserve estimates have a degree of uncertainty

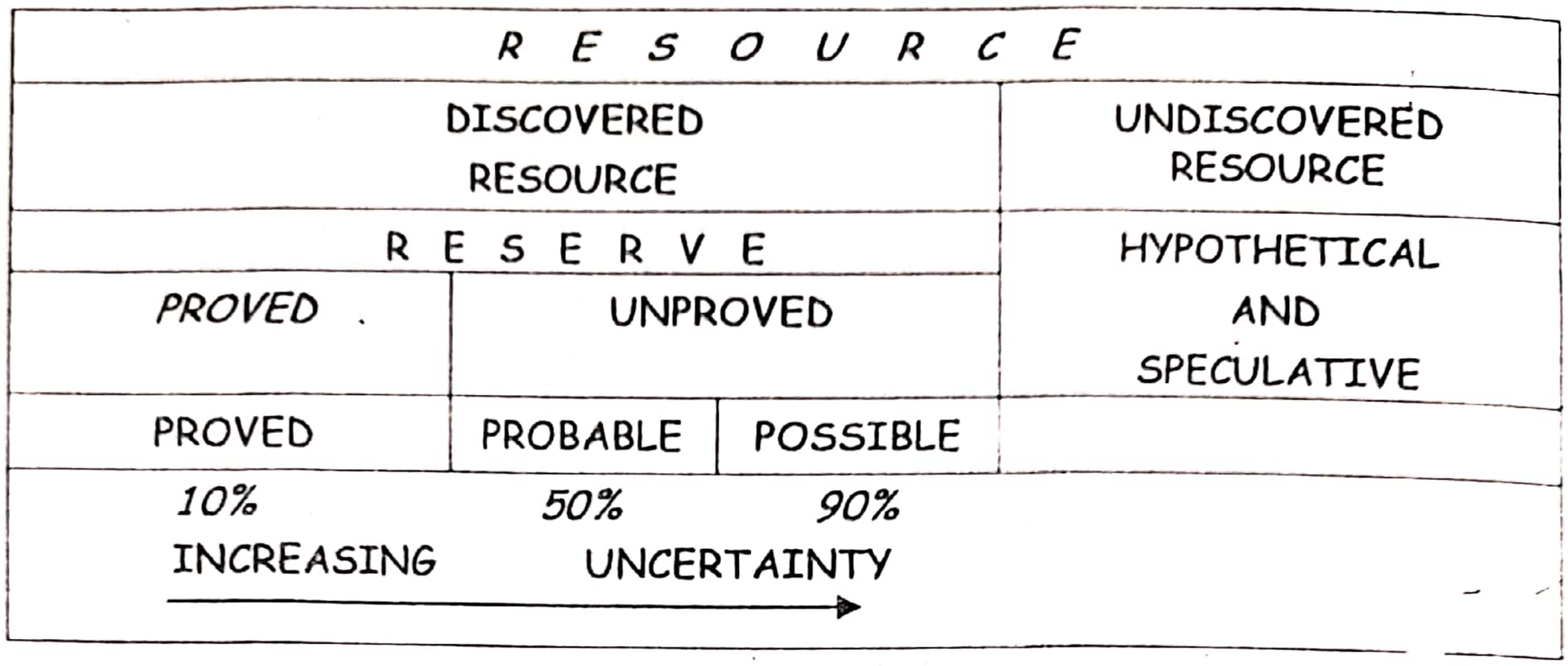


Figure 3.4 Classifications of petroleum resource and reserves

embedded in its definition. 'Reserves' are classified into three categories i.e. proved reserve, probable reserve and possible reserve on the basis of the degree of uncertainty with proved reserve having lowest and possible reserve having highest degree of uncertainty.

It is important to distinguish between reserve and resource. While reserve refers to the discovered oil and gas volumes, resource include both discovered and undiscovered ones that are speculated to be found in future (Figure 3.4).

In 1997, World Petroleum Congress (WPC) and Society of Petroleum Engineers (SPE) have jointly set out definitions, as cited below, for the proved, probable and possible reserves for use universally in the international petroleum industry (Martinez and McMichael, 1999).

i) Proved reserve refers to the quantity of gas which by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable from known reservoir under the present economic and operating conditions. The term 'reasonable certainty' is intended to express high degree of confidence. In a probabilistic count, a probability of at least 90% (uncertainty 10%) is assigned meaning that there should be at least 90% probability that the actual quantities recovered will exceed the estimate (Figure 3.4). SPE requires that reserve may be considered proven if producibility is supported by either actual production or well test. Since the degree of confidence level of estimates of proved reserve is very high, it is considered bankable asset by financial institutions.

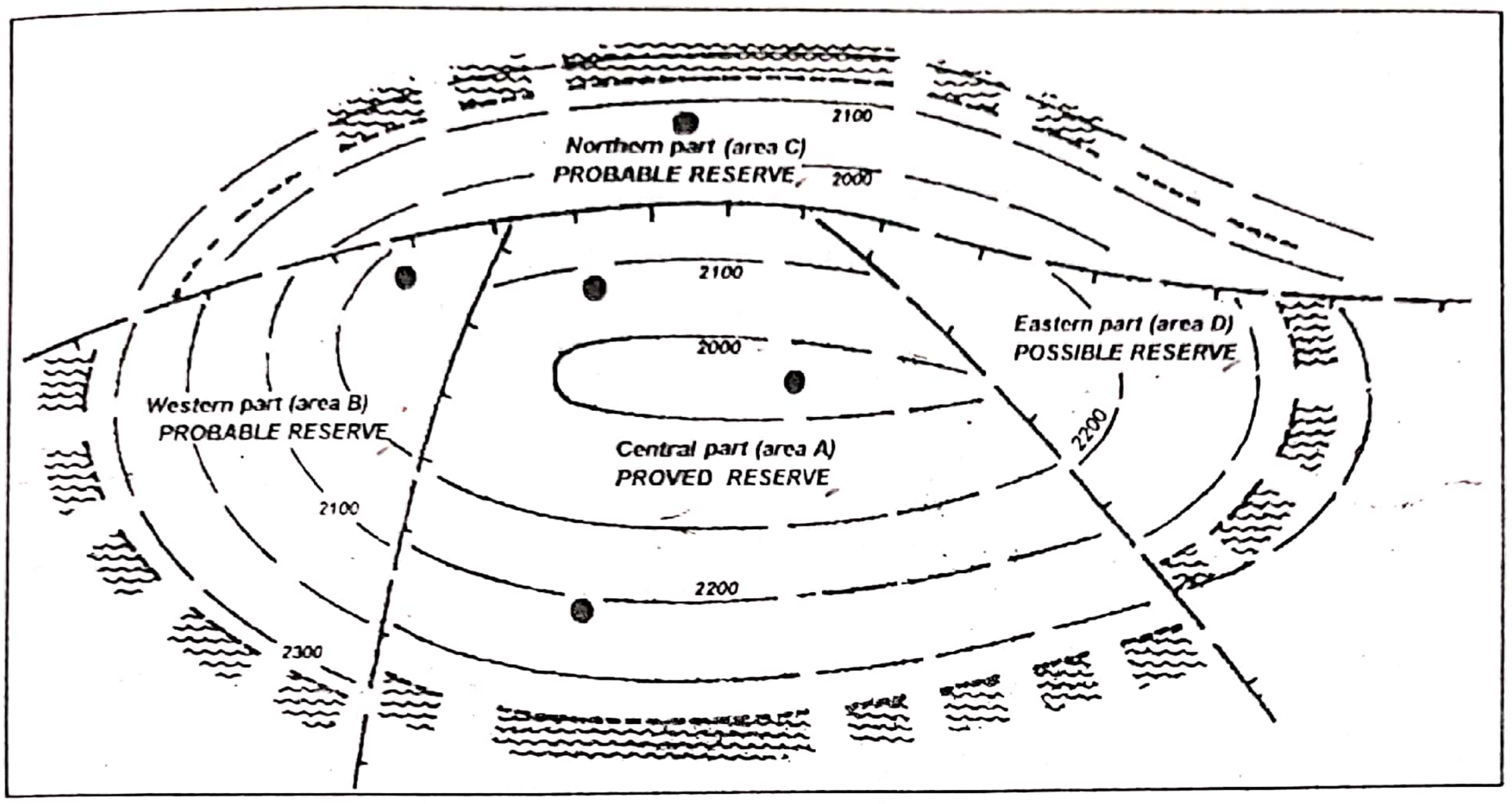


Figure 3.5 Illustration for defining proved, probable and possible reserves of gas

ii) Probable reserve refers to those unproved reserves which, as the geological and engineering data suggest, are more likely than not to be commercially recoverable. In probabilistic count, there should be at least 50% probability that the quantities recovered will equal or exceed the proved plus probable reserve. In simple words, the degree of certainly of the estimate is 50%. Because of lower level of confidence of the estimates, probable reserve is not considered bankable asset by financial institutions.

iii) Possible reserve are those unproved reserve which, as the geological and engineering data suggest, are less likely than probable reserve to be commercially recoverable. Here the certainty level of the reserve estimate is very low i.e. only 10% (uncertainty 90%). In probabilistic term, as the definition dictates, there should be at least a 10% probability that the actual quantities recovered should equal or exceed the estimated proved plus the probable plus the possible reserve. Because of the very low level of confidence of possible reserve estimates, it usually is more of an academic exercise than commercial use.

Figure 3.5 illustrates a hypothetical gas field in which proved, probable and possible reserves are assigned based on the status of the wells drilled (successful or unsuccessful). The gas field is divided into four parts or compartments by geological

faults. All the three wells in the middle part (area A) are successful (gas) and therefore the certainty level of reserve estimation is high. Thus the reserve in this part is assigned as proved reserve. In the west and north parts (area B and C) one well drilled in each is successful (gas), the certainly level of reserve estimation is moderate, yet lower than area A. The estimated reserves in area B and C are considered as probable reserve. There is no well drilled in the eastern compartment (area C); the certainly level of estimation is very low and the reserve in this area is considered as possible reserve.

All reserve is resource, but all resource are not reserve.

3.3.2.3 Difference between reserve and resource: As defined above, reserves are those quantities of gas that are considered commercially recoverable from a known discovery of gas in the underground. Resource refers to the total quantity of gas that are known to occur underground plus the quantity that are geologically forecasted to be discovered in future (Figure 3.4).

'Resource' is differentiated from 'Reserve' by the fact that reserve refers only to the discovered gas while resource include unknown and speculated gas that may be lying in untested areas (undiscovered resource) in addition to the one that is known by discovery (discovered resource). While reserve is estimated from objective data on discovered gas fields, resource estimation includes hypothetical and speculative data and is therefore conjectural.

In simple words and for comparison, reserve is like the "money one has in his bank account" while resource is like the "money he reasonably estimate to have in future". In recent years, as gas issue is discussed in various forums in the country, confusion often arises for not using the terms "reserve" and "resource" in their proper senses and also by using these interchangeably.

3.3.3 Gas reserve determinations

There are generally two methods that are applied to determine gas reserves: i) volumetric method, ii) material balance method. Each has its own merits and demerits and both are usually practiced in the petroleum industry.

3.3.3.1 Volumetric method: This method of reserve estimation can be used early in the life of a gas field, i.e. before there are sufficient production and pressure data available to use.

The formula used in the method is as follows:

Gas reserve = A x h x 43560 x Ø x (1 - Sw) x Bgi x R

A = Area in acre

h = Average thickness in feet (net sand)

43560 = Conversion factor (acre feet to cubic feet) (1 acre = 43560 sq. feet)

Ø = Average porosity

Sw = Water saturation

Bgi = Gas expanding factor = 1/ Gas compressibility factor

R = Recovery factor

3.3.3.2 Material balance method: This method utilizes the knowledge of reservoir fluid pressure response as a result of commercial production. During the active life of a gas field, the reservoir pressure declines as the cumulative production increases. Therefore this method can be used when sufficient historical reservoir pressure data and production data are available. A rule of thumb regarding the latter suggests use of material balance only after production of about 10% of the in-place reserve.

Estimation of in-place reserve is done using graphical technique referred to as P/Z plot following gas material balance equation. A plot of P/Z (P=shut in reservoir pressure and Z=compressibility factor) against the cumulative productions(Gp) at times when pressure measurements are made will produce a straight line as set out in figure 3.6. The Gas-initially in place (G) is defined as the intercept of the straight line on the x-axis.

The accuracy of the method depends on accuracy of the production and the reservoir pressure measurement and fluid property description. Accuracy increases as the cumulative production increases and reservoir pressure declines.

This method has an advantage over volumetric method in the sense that it accounts for the reservoir heterogeneities and continuity variation which occur away from the boreholes. One drawback of this method is that it works very well in expansion drive (depletion drive) reservoirs and not so in reservoirs with water drive.

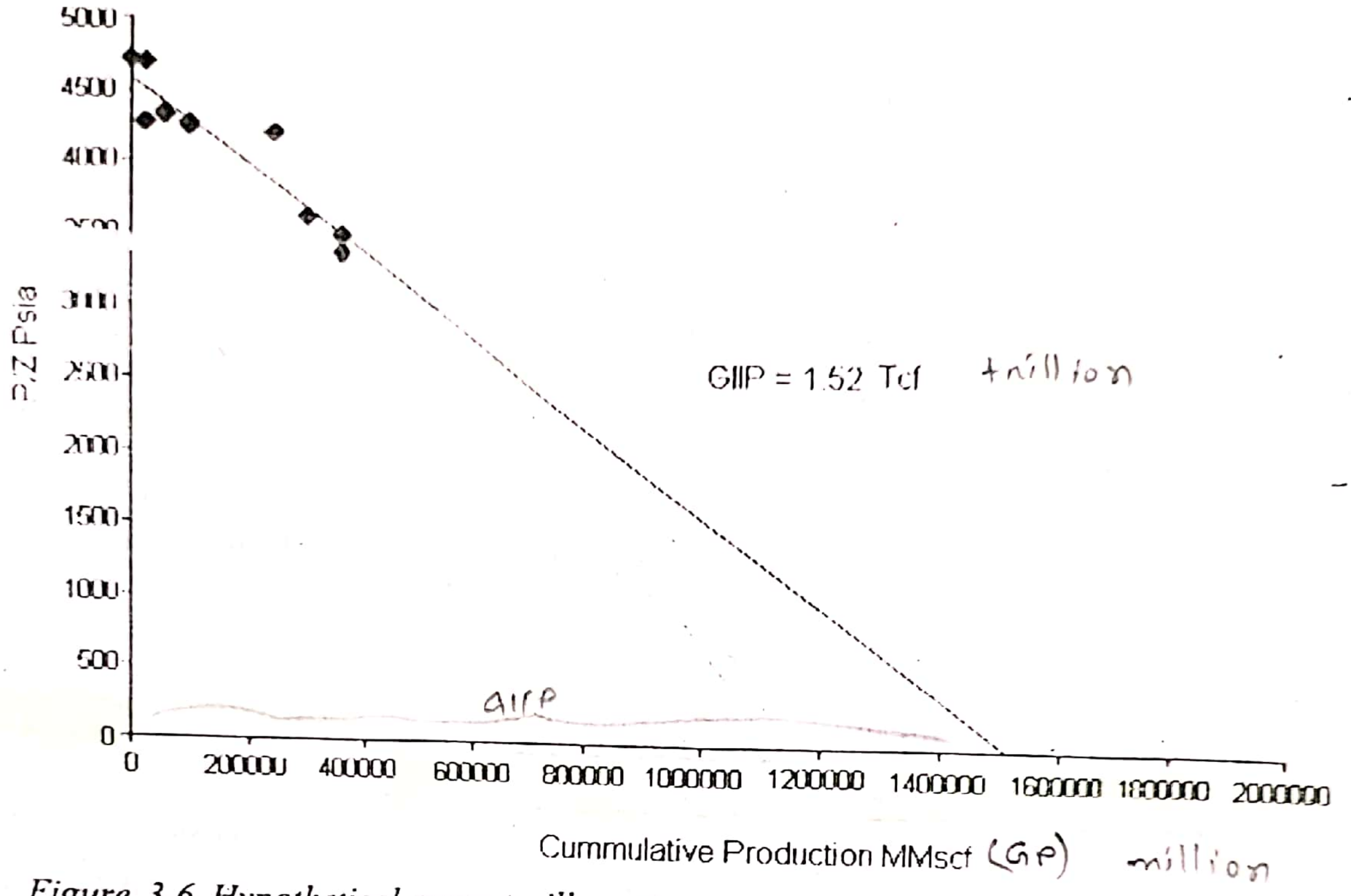


Figure 3.6 Hypothetical curve to illustrate material balance method for gas reserve estimation.

3.3.4 Gas fields by size

A 'gas pool' is a single accumulation of gas in a geologic trap; a 'gas field' comprises one or several adjacent or overlapping gas pools associated with a common geologic structure or feature. The size of a gas field refers to the volume of recoverable gas that it contains, rather than the geologic area it covers. An average size gas field covers a few square kilometer; on the other hand, world's largest gas fields North dome/South Par in the Persian Gulf covers an area of 9700 square kilometer.

A 'commercial accumulation' is one whose development appears to be worth the investment of necessary capital and effort. A gas field discovered near populated or industrialized area could be relatively small and yet be commercial, whereas another field situated in a remote region with little accessibility and local demand would need to be much larger to be 'commercial'. In particular, offshore fields need to be larger than land based ones to offset the costs and risk that their development entails.

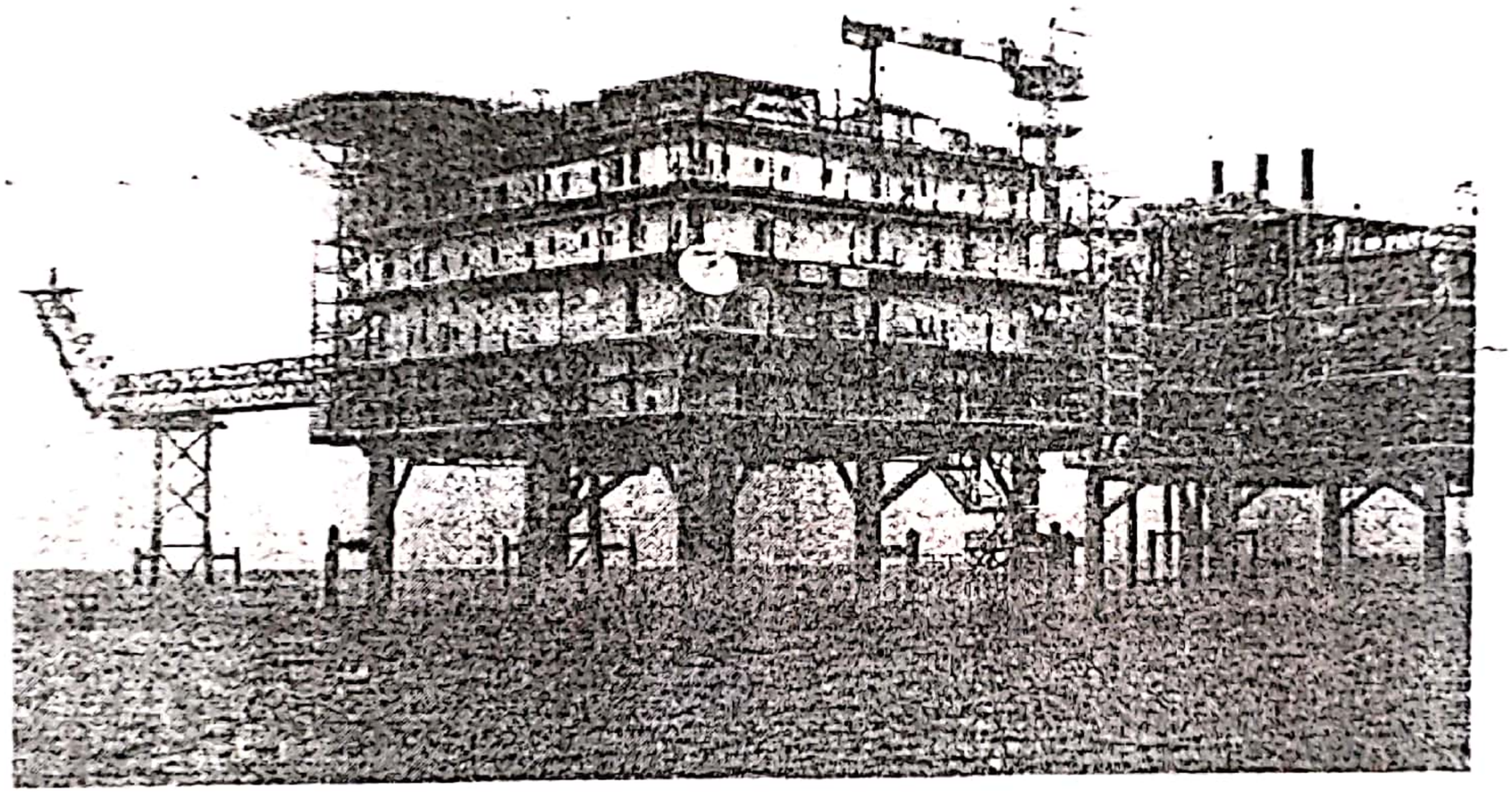


Plate 3.1 World's largest gas field, the supergiant North dome/South Par, located in the Persian Gulf and shared by Qatar and Iran has initial reserve of 1260 Tcf gas.

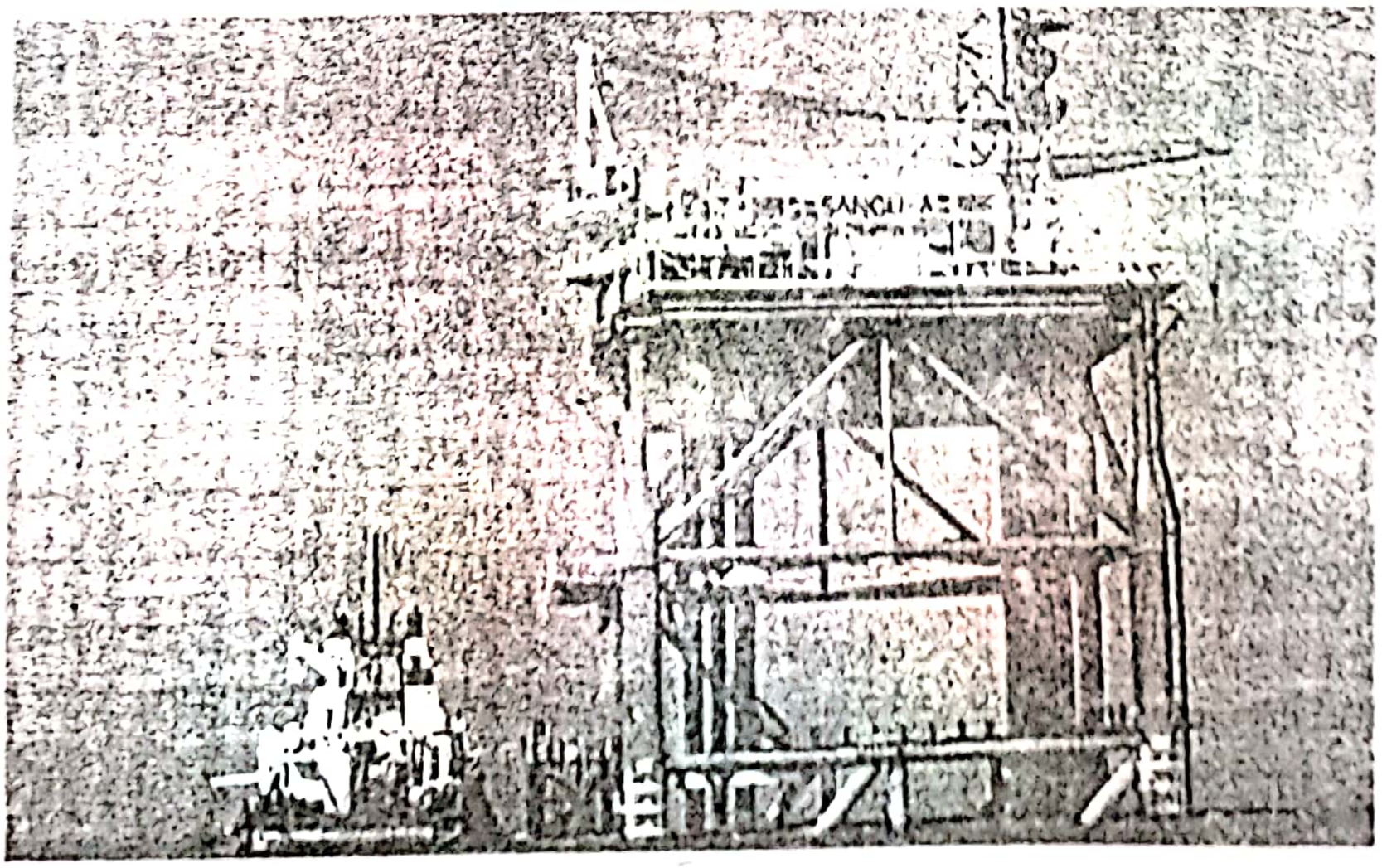


Plate 3.2 Sangu gas field in teh Bay of Bengal is the only offshore producing gas field in Bangladesh and has an initial reserve of less than 1 Tcf gas.

Energy Resources of Bangladesh.

A 'major gas field' is one with more than 300 Bcf (0.3 Tcf) of recoverable gas reserve (Hobson and Tiratsoo 1981) (Table 3.3). A 'Giant gas field' is one which has more than 3 Tcf of recoverable gas and a 'Supergiant gas field' is one which has more than 30 Tcf of recoverable gas (Hunt 1996). Table 3.4 lists some of the supergiant gas fields in the world. Two of the largest super giant gas fields in the world are the North dome/South Par (reserve 1260 Tcf) in the Persian Gulf and the Urengoy (reserve 222 Tcf) in Russia.

Table 3.3 Classification of gas fields by reserve size (after Hunt 1996, Hobson and Tiratsoo 1981)

Reserve size	Field category
>30 Tcf	Super giant
>3 Tcf - 30 Tcf	Giant
>1 Tcf - 3 Tcf	Very large
>300 Bcf - 1 Tcf	Major
>60 Bcf - 300 Bcf	Minor
60 Bcf or less	Dwarf

Table 3.4 Few examples of super giant gas fields.

Gas field	Country	Year of discovery	Recoverable reserve (Trillion cubic feet)
North dome/South Par	Qater/Iran	1971	1260
Urengoy	Russia	1966	222
Yamburg	Russia	1969	138
Zapolyareye	Russia	1965	95
Groningen	Netherland	1959	73
Hassi R Mel	Algeria	1956	123

3.4 Natural gas in Bangladesh

Bangladesh is a young deltaic sedimentary basin which meets the geologic requirements for generation and accumulation of natural gas in the subsurface. The country has a proved natural gas rich province in the eastern part. Since the beginning of petroleum exploration in the area in 1910, a total of 76 exploratory wells have been drilled till 2010 (Table 3.5, Figure 3.7). This resulted in 25 gas field discovery recording an average exploration well to success ratio of about 3:1 (drilling 3 wells make 1 gas discovery).

However the success ratio varies widely among the different parts of the country. In the northeast, east and southeastern part of the country (Sylhet-Comilla-Chittagong), referred to as fold belt, exploration well to success ratio is most promising i.e. 2.3:1; in the offshore it is an unimpressive 7:1 while the success ratio is 6:0 meaning no success in the western Bangladesh (Khulna-Jessor-Bogra-Rangpur). Table 3.5 lists the exploratory wells drilled in Bangladesh.

3.4.1 Petroleum exploration history in Bangladesh

Phase I- The British period (Pre 1947): Hydrocarbon exploration in Bangladesh area began with geological mapping and exploration drilling in 1910 at Sitakund in Chittagong. By 1914 the Indian Petroleum Prospecting Company and the Burmah Oil company (BOC) drilled 4 wells on the Sitakund structure to a maximum depth of 1023 meter below surface, but all were dry holes. BOC came back in 1923 and drilled 2 wells at Patharia in Sylhet but left in 1933 without any commercial discovery. Exploration activities in the area remained suspended for the next 17 years due to World War II and subsequent political instability in the region. No gas field was discovered during exploration phase I.

Phase II- Pakistan period (1947-1970): The second phase petroleum exploration began after the partition of the Indian subcontinent. Three international oil companies and the state owned oil company (OGDC) were active in different part of the country. This phase is described for exploration activities under two decades, 1950s and 1960s (Table 3.6).

Table 3.5 Petroleum exploration wells drilled in Bangladesh in chronological order (Source: Petrobangla)

	Well Name	Year completed	Operator	Total depth (m)	Status
	ONSHORE WELLS (61)				
1	Sitakund-1	1910-1914	IPPC	762	Dry hole
2	Sitakund-2		IPPC	-	Dry hole
3	Sitakund-3		IPPC	-	Dry hole
4	Sitakund-4		Burmah Oil	1024	Dry hole
5	Patharia-1	1933	Burmah Oil	875	Dry hole
6	Patharia-2	1933	Burmah Oil	1047	Dry hole
7	Patharia-3	1951	PPL	1650	Dry hole
8	Patharia-4	1953	PPL	830	Dry hole
9	Patiya-1	1953	PPL	3102	Dry hole
10	Sylhet-1	1955	PPL	2379	Gas blowout
11	*Sylhet-2*	*1956*	*PPL*	*2819*	*First Gas discovery*
12	Lalmai-1	1958	PPL	2993	Dry hole
13	*Chattak-1*	*1959*	*PPL*	*2135*	*Gas discovery*
14	Kutchma-1	1959	SVOC	2875	Dry hole, coal
15	Bogra-1	1960	SVOC	2187	Dry hole
16	Fenchuganj-1	1960	PPL	2438	Dry hole
17	*Rashidpur-1*	*1960*	*Shell Oil*	*3860*	*Gas discovery*
18	Hazipur-1	1960	SVOC	3816	Dry hole
19	Lalmai-2	1960	PPL	4117	Dry hole
20	*Kailash Tila-1*	*1962*	*Shell Oil*	*4139*	*Gas discovery*
21	*Titas-1*	*1962*	*Shell Oil*	*3758*	*Gas discovery*
22	*Habiganj-1*	*1963*	*Shell Oil*	*3508*	*Gas discovery*
23	Jaldi-1	1965	OGDC	2300	Dry hole
24	Jaldi-2	1966	OGDC	3360	Dry hole
25	*Semutang-1*	*1969*	*OGDC*	*4088*	*Gas discovery*
26	*Bakhrabad-1*	*1969*	*Shell Oil*	*2838*	*Gas discovery*
27	Jaldi-3	1970	OGDC	4500	Dry hole
28	Muladi-1	1976	Petrobangla	4732	Dry hole
29	*Begumganj-1*	*1977*	*Petrobangla*	*3655*	*Gas discovery*
30	Muladi-2	1981	Petrobangla	4556	Dry hole
31	Singra-1	1981	Petrobangla	4100	Dry hole
32	*Beanibazar-1*	*1981*	*Petrobangla*	*4109*	*Gas discovery*
33	*Feni-1*	*1981*	*Petrobangla*	*3200*	*Gas discovery*
34	*Katma-1*	*1982*	*Petrobangla*	*3614*	*Gas discovery*
35	Atgram-1	1982	Petrobangla	4961	Dry hole
36	Sitakund-5	1988	Petrobangla	4005	Dry hole

37	*Fenchuganj-2*	*1988*	*Petrobangla*	*4977*	*Gas discovery*
38	Salbanhat-A	1988	Shell Oil	2518	Dry hole
39	Sitapahar-2	1988	Shell Oil	1560	Dry hole
40	Bogra-2	1989	Petrobangla	2100	Dry hole
41	*Jalalabad-1*	*1989*	*Scimitar*	*2626*	*Gas discovery*
42	Surma-1	1989	Scimitar	2253	Gas show
43	*Meghna-1*	*1990*	*Petrobangla*	*3069*	*Gas discovery*
44	*Narsinghdi-1*	*1990*	*Petrobangla*	*3450*	*Gas discovery*
45	Patahria-5	1992	Petrobangla	3438	Dry hole
46	*Shahbazpur-1*	*1995*	*Petrobangla*	*3342*	*Gas discovery*
47	*Shaldanadi-1*	*1996*	*Petrobangla*	*2511*	*Gas discovery*
48	Moulvibazar-1	1997	Oxy/Unocal	800	Gas blowout
49	Halda-1	1998	CairnEnergy	4519	Dry hole
50	*Bibiyana-1*	*1998*	*Oxy/Unocal*	*4014*	*Gas discovery*
51	*Moulvibazar-2*	*1999*	*Oxy/Unocal*	*3535*	*Gas discovery*
52	Kapna-1	1999	Unocal	3149	Dry hole
53	Ratna-1	2000	Unocal	3835	Dry hole
54	Rasulpur-1	2004	Tullow	3295	Dry hole
55	Lalmai-3	2004	Tullow	2800	Dry hole
56	*Bangura-1*	*2004*	*Tullow*	*3636*	*Gas discovery*
57	Srikail-1	2004	Petrobangla	3583	Gas show
58	Kajal-1	2010	Chevron		Dry hole
59	*Sundalpur-1*	*2011*	*Petrobangla*		*Gas discovery*
60	Kapasia-1	2012	Petrobangla		Dry hole
61	*Srikail-2*	*2012*	*Petrobangla*		*Gas discovery*
OFFSHORE WELLS (15)					
62	Cox's Bazar-1	1969	Shell Oil	3698	Dry hole
63	BODC-1	1976	BODC	4598	Dry hole
64	BODC-2	1976	BODC	4436	Dry hole
65	Bina-1	1976	INA	4095	Dry hole
66	ARCO-1	1976	ARCO	3903	Dry hole
67	Bina-2	1977	INA	4294	Dry hole
68	*Kutubdia-1*	*1977*	*Union*	*3508*	*Gas discovery*
69	BODC-3	1978	BODC	4488	Dry hole
70	*Sangu-1*	*1996*	*Cairn Energy*	*3500*	*Gas discovery*
71	Sonaida-1	1998	Cairn Energy	4028	Dry hole
72	Reju-1	2000	Oakland	4450	Dry hole
73	Swandip East	2000	Shell Oil	3696	Dry hole
74	South Sangu-2	2001	3850	Shell/Cairn	Dry hole
75	South Sangu-3	2007	3510	Shell/Cairn	Dry hole
76	Magnama-1	2008	4003	Shell/Cairn	Dry hole

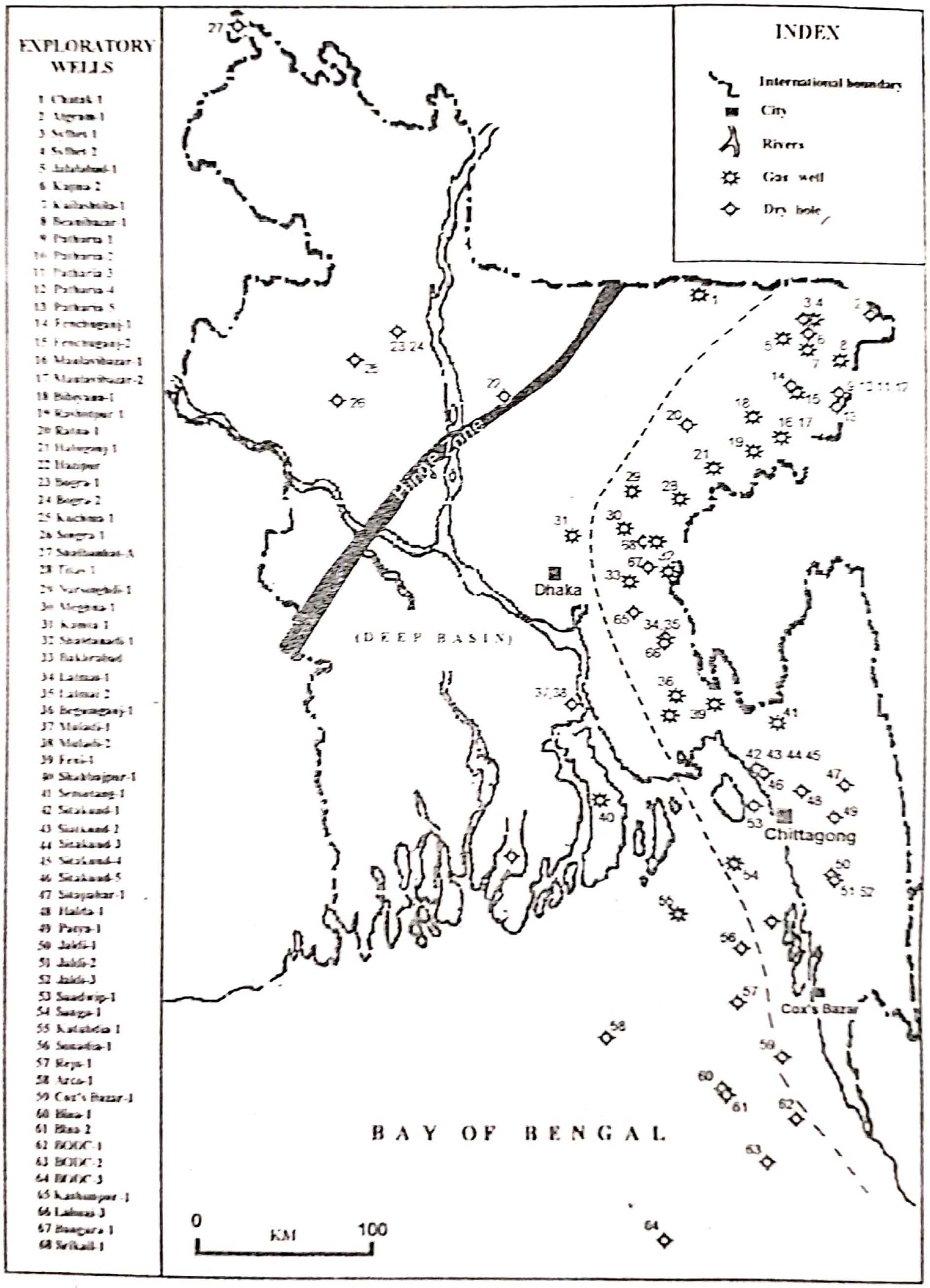


Figure 3.7 Map showing exploratory wells drilled in Bangladesh.

1950s: This decade marked the beginning of gas discovery in Bangladesh. Pakistan Petroleum Limited (PPL), a consortium of International oil companies led by Burmah Oil company (BOC), drilled exploratory wells at four structures: Sylhet, Chattak, Lalmai and Patiya in the eastern part of the country between 1951 and 1959 and discovered the first two gas fields i.e. Sylhet in 1955 and Chattak in 1959. During the same period Standard Vacuum Oil Company (SVOC) was active in the northwestern part of the country conducting magnetic, seismic and exploration drillings. SVOC drilled 3 wells, Kuchma-1, Hazipur-1, and Bogra-1 during 1959-60 but no petroleum discovery was made.

During this decade a total of 8 exploratory wells were drilled and 2 gas fields were discovered with a cumulative reserve of 0.79 Tcf.

1960s: The decade of 1960s was a golden era for gas discovery in this country. The Shell Oil Company initiated exploration in 1961 with extensive seismic surveys in eastern part and conducted the most successful drilling. From 1961 to 1969 Shell Oil discovered five large gas fields i.e. Rashidpur, Kailashtila, Titas, Habiganj and Bakhrabad. It was through the discoveries of these large gas fields that Bangladesh, specially its eastern part has been known as rich natural gas province. The one offshore well, Cox's Bazar-1, Shell Oil drilled in 1968 was however, dry.

The national oil company Oil and Gas Development Corporation (OGDC) was established in 1961. The company carried out exploration in Chittagong and Chittagong Hill Tract and drilled exploratory wells in Jaldi and Semutang structures resulting one gas field discovery at Semutang in 1969. (first by national company)

During this decade a total of 13 exploratory wells were drilled and 6 gas fields were discovered with a cumulative reserve of 15.74 Tcf (Table 3.6). This is the highest volume of gas discovery in any single decade in Bangladesh. This decade is thus referred to as a golden time of gas discovery in the country.

OGDC (Govt)
↓
BMOGC
↓
Petrobangla

Phase III – Bangladesh period (1971-2011): After the independence of Bangladesh in 1971, the petroleum exploration gathered pace with participation of both national and international oil companies. The part of OGDC that was in operation in Bangladesh was reorganized as Bangladesh Mineral Oil and Gas Corporation (Petrobangla) which continued exploration and production activities in

the country. The Bangladesh Petroleum Act was enacted in 1974 to facilitate international participation under production sharing contract (PSC). Petroleum exploration continued for the next four decades with varying phases of highs and lows and is described under the successive decades i.e. 1970s, 1980s, 1990s and 2000s.

(2) *1970s:* During the first decade following the independence of the country, a major exploration activity began as the first PSC (production sharing contract) round was held in 1974. Under this PSC round the Bay of Bengal was divided into six blocks and was awarded to six international oil companies (IOC). These blocks were in the shallow sea up to water depth of about 200m (Figure 3.8). The IOCs under this PSC included Union Oil, Arco, Ina Napthaplin, BODC (Japex), Ashland and Canadian Superior. Following seismic surveys, the companies drilled a total of 7 wells during the period 1974-1977. Only one gas field was discovered by Union Oil Company. Named Kutubdia, the first offshore gas field in Bangladesh, it was not considered suitable for commercial development at that time because of small reserve. Apparently the major interest of the IOCs was oil and there was not enough gas discovery either. By 1978, all the foreign oil companies relinquished their blocks and left the country.

In the meantime, Bangladesh carried out a landmark negotiation with Shell oil company and successfully entered into an agreement for taking over the six large gas fields discovered and owned by Shell. The deal, signed in early August 1975 allowed Bangladesh to purchase the five major gas fields Titas, Habigabj, Kailashtila, Rashidpur and Bakhrabad (total initial reserve of 16.1 Tcf as per latest estimate) at a throw away price of about 4.5 pound sterling. This may be considered as the most successful negotiation between Bangladesh and any IOC.

Initial exploration of Petrobangla consisted of geological, geophysical and drilling activities with technical and financial assistance from Soviet Union, West Germany and Great Britain. Petrobangla started its exploration drilling in Muladi-Begumganj area in southern Bangladesh in mid 70s and discovered Begumganj gas field in 1977.

During this decade a total of 10 exploratory wells were drilled and 2 gas fields were discovered (Table 3.6).

1980s: During 1980s Petrobangla increased its exploration drilling and discovered several gasfields. Among these, the Fenchuganj well, one of the new gas discovery, remains the deepest drilled well (4977m) in Bangladesh. Other gas discoveries by Petrobangla include Feni, Beanibazar and Kamta. In 1989, Bangladesh petroleum exploration company (Bapex) was formed to work as an exploration company under Petrobangla. Later Bapex became an exploration and production company being responsible for producing gas from its own discoveries. Bapex continues its exploration program with several successes in the decades ahead.

In a second PSC round in 1986/87, Shell Oil Company was awarded two onshore blocks 22 (Chittagong Hills Tracts) and 23 (northern most onshore block). Shell drilled one well in Sitapahar in Chittagong hills. Shell could not continue its work in Chittagong Hill Tracts because of insurgency problem. At one point Shell personnels were kidnapped by the insurgents and was released against the payment of handsome ransom money. Shell drilled another well in the farthest northern corner in Rangpur. Both the wells drilled by Shell were dry and Shell relinquished the blocks and left the country in 1988.

A new milestone was achieved when Petrobangla discovered the first commercial oil pool in Sylhet-7 (Haripur oilfield) on December, 1986. In 1987, a foreign oil company, Scimitar Exploration, was awarded a block in Sylhet area under an unsolicited and controversial PSC deal. Under the deal, the block was leased out to the company for exploration as well for the development of Haripur oil field. A People's inquiry Commission (Gono Tadanda Commission) formed by eminent lawyers and petroleum experts concluded that the PSC deal with Scimitar Exploration was done against the interest of the country (Imam 1990). Scimitar drilled 2 wells and discovered Jalalabad gas field, but failed to develop Haripur oilfield. The contract with Scimitar was cancelled later because of not fulfilling the contractual obligations and alleged fraud (Box 4.1).

Table 3.6 Decade wise exploration wells and gas field discovery

Decade	No. of exploratory wells	No. of gas field discovery	Gas reserve discovered (Tcf) (after Petrobangla 2011)	Comment
Pre-1950	6	-	-	-
1950s (1950-1959)	8	2	0.79	First gas field discovery
1960s (1960-1969)	13	6	15.74	Golden age of gas discovery
1970s (1970-1979)	10	2	0.66	Only a few small fields
1980s (1980-1889)	13	5	1.84	Oil field discovery by Petrobangla
1990s (1990-1999)	12	7	7.77	IOC's exploration lead
2000s (2000-2010)	10	1	0.52	Low exploration success

During the decade of 1980s a total 13 wells were drilled and 5 gas fields were discovered. The individual reserves of these gas fields were small with a cumulative reserve of 1.84 Tcf (Table 3.6).

1990s: During this decade hydrocarbon exploration, specially by IOCs took up momentum with new PSC model and incentive to foreign oil companies. The country was divided into 23 blocks including offshore areas (Figure 3.8). In a third PSC round the whole of the country with 23 blocks was offered for IOC bidding. There were very good responses and interest from among the international oil companies. Under this PSC rounds, eight blocks were awarded to Occidental (blocks 12, 13 and 14), Cairn Energy (blocks 15 and 16), Oakland and Rexwood (blocks 17 and 18) and United Meridian International Corporation (block 22). Occidental discovered Molvibazar and Bibiyana gas fields in 1997 and 1998 respectively. In 1999, Unocal Oil fully aquired Occidental's operation and liabilities. At a later time Unocal merged with Chevron Corporation and ceased to operate as an independent company. Cairn Energy discovered Sangu gas field in the offshore in 1996. Sangu became the second offshore gas discovery in Bangladesh and it started gas production in 1998. It remains the sole offshore gas producer till date.

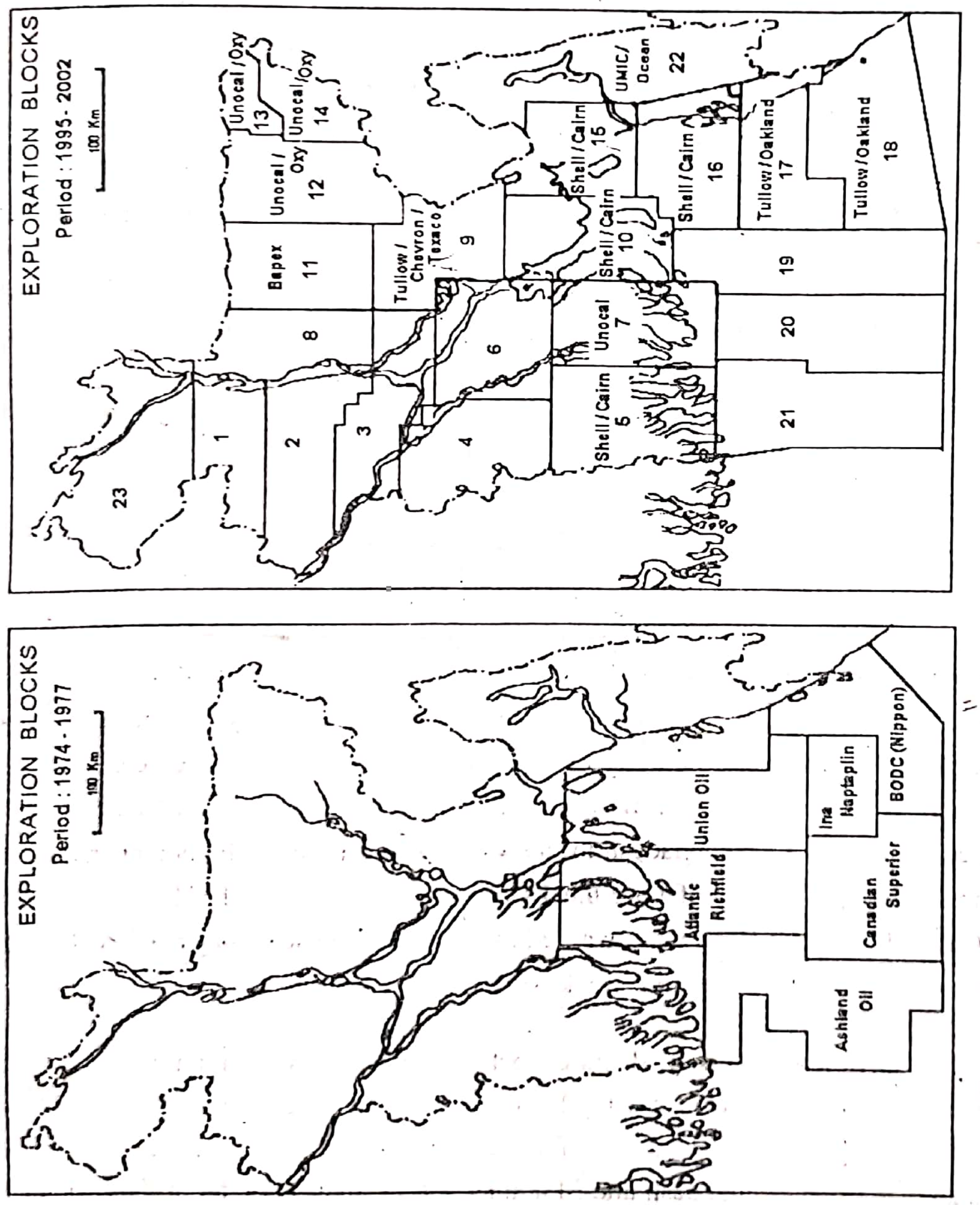


Figure 3.8 International oil companies in petroleum exploration blocks in Bangladesh

In 1997, a fourth PSC round was held and three new PSCs were signed with IOCs by 2001; two blocks were awarded to Shell Oil/Cairn Energy (blocks 5 & 10), one block to Unocal (block 7) and one block to Tullow/Chevron Texaco (block 9). With this bidding, BAPEX ensured 10% right of each block. At a later date Chevron Texaco sold out its share of block 9 to Niko resources.

During this decade Petrobangla discovered 2 small gasfields, Meghna and Narsingdi. Furthermore Bapex (Petrobangla) exploration drillings led to the discovery of two more gasfields, Shahbazpur in 1995 at Bhola Island and Saldanadi in 1996 adjacent to Indian border near Comilla. Interestingly, part of the latter lies inside Indian territory from which Indians have been producing gas for several years.

During this decade a total of 12 exploratory wells were drilled and 7 gas fields were discovered with a cumulative gas reserve of about 7.77 Tcf (Table 3.6).

2000s: Exploration drilling continued with a slow rate in the first decade of new century. In 2008 Petrobangla prepared a new offshore acreage map in which deep sea blocks were added. The total offshore area was divided into 30 blocks in which the shallow water area was redefined into 10 blocks (upto 200m water depth) and deep water area was divided into 20 blocks (upto about 2000m water depth) (Figure 3.9). In the same year PSC round was held for the offshore blocks only (Offshore Bidding Round- 2008). The response to this PSC round appeared less than expected and this was due to the dispute on maritime boundary between Myanmar and Bangladesh in the east and India and Bangladesh in the west. Apparently both the neighbors placed claims on several of the offshore blocks proposed by Bangladesh. However, in this PSC round ConocoPhillips was awarded two blocks (deep sea blocks 10 and 11) and Tullow Oil was selected for one block (shallow sea block 5).

The maritime boundary disputes between Bangladesh, Myanmar and India remained a major bar for earnest offshore exploration. The dispute led to filing of cases in the international courts for settlement. The case regarding maritime boundary between Bangladesh and Myanmar was heard at the International Tribunal for the Law of the Sea (ITLOS), based in Hamburg in Germany and the judgment was given on 14 March 2012. The judgment went in favor of Bangladesh in certain areas while it settled certain part in Myanmar's favor. The maritime boundary set out

by

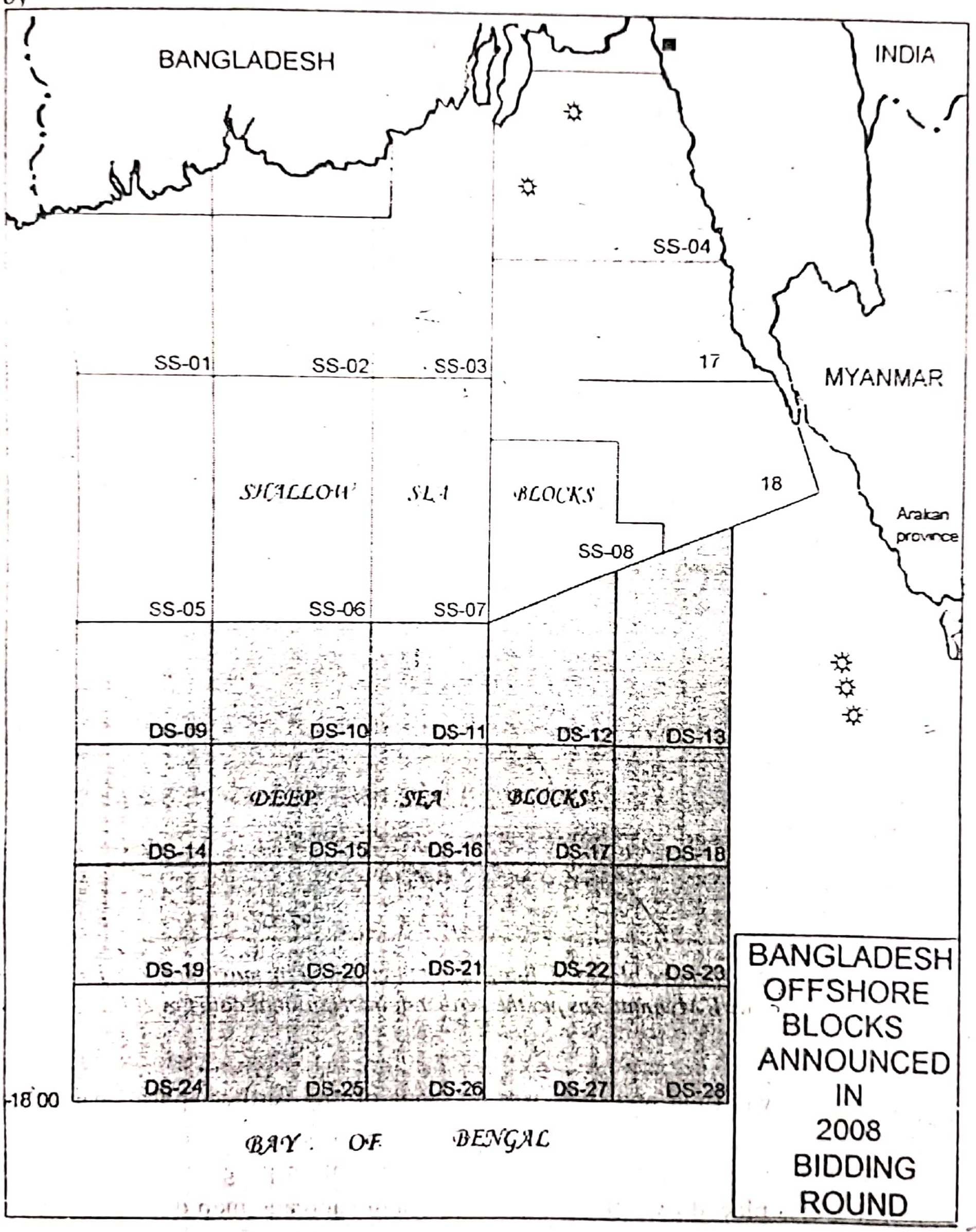


Figure 3.9 Bangladesh offshore acreage map with deep sea blocks announced in 2008 bidding round; SS=Shallow water block DS=Deep water block (Source: PetroBangla)

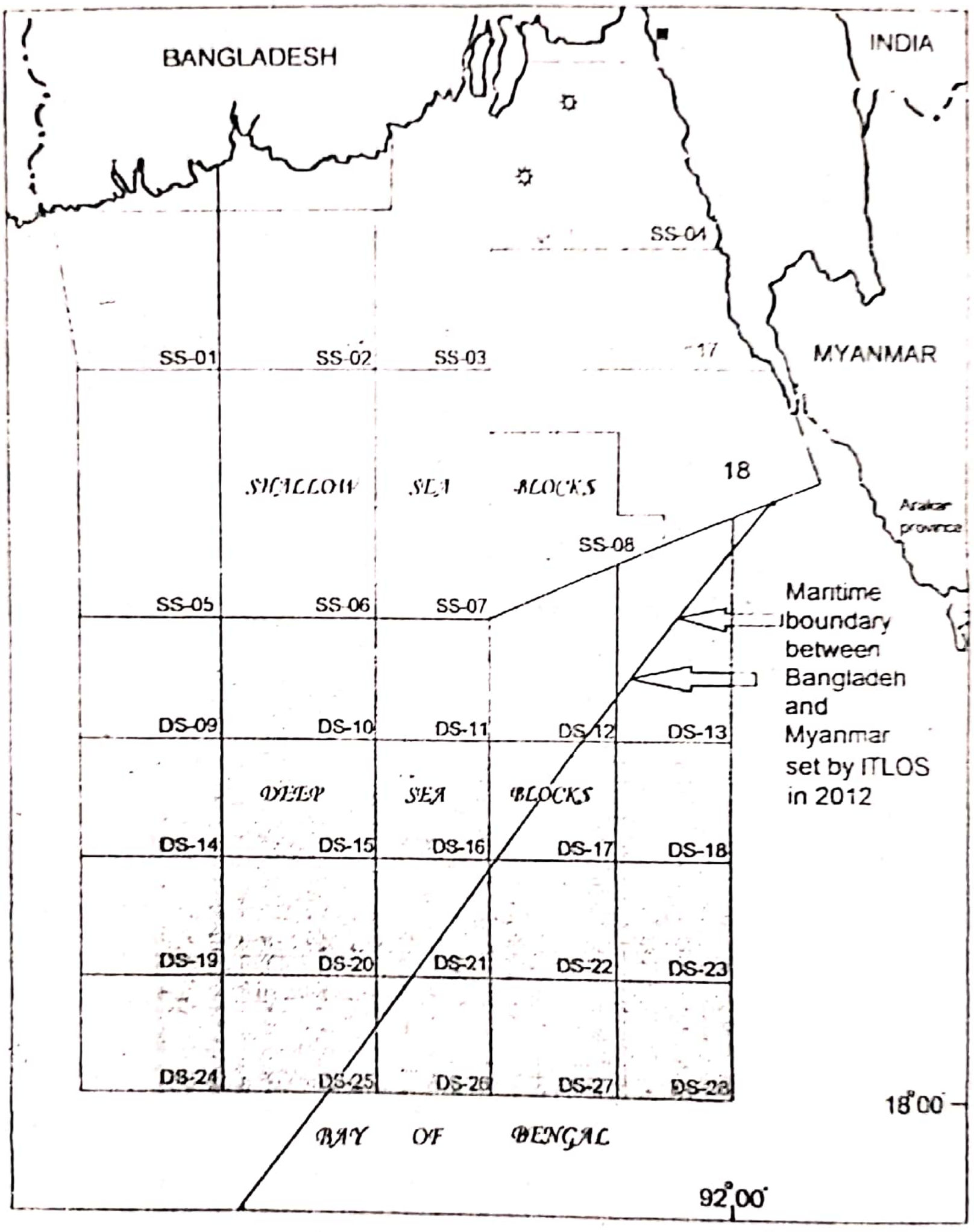


Figure 3.10A Offshore blocks of Bangladesh intercepted by maritime boundary with Myanmar as per the verdict of international court in 2012.

by the tribunal was final and there was no scope of any further appeal against the verdict (figure 3.10A). The way the new boundary affects the offshore blocks of Bangladesh is an issue central to any offshore exploration program. When the new boundary line is placed over the Bangladesh offshore acreage map declared in 2008, it cut across several deep sea blocks. In fact, the new boundary places five of the Bangladeshi deep sea blocks completely inside Myanmar territory while four others are divided between Bangladesh and Myanmar (Figure 3.10A). Accordingly, Bangladesh redefined its offshore blocks in December 2012 and announced bidding round for 9 shallow sea blocks and 3 deep sea blocks in order to engage foreign oil companies (Figure 3.10B).

Table 3.7 International Oil companies (IOC) under PSC in Bangladesh (1971-2012)

IOC	Year PSC signed	Block	No. of wells	Gasfield Discovery	Comment
PSC Round 1974 - offshore blocks					
Union Oil (Unocal)	1974	Offshore	1	Kutubdia	Relinquished in 1978 and left
Atlantic Richfirld	1974	offshore	1	0	Relinquished in 1978 and left
BODC (Nippon Oil)	1974	offshore	4	0	Relinquished in 1978 and left
Ina Naphtaplin	1974	offshore	2	0	Relinquished in 1978 and left
Ashland Oil	1974	offshore	0	0	Relinquished in 1978 and left
Canadian Superior	1974	offshore	0	0	Relinquished in 1978 and left
PSC Round 1986 - Countrywide acreage redefined into 23 blocks					
Shell Oil	1986	22 & 23	2	0	Relinquished
Scimitar Exploration	1987	13	2	Jalalabad	Terminated
PSC Round 1993- Countrywide acreage					
Cairn Energy/Shell Oil	1994	15 & 16 (Offshore)	5	Sangu gas	Handed over to Santos in 2012
Occidental/Unocal	1995	12, 13 & 14	4	Moulvibazar & Bibyana	Taken over by Chevron
Oakland/Rexwood	1995	17 & 18 (offshore)			Relinquished
United Meridian International Corp(UMIC)	1995	22	0	0	Taken over by Ocean Energy which relinquished in 2001.
PSC Round 1997- Countrywide acreage					
Shell Oil/Cairn Energy	2001	5 & 10	0	0	Relinquished
Unocal	2001	7	1	0	Taken over by Chevron
Tullow/Chevron/ Texaco	2001	9	3	Bangura	
PSC Round 2008 – Offshore acreages redefined into 28 shallow water and deepwater blocks					
ConocoPhilips	2010	10 & 11 (deepwater)	-	-	
PSC Round 2012 – Offshore acreages redefined following settlement of maritime boundary by ITLOS. Offshore bidding round announced for 9 shallow and 3 deep sea blocks.					

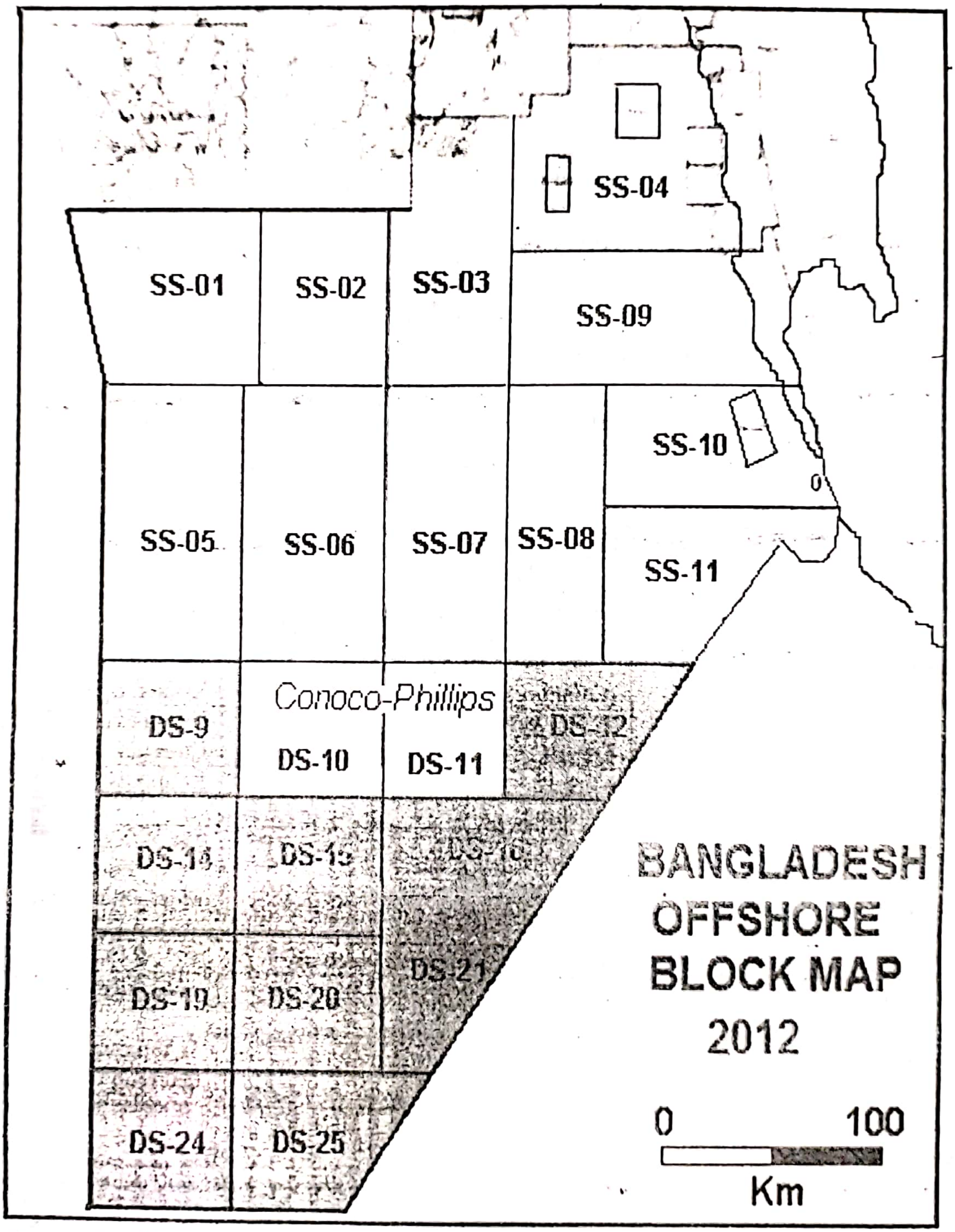


Figure 3.10B Offshore blocks in Bangladesh redefined following the settlement of maritime boundary between Bangladesh and Myanmar by ITLOS in 2012. Several deep offshore blocks defined by Bangladesh in 2008 bidding round (see figures 3.9 and 3.10A) were placed in Myanmar deep water territory (DS = Deep water block, SS=Shallow water block). (Source : Petrobangla).

3.4.2 Gas fields in Bangladesh

By the end of 2012, there have been 25 natural gas fields discovered in Bangladesh. The gas fields are located in the eastern half of the country (Figure 3.11). These gas fields, in order of discovery year, are Sylhet (1955), Chattak (1959), Rashidpur (1960), Titas (1962), Kailashtila (1962), Habiganj (1963), Bakhrabad (1969), Semutang (1969), Begumganj (1977), Kutubdia (1977), Beanibazar (1981), Feni (1981), Kamta (1981), Fenchuganj (1988), Jalalabad (1989), Narshingdi (1990), Meghna (1990), Shahbazpur (1995), Sangu (1996), Saldanadi (1996), Bibiyana (1998), Moulvibazar (1999), Bangura (2004) and Sundalpur (2011) and Srikail (2012). Only two of the gas fields, Kutubdia and Sangu are located in the offshore.

Bangladesh is generally rated well for further gas prospects. However, from the geologic analyses, the rating appears to hold true for the eastern half of the country. The western half does not have as good a petroleum prospect as the east. Being one of the largest delta basins of the world, petroleum prospect of Bangladesh is supposed to be comparable to those of the other petroliferous delta basins of the world. However, there are some geologic peculiarities of the Bangladesh delta basin (Bengal Basin) that has influenced the natural gas and oil habitat. This point will be discussed further later.

The salient features of the gas fields of Bangladesh are outlined below. A more elaborate discussion on the general characteristics of the gas fields are given later.

i) Most of the gas fields are located in the eastern part of the country. This is because of the fact that fold structures favoring gas accumulation occur in the eastern part i.e. in the eastern fold belt. In the western part such fold belt is absent.

ii) The gas fields are located in folded anticlines. The fold structures generally have higher amplitude (larger vertical closer) towards the east and have lower amplitude (smaller vertical closer) as one moves toward west and the basin centre. Few of these gas field structural traps have some degree of stratigraphic control thus making a combination trap rather than purely structural in nature. There is no gas field found in purely stratigraphic trap yet.

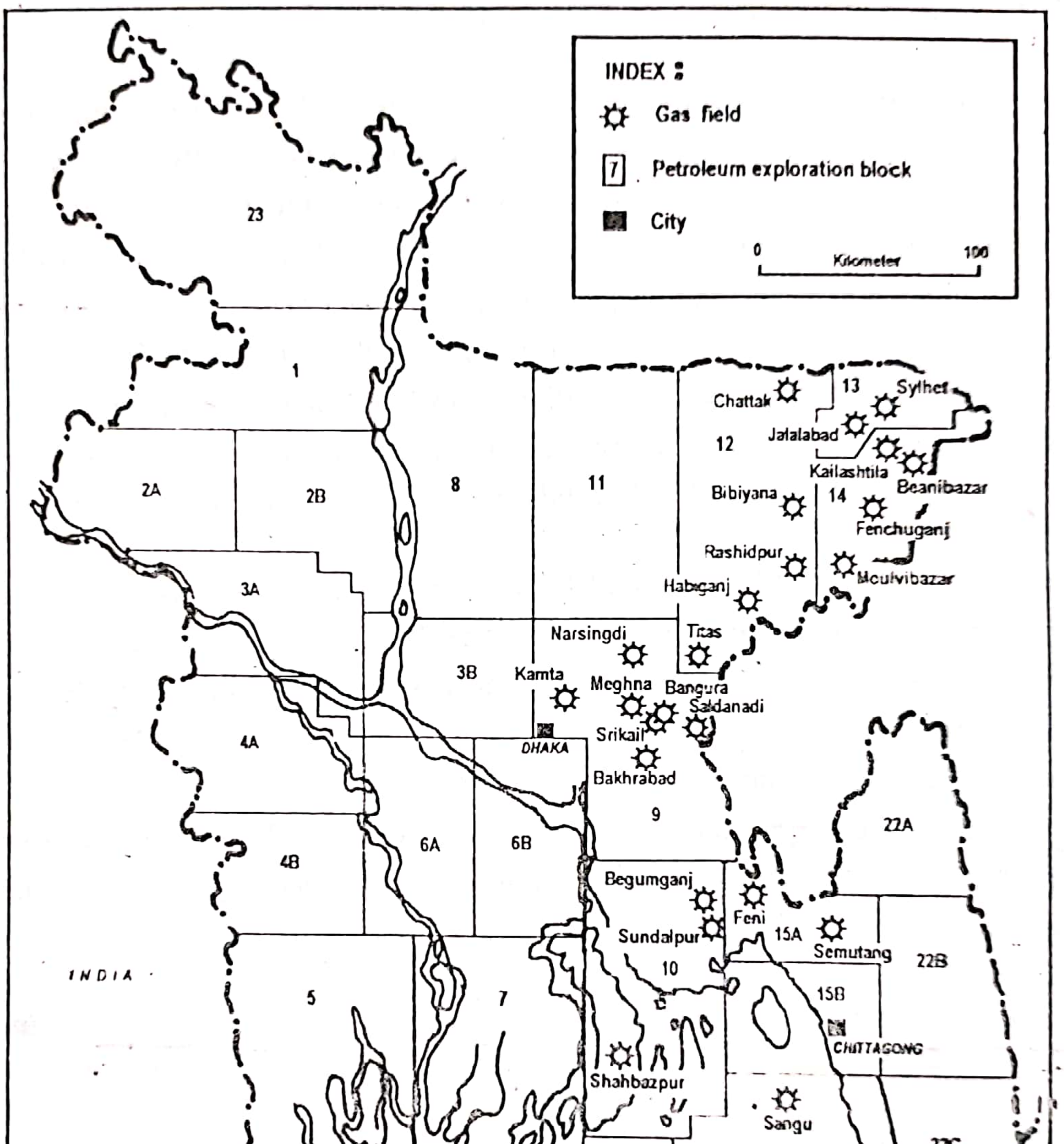


Figure 3.11 Gas fields in Bangladesh and petroleum exploration blocks.

iii) The gas pools or zones are located at depths ranging from less than 1000 m to more than 3000 m below the surface (Figure 3.12). The gas is reserved within the sandstone reservoirs of the Bhuban and Bokabil rock units. Most of the gas fields have multi-layer gas zones with some having more than 12 gas zones in vertical sections. The shale layers interbedded with reservoir sandstones act as seal of the trap.

iv) Gas generation took place at depths of about 5000 to 7000 m below the surface within 'oil window' in organic rich shale layers of Oligocene age (about 25 to 35 million years before present). After generation, the gas migrated upward though multi layer sand-shale sequence into the sandstone reservoir rocks of the Miocene-Pliocene age (about 5 to 25 million years before present).

v) The organic matter from which petroleum has been generated in Bengal Basin is mostly humic type (type III) of terrestrial origin. Such type of organic matter can produce significant amount of gas but little oil. This is the likely reason why significant gas discoveries are not accompanied by significant oil finds in Bangladesh.

vi) Geologic structures (traps) or the anticlines housing the gas accumulations were formed very late in geologic time scale i.e. mainly in the Pliocene age (2 to 5 million years before present). Gas accumulation into these structures took place after that. Thus the gas fields of Bangladesh are considered geologically very young. The relatively low degree of trap fill of some of the gas fields is a result of the very young to sub recent growth of the traps and subsequent gas accumulation (Hiller 1988).

3.4.3 Gas reserves of Bangladesh

Several national and international organizations or agencies, at different times, conducted reserve estimations on individual gas fields or group of gas fields of Bangladesh. These include Pakistan Petroleum Limited (1964), British National Oil Company (1978), Hydrocarbon Habitat Study Group (HHS -1986), Tecknica (1989), Intercomp Kanata Management (IKM -1990), Hydrocarbon Unit with Norweigian Petroleum Directorate (HCU/NPD -2003), Bangladesh Petroleum Exploration and Production Limited (BAPEX), the International oil companies (IOC) working in Bangladesh and several international reserve evaluation service companies or

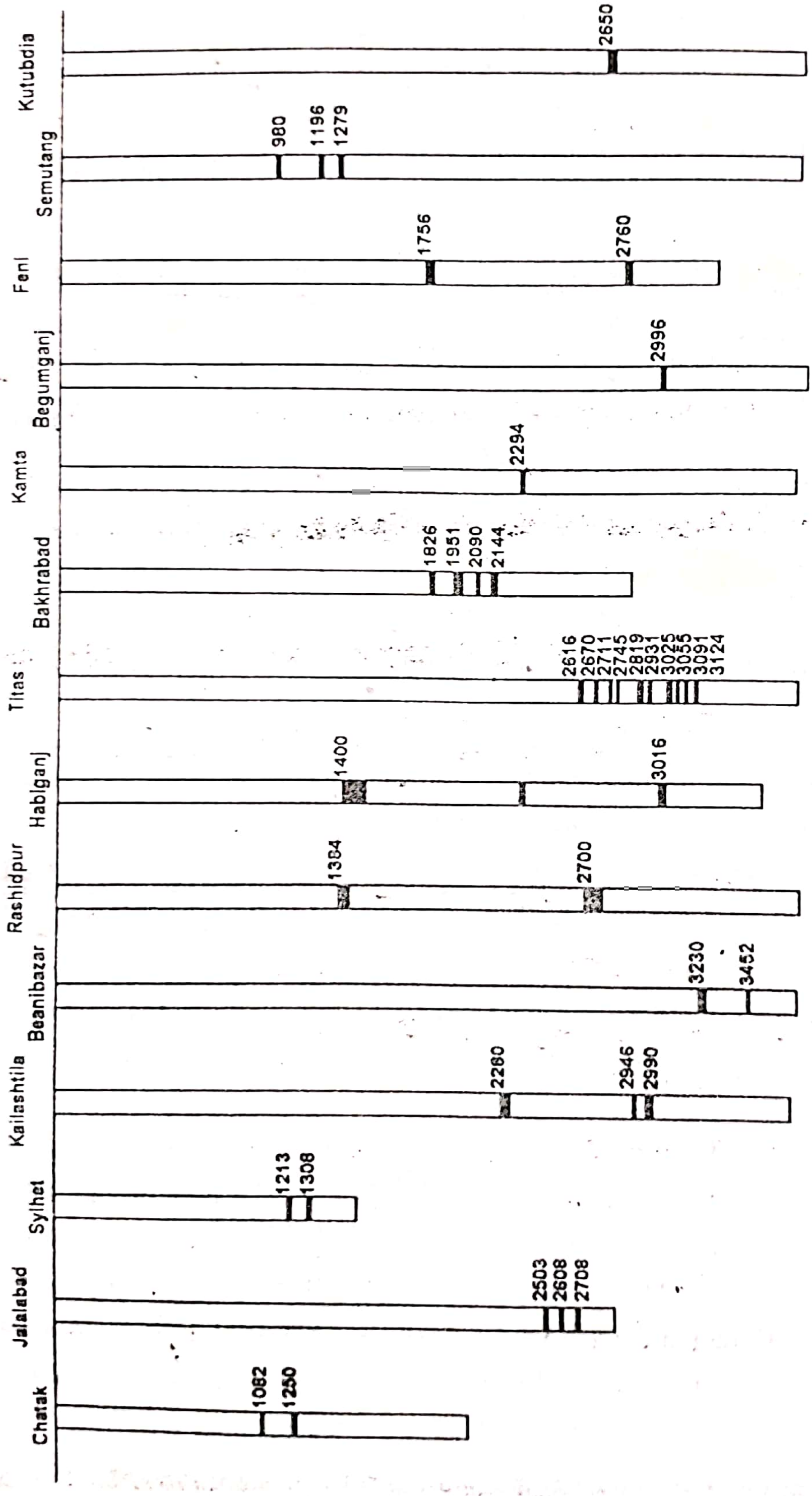


Figure 3.12 Depths of gas zones below the surface in gas fields of Bangladesh (Source: Petrobangla).

consultants like DeGolyer and MacNaughton (D and M), Gustavson Associate (2011) and RPS Energy (2011).

Petrobangla uses these reserve data to build up its own data base on the gas field reserves, which it updates from time to time as new studies or estimates are available. The lastest reserve update was done in 2010 by RPS Energy and the present reserve data base of Petrobangla is essentially based on this work (Petrobangla 2012).

In the prevalent practice of Petrobangla and government organizations dealing with the gas sector, gas reserves are shown mostly in 'Proved plus Probable' category. According to Petrobangla latest update the cumulative initial recoverable reserve (proved plus probable or 2P) of gas in the country, has been estimated at 26.84 Tcf. (Petrobangla 2012). Out of this total initial reserve, about 10.10 Tcf gas has been produced till December 2011, leaving a remaining recoverable reserve of about 16.74 Tcf. The above reserve does not include the last two discoveries as their reserves are not officially declared, although preliminary estimates determine small reserves for both the fields i.e. 50 Bcf for Sundalpur and 200 Bcf for Srikail. Table 3.8 list the gas fields of Bangladesh with their initial GIIP, initial reserves, remaining reserve and related data. Figure 3.13 gives an illustrative representation of initial reserve and remaining reserve of each gas field in Bangladesh.

According to the above source the proved initial reserve of the country as of December 2011 has been estimated at 20.7 Tcf. Considering the fact that 10.10 Tcf gas has been produced by Dec 2011, the proved reserve at that time stands at 10.6 Tcf (Petrobangla 2012).

The gas fields of the country may be grouped into four categories on the basis of their reserve sizes as follows: giant (> 3 Tcf), very large (> 1 Tcf to 3 Tcf), major (>300 Bcf to 1 Tcf), minor (>60 Bcf to 300 Bcf) and dwarf (60 Bcf or less). It may be noticed that two giant gas fields, Titas (initial reserve 6367 Bcf) and Bibyana (initial reserve 5754 Bcf) account for about 45% of the total initial gas reserve of Bangladesh (Table 3.9, Figure 3.14). These are world class gas reserves being among the largest gas fields in the subcontinent. Also notice that five very large gas fields each having initial reserve of > 1 Tcf to 3 Tcf, account for 31% of total initial

Table 3.8 Gas reserve (Proved plus Probable) in Bangladesh (Source:Petrobangla Annual Report 2011). Gas reserve, by definition (WPC and SPE) is the quantity which is commercially recoverable.

	Gas field	Year of Disco-very	GIIP (Proved+ Probable) (Bcf)	Initial Reserve (Proved+ Probable) (Bcf)	*Production upto Dec 2011 (Bcf)*	Remaining reserve (Proved+ Probable) as of Dec 2011 (Bcf)
1	Sylhet	1955	370	319	*195*	124
2	Chattak	1959	1039	474	*27*	447
3	Rashidpur	1960	3650	2433	*490*	1943
4	Titas	1962	8149	6367	*3330*	3037
5	Kailashtila	1962	3610	2760	*507*	2253
6	Habiganj	1963	3684	2633	*1859*	774
7	Bakhrabad	1969	1701	1231	*736*	495
8	Semutang	1969	654	318	*<1*	317
9	Begumganj	1977	39	21	*0*	21
10	Kutubdia	1977	65	45	*0*	45
11	Beanibazar	1981	231	203	*76*	127
12	Feni	1981	185	125	*62*	63
13	Kamta	1981	72	50	*21*	29
14	Fenchuganj	1988	553	381	*82*	299
15	Jalalabad	1989	1491	1184	*645*	539
16	Narsingdi	1990	369	277	*129*	148
17	Meghna	1990	122	70	*42*	28
18	Shahbazpur	1995	677	390	*5*	385
19	Sangu	1996	900	578	*480*	98
20	Saldanadi	1996	380	279	*65*	214
21	Bibiyana	1998	7427	5754	*987*	4767
22	Moulvibazar	1999	1053	428	*187*	241
23	Bangura	2004	1198	522	*176*	346
Total in Bcf			**37618**	**26842**	**10102**	**16740**
Total in Tcf			**37.61**	**26.84**	**10.10**	**16.74**

Note: The gas reserves of the last two discoveries (Sundalpur and Srikail) are not known yet from Petrobangla official source, but preliminary estimates suggest GIIP of 50 Bcf in Sundalpur and 200 Bcf in Srikail with 70% expected recovery.

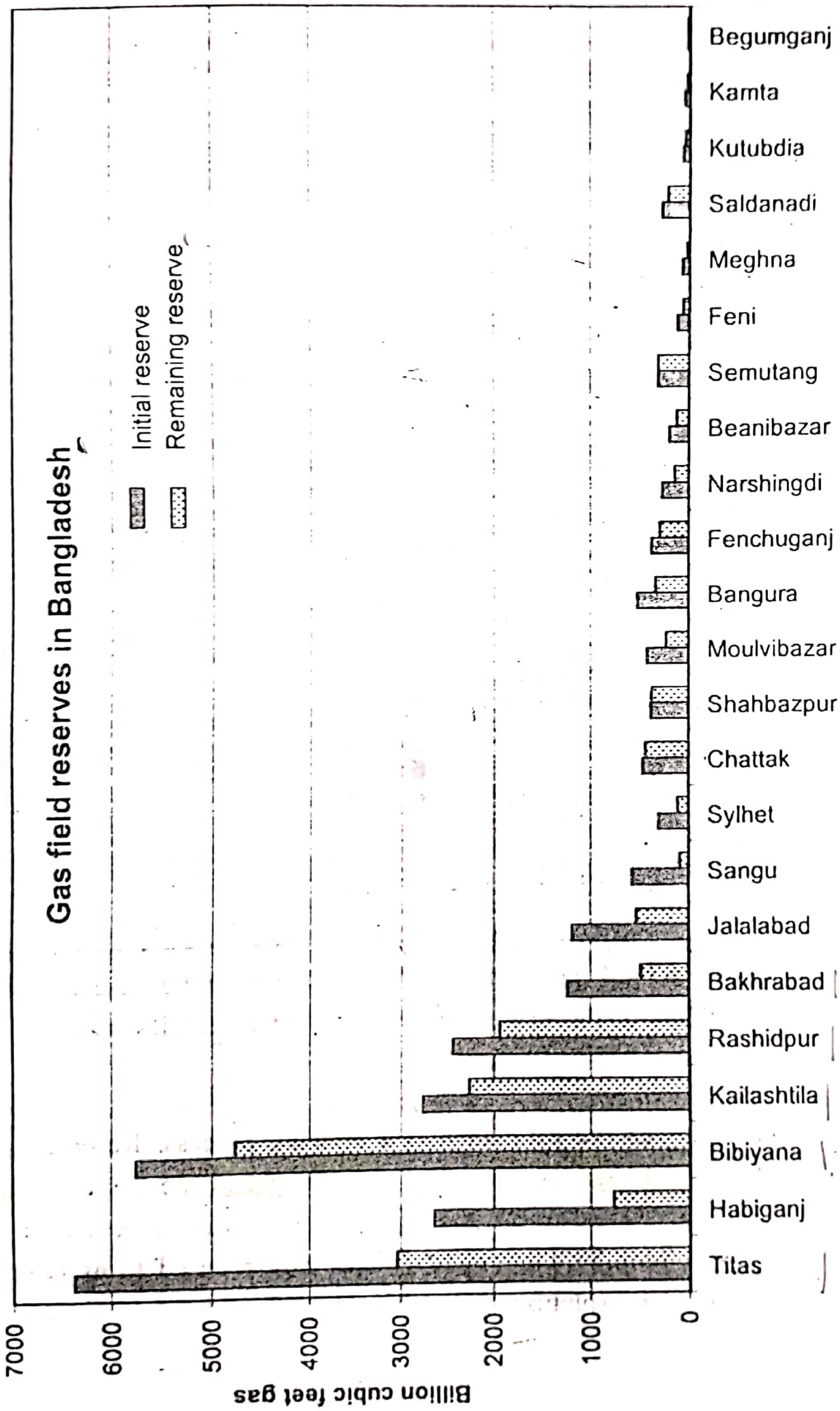


Figure 3.13. Gas reserves in Bangladesh by fields (after Petrobangla 2012)

Table 3.9 Percentage share of reserves by gas field category in Bangladesh

Gas field size category	Gas field	Initial reserve (Bcf)	Percentage among total gas reserve
Giant	Titas	6367	45%
	Bibiyana	5754	
	Habiganj	2633	31%
Large	Kailashtila	2760	
	Rashidpur	2433	
	Bakhrabad	1231	
	Jalalabad	1184	
Major	Sangu	578	24%
	Chattak(W)	474	
	Sylhet	318	
	Shahabazpur	390	
	Moulvibazar	428	
	Bangura	522	
	Fenchuganj	381	
Minor	Narsinghdi	277	
	Beanibazar	203	
	Semutang	318	
	Feni	125	
	Saldanadi	279	
	Meghna	70	
Dwarf	Kamta	50	
	Kutubdia	45	
	Begumganj	21	

gas reserve. That means the top 7 gas fields hold 76% of the total initial reserve while the remaining 16 gas fields in the major, minor and dwarf categories account for about 24% of the total initial reserve (Figure 3.14).

It may be noted that reserve estimation is a dynamic process. Reserves are updated and are likely to change as more data are available in the course of the development of a gas field. As the reserves are updated, an increase of reserve from original estimate may be seen in a particular field, a case referred to as reserve growth. The following section explains more on this issue.

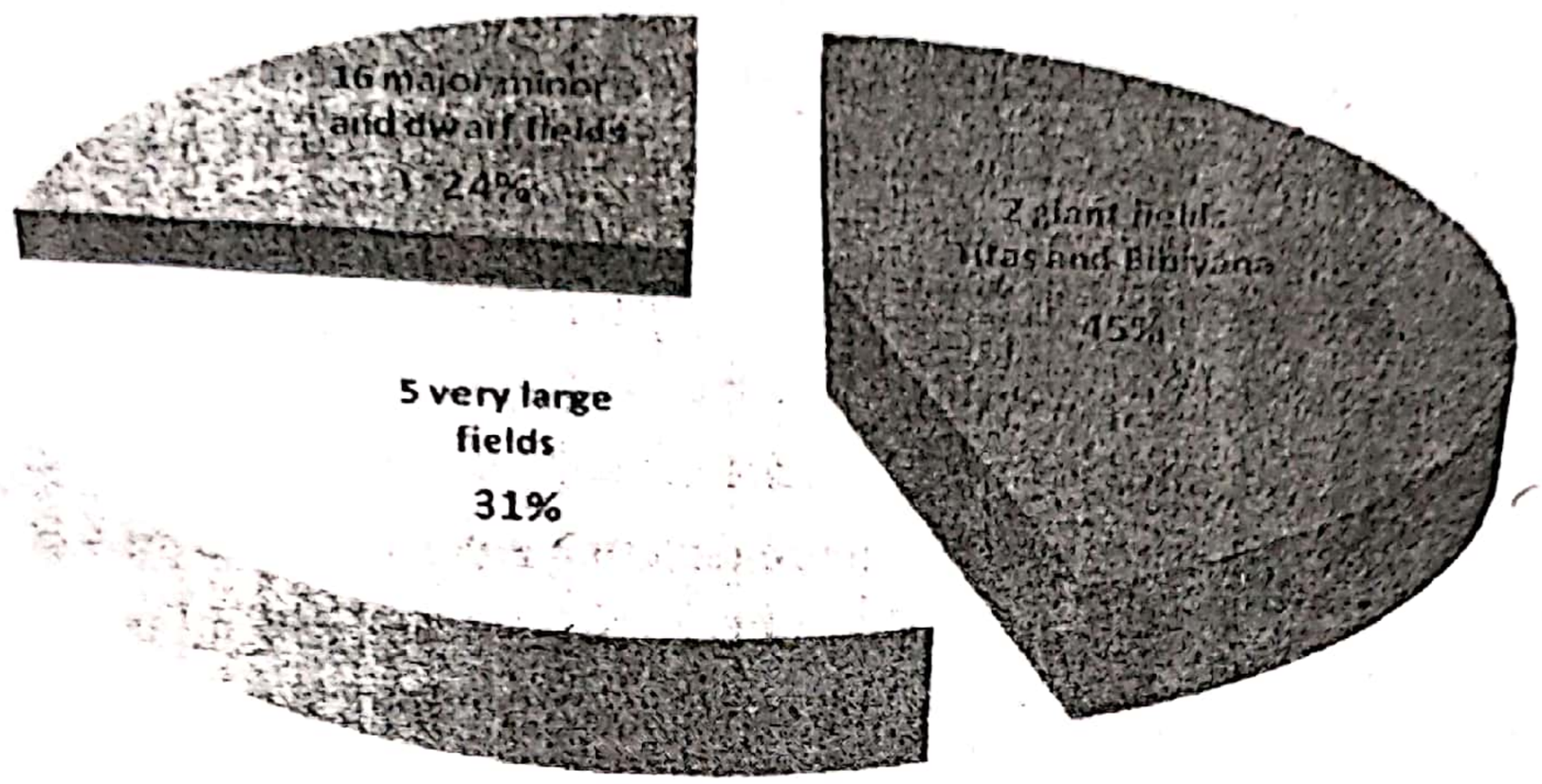


Figure 3.14 Percentage shares of gas reserves by field size categories in Bangladesh

3.4.4 Reserve growth

Reserve growth (also referred to as 'field growth') refers to the addition to already known reserve in a gas (or oil) field in the course of field development (Milici and Attanasi 1999). The additions of the gas reserve (field growth) are expected during normal field development as boundary of proved gas areas are extended by new drilling and as new pay zones/pools are found and confirmed by drillings. Reserve does not grow automatically, but it is the new data acquired through the field development process that led to the increased estimation of the reserve.

Milici and Attanasi (1999) imply that gas field developments in Bangladesh are mostly in initial stage and are undergoing primary production phase. They optimistically note that once the field development expands and reaches a matture stage in Bangladesh, reserve growth would be observed.

Although majority of the gas fields in Bangladesh are still in an early stage of development, there are some large fields where development drillings over the years enable one to judge field growth phenomena. Four large gas fields i.e. Titas, Habiganj, Rashidpur and Bibiyana may be taken as test cases to judge whether the estimated gas reserves in these fields grew over the years as the fields are developed

and reserves reevaluated. One may mark three points in time i.e. 1991, 2001 and 2010, when these gas fields were reevaluated for their reserves at different stage of their development. Then a comparison may be made to see if reserve growth has taken place (Table 3.10).

For Titas gas field, for example, it may be noticed that in 1991 the gas reserve of the field was estimated by international consultant IKM to be 2.10 Tcf. About ten years later in 2001 and after several more development wells were drilled, the reserve of the field was re-estimated by HCU-NPD to be 5.13 Tcf, a significant growth from previous estimate (Table 3.10). Furthermore, in 2010, with some more development work done, the gas reserve of Titas field was again estimated by international consultant RPS Energy to be 6.36 Tcf (Figure 3.15). Therefore Titas gas field is an example where significant field growth has been documented as the development of the field proceeds over the years.

TABLE 3.10 Reserve growth in some large gas fields in Bangladesh (Ref: HCU-NPD 2004, Petrobangla 2011)

Reserve estimation agency	Year	TITAS		HABIGANJ		RASHIDPUR		BIBIYANA	
		Initial GIIP	Initial reserve	Initial GIIP	Initial re-serve	Initial GIIP	Imtial reserve	Initial GIIP	Initial reserve
IKM	1991	4.14	2.10	3.67	1.89	2.24	1.31	-	-
HCU-NPD	2001	7.32	5.13	5.14	3.85	2.02	1.40	3.15	2.40
RPS Energy	2010	8.14	6.36	3.68	2.63	3.65	2.43	7.43	5.75

A similar field growth phenomenon may be noticed, though in different scale, for Rashidpur and Bibiyana gas fields taking into account the estimates made at different times and at different stages of field developments (Table 3.10).

It may be pointed out that field growth is more complex and non homogenous and can not be generalized in the gas fields of Bangladesh. While some fields like Titas, Rashidpur and Bibiyana have reportedly shown field growths, few others do

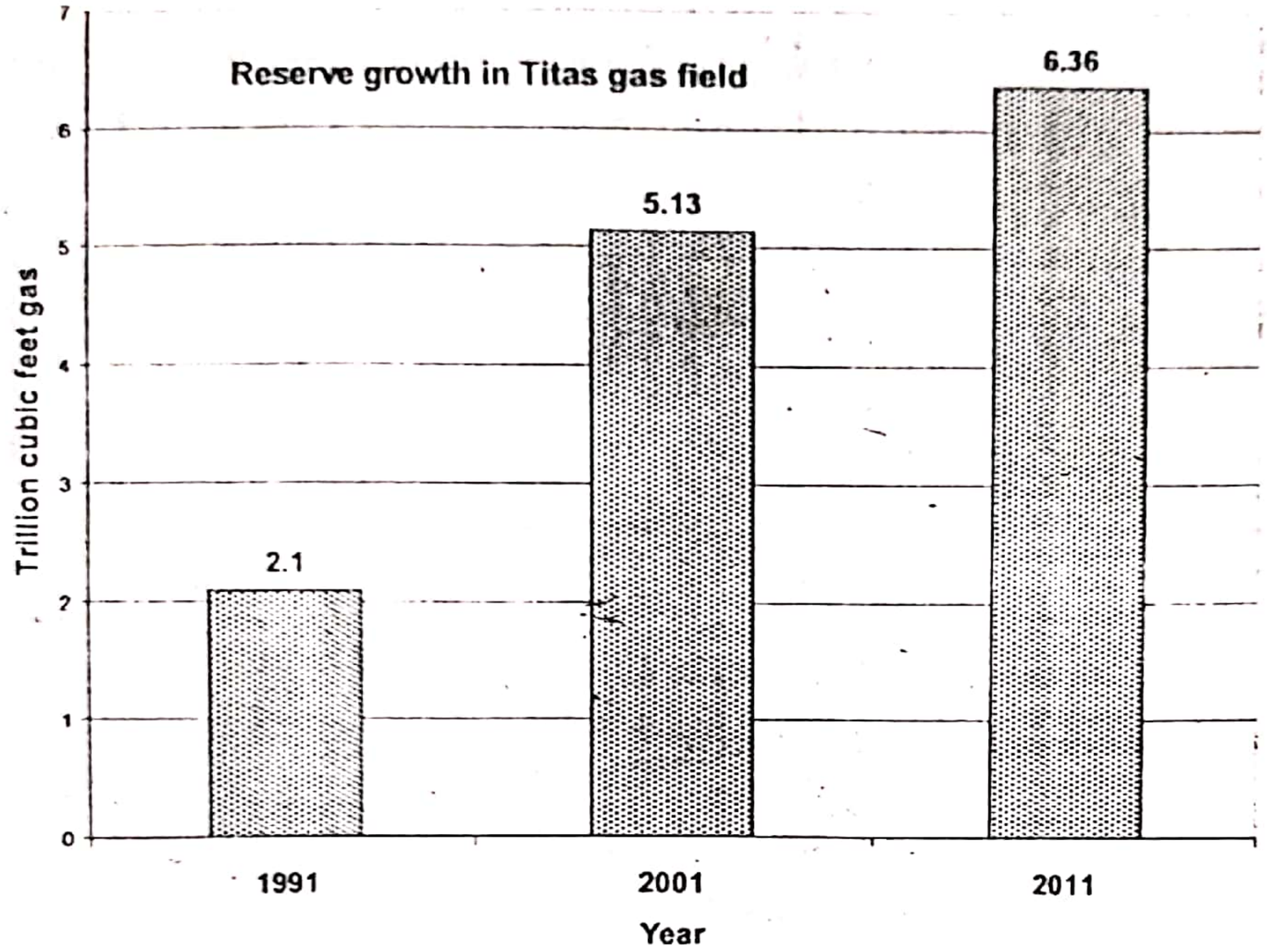


Figure 3.15 Reserve growth observed in Titas gas field (Source: Petrobangla)

show an opposite trend i.e. negative growths. There are insufficient data from most of the other producing fields, at present, to judge if reserve growth of any significance occurs or not. It would therefore perhaps be premature to make generalized comment on the reserve growth phenomena for the Bangladesh gas fields.

In addition to the conventional development drilling, there has been several advanced technologies that may significantly contribute to reserve growth. These include i) 3D seismic survey, ii) state of earth logging techniques, i.e. thin bed imaging and iii) compression (Shamsuddin et al 2002).

3D seismic surveys have major positive impacts on reserve growth. One case history documented the result of application of 3D seismic data on reserve growths at top 76 producing fields in USA, 42 of which were fully covered by 3D seismic. For those 42 fields, the average field growth through positive revisions was more than twice the average for all 76 fields (Aylor 1999). The first ever 3D seismic in Bangladesh was carried over Bibiyana gasfield in 1999 during field appraisal. Prior to that Bibiyana's proved plus probable (2P) reserves were estimated at 2.1 Tcf. After analysis with 3D seismic, the field's estimated proved plus probable reserve rose over

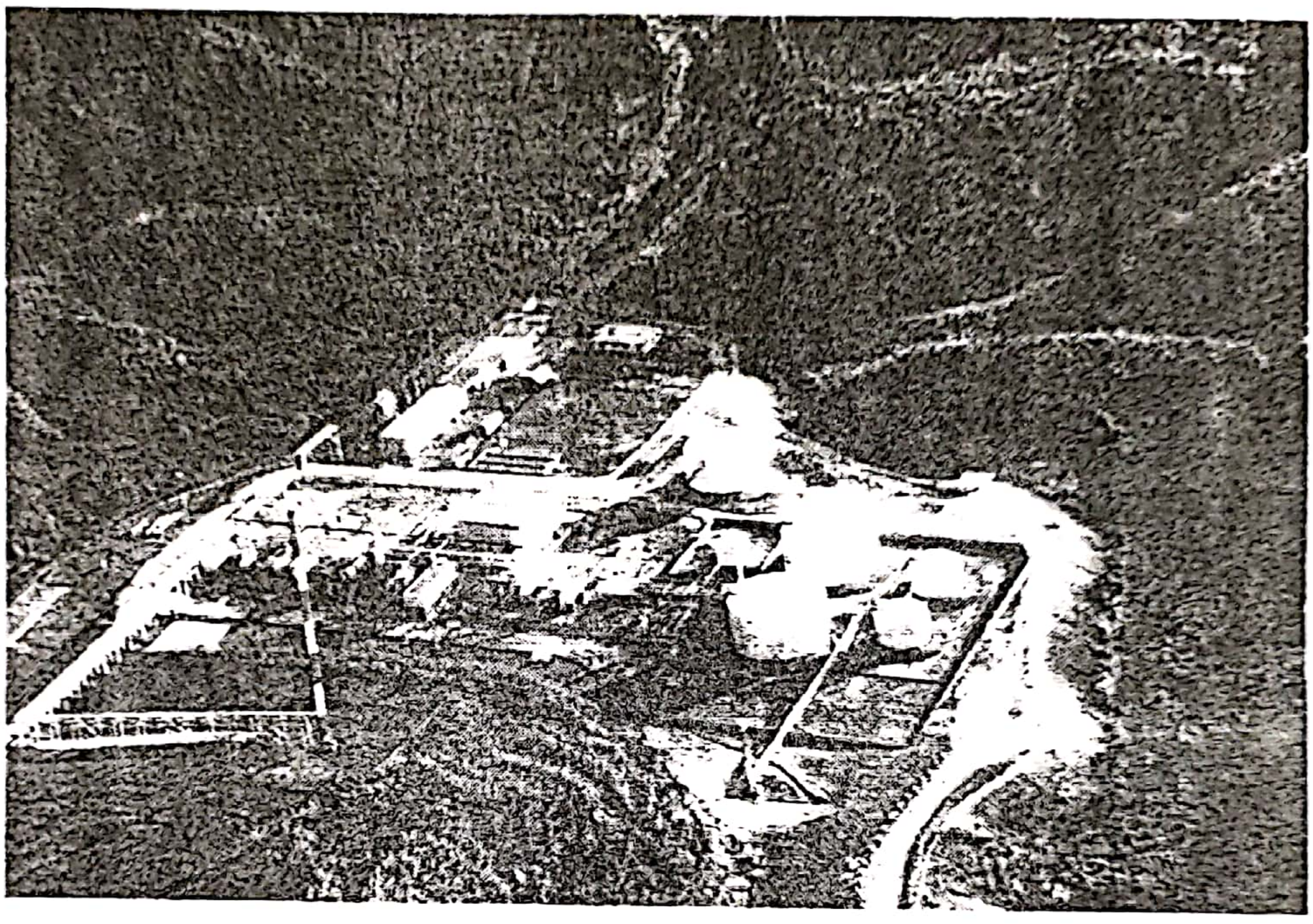


Plate 3.3 Jalalabad gas field in Sylhet.

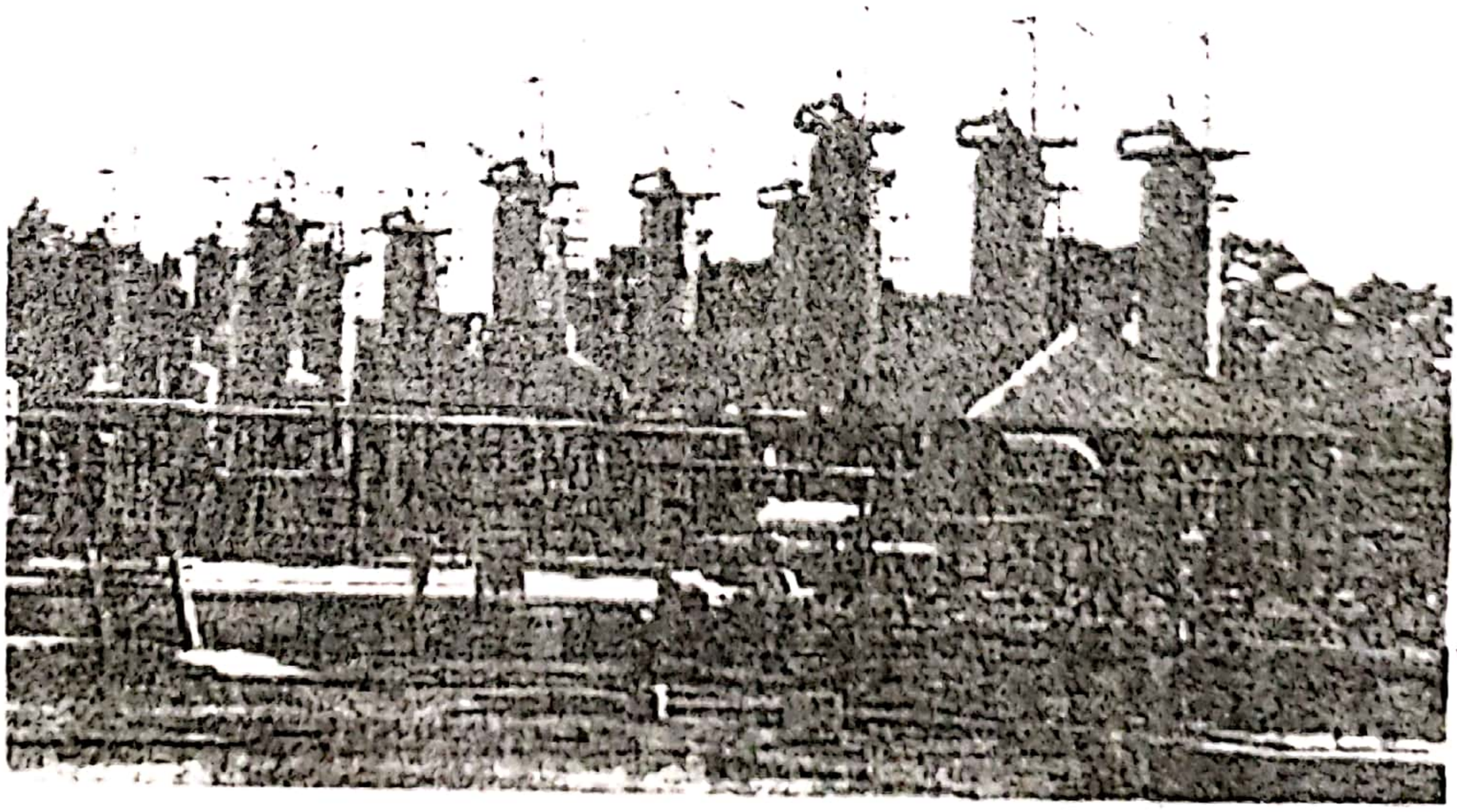


Plate 3.4 Bakhrabad gas field in Comilla.

10% to 2.4 Tcf even before drilling wells (Shamsuddin et al 2002). Bibiyana reserve was further revised upward to 5.75 Tcf later following development drillings. 3D seismic has since been applied to a number of gas fields in Bangladesh and these has significantly enhanced the understanding of the reservoir nature that may lead to enhanced estimates wherever possible. It has been suggested that the overall potential growth to Bangladesh's 2P reserve base through 3D seismic is a conservative 20% of the recoverable gas in Petrobangla operated fields (Shamsuddin et al. 2002).

Thin beds refers to thin (<1 ft) reservoir quality beds (sands) interbedded and interlaminated with non reservoir layers (shale). Standard wireline logs (SP,gamma. density, neutron etc) do not respond accurately to the presence of thin beds. Gamma ray counts from adjacent shales in thin sand beds results in very high GR reading over such thin bed sections. A 200 ft thick sand shale sequence (50/50) can have 100 feet of clean hydrocarbon bearing sand that are completely missed by standard wireline logs. Large gas show over thick shale can be the result of thin sands within shale that are invisible to standard well logs. Advanced logging tool i.e. Formation micro scanner, have vertical resolution of 0.2 inch or better and can identify thin beds. Presence of thin beds in Bangladesh gas fields has been confirmed recently as exemplified by such fields as Bibiyana and Rashidpur (Smith et al 1999, Shamsuddin et al. 2002, Ashraf et al 2000). Conventional log analysis, for example, documented 122 m of maximum net pay for Bibiyana. However, analysis of the same borehole with thin bed logging tool increased the total net pay over 250% to 324 m (Shamsuddin 1999). Recognizing that thin bed pays may not exist in every fields, the overall potential growth to Bangladesh's 2P reserve base is conservatively 30% of the 2P recoverable reserve in Petrobangla operated fields.

Gas compression is a proven technological application that may provide reserve growth by lowering the abandonment pressure. Present reserve totals of all Petrobangla gas fields are based on depletion down to an average abandonment wellhead pressure of 1100 psi. By installing compressor between wells and pipelines, the abandonment wellhead pressure can be reduced to 500 psi, thus significantly increasing gas recovery. A field study conducted by Well Drill shows field reserves growth of at least 30-40% by reducing average abandonment wellhead pressure from 1100 psi to 600 psi for Titas, Habiganj, Rashidpur and Kailashtila gas fields. Overall,

Abundonment Pressure - is the pressure when the producing well reaches its economic limit following a decline in rates.

compression is conservatively estimated to add at least 20% of the 2P recoverable reserve in Petrobangla operated fields (Shamsuddin et al. 2002).

3.4.5 When is Bangladesh likely to run out of gas

"How long the estimated gas reserve would run" is a question frequently asked. Widely circulation notion published in the media reports variously suppose that the gas reserve of the country would be exhausted by 2015, 2017 or 2020. A more realistic assumption may be made by looking into the data base available.

Bangladesh produced and consumed about 0.7 Tcf gas in 2011 and the annual gas consumption is likely to increase to about 1 Tcf within three to four years. Assuming an average production and supply rate of about 1 Tcf gas per year, the 16 Tcf of remaining reserve (as of Dec 2011) should run for about 16 years; in other words, Bangladesh is likely to exhaust its gas reserve by about 2026. But how realistic or simplistic is this statement.?

There are a few points that need to be considered in this regard: i) gas production and supply will not remain static over the years, ii) gas production and supply in Bangladesh are expected to grow in future, but the growth will not continue, iii) it is expected that the gas production and supply will grow till certain time and then start to decline and the line representing the decline will have a long tail, and finally iv) estimated gas reserves may change with time due to reserve addition from new discoveries and reserve growths.

From Petrobangla published data, we may look into how the estimated gas reserves of the country have changed over the last 20 years (Table 3.11). In 1993, there were 17 gas fields in the country with an estimated total initial gas reserve (2P) of 12.43 Tcf and a remaining reserves (2P) of 10.55 (Petrobangla 1993). In 2003, the number of gas field was 22 and the total initial gas reserve (2P) was estimated at 20.51 Tcf and a remaining reserve (2P) at 15.4 Tcf (Petrobangla 2004). In 2011, the number of gas field has been 23 with an estimated initial gas reserve of 26.84 Tcf and a remaining reserve of 16.74 Tcf. Interestingly the estimated remaining reserve of the country has increased from 10.55 Tcf in 1993, to 15.4 Tcf in 2003 and to 16.74 Tcf in 2011 (Figure 3.16). This is in spite of the fact that both demand and production of gas have increased over the years. However, future projections into gas production and

Table 3.11 Estimated gas reserves of Bangladesh over the years (Ref: Petrobangla 1993. 2004 and 2012)

Year	Number of gasfields	Initial Reserve (2P) (Tcf)	Cumulative production (Tcf)	Remaining Reserve (2P) (Tcf)	Reference
1993	17	12.43	1.87	10.55	Petrobangla (1993). based on IKM evaluation of gas reserves
2003	22	20.42	5.31	15.11	Petrobangla (2004). based on HCU-NPD evaluation of gas reserve
2011	23	26.84	10.10	16.74	Petrobangla(2012), based on RPS Energy evaluation of gas reserves

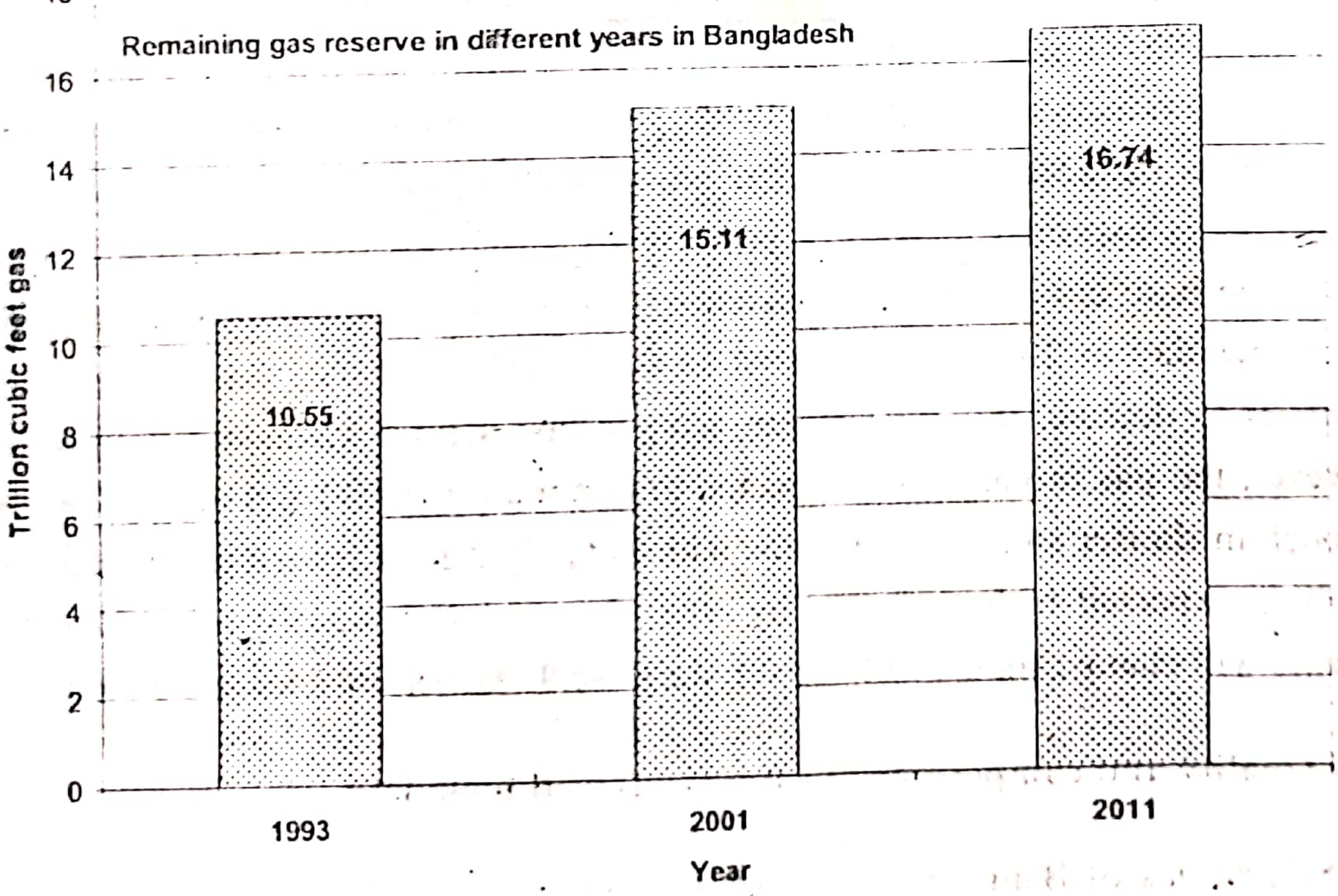


Figure 3.16 Remaining gas reserves of Bangladesh at different years (Source: Petrobangla).

supply suggest that the gas supply will decline from a point in time. As the projected gas demand continues to grow, a fall in production and supply means a gap between demand and supply. This gap will continue to widen as the production is expected to decline further in the medium to long term future.

In 2006, Bangladesh Gas Sector Master Plan (GSMS 2006) was prepared by Petrobangla/World Bank (consultant: Wood Mackenzie) with forecasts of future demand and supply scenarios. In the forecast of gas supply from the existing gas fields the production is expected to increase and reach a peak in 2016 and thereafter it is expected to decline. As the gas demand continues to grow, the gap between demand and supply would continue to widen as the production continue to decline after 2016. The gas production from the existing reserves is expected to continue to 2025 and beyond although in short supply.

In 2011, Power Sector Master Plan (PSMP) prepared by JICA, long term production forecast were set and three scenario were compared: a government plan (high case), PSMP plan-1 (base case) and PSMP plan-2 (low case). In each case, in addition to production from existing fields, production from identified new prospects (expected to be added as new fields) are considered. In all three cases the gas production is expected to reach a peak in 2017 and then decline (Figure 3.31). Taking the base case scenario as reference, production is expected to peak at 3320 mmcfg per day in 2017 and then start to decline (JICA 2011). As the production continues to decline, the gap between demand and supply will continue to widen. However, the gas production is expected to continue till 2030 and perhaps beyond although in shorter and shorter volume with time. The gap between gas demand and supply is expected to be balanced by other form of fuel, mainly coal. The above scenario will change should there be very large scale gas discoveries in the country.

3.4.6 Quality and composition of natural gas of Bangladesh

Natural gas of Bangladesh is known for its purity. The methane content of the gas ranges from about 93% (Beanibazar) to 98% (Rashidpur) with an average of 95% in 23 gasfields (Petrobangla 2012). This compares with 90% methane in Sui gas field in Pakistan, 81 % methane in Groningen field in the Netherland etc. The gas have 0.2% to 3.9% ethane, 0.05% to 1.2% propane, 0.1% to 0.72% butane and

lesser amount of higher hydrocarbons. The average composition of gas of the individual gas fields is shown in Table 3.12.

Natural gas in Bangladesh is free from poisonous hydrogen sulfide and therefore does not need purification. The gas have insignificant to very low amount of CO_2 (0.05 to 0.9%) and N_2 (0.1 to 1.0%). The gross calorific value of the gas in different fields ranges from 1005 to 1062 Btu/cft.

The gas in Bangladesh is mostly dry. However, four gas fields have significantly higher condensate percentages. These include Beanibazar, Jalalabad ,Kailashtila and Sylhet gas fields (Table 3.13).

3.4.7 Condensate and its reserve

Condensate is a hydrocarbon mixture that exists in gaseous state in the subsurface under high reservoir pressure condition but condenses into liquid when produced at the surface because of lowering of pressure. Condensate is collected in liquid form in a separator.

Condensate is generally lighter than light oil and have API gravity higher than 55 degree. Most condensate are composed of hydrocarbon in the light gasoline range (butane, pentane, hexane) which makes it lighter than oil. Condensate may have several mode of origin, such as i) from organic matter (kerogen) as an intermediate product between oil and gas, ii) from conversion of oil to gas in a reservoir and iii) from the gas phase migration of hydrocarbon out of an oil pool by vaporization or gas stripping (Hunt 1996).

Although majority of the gas fields in Bangladesh produce dry gas and little condensate, some fields have high condensate to gas ratio. The condensate to gas ratio in the gas fields range from trace to 17.0 barrel of condensate per million cubic feet of gas (bbl/mmcfg). The four most condensate rich (high condensate/gas ratio) gas fields are Beanibazar (17 bbl/mmcfg), Jalalabad (7.7 bbl/mmcfg) and Kailashtila (9.2 bbl/mmcfg) and Sylhet (9 bbl/mmcfg) (Table 3.13).

The total initial reserve of condensate in Bangladesh is estimated at 77 million barrel of which 27.5 million barrel are initially stored in Kailashtila gas field.

Table 3.12 Average composition of natural gas in Bangladesh (Source: Petrobangla).

Gas field	Methane	Ethane	Propane	Butane (nor+iso)	Higher HC	Nitrogen	Carbon di oxide	Calorific value (BTU/CFT)
Sylhet	96.63	2.00	0.05	0.15	0.17	0.66	0.34	1050
Chattak	97.90	1.80	0.20	-	-	-	-	1005
Rashidpur	98.00	0.21	0.24	-	0.17	0.02	0.05	1024
Titas	96.76	1.80	0.39	0.43	0.06	0.30	0.42	1029
Kailashtila	94.03	2.73	1.02	0.55	1.24	0.38	0.05	1030
Habiganj	97.60	1.31	0.27	0.12	0.06	0.38	0.07	1016
Bakhrabad	94.20	3.65	0.72	0.30	0.24	0.42	0.47	1050
Semutang	96.94	1.70	0.14	0.01	-	0.86	0.35	-
Begumganj	95.46	3.19	0.64	0.21	-	-	0.30	1045
Kutubdia	95.72	2.87	0.67	0.31	-	0.36	0.07	1042
Beanibazar	93.27	3.06	1.21	0.72	0.42	0.38	0.09	1062
Feni	95.71	3.29	0.65	0.20	-	-	0.15	1050
Kamta	95.36	3.57	0.47	0.09	-	-	0.51	1043
Fenchuganj	98.10	1.00	0.63	0.15	-	-	0.06	1043
Jalallabad	96.02	2.45	1.07	0.55	0.18	0.19	0.07	1067
Narsinghdi	94.79	2.49	0.60	0.35	0.13	0.34	0.60	-
Meghna	95.15	2.83	0.60	0.25	0.07	0.37	0.53	-
Shahbazpur	93.68	3.94	0.71	0.27	0.04	0.46	0.90	1046
Sangu	94.51	3.17	0.61	0.26	0.41	0.44	0.60	1058
Saldanadi	95.12	2.16	0.45	0.19	0.05	0.27	0.56	1032

The total daily production of condensate is 3444 barrel (Dec 2011 average). As shown in Table 3.13, about 50% of the total daily production of condensate in the country comes from only one field, Bibiyana because of the high volume of gas produced. Other major producers of condensate include Jalalabad (1269 bbl/day). Kailashtila (797 bbl/day) and Titas (377 bbl/day). Generally the gas fields in the northeastern part of Sylhet area are relatively rich in condensate and the amount of condensate decreases towards west and south (Reimann 1993).

Table 3.13 Daily condensate and gas production and condensate to gas ratio (Production data for average December 2011, Source Petrobangla 2012)

Gas field	Number of producing wells	Average daily gas production (mmcfd)	Average daily condensate production(bbl)	Condensate to Gas ratio (bbl/mmcfg)
Beanibazar	02	9	153	17.0
Kailashtila	05	86	797	9.26
Jalalabad	04	164	1269	7.73
Sylhet	02	10	73	7.3
Bibiyana	12	752	3105	4.12
Bangura	04	102	336	3.29
Narsingdi	02	30	65	2.16
Meghna	01	10	19	1.9
Fenchuganj	03	23	15	0.65
Saldanadi	03	18	13	0.72
Titas	15	445	377	0.84
Bakhrabad	05	33	18	0.54
Semutang	01	14	9	0.64
Sangu	03	14	5	0.35
Moulvibazar	04	42	5	0.12
Rashidpur	04	48	45	0.93
Habiganj	09	259	13	0.05

The condensate produced in Bangladesh is light yellow to colorless. Some of the condensate in Bangladesh are heavier (46 degree API or less) than condensate proper (55 degree API or more). For example, some condensate of Habiganj gas field has 29.4 degree API gravity and that of Beanibazar 45.6 degree API gravity, values equivalent to medium density to light oil respectively (Shahjahan et al 2002). The high density (low API gravity) of these condensates is supposed to be due to biodegradation by meteoric water.

Analysis of the Beanibazar-IX and Kailashtila-1 condensate show that these contain up to C_{34} n-alkane hydrocarbon. Presence of such a high n-alkane in condensate is unusual. It has been suggested that the condensate was perhaps originally produced as oil in the deeper subsurface level. As it migrates up and becomes lighter by the process of separation-migration, it retains some high molecular component with it (Khan et al 1988). The above notion supposes that the condensate, at least some of it originated from oil that exist in the deeper level. Condensate is processed in NGL fractionation plant to produce LPG, motor spirit, and kerosene that are used in the local market.

3.5 Geological characters of Bangladesh gas fields

As mentioned earlier, a petroleum pool or field in the underground results from satisfactory coexistence of following four geological factors: the source rock in which the gas is generated, the reservoir rock into which the gas migrates and accumulates, the trap (and seal) which allow this accumulation to take place and right timing of gas migration from source to reservoir. The general characteristics of the gas fields of Bangladesh in terms of source, reservoir, trap and migration pattern are outlined below.

3.5.1 The source rock: Where the gas is generated

What is the source of the natural gas in Bangladesh? What type of rock layer has been considered as source? Is the gas generated in close proximity to the reservoirs, or is the source lies much deeper in the subsurface?

The generally acceptable view of the source of the natural gas found in Bangladesh is that most of the gas was generated in the organic rich shale of Oligocene age, stratigraphically belonging to the Jenum Formation of the Barail Group (Hiller 1988; Ismail and Shamsuddin 1991; USGS-Petrobangla 2001; Curiale et. al. 2002). The Oligocene Jenum shale is relatively rich in organic matter and has experienced thermal maturity by deep burial. The organic matter is Jenum shale is mostly type III with minor type II of terrestrial origin and thus is gas prone. Gas prone source rock with up to 2 - 4% TOC was detected in 261 m of Jenum shale encountered in Atgram-1X well in Sylhet Basin (Hiller 1988). The shale have attained thermal maturity with vitrinite reflectance of 0.65% at total depth indicating

- Vitrinite reflectance is a measure of the percentage of incident light reflected from the surface of vitrinite particles in a sedimentary rock.
- Vitrinite has a shiny appearance resembling glass (vitreous).

vitrinite reflectance & maturity (Rmo %)

marginal maturity but would be fully mature in adjacent generative depression (Shamsuddin and Abdullah 1997).

Hiller (1988) hypothised a gas generation potential model that expected as much as 31 Tcf of gas sourced from Jenum shale in Surma Basin, taking an average 1.5% TOC with 75% of them in an overall present maturity of Rmo 1.9% and an expulsion and migration efficiency factor of 0.75. It has been suggested that the major part of the gas was formed at depths range of 6000m to 7000m below the surface within the oil window. After the generation, the gas migrated up through multi kilometer sand-shale sequence perhaps via fault conduits into the overlying Bhuban and Bokabil sandstone reservoirs of Surma Group of Miocene-Pliocene age and accumulated in the traps (Figure 3.17). The gas reserves occur at depths between about 1000 to about 3000 meter below surface.

The gas originated in petroleum generative depression adjacent to the present gas field areas. The term petroleum generative depression or the hydrocarbon kitchen, as it is also called, has been defined by Hunt (1996) as the area where organic rich source beds are buried at high enough temperature to generate and migrate substantial quantities of petroleum. Several such generative depressions lie in the vicinity of the gas field areas, for example, Kushiara trough, Goyain trough in north eastern Sylhet region (Figure 3.18) and Hatia trough in the southern coast and offshore (Hiller 1988). It has been suggested that deep-seated faults have acted as convenient conduits for the gas migration (Shamsuddin et. al. 2001). The absence of gas in some of the tested anticlines is probably because of absence of a suitable conduit through which gas could otherwise have migrated up from deeply buried Oligocene Jenum shale.

In addition to the Oligocene Jenum shales, a second candidate for gas source is suggested to be the Miocene shale of Bhuban Formation (Hiller 1988, Curiale et. al. 2002). Geochemical studies suggest that most of the shale in the very thick Miocene section do not contain enough organic matter to generate hydrocarbon gas sufficiently to form a gas pool. However the lower part of Miocene, i.e the Bhuban Formation have both the required TOC (mostly with type III organic matter) and marginal thermal maturity level to be classified as marginal source rock. For example, about 40% of the Bhuban shale in Atgram 1X and Beanibazar wells have

Petroleum Generative Depression = Hydrocarbon kitchen

ANTICLINAL FOLD STRUCTURES FORMING GAS FIELDS IN SYLHET AREA

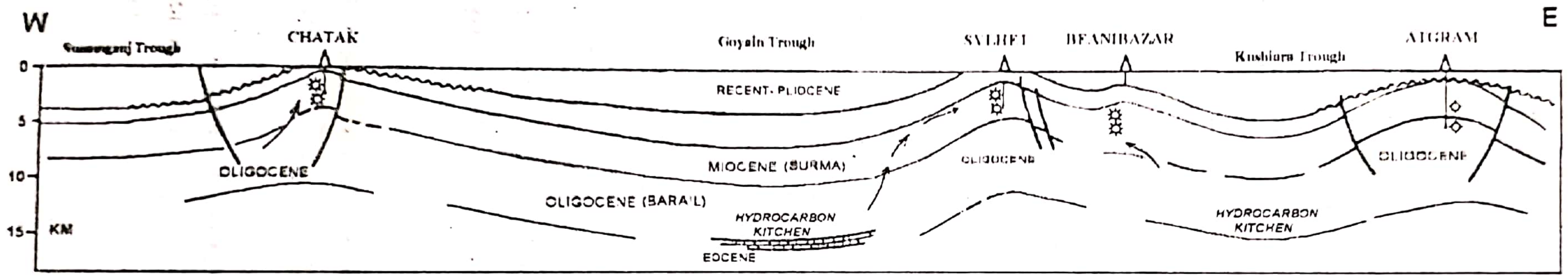


***Figure 3.17** Anticlinal folds forming gas fields in Sylhet area. Gas migration paths from Oligocene shale source to Miocene sand reservoirs also shown (adopted after Hiller and Elahi 1984).*

Douki Fault - E-W trending reverse fault inclined towards the N. (5-6 km)

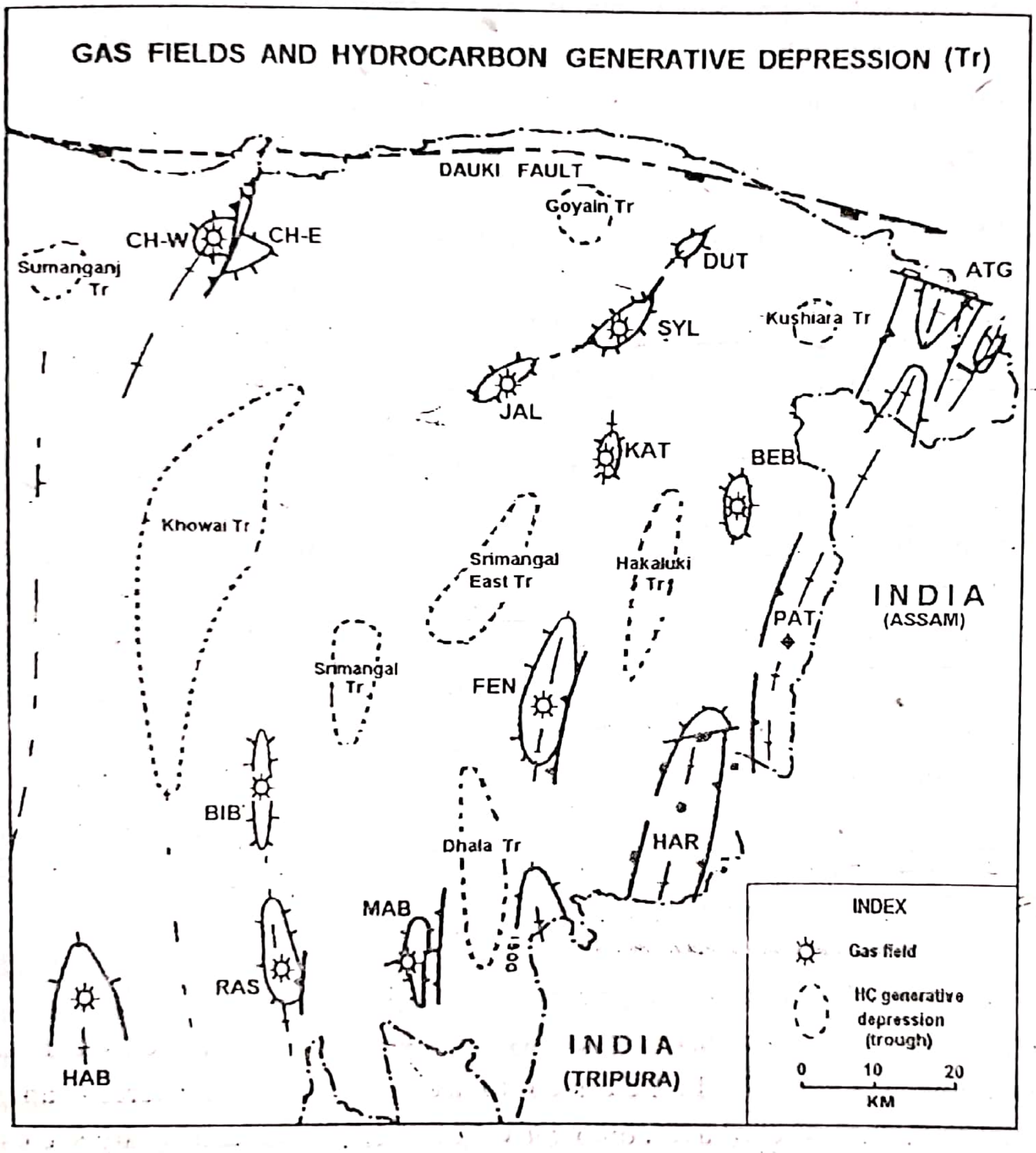


Figure 3.18 Gas fields and adjacent hydrocarbon generation troughs (Tr) or hydrocarbon kitchens in Sylhet region (after Hiller and Elahi 1984).

TOC above 0.5% (going upto 0.9%), considered as threshold value for gas generation. Curiale et. al. (2002) based on isotopic data suggests that while Oligocene Jenum shale is the source of gas in Sylhet area fields, Miocene Bhuban shale sourced the fields of southern Bangladesh.

An important aspect of the petroleum source rocks in Bangladesh is that the organic matter is predominantly terrestrial humic type, mostly type III with minor type II. Generally, the humic type organic matter (type III) has potential of generating

enough hydrocarbon gas but not enough oil. For this reason, most of the hydrocarbon found in the Bangladesh basin is gas rather than oil. A more pointed discussion on the occurrence of oil and gas as these relate to the type of organic matter is made in chapter 4.

3.5.2 The trap and seal: Where the gas is trapped

Trap refers to a kind of framework or pattern of the rock layers which bar gas from further migration and within which therefore the gas is accumulated. It may be a structural trap like a fold in the rock layer (an anticline) or a stratigraphic trap formed due to lateral change in rock type like a sand layer pinching out in clay envelop.

The gas fields of Bangladesh are housed in structural traps i.e. folded anticlines (Figure 3.17). Generally the anticlines are affected by one or more faults, either normal or thrust type. In all the cases shale layers above the sandstone reservoirs form the seal. The reason why all the gas fields are found in the eastern part of the country is that. tectonic deformations in the geologic past have created anticlinal folds in the eastern Bangladesh giving rise to many structural traps that host the gas fields. However, some of these accumulations have a degree of stratigraphic control thus making a combination trap rather than purely structural trap.

The anticlinal fold traps are generally elongated in a north south direction. The pattern of the fold structures as well as their vertical and areal closures varies considerably (Figure 3.19). In the eastern folded belts, the fold structures (traps) are commonly faulted. These have comparatively higher amplitude and larger closure, thus capable of holding larger gas reserves i.e. Titas, Rashidpur, Kailashtia for example. On the other hand, the fold structures in the foredeep area in the central Bangladesh have low to very low amplitude and small vertical closure capable of holding smaller gas reserves, i.e Kutubdia, Bengumganj, Kamta for example. In some of the gas fields the anticlinal traps have topographic expression in the form of modest hilly terrain (Sylhet, Habiganj, Semutang fields), whereas in some others the fold structures are very gentle and are concealed underground without any topographic expression at the surface (Kamta, Shahbajpur, Begumganj fields).

In some of the strongly folded anticlinal traps, a number of faults cause compartmentalization of the reservoirs thus disrupting the continuity of the latter. In

Thrust fault – is a nevense fault. dip is $<45°$

Overthrust – dip is $<15°$

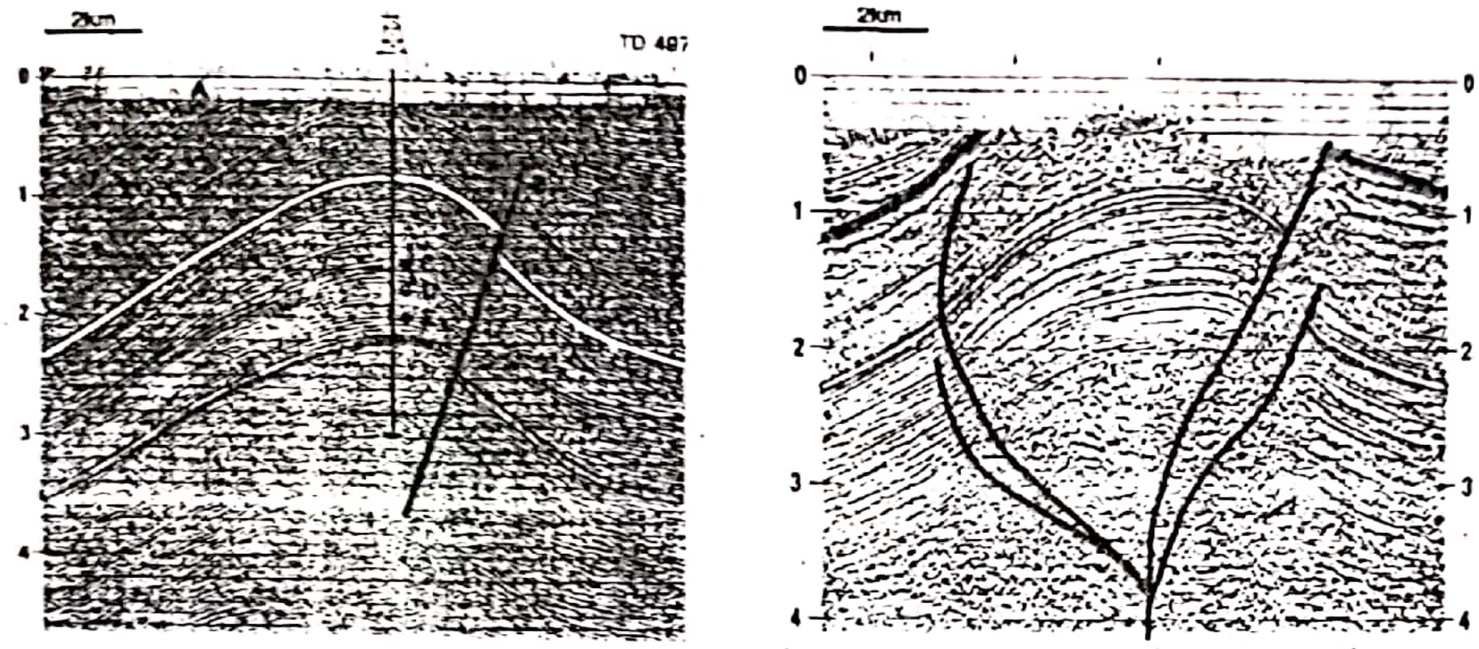


Figure.3.19 Patterns of anticlinal folds in some gas fields in Bangladesh (Source Petrobangla).

the extreme eastern part of the fold belt, the anticlinal structures are severely disrupted by major thrust faults often with diapiric intrusions in the subsurface. These structures are thus breached and their trapping capabilities are damaged or destroyed. In one of the recent studies, the USGS-Petrobangla gas assessment team has rated extreme eastern part of the Chittagong Hill Tracts very poorly for gas prospects because of the above reason (USGS-Petrobangla 2001).

A peculiarity of Bengal Basin is that, although being one of the largest delta basin in the world, it has neither developed large scale growth fault system, nor is there any salt tectonics similar to some other deltaic petroleum rich basins like Niger delta basin and the Gulf Coast basin, USA (Petrobangla 2000).

Gas field in stratigarphic trap has not yet been found in Bangladesh. However, the deltaic growth of the Bengal basin has given ample scope of formation of stratigraphic traps. These include channel sand, valley filled sand etc. and these are rather common in Bhuban and Bokabil units (Lee et al 2001). However, these type of trap are subtle and are difficult to detect in the subsurface. Also these have limited lateral extents and their size would normally be small. Two of the late exploratory wells (Kapna-1 and Ratna-1) targeted at such stratigraphic sand traps have failed to make any commercial gas discovery.

3.5.3 The reservoir rock: Where the gas is stored

Reservoir is the rock into which the gas is accumulated. Any rock that has reasonable porosity and permeability can be a reservoir rock. However sandstone and limestone are the two most common petroleum reservoir throughout the world.

The reservoir rock of all the gas fields in Bangladesh is sandstone. The sandstone belong to the Surma Group unit (Bhuban and Bokabil Formaion) of Mioccene-Pliocene age. The repetitive and monotonous alterations of sandstone and shale in the Bhuban and Bokabil Formations provide enough reservoir-seal combinations for the gas to be accumulated provided suitable traps exist. In many of the gas fields multi-layered gas sands are present. The sand reservoirs of gasfields occur at depth from less than 1000 m to more than 3000m. The reservoir sandstones are generally fine to medium grained, well sorted clean sand with little clay. These are of deltaic and shallow to marginal marine in origin.

The porosity permeability properties of the reservoirs are good to excellent. The porosity generally ranges from 15% to 20% and the permeability 100 to 400 millidarcy. In some cases, like the Habiganj gas field, porosity as high as 30% and permeability in excess of 1 darcy are encountered in the gas reservoirs - considered excellent in world standard.

Post-depositional changes due to burial of the reservoir sandstones are generally minor up to depth of about 2000m, thus preserving good poro-perm properties. Below that depth, burial cementation and compaction generally have moderate to strong affect on reservoir porosity and permeability. In some deeper reservoirs however, pressure solution, quartz and calcite cements significantly reduce poro-

perm values (Imam and Shaw 1985). Generation of secondary porosity by dissolution of rock components is commonly observed in moderately to deeply buried sand reservoirs. In some cases secondary dissolution porosity is the dominant pore types (Imam and Shaw 1987).

3.5.4 Timing of Gas migration and accumulation

The history of trap formation and gas migration from source to reservoir-trap is one of a very young geological episode in Bangladesh. The anticlinal folds that house the gas fields were formed in Pliocene time (about 2 to 5 million years ago). The migration of the gas has taken place after this event. It is suggested that the growth of traps continues to date in response to the tectonic subduction of the Indian plate. Also the migration of gas from the source rock and its accumulation in the traps continues in geological Recent epoch. A relatively low degree of trap fill in some gas fields may indicate a very young and incomplete gas accumulation process (Hiller and Elahi 1984).

Natural gas in Bangladesh is mostly supposed to have long distance migration. It has been suggested that the gas migrated as much as 4000 meter upwards from source rock to accumulate in the reservoir rocks above (Petrobangla 2000). Once accumulated, the gas is barred from further migration until a well is drilled to the gas pool and the gas is produced.

3.6 Petroleum geological provinces in Bangladesh

The tectonic character, sedimentary environment and evolution of different parts of the Bengal Basin have variously controlled the source rock, reservoir rock, trap and seal developments in the respective areas. Accordingly, Bangladesh may be divided into three main hydrocarbon-geological provinces (Imam and Mahbub 2002; Shamsuddin and Abdullah 1991). These include: i) The fold belt in the east ii) The foredeep in the center and iii) The Stable Shelf and Hinge Zone in the west-northwest (Figure 3.20). The provinces are discussed in terms of petroleum geology (petroleum system) and their petroleum prospects.

- Teclonic Chanacten
- Sedimentary Envirionment
- Evolution of diflenent parts of the bengal basin

} controlled → { Source Rock, Reservoir Rock, Trap & Seal developments in the respective areas

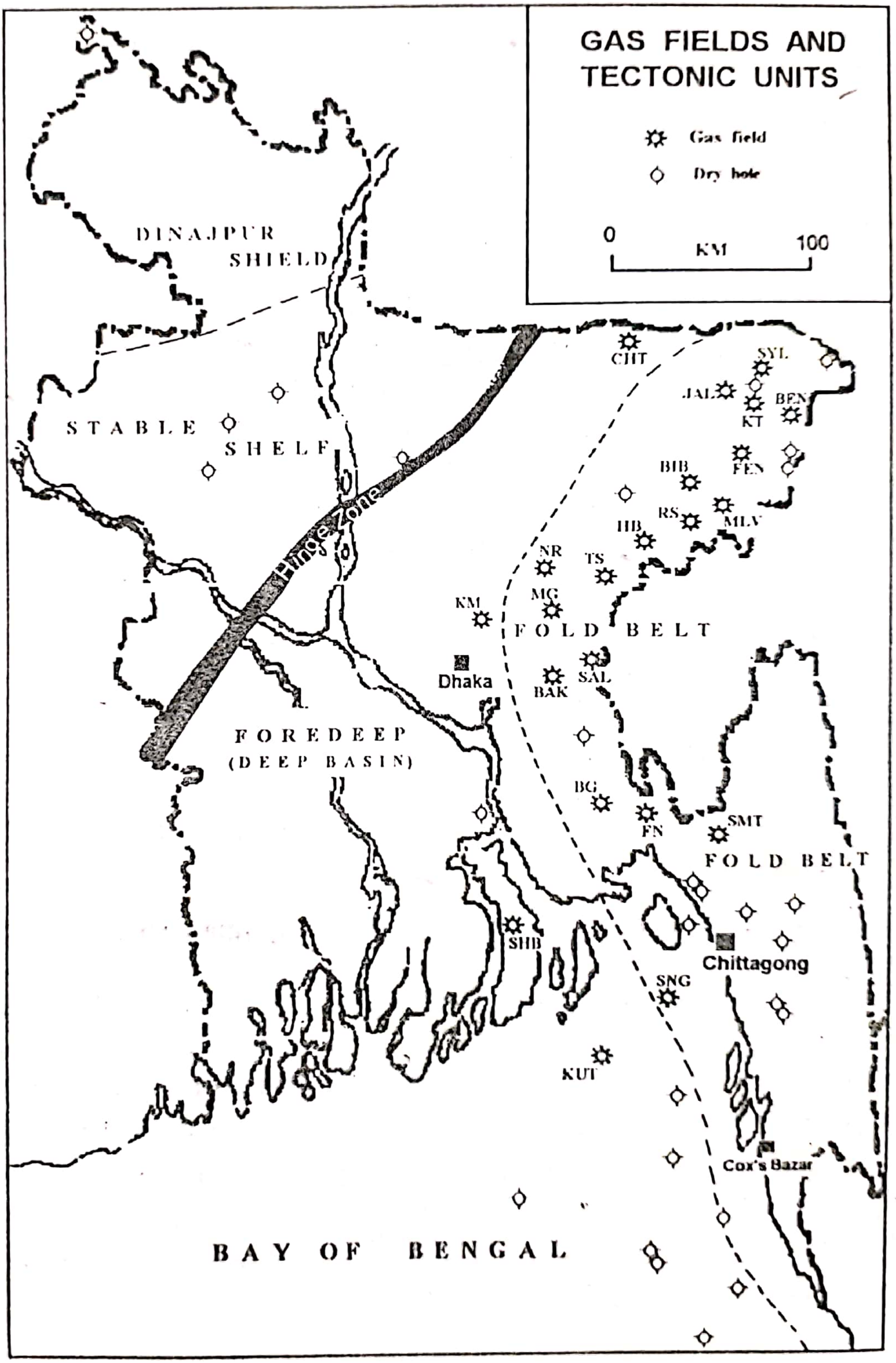


Figure 3.20 Gas fields and tectonic units in Bangladesh

3.6.1 Eastern fold belt –The gas rich province

The eastern fold belt is the most prolific natural gas province and has been the center of exploration activities in Bangladesh. Out of the total of 25 gas fields discovered so far in the country, 22 are located in this province.

The province extends north to south along the eastern part of the country and includes Sylhet, Comilla, Chittagong and Cox's Bazar area with the adjacent offshore Bay of Bengal (Figure 3.20). The sedimentary sequence in the fold belt measures up to about 20 km in Sylhet area and is mostly Tertiary in age (Hiller and Elahi 1984). The fold belt is characterized by series of meridional to submeridional folds which extends into the Indian territory of Assam, Tripura and Mizoram to the east. Also known as frontal fold belt, this province represents the western and outermost part of the Indoburman orogen. The fold belt shows sign of diminishing intensity of structures towards the west in which direction it gradually fade away and merge with the central foredeep province. Its boundary with the foredeep is therefore gradational. indistinct and arbitrary.

The source- reservoir-trap-seal components in the eastern fold belt geological province have been described in section 3.5.1 and 3.5.2. These have formed the most active known petroleum system in Bangladesh called Jenum-Bhuban-Bokabil petroleum system. The source of the natural gas in the system is Jenum shale, the reservoirs are Bhuban and Bokabil sand and the traps are anticlinal fold. A less prominent, petroleum system, also recognized in this province is the Bhuban-Bokabil petroleum system in which Bhuban (lower part) is the source rock while the reservoirs are both Bhuban and Bokabil sands with anticlinal folds as traps. Generally speaking Miocene shale have low TOC content and are thermally immature to marginally mature in the drilled sections, but Miocene shale in the lower Bhuban Formation have the required TOC and thermal maturity (when within generative depression) to generate gas (see section 3.5.1).

Reservoir rocks of the province are all sandstone of Miocene Bhuban and Bokabil Formation. These have good to excellent reservoir quality and have been described in detail in section 3.5.3.

The traps of the fold belts are formed by the anticlinal folds with shale seal. The anticlinal folds provide excellent traps for gas accumulation rendering the fold belt a rich natural gas province. The anticlines in the fold belt range from simple gentle and concealed undulation in the subsurface in the western part of the fold belt to high amplitude strongly faulted ones with highly rugged surface topography towards east. Accordingly, the fold belt is divided into i) an western zone of moderately folded anticlines, ii) a middle zone of high amplitude faulted anticlines and iii) an easternmost zone of extremely folded anticlines (USGS-Petrobangla 2001).

i) The western moderately folded zone consists of low to moderate amplitude simple anticlinal structures. This is the most prolific hydrocarbon zone in Bangladesh with the largest and most important gas fields like Titas, Kailashtila, Bibiyana, Rashidpur and Bakhrabad. The structures are not very strongly affected by major faults and show simple four way closures. The intensity of deformation and folding in the zone gradually decreases to the west which eventually merges with the foredeep. In fact the westernmost anticlines bordering the foredeep lack surface expression.

ii) The middle high amplitude faulted fold zone is characterized by high amplitude faulted anticlines like Patya, Sitapahar, Semutang etc (Figure 3.21). The NW-SE trending elongated anticlines are areally narrow compared to adjacent synclines meaning these are separated by wide synclines. Some of the anticlines have shale diapirs in the cores thus making them more complicated in the subsurface (Hiller 1988, Sikder et al 1994). A limited number of exploration wells (Patya, Jaldi Sitapahar) have been drilled in this zone with one discovery in Semutang structure. In addition to the surface anticlines, a second set of anticlines is often reported underneath the wider synclinal valleys (stream valleys) in this zone (Murphy 1988), thus raising the prospect of hydrocarbon accumulation in the broad synclinal areas as well.

iii) The eastern extremely fold zone is characterized by high relief, tighter folds with thrust faults as expressed in the surface by rugged topography. The lengths of the individual folds range up to 150 km. The high topographic hill ranges corresponds to high amplitude anticline like Kasalong, Barkal, and further to the east Uttanchatra along the border with Mizoram India (Figure 3.21). The intensity of

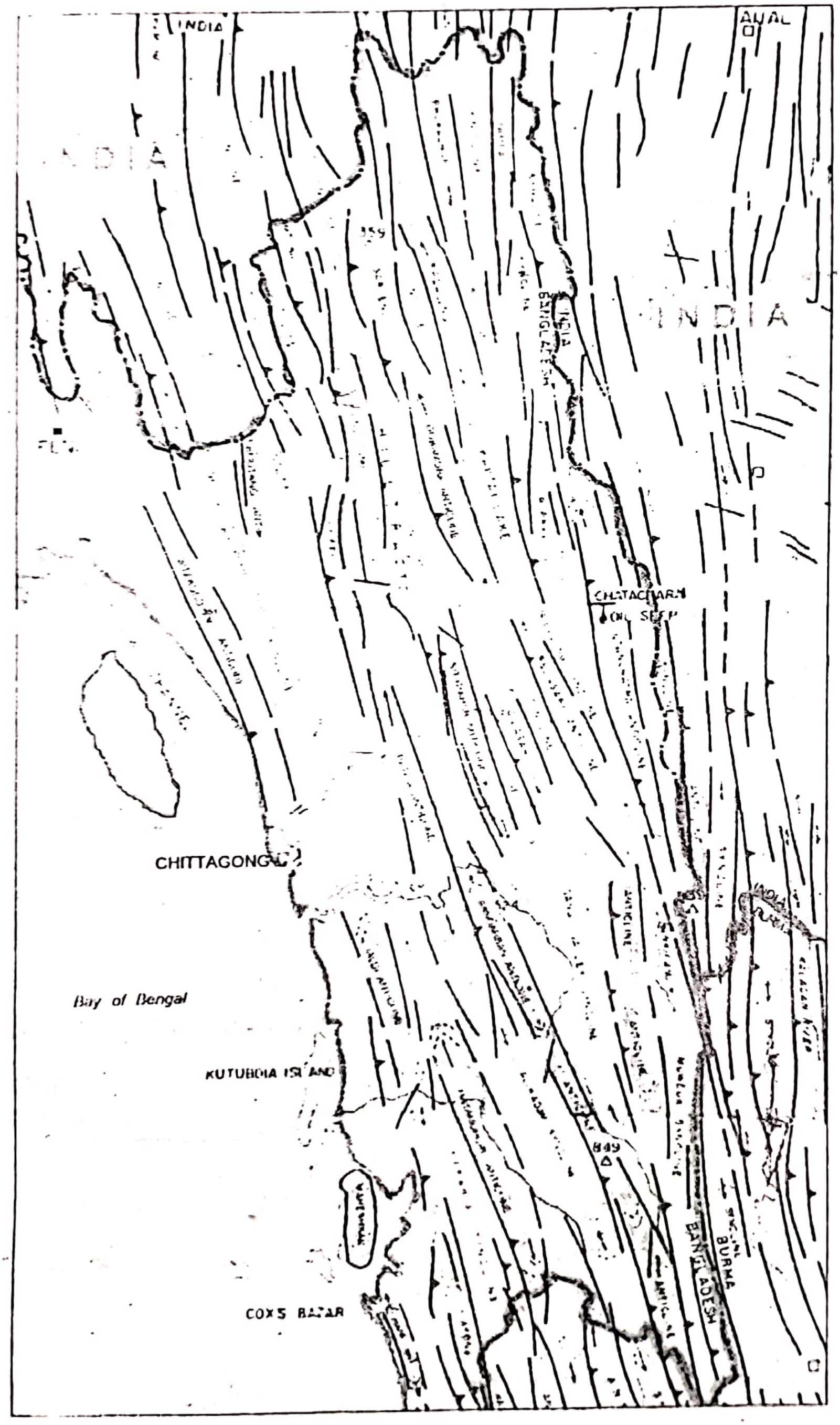


Figure 3.21 Folded anticlines (shaded) and synclines in Chittagong and Chittagong Hill Tracts (Source: Sikder et al 1994).

faulting generally increases towards east. Remote sensing data of the Tripura-Cachar area, eastern India, suggest internal complexities in some individual structures in the forms of cross faults and oblique faults dividing the folds into separate blocks (Ganguly 1983).

Many of these anticlines in the eastern zone have been intruded by clay diapers in their cores associated with overpressured shale in the deeper subsurface. Because of the intense folding and faulting, the source rock and reservoir rocks are exposed at the surface and the anticlines are breached by erosion (USGS-Petrobangla 2001). Because the major structures have been breached by erosion, likely exploration targets would be along the noses of major plunging anticlines where the structures descend into the subsurface.

3.6.2 Central foredeep – Modest prospect

The central foredeep (also called Bengal foredeep) province is occupied by the large Ganges Brahmaputra delta plain in the central part of Bengal Basin and the Bay of Bengal to the south (Figure 3.20). It is a geosynclinal depression in between the hinge zone to the west and fold belt to the east. The boundary between the fold belt and foredeep is transitional rather than sharp as the fold belt of the east gradually merges westward into the foredeep.

Reimann (1993) arbitrariry set the boundary between the fold belt and the foredeep by a line drawn from the western shore of St.Martin's Island in NNW direction to the western shore of Sandwip island and continuing onshore as far as Daudkandi and then following the Meghna river upward turning in Ashuganj area to northeast and finally ends at foothills of Shillong Hills. The foredeep is an active basin and contain a maximum of over 20 kilometer of sediment beneath the continental shelf off the Hatia coastal area (Curray 1991). The width of the foredeep province range from 200 km in the north to 500 km to the south in the Bay of Bengal (down to water depth of < 200m). Foredeep has experienced much less tectonic folding compared to fold belt and these folds are gentle to subtle and subdued in nature occurring in the subsurface without surface expression.

Although less intensely explored, this area has attracted attention of petroleum explorers at different time. In fact, this is the second most important petroleum

province in the country containing four gas fields namely Kamta, Narsinghdi, Shahbazpur and Kutubdia.

The source rock of the gas in the foredeep petroleum province is yet to be identified and demonstrated. The Neogene sediments in the foredeep are generally poor in organic content and are immature to marginally mature at drilled depth. Results of the analysis of the shale samples from the Muladi-1 well show TOC in the range of 0.24% to 0.50% down to the last core from depth of 4532m. (Upper Miocene at T.D - Bhuban Formation) and thermal maturity 0.65% Ro at 4532 m. However equivalent rocks in some other wells including offshore has showm TOC in the range of 0.6% to 1.0% and these are likely to reach thermal maturity in the adjacent petroleum generative depression like Hatiya trough. Bhuban shale has therefore been suggested as the likely source of the gas in the foredeep gas fields. A petroleum system referred to as Bhuban-Bokabil petroleum system is suggested to have been active in the southern Bengal delta basin area (Curielle et al 2002).

Oligocene sediments in the foredeep area is buried deeper and was not penetrated in any well. The source potentials of these sediments therefore remain unknown. The occurrence of overpressured zone at depths ranging from 3500 to 4500 did not permit drilling very deep into the basin. Investigation of the exact nature of the basin wide overpressure zone may provide clues to the hydrocarbon source as well as possible reserves within. The high rate of sedimentation and a predominant shale lithology has resulted in compaction disequillibrium and consequent basin wide overpressuring at certain critical depths in the deep basin area. Overpressure remains an important factor in petroleum investigation particularly petroleum drilling in Bangladesh (Box 3.2).

The foredeep is characterized by minor tectonic deformation and this resulted in lack of high relief structures like those of fold belt. Only very gentle, low relief subsurface structures with limited deformation and narrow closures are found by seismic mapping. Traps of the foredeep area are mostly anticlinal folds, though much gentler and subdued compared to those of the fold belts. For example Kamta gas field is housed into an anticline whose flank dips only a few degrees on both sides. However, in the southern delta and offshore areas, large gentle structures are revealed recently by comprehensive seismic studies in areas previously covered by

Box 3.2 Overpressure and Natural gas

The rock layers in the subsurface have their pores filled with fluids, generally water. With increasing burial depth, fluid pressure (hydrostatic pressure) increases in a normal gradient. However in certain cases, pressure, higher than normal hydrostatic pressure is generated. This is known as overpressure. In other word, fluid pressure in the subsurface rock layers which exceed the hydrostatic pressure is called overpressure.

Overpressure may be caused by a number of mechanisms whereby stresses are built up to increase fluid pressure (Hunt 1996). These include: i) compaction disequillibrium due to rapid loading, ii) thermal expansion of fluid, iii) compression by tectonic force, iv) clay dehydration during burial diagenesis and v) occurrence of gas pool in shallow depth.

One of the widely accepted mechanism for generation of overpressure is compaction disequillibrium caused by rapid loading of fine grained sediments. If thick shale sequence, for example, are deposited rapidly, the water within the sediment would not have enough time to migrate out normally before being partly trapped inside and causing stress. Compaction will not reach equilibrium and sediments will remain undercompacted. This will lead to overpressure. The primary cause of overpressures found in many deltaic sequences around the world including Niger delta basin, US Gulf coast basin, Mahakam delta basin, McKenzie river delta, Nile delta is believed to be compaction disequillibrium. Other mechanisms are mentioned in various sedimentary basins as major or supplementary cause of overpressure.

In the Bengal basin, Bangladesh, many wells encountered overpressure in the subsurface in the geosynclinal part of the basin. The depth to top of overpressure in the wells ranges from 460 meter (Pathria-5 well), to 4500 meter (BODC-2). The table below lists well names and depths to top overpressure in several wells in Bangladesh. The occurrence of overpressure is related to the thick shale sequence in the Miocene Bhuban Formation. Consequently, the top of overpressure is encountered at shallower depth in the fold belt in relation to those in the foredeep area where Bhuban shale occur at greater depth. Overpressure occurs as a basin wide feature over the foredeep and fold belt areas. Almost all of the wells encountering overpressure had to terminate the drilling near the top overpressure zone because of the potential drilling hazard including blow out. Wells drilled in the stable platform of the Bengal basin have not encountered any overpressure.

On the basis of comparison of the sedimentation history of the thick Tertiary deltaic sequence of Bangladesh with those of other parts of the world, it appears that the most likely cause of overpressure in Bengal Basin is compaction disequillibrium. However, generation of hydrocarbon gas in deep subsurface sediments may also cause overpressure. Imam and Shaw (1985) and Imam (1987) have shown evidence of illitization and smectite clay dehydration in Neogene sequence from clay mineral studies of shale samples from drilled wells. Clay dehydration and dewatering may also contribute to the generation of overpressure in Bangladesh.

Overpressure zone in the subsurface Bangladesh have attracted the attention of geoscientist for several reasons:

i) Overpressure zone is a potential hazard for petroleum exploration drillers. Accidental blow out of rig during drilling into overpressure are reported many time in the world. Such hazards are especially great in drilling exploratory well. Proper understanding of the depth and nature of overpressure is very important to run a safe petroleum exploration drilling.

ii) The Oligocene sediments, one of the prime hydrocarbon play target lies beneath the overpressured Neogene section in the deep basin. Because of technological difficulties of penetrating the overpressure zone, wells are terminated near the top of overpressure and thus Oligocene could not be tested. Recently, interest to drill deep wells through the overpressure are shown by multinational oil companies and this can unfold the hydrocarbon prospect of Oligocene in Bangladesh.

iii) Hydrocarbon reserve within the overpressure zone are discovered in some basins of the world and these tend to contain large reserve because of high pressure under which the hydrocarbon (specially gas) exist. Only a very few wells have been tested for its hydrocarbon potentials within the overpressure zone in Bangladesh. Shell Oil Company drilled two wells (onshore Halda-1 drilled in 1997 and offshore South Sangu drilled in 2000) through several hundred meters into the overpressure zones and carried out test for hydrocarbon. These test did not lead to any commercial discovery. However, overpressure zone may remain a prime target of petroleum explorer, considering the widespread occurrence of overpressure in the subsurface in Bangladesh.

Name of well	Year of drilling	Depth to top overpressure (m)
Patiya-1	1952	2575
Sylhet-2	1956	2700
Chattak-1	1959	1980
Lalmai-2	1960	4052
Rashidpur-2	1960	4120
Kailashtila-1	1961	3560
Titas-1	1962	3650
Semutang-1	1967	3200
Muladi-1	1975	4500
Begumganj-1	1976	3300
Beanibazar-1	1981	4016
Sitakund-1	1983	1620
Fenchyganj-2	1985	3124
Sitapahar-1	1983	1110
Patharia-5	1999	460

iv) The theory of 'episodic breaking and sealing' of overpressure zone suggests that hydrocarbon generation within the overpressured zone and thermal expansion of pore fluids causes fracturing of top seal of the overpressure compartment (Hunt 1996). This allows the oil and gas to move cross stratally into the overlying lower pressured rocks and accumulate in nearest structural and stratigraphic traps. Eventually the compartment reseal and pressure build up towards another breakout. This process continues episodically with resealing and breakout cycles occurring in geologically short period of time in rapidly sinking basin.

The above theory suggests that overpressure zone may not only host large hydrocarbon accumulation within itself, but it provides mechanism of generation and migration of gas in the normal pressured sediment lying above it. The Bengal Basin is a rapidly sinking young Tertiary deltaic basin which fits well into a scenario whereby the above process may have taken place.

only sparse seismic lines. It has been suggested that there are others of these kinds remaining to be delineated in the area (Petrobangla 2000).

An important difference between other major delta basins and the Bengal delta basin is the lack of well developed down to the basin growth fault system and associated roll over anticlines in the latter (Lohmann 1995, Lindsay et al 1991. Petrobangla 2000). Major Tertiary delta basins like Mississippi delta and Niger delta have developed prolific hydrocarbon traps associated with these types of syn-sedimentary faults and roll-over anticlines, but why this has not been the case in Bengal Basin is uncertain. Lohman (1995) pointed out seismic evidence of only a few listric faults in north central Bangladesh and questioned why there are so few and only in a restricted area. Roybarman (1983) stated that there are indications of few growth fault related features in the deltaic Miocene-Pliocene sediments in West Bengal part (India) of the deep basin, and observed that these are not common as in other deltaic basin elsewhere. Mukherjee and Neogi (1993) suggested sand bodies associated with low amplitude growth fault and associated with sag rollover structure in Roghunath-1 prospect in West Bengal.

Apart from structural traps there are suggestions that the foredeep have good prospects of having stratigraphic traps. Among common prospects of stratigarphic plays in this zone are the channel sands and valley fill sands as seen in seismic sections. The channels and incised valleys form closures to traps when shale filled and hydrocarbon reservoirs when sand filled (Lee et.al 2001).

Seismic dip lines indicate series of clastic wedges of sand and shale interbeds in Oligocene to Pliocene sequences; these wedges migrates bansinwards and stratigraphically upward and may have sutle stratigraphic plays (Lindsay et al 1991, Salt et al, 1986). Stratigraphically controlled hydrocarbon fairways are likely to be found in areas where delta front sand wedges updip against delta plain clays (Roybarman 1983). However, these kind of stratigraphic traps are frequently subtle and their sizes are likely to be small.

Reservoirs of the gas fields in the foredeep are Miocene-Pliocene sandstones. Reservoir sands are abundant with common occurrence of repetitive sand-shale interbeds forming reservoir-seal couplet in the Bhuban and Bokabil Formations.

These are good to excellent quality reservoirs similar to the fold belt gas reservoirs. The reservoirs are fine to medium grained sands, texturally mature with little clays. Generally, the reservoir porosity and permeability are good to very good at the depth levels of hydrocarbon occurrence. Sands are poorly to moderately compacted up to a depth of about 2000m. Deeper reservoir sands are cemented by quartz and calcite cements. However, their influence on the reservoir properties is not pervasive except for rare occasions. Furthermore, there is significant evidence of development of secondary dissolution porosity in the deeper reservoirs as seen in the Titas and Fenchuganj gas field reservoirs (Imam and Shaw 1987). The sandstone reservoirs were originated in deltaic to shallow marine depositional condition.

3.6.3 Stable shelf and hinge zone –Unproved prospects

The western platform flank of the Bengal Basin is occupied by two major tectonic elements. i) the Stable shelf (also known as Bogra shelf) and ii) the Hinge zone (Figure 3.20). The Bogra shelf is bounded in the southeast by the Hinge zone which separates it from the Bengal foredeep. In the northwest, the Bogra shelf is bounded by Rangpur saddle also referred to as Dinajpur shield (Khan 1991). There has been no commercial hydrocarbon discovery in the area yet, although some wells drilled here recorded oil and gas shows. Five wells, Kuchma-1, Bogra-1, Bogra-2, Singra-1 and Hazipur-1 were drilled in the area.

The Bogra stable shelf, a gently dipping epirogenic platform, is 60 km to about 130 km wide and covers an area of 25,000 square kilometers within Bangladesh territory (Hiller 1988, Reimann 1993). It extends southwest into the Indian state of West Bengal. The Bogra shelf is characterized by Permian to Recent sedimentary cover of limited thickness increasing from about 2 km in the northwest up to 6 km in the southeast near the Hinge zone. Permian age Gondwana strata are preserved in the faulted graben basin in the Bogra shelf. These are overlain by Cretaceous to Eocene rocks and younger Tertiary clastics representing successive periods of deltaic progradation (Salt et al. 1986). The regional gentle trend of the shelf is marked by 1 to 3 degree southeasterly dip of the Sylhet Limestone Formation, a widely developed and consistent unit seen in seismic section. The stable shelf lacks tectonic deformation.

The Hinge zone or the Eocene Hinge zone as it is also called marks the Eocene shelf edge and continental slope (Reimann 1993). It is a 25 km wide NE-SW trending zone and reflects the structural and depositional transition from stable shelf to foredeep basin to the east. It is marked by sudden increase of dip from 3 degree to more than 15 degree in the Sylhet limestone strata. Also the Sylhet limestone grades onto a shaly facies as it is seismically traced across the hinge into foredeep basin (Sengupta, 1966; Reimann, 1993). The Hinge zone has no surface expression and is covered by Bengal alluvial plain.

Limited tectonic deformation and lack of anticlinal structures characterize the shelf-hinge area. This is the reason of apparently less interest of petroleum explorer in the area. However, this area has potential fault plays and stratigraphic plays as suggested by seismic interpretation and geologic modeling. Identification of prospects in the area depends on high-resolution seismic and multi-disciplinary approach to exploration. The petroleum prospect of this area may depend on the identification of stratigraphic traps and occurrence of suitable source reservoir parameters. Following is a geologic overview of such plays and possibilities in the stable shelf area.

3.6.3.1 Eocene reef and carbonate build up plays: The most important prospect in the area is likely to be associated with the Eocene Sylhet Limestone Formation, as carbonate build up and reef plays. Developed over the entire shelf and 190m to 240m thick in drilled sections, the Sylhet limestone unit thickens near the shelf edge.

The shelf edge is a favorable locale for carbonate reef development as shown by numerous examples elsewhere in the world. Favorable site for reservoir quality reefal growth presumably existed towards the east of the Eocene shelf-slope break (hinge zone). However, 30 exploratory wells penetrating the limestone section in different parts of the basin fail to encounter a single reefoidal body in West Bengal (Dey et al. 1998). Deep drilling (5800 meter) in Golf green well in West Bengal also found non reservoir type lagoonal carbonate, but no reef body. However, from seismic interpretation, Shrivastava and Mathur (1985) reported the presence of reef complex within the Sylhet Limestone facies in Eocene shelf margin beneath the Bay of Bengal in the Indian territory of West Bengal. Possible reef complex along the Eocene shelf edge has also been described in the onshore drilled area of West Bengal (Royburman

1983). Similar reef complex may possibly be identified in seismic section in the northeastern extension of the shelf-hinge boundary within Bangladesh territory.

Drilled sections of Eocene Sylhet Limestone are reported to be composed of biomicrite, packestone and wackestone (Moor and Leyenburger 1992). Presence of abundant forams (Nummulites and Discocycline) in this possibly quieter lagoonal or back barrier facies indicates the possibility of presence of carbonate grainstones in basinward high energy shoaling environment (Figure 3.22). Such coarser facies are likely to have reservoir properties as porosity may be preserved as primary or may have been developed as secondary during the sub aerial exposure of Sylhet Limestone during lowstand.

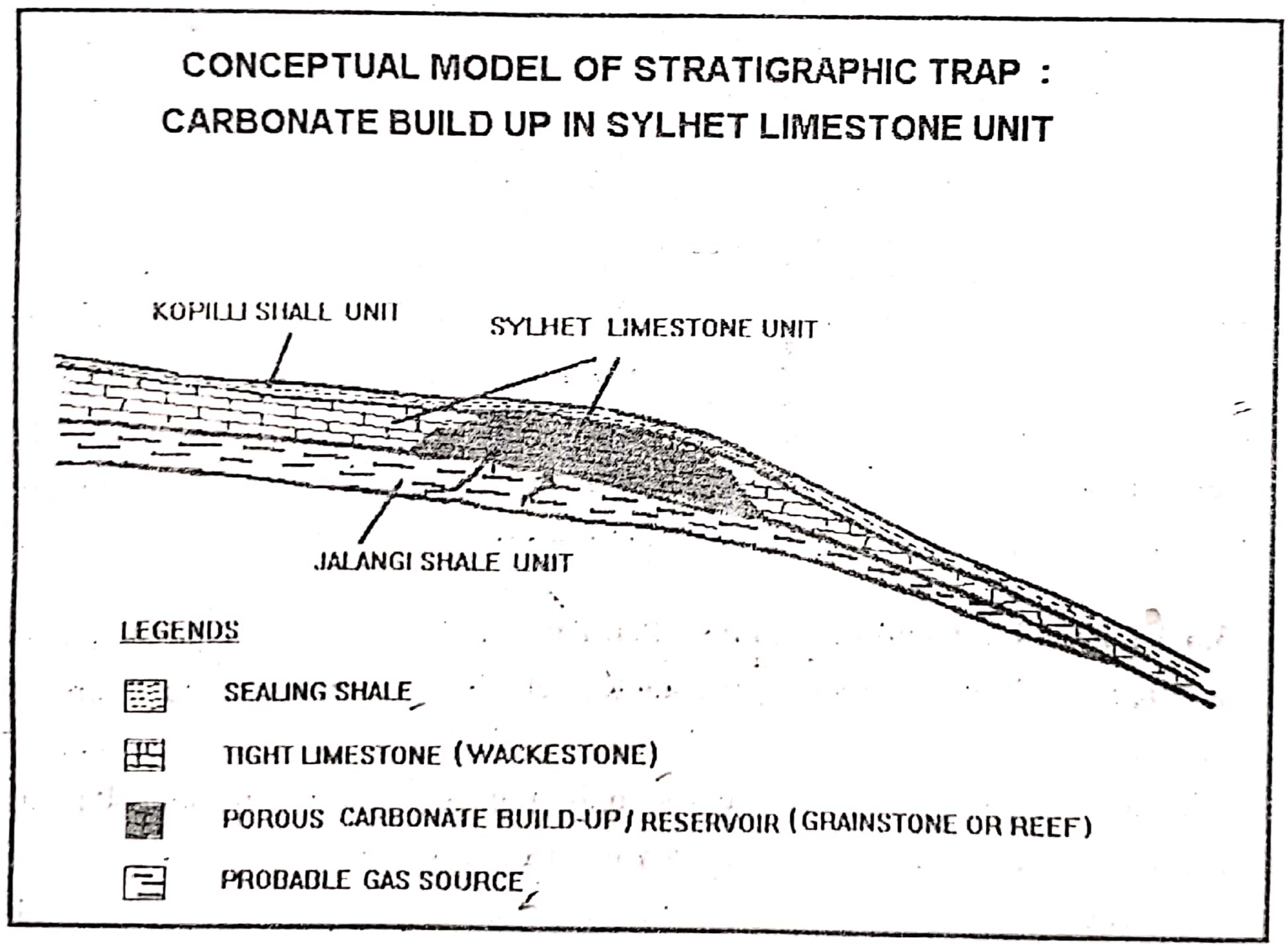


Figure 3.22 Conceptual model of stratigraphic trap in carbonate rock (Sylhet Limestone unit) in Bangladesh (Source: Moore and Leyenburger 1992).

What could be the possible source rock for any hydrocarbon system in this area? There are two possible source rocks i.e. i) Jalangi Shale and ii) Upper Eocene Kopili Shale. In the case that the reef complex or carbonate shoal forms the potential stratigarphic trap, there is a chance that such features may lie in the hydrocarbon migration pathway from the underlying Paleocene-Eocene shale known as Jalangi Shale (Moore and Layerburgen 1992). The Shale has average TOC content of 4.7% with some TOC in excess of 6%. Although the Jalangi Shale in the drilled section is immature, it is supposed to be within the oil window immediately beneath and basin ward of Eocene Hinge zone. Any hydrocarbons generated from the Jalangi Shale may have moved up dip beneath Sylhet Limestone towards basin margin where reservoir quality reef and carbonate shoals, if existed, may possibly have trapped it.

The Upper Eocene Kopili Shale overlying the Sylhet Limestone marks the transitional standstill period prior to regression of the sea from the area. The Kopili Shale have average TOC of 1% but immature in the shelf area. However, in the deepest part of the shelf-hinge boundary the shale may be within the oil window and may have generated hydrocarbon. This then may feed the post Eocene stratigraphic plays likely to be present in the overlying Oligo-Miocene deltaic wedges or even the pre-Kopili, Sylhet Limestone reservoirs, should the latter be juxtaposed against the former in fault related displacements in the subsurface. Kopili Shale, however, forms a regional seal all over the shelf area. Shamsuddin et al (2001) describe a hypothetical/unknown Cherra-Kopili-Sylhet Limestone petroleum system in the area.

3.6.3.2 Permian Gondwana plays: Permian coal bearing Gondwana sediments are reported in half graben basins in the stable shelf. The Gondwana sediments are up to 1200m thick (Kuchma well) and consist of fluvial sandstones, siltstones, subordinate shale and many coal seams. Individual coal seams are upto 45m in thickness and reached the stage of maturity of medium volatile bituminous coal with vitrinite reflectance 1.2% to 1.5% indicating their gas generating source rock potential (Reimann 1993). However, Islam and Eickhoff (2001) indicated that hydrocarbon generated in the Singra-Kuchma area escaped in Pre-Cretaceous time and could not have been trapped in post-Cretaceous sediments. They have suggested that in Pabna-Kushtia area, a second phase of methane generation had taken place in Miocene and therefore some gas may have been trapped there.

Although the Gondwana coal represents good coal source rock potentialities, the absence of suitable structure, and also reservoir quality rock in the immediate vicinity downgraded the Gondwana plays. Normal faulted structures may be present as trap and feldspar-rich arkosic sandstones can form potential reservoir only if subjected to dissolution (acidic water flushing!). The extensively developed Rajmahal volcanic of Late Jurassic-Early Cretaceous age is an effective seal that separates the Gondwana sediments from the younger Cretaceous-Tertiary sediments above (Reimann 1993).

The prospect of non-traditional hydrocarbon gas, coal bed methane (CBM), in one of the coal basins (Jamalganj) has been rated well. This would hold smaller reserve compared to the conventional gas fields in Bangladesh, but may open up a new frontier in the exploitation of hydrocarbon gas in Bangladesh. This is discussed in more detail in chapter 5 (see section 5.2.6).

3.6.3.3 No success yet in stable shelf or hinge zone: In spite of the prospects of source-trap-reservoir of gas in the stable shelf and hinge zone area as discussed above, the fact to date (end 2012) remains that the stable shelf and the hinge zone are yet to see any commercial hydrocarbon discovery. In other word the exploration well to success ratio in the area is zero. (not have in 2021)

The stable shelf may be divided into two parts: an upper stable shelf – updip (northwest) of the Bogra-fault system and a lower stable shelf – down dip (southeast) of Bogra fault system. The upper stable shelf has a sedimentary thickness of 2 n 2.5 km and has average temperature gradient of 3C/100m and is therefore considered non-prospective for hydrocarbon (Hiller 1988). The lower stable shelf has a sediment thickness up to 6 to 7 km close to the hinge zone and is considered prospective for hydrocarbon.

There has been very limited drillings carried out in the Bangladesh part of the stable shelf and Hinge zone. Therefore it may be premature to comment of the true potential of specially the lower stable shelf and hinge zone in Bangladesh. However, these two tectonic units extends westward into the West Bengal, India where extensive exploratory drilling were carried out but failed so far to discover a single commercial oil or gas field. In West Bengal, India, about 50 exploratory wells were drilled to date without any commercial success, although numerous gas shows and

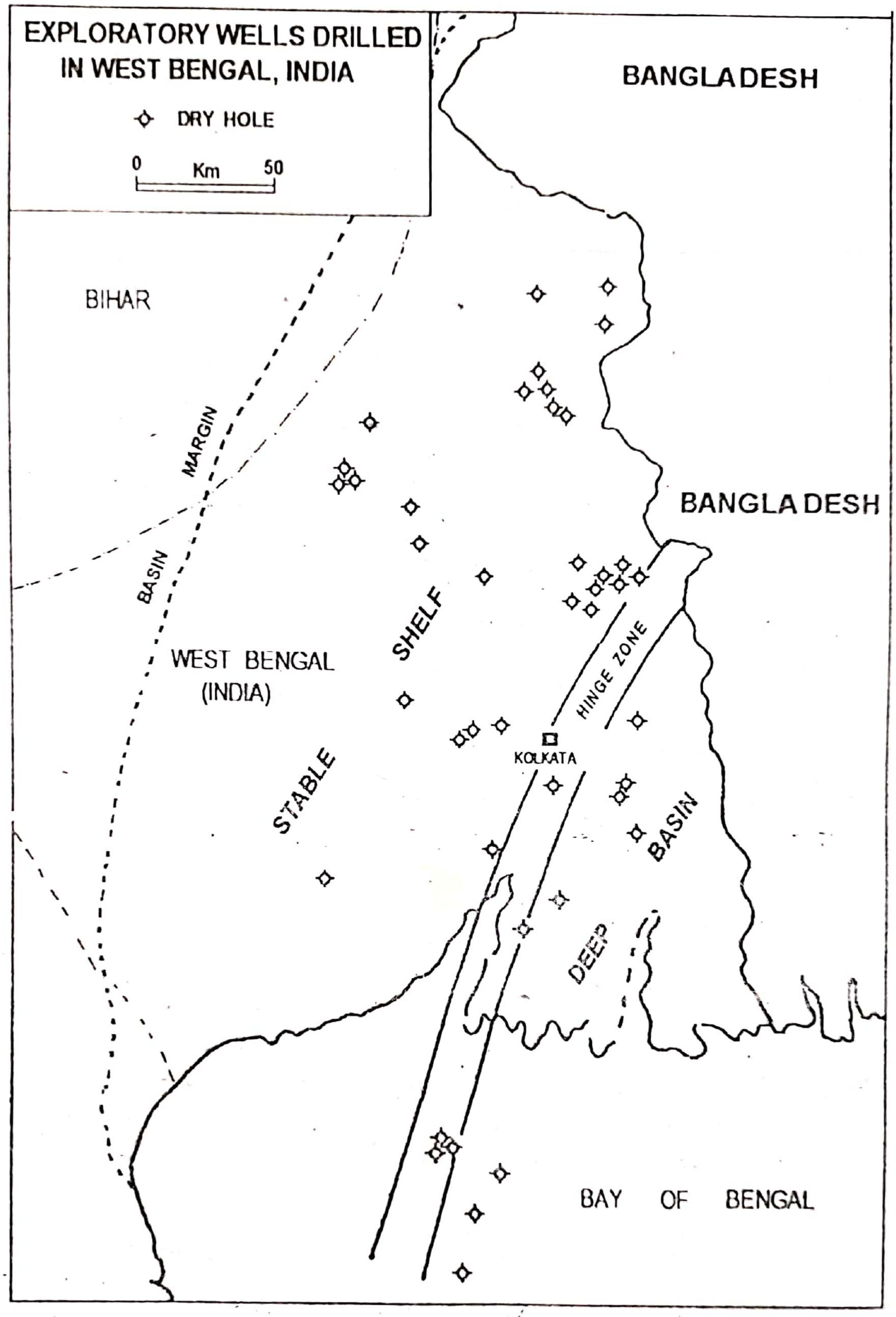


Figure 3.23 Exploratory wells drilled in West Bengal, India. All are dry hole.

one non-commercial oil flow in a well were recorded (Mukherjee and Neogi 1993). Figure 3.23 shows the locations of the exploratory wells drilled in West Bengal and Table 3.14 list these exploratory wells with relevant information.

Table 3.14 Status of exploratory wells drilled in West Bengal, India (Source: Mukherjee and Neogi 1993).

Serial no.	Well name	Operator	Year	Total depth (m)	Status
1	Bakultala-1	ONGC	1976	3700	Dry hole
2	Bishupur-1	ONGC	1982	3006	Dry hole
3	Ranaghat-1	ISPP	1956	3965	Dry hole
4	W.Ranaghat-2	ISPP	1960	2604	Dry hole
5	W.Ranaghat-3	ONGC	1988	3010	Dry hole
6	Raghanath-2	ONGC	1989	5339	Dry hole
7	Bodra-1	ONGC	1966	4197	Dry hole
8	Bodra-2	ONGC	1987	4950	Dry hole
9	P.Caming-1	ISPP	1960	4042	Dry hole
10	SMMI	ONGC	1988	4051	Dry hole
11	SMM-2	ONGC	1988	4975	Dry hole
12	BB-B-1	C&N	1976	4975	Dry hole
13	BB-A-1R	C&N	1976	4073	Dry hole
14	Deganga-1	ONGC	1987	5007	Dry hole
15	SME-4	ONGC	1989	5575	Dry hole
16	SME-1	ONGC	1987	5079	Dry hole
17	D Harbour-1	ONGC	1981	5555	Dry hole
18	Domjur-1	ONGC	1988	5189	Dry hole
19	Jaguli-1	ONGC	1983	5637	Dry hole
20	Maju-1	ONGC	1984	4020	Dry hole
21	Maju-2	ONGC	1985	4009	Dry hole
22	Radna-1	ONGC	1981	3506	Dry hole
23	SME-5	ONGC	1989	5841	Dry hole
24	Memari-1	ISPP	1956	3807	Dry hole
25	Burwan-1	ISPP	1958	2720	Dry hole
26	Bolpur	ISPP	1958	1524	Dry hole
27	Ghatal-1	ISPP	1960	3109	Dry hole
28	Abhay-1	ONGC	1982	2900	Dry hole
29	Dhnnanjaypur-1	ONGC	1985	5204	Dry hole
30	Galsi-1	ONGC	1977	1238	Dry hole
31	Naidaha-1	ONGC	1983	3506	Dry hoe
32	Jalangi-1	ISPP	1958	3576	Dry hole
33	Debagram-1	ISSP	1956	3106	Dry hole
34	Chandkuri-1	ONGC	1989	3862	Dry hole
35	Galsi-1	ISPP	1958	1296	Dry hole
36	Galsi-3	ONGC	1978	2484	Dry hole
37	Karandighi-1	ONGC	1989	3541	Dry hole
38	Mainger-1	ONGC	1989	4221	Dry hole
39	Palasi-1	ONGC	1989	5840	Dry hole
40	Rajgung-1	ONGC			Dry hole
41	Ichapur-1	ONGC	1990		Dry hole
42	Golf Green-1	ONGC	1990		Dry hole

3.7 Undiscovered gas resource estimates in Bangladesh: Conjectural and hypothetical

Undiscovered gas resource refers to the quantity of gas that may be found in future. The evaluation of undiscovered gas resource is based on probability studies of factors responsible for gas accumulation. These include probabilities of finding source rock, reservoir rock, trap and timely migration as outlined earlier in section 3.3.1. Probabilities are determined for each of these factors indivdually and these probability values are multiplied together to determine the geologic risk for an accumulation of gas (USGS-Petrobangla 2001). The gas quantities thus assessed are therefore hypothetical, speculative and conjectural. These are referred to as 'resources' rather than 'reserves'. The conjectural nature of the gas resource assessment means that these should only be considered as a guide for upfront exploration planning and should not be considered for commercial decisions (marketing. trading etc).

Bangladesh has a proved gas rich province in the eastern part. How much gas still remains undiscovered, has been a subject of much speculation and there has been several studies by oil companies and other organizations to suggest that. Among these studies, two of the recent and widely publicized ones are : i) USGS-Petrobangla joint assessment of undiscovered gas resource and ii) Hydrocarbon Unit -Norway Petroleum Directorate (HCU-NPD) joint assessment of undiscovered gas resources of the country.

3.7.1 Undiscovered gas resource assessment by USGS-Petrobangla: In 2000, an USGS-Petrobangla joint team of geoscientists conducted a 21month long study to assess the undiscovered gas resource of Bangladesh. The work was funded by US Agency for International Development (USAID). In January 2001, the team concluded its assessment and submitted report entitled, 'USGS-Petrobangla Cooperative Assessment of Undiscovered Natural Gas Resources of Bangladesh'. As the title reflects the team did not assessed the gas reserve of the country, but assessed the undiscovered gas resource that may be found in future.

The methodology used for the assessment was that of USGS World Energy Assessment team 2000, adopted for undiscovered gas resource assessment

throughout the world. In this method, geologic risk probabilities are determined for source rocks, reservoir rocks, traps and timing of gas migration. These probabilities are multiplied together to determine geologic risk for a supposed accumulation of gas. These data are fed onto a seventh approximation form and then into a computer program that generates probabilistic forecasts of the undiscovered gas resources of the area in question (USGS-Petrobangla 2001).

The USGS-Petrobangla joint assessment report (2001) suggested that Bangladesh has 95% probability of finding 8.4 Tcf of yet undiscovered gas resource. Of the above total undiscovered gas. 6.0 Tcf is assigned to the onshore area and 2.4 Tcf is assigned to the offshore. This study also suggests, a mean (about 50%) probability of finding 32.1 Tcf of yet undiscovered gas resource in the country.

In the above assessment, Bangladesh has been divided into six assessment units (AU) (Figure 3.24). Risk factors for each of the units were separately considered for the geologic parameters as mentioned earlier. Gas resource probabilities are assessed separately for each of these assessment units rating for 95%, 'Mean' and 5% probabilities for each of the units. According to the above study, the western part of the country has been rated as poor to lowly prospective while some units in the eastern part have been rated as moderately to highly prospective.

The six Assessment units (AU), considered in the above study are i) Surma Basin unit (Bang0101), ii) Easternmost extremely folded belt unit (Bang 0102), iii) High amplitude faulted anticline unit (Bang 0103), iv) Moderately folded anticline unit (Bang 0104), v) Western slope unit (Bang 0105) and vi) Western platform unit (Bang0106). The assigned probabilities (95% and 'Mean') of undiscovered gas resources of these units as suggested in this study are shown in Figure 3.24 and Table 3.15.

Although widely publicized, the above study and report has been criticized for not specifying the prospects and leads on which the risk factors were considered. Nevertheless, this report has been taken as good reference to the debate of the yet undiscovered gas resource of the country.

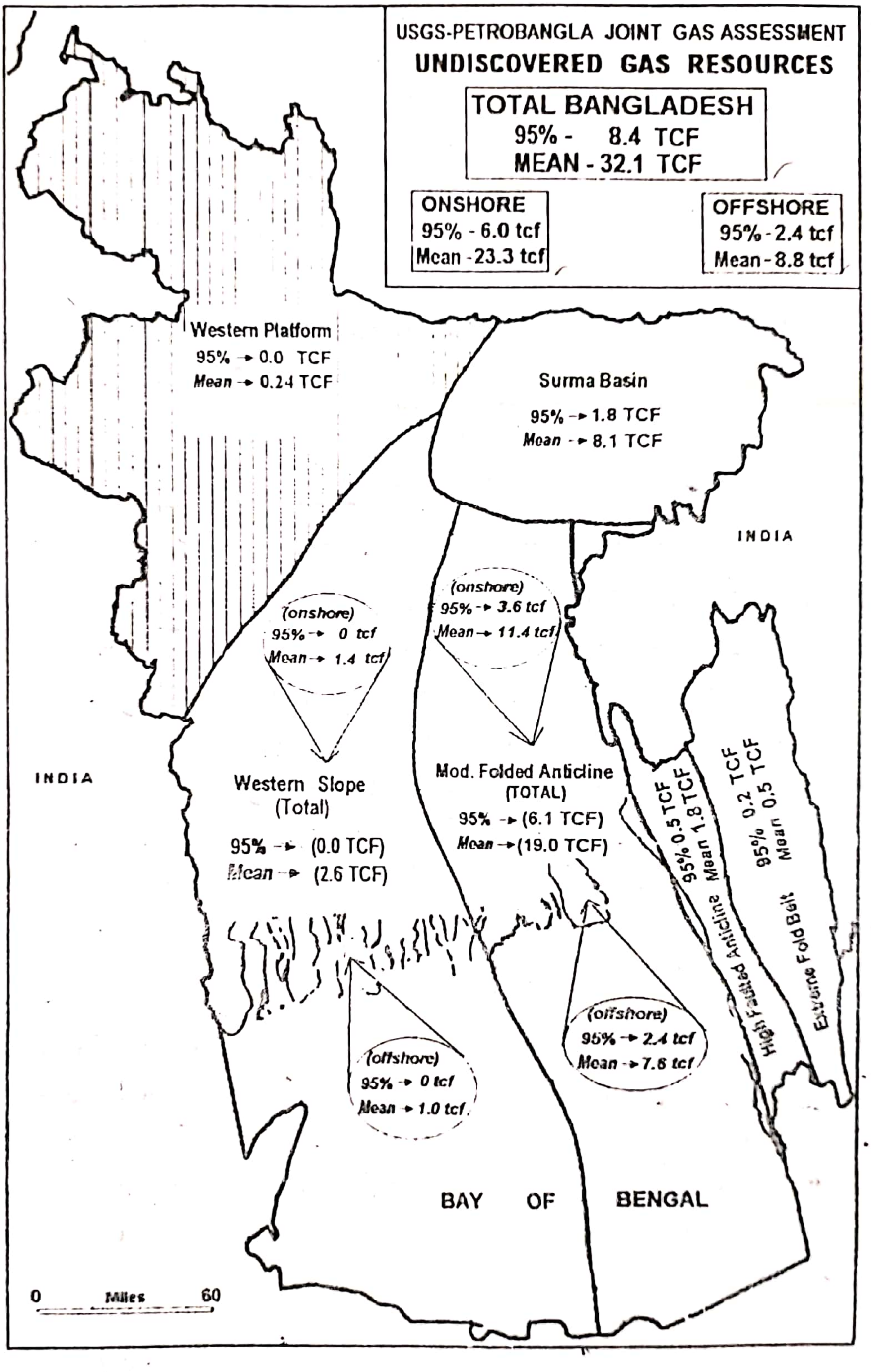


Figure 3.24 Map showing speculated undiscovered gas resources in Bangladesh as reported by USGS-Petrobangla team.

Table 3.15 Hypothetical assessment of undiscovered gas resources of Bangladesh (Source: USGS-Petrobangla Gas Assessment Team 2001).

Assessment unit (AU)	Probabilities of finding undiscovered gas resources	
	95% probability	Mean probability
Surma Basin unit (Bang 0101)	1.8 Tcf	8.14 Tcf
Easternmost extremely folded belt unit (Bang 0102)	0.0 Tcf	0.35 Tcf
High amplitude faulted anticlines unit (Bang 0103)	0.5 Tcf	1.8 Tcf
Moderately folded anticline unit (Bang 0104)	6.1 Tcf	19.0 Tcf
Western slope unit (Bang 0105)	0.0 Tcf	2.6 Tcf
Western platform unit (Bang 0106)	0.0 Tcf	0.24 Tcf
Total	8.4 Tcf	32.1 Tcf

3.7.2 Undiscovered gas resource assessment by HCU/NPD: In 2001, a joint team of geoscientists from Hydrocarbon Unit (HCU) of Bangladesh and Norway Petroleum Directorate (NPD) conducted a gas assessment job on Bangladesh. The aims of the HCU/NPD's assessment job were i) to update the estimates of gas reserves in existing fields and ii) to establish a reliable estimate of undiscovered gas resource potential of the country using available data. In January 2002, the team concluded its report entitled 'Bangladesh Petroleum Potential and Resource Assessment'.

Reference to the estimate of the gas reserves of discovered fields as reported by the team has been made earlier in this chapter. Following is a brief on the team's assessment of the undiscovered gas resource of the country. The above assessment work divided the country into two petroleum provinces as western and eastern. These are subdivided into six petroleum systems. The Western petroleum province includes a) Gondwana petroleum system, b) Bogra shelf petroleum system and c) Western delta petroleum system. The Eastern Petroleum province includes a) Surma petroleum system, b) Southeast delta-Hill Tract petroleum system and c) Southeast offshore petroleum system.

Table 3.16 Hypothetical estimates of undiscovered gas resource in Bangladesh (Source: HCU/NPD 2002).

	Type of estimate	90% probability	Mean probability
Undiscovered Gas Resource	Hypothetical (Mapped prospect)	10.6 Tcf	16.9 Tcf
	Speculative (Lead/Unmapped prospect)	7.8 Tcf	24.7 Tcf
	Total	**18.5 Tcf**	**41.6 Tcf**

The team used available data to identify the prospects, leads and plays. Gas probability studies on these were carried out. The above study reviewed available data both onshore and offshore up to the water depth of 200 meters. Computer simulations were used to assess undiscovered gas resources using PC based program.

Based on the above study, the HCU-NPD team suggested that the total undiscovered recoverable gas resource of the country at 90% probability is 18.5 Tcf of which 10.6 Tcf is assigned to hypothetical estimate (mapped prospect) and 7.8 Tcf is assigned to speculative estimate (unmapped prospects). The study also suggested a 'Mean' (50%) probability of finding 41.6 Tcf undiscovered gas resource of which hypothetical estimate on mapped prospects include 16.9 Tcf and speculative estimate of unmapped prospect includes 24.7 Tcf (Table 3.16).

It may be noted that there exists significant difference on the estimates of the undiscovered gas resource of Bangladesh. The difference between the estimates of USGS/Petrobangla and HCU-NPD teams of the 'Mean' probability of undiscovered gas resources of the country as discussed above has been 9.5 Tcf. This is close to half of remaining gas reserve of the country at present. The significant difference in the undiscovered gas resource estimates of the above two teams is not very surprising, considering the facts that these estimates are hypothetical and speculative and are made on the basis on computer simulation rather than actual field investigations. Such conjectural estimate by a third or a fourth party may have similar difference from each other.

3.7.3 Other undiscovered resource assessments: In addition to the above two widely publicized gas resource assessments; there have been several other gas resource assessments in the past.

Hydrocarbon Habitat Study (1986): This was the first comprehensive study that reviewed all geological provinces in Bangladesh. Petrobangla conducted the study in 1986 with technical support from Well Drill. The study identified a number of leads and prospects in eastern and western Bangladesh and estimated a total undiscovered resource potential of 42.8 Tcf gas, of which 18 Tcf were allocated for leads and prospects identified in western Bangladesh. It is important to notice that the HHS did not identify many of the more recent prospects some of which became significant discoveries – such as onshore Bibyana and offshore Sangu.

Bangladesh Study Group (1989): Represented by four oil companies (Trend International Ltd, Idemitsu Oil Dev. Co., Repsol Exploration Indonesia and Eurafrep) the group conducted an intensive joint technical study for the onshore Bangladesh (except block 13 and 14). The study assessed 130 leads and prospects and reported a total undiscovered gas resource of 62 Tcf.

Overseas Development Agency (1986): In 1986, Petrobangla and Well Drill, undertook a study in block 4 in the hinge zone. The total undiscovered resource potential was estimated at 7.5 Tcf.

Anglo-Scandinavian Group (1988): The group studied the hydrocarbon potential of Mymensingh area, which covers block 8 and 11. Nine leads were assessed to have total undiscovered resource of 7 Tcf gas.

Shell Exploration Bangladesh (1999): Shell Exloration Bangladesh, conducted a study and concluded that the risked success gas volume was 38 Tcf. In April 2001, Shell published its new assessment of total undiscovered resource potential which ranges from 20 to 40 Tcf and mean of 32 Tcf.

3.8 Selected gas fields in Bangladesh

3.8.1 Titas – the largest gas field

Titas gas field is situated in Brahmanbaria district in the vicinity of Brahmanbaria town. During 1950s PPL, a subsidiary of BOC, carried out gravity surface and indicated a subsurface structure in the area. In late 1950s Shell Oil conducted single-fold seismic and confirmed a large gently folded anticline. The gas field was

discovered in 1962 by Shell Oil Company by the exploratory well Titas-1 drilled about 4 km north of Brahmanbaria town. In 1975, the field was purchased by Bangladesh and has since been operated by BGFCL, a subsidiary production company under Petrobangla. Titas is the largest gas field in Bangladesh and is, at present, the second highest producer after Bibiyana in the country. Titas may therefore, be seen as the life line of Bangladeshi gas operation.

A part of the Titas gas field has been affected by uncontrolled gas seepage through numerous points in the ground surface, ponds, river and tube wells. The gas seepages have been recorded since 2005 and continue to date (end 2012). This causes significant loss of gas and degradation of environment in the area (see Box 3.3).

3.8.1.1 Structure: The Titas gas field is formed by a gentle subsurface anticlinal structure with a broad axial area (Figure 3.25).The structure has one of the largest closure among the gas fields in the country, measuring in excess of 16 km by 8 km at the topmost pay sand level. There is no surface expression of Titas structure as it is covered by the Titas-Meghna flood plain.

The broad axial nature of Titas anticline is in contrast to the neighboring anticlines which are narrow in their outlines. It is structurally higher than the surrounding Rashidpur and Habiganj anticlines indicating that Titas may have been influenced by tectonically positive element from deep subsurface. The structure is elongated in north south direction and is asymmetric with steeper eastern flank (12°±) and gentler western flank (6°±). Evidence of faulting is not conclusively shown as some studies suggested fault in the eastern flank, while other suggested no evidence of fault in the gas sand levels (HCU/NPD 2003).

3.8.1.2 Reservoir: The Titas gas reservoirs include multiple sandstone layers in the Bhuban and Bokabil Formations of Miocene-Pliocene age. The depths of the gas reservoirs range from about 2616 m to 3124 m below the surface. There are more than 10 gas zones (gas sand) of which 5 are major with lateral extension across the gas field (Figure 3.25). The remaining gas zones are thinner and relatively restricted in areal extent. The gross thickness of the five gas zones is about 125 m to 200 m.

Box 3.3 Gas seepage in Titas gas field:

Titas, the largest gas field in the country has been the site of alarming and uncontrolled gas seepages for several years. Gas seeps through numerous points in the ground surface, the river and ponds and tube wells. In a part of the gas field area, paddy fields are dotted with large and small holes induced by gas bubbling up from underground; similar gas bubbles are abound in the river and ponds and the tube wells run non stop with gas charged water. In addition to the gas being lost, the environment of the seepage areas are severely affected. The gas seepages are mostly noticed in and around the well # 6 8, 9 and 10. These wells are located in the central area of the gas field (location C). These include the locality of Anandapur, Bakhail Luckka bill and many people living in villages in and around the area have been affected. There is however, no gas seepage noticed in the northern or southern part of the gas field.

Gas seeping out of the ground was initially noticed by the villagers living in the gas field area in 2005. In 2006, Petrobangla officially reported the seepage, collected the seeped gas samples and performed laboratory analysis which pointedly offered the idea that the gas is thermogenic and is being seeped from main sand reservoir underground. By the end of 2006 Petrobangla formed an expert committee to conduct a survey in order to find out the cause of gas seepage and to suggest remedy.

The committee submitted its report to the authority in February 2007 based on the study of the situation in the ground as well as the well records and pointed out the followings (Huq 2009): i) The seepage of gas have been created, most likely, due to poor cement bond in the well. Due to poor cement bond, a conduit for cross flow of gas upward may have been created. iv) Wells nos. 10, 9 and 8 should be the prime target of investigation in which well logging for cement bond tests are required. Based on the result of the logging in the wells, cement squeeze job should be carried out as remedial method. v) International reputed oil well cementing company should be engaged for carrying out the remedial work.

From the above it appears that the likely cause of gas seepage is the poor cement bond within a gas section in the borehole. That such a condition may have been created due to imperfect drilling job and subsequent negligence in the past is suspected. For example, when well no.10 was drilled in 1988, the cementation of production casing was quite bad. Well log (CBL-VDL) indicated poor or no cement within the top 27m of "A" gas sand, the main gas reservoir. The drilling Consultant OMS of UK, identified the danger of this open hole and advised not to produce gas before fixing the above condition. However, against the recommendation of the consultant the well was completed and gas production began without cement squeeze job.

Although the Petrobangla expert Committee pointedly placed its recommendation to deal well 8, 9 and 10 for the seepage problem, a second opinion was placed to deal with well no.3 located at about a kilometer north from the seepage area. It was decided to kill the well#3, though there was no seepage noticed in and around the well. International consultant Boots and Coots was engaged in 2008 and the well was permanently killed. Gas seepage in Titas gas field continued to date (end 2012), four years after the above operation was completed. This operation cost Petrobangla $10 million plus the local expenses. Furthermore the production of 25 -30 mmcf gas per day from well no.3 was permanently lost (Huq 2009).

Petrobangla is yet to take a comprehensive action to effectively deal with the seepage problem in Titas gas field. In the mean time large volume of gas has been lost during the last seven years since the gas seepage was noticed in 2005. There is no official estimate as to how much gas seeps out per day. However, unofficial estimates from the local experts suggest that about 10 to 15 million cubic feet gas is being lost per day in this gas field.

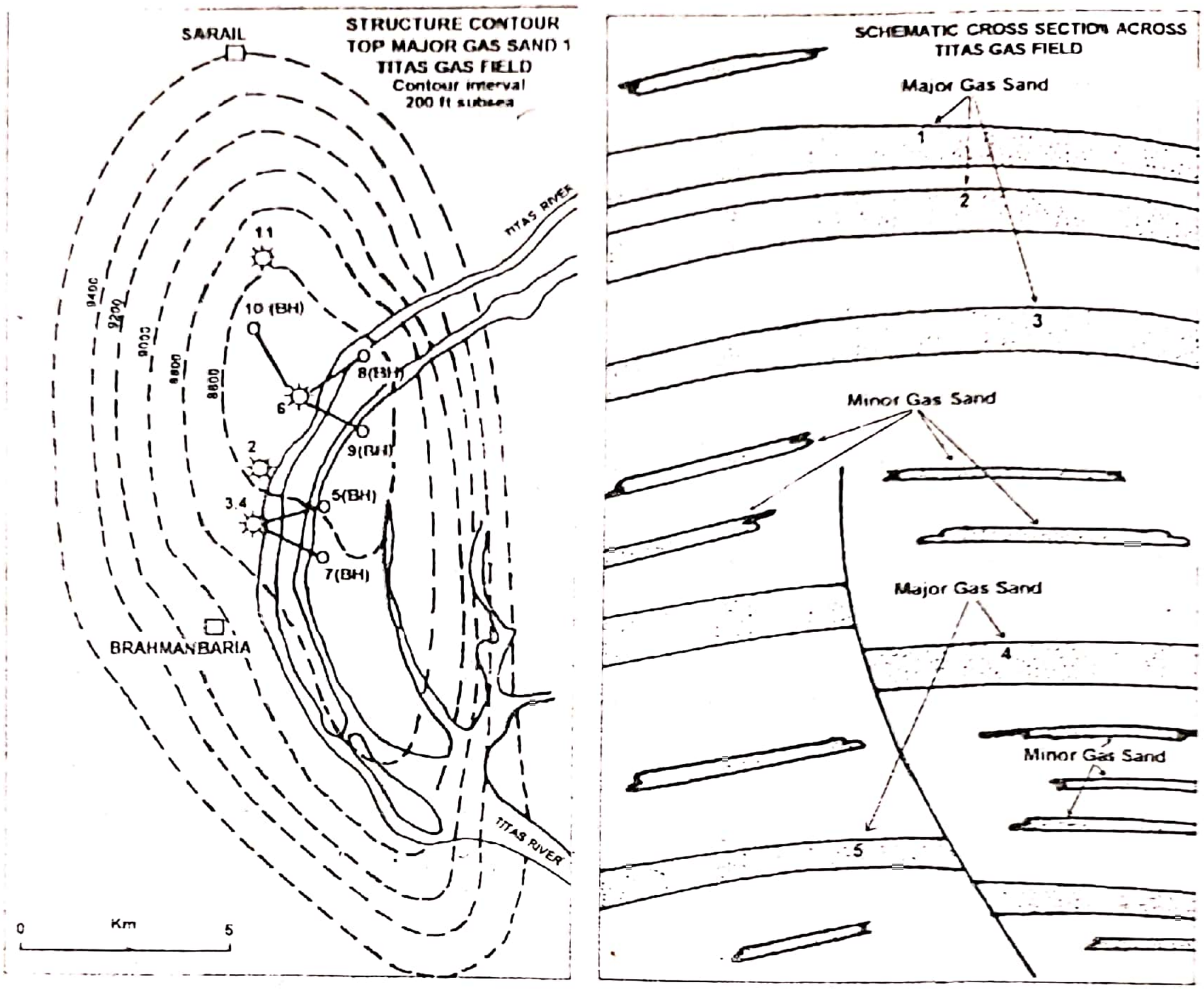


Figure 3.25. Titas gas field: structure contour (left), schematic cross section (right) showing the gas sands.

The gas sands are divided into three groups named "A", "B" and "C" sands. Each group contains three to four sands marked, for example, as A1 to A4 and so on. Some of the major gas sands are areally extensive and therefore hold large gas reserves. These sands are believed to have deposited in marginal marine depositional environments like barrier bar, offshore bar, and beach sand allowing elongated and extensive sand body to form and serve as reservoirs.

The quality of the reservoir sandstones are generally very good with average porosity in the range of 20% and average permeability in the range of 100- 400 millidarcy. The sandstone reservoirs are medium to very fine grained, well sorted and clean with little or no clay matrix. The reservoirs suffer moderate degree of diagenetic compaction and cementation with quartz, calcite and clay mineral cements. Significant amount of secondary dissolution porosity have been observed in thin section studies of the sandstone reservoirs (Imam and Shaw 1987).

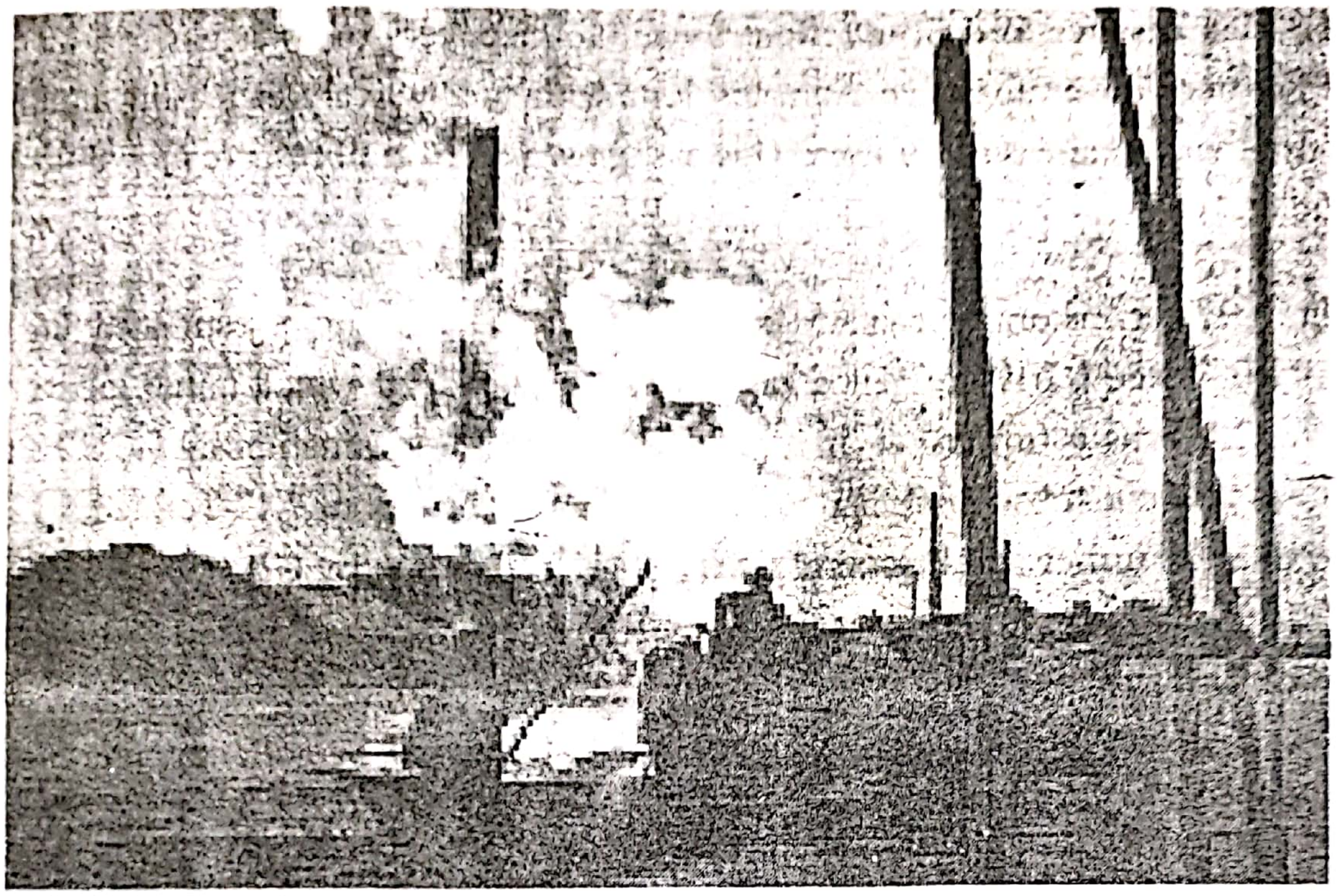


Plate 3.5 Blazing fire on Titas river water surface from the seepage of Titas gas field, Brahmanbaria district.

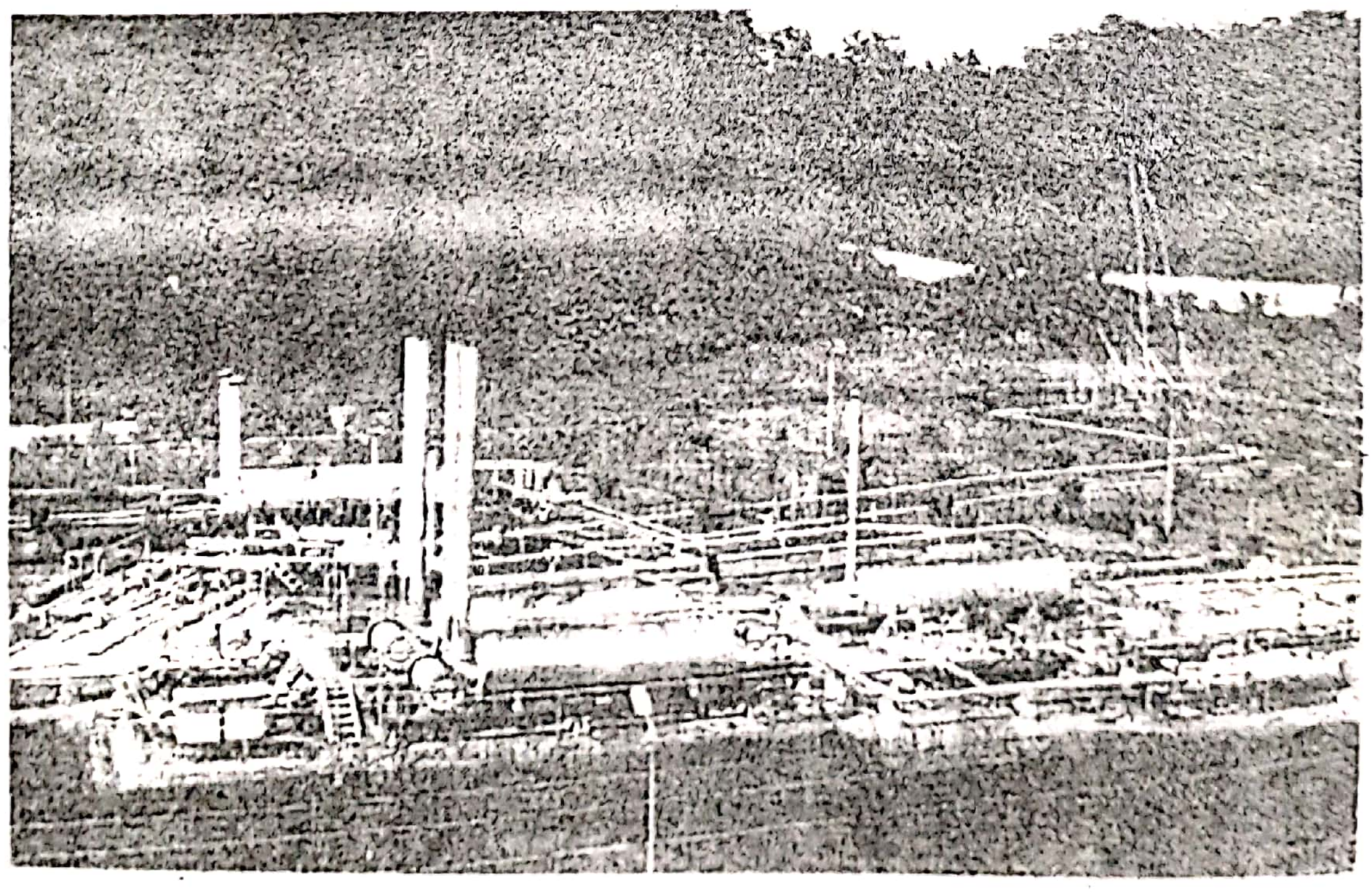


Plate 3.6 Areal view of the Habiganj gas field, Habiganj district.

3.8.1.3 Gas reserve and production: Since the discovery of Titas gasfield in 1962, there has been several reserve estimates done with successively increasing amount of well data with the passage of time. This has shown an overall reserve growth in Titas gas field.

In 1992, Interkomp-Kanata-Management(IKM) consultant estimated the Gas Initially In Place (GIIP) of Titas gas field at 4.14 Tcf of which initial recoverable reserve (2P) was estimated at 2.10 Tcf. The reserve reevaluation by HCU/NPD in 2003 has made a substantial increase of GIIP and reserves to 7.12 Tcf and 5.12 Tcf respectively. Further revaluation of the Titas gas field done by Guvtavson Associates in 2010 have suggested even higher GIIP and reserve. And finally in 2011 Petrobangla officially published the latest reserve evaluation data of Titas carried out by RPS Energy consultant who estimated initial GIIP at 8.14 Tcf and initial reserve (2P) as 6.36 Tcf (Petrobangla 2012).

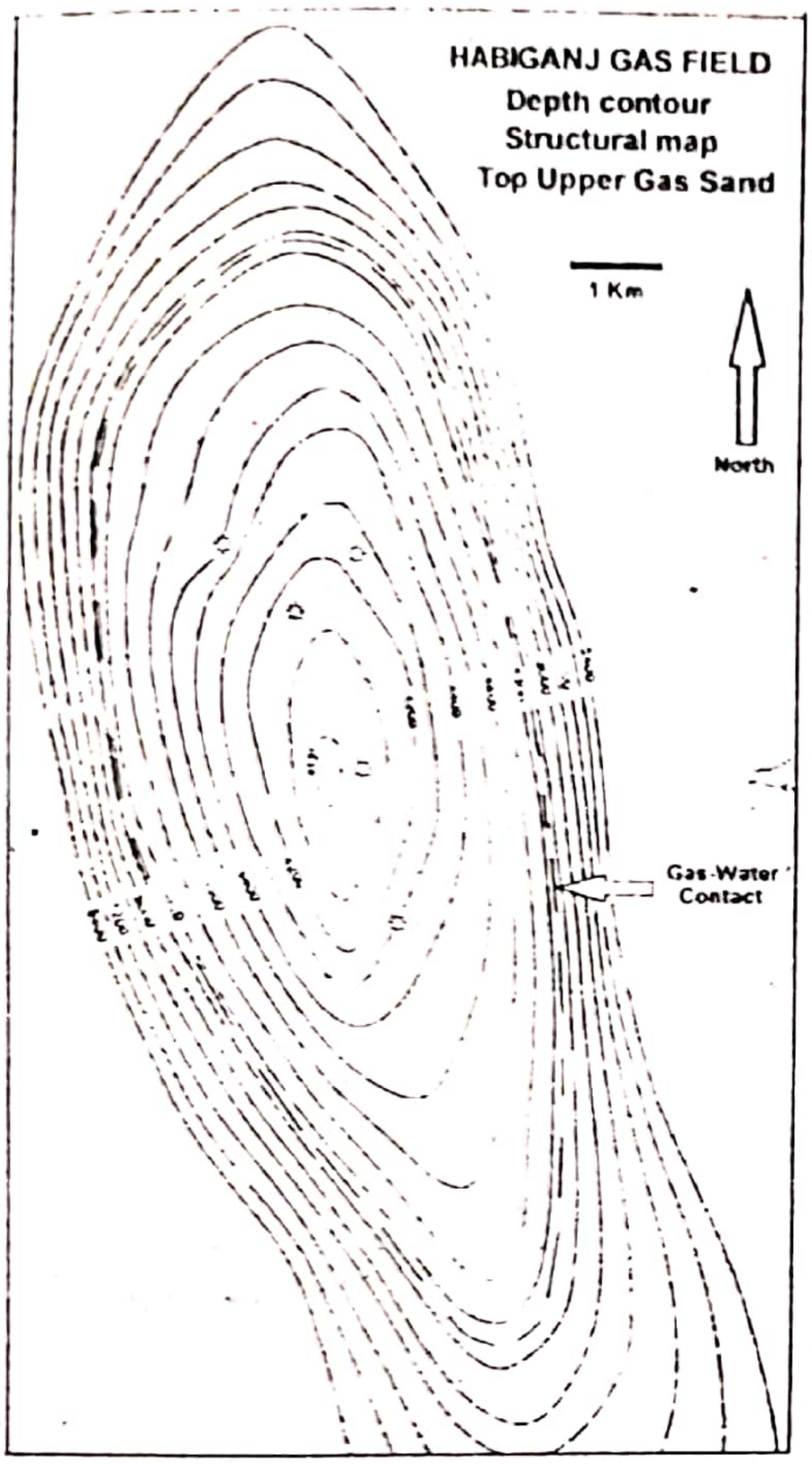
Titas gas field has been an example in which significant reserve growth has been demonstrated. Although the Titas gas field started production in 1968, the field is however yet to enter into a mature state of development and most of the 16 production/appraisal wells drilled are concentrated at the crestal part of the structure.

The Titas gas field at the end 2012 is producing about 450 million cubic feet of gas per day (mmcfd) from 16 wells. This is the second largest supplier of gas field (after Bibiyana) to the national grid. The gas field is operated by Bangladesh Gas Field Company Ltd, a subsidiary of Petrobangla.

3.8.2 Habiganj gas field

The Habiganj gas field is located in Habiganj district and lies 32 km northeast of Titas gas field. The gas field was discovered by Shell Oil Company in 1963 and has been one of the major gas producers in the country.

3.8.2.1 Structure: The Habiganj gas field is formed by a north south elongated anticline which lies in the northernmost end of the 130 km long Baramura anticlinal trend or lineation from Tripura (India) in the south. However, the Habiganj closure is entirely separated from and independent of the Baramura anticlinal closure. The structure is expressed by surface topographic relief and dip reversal of the



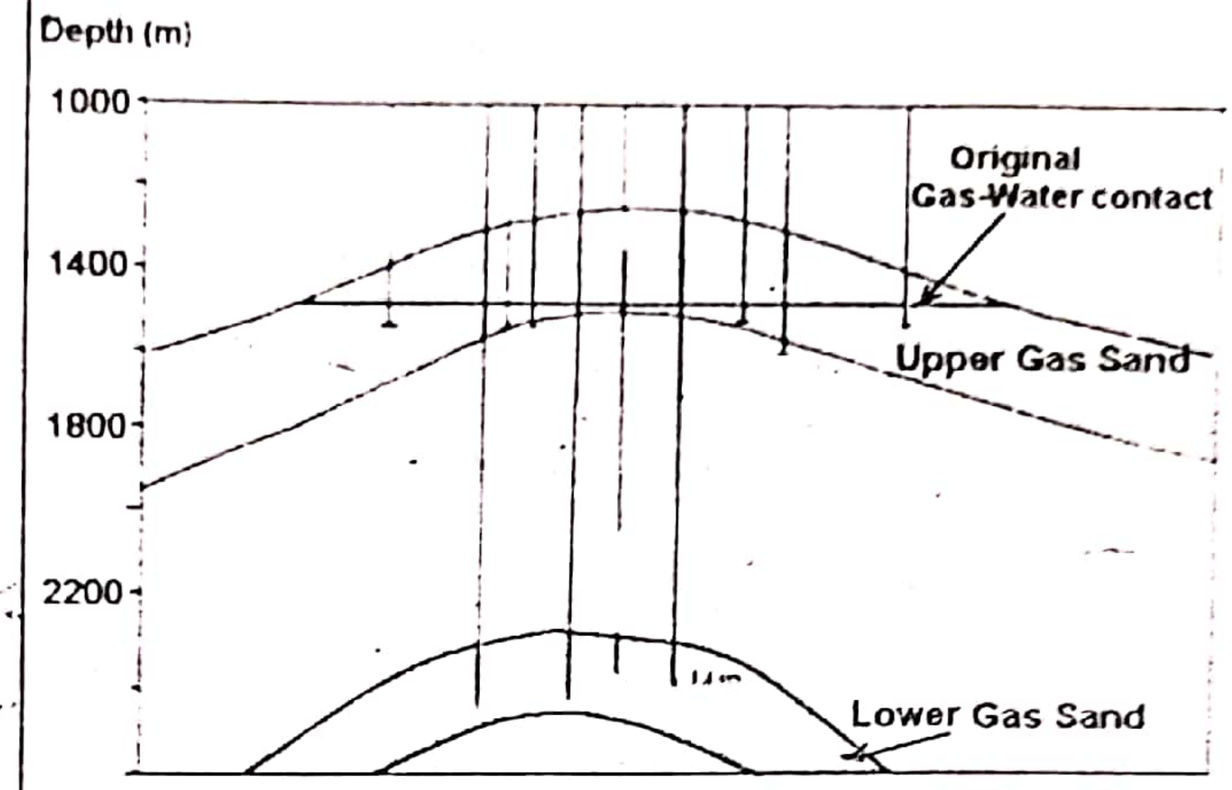


Figure 3.26
Left: Depth contour of top Upper Gas Sand, Habiganj gas field.
Right: Cross secrion across Habiganj gas field with two gas sand.

outcropping flanks. The structure has a four way closure without any significant faulting. The closure in the gas water contact level is 11.5 km long and 4.5 km wide. No significant difference between the dip of the opposite flanks are noticed. Near the central part of the structure, the western flank dips 10° and the eastern flank dips 9°.

3.8.2.2 Reservoir: The Habiganj gas field is known for its excellent quality reservoirs. The reservoirs are sandstones belonging to the Surma Group (Bhuban and Bokabil Formations) of Miocene-Pliocene age. There are two gas zones known as upper gas sand (UGS) and lower gas sand (LGS) (Figure 3.26).

The upper gas sand lies at a depth of 1320 meter below surface and has a maximum gross pay 230 meter thick. This is the primary gas reservoir of the field. The gas sand is medium to fine grained, well sorted, clean and unconsolidated and has average pososity in the range of 30% and average permeability in the range of 2 to 4 darcy. This is the best quality reservoir found among the gas fields in the

country. Because of the very thick gas column, shallow depth, high porosity and permeability, the upper gas sand has direct hydrocarbon indicator (DHI) or bright spot shown in seismic section.

The lower gas sand lies at a depth of about 3000 meter below surface and is thinner and has lesser areal extent than upper gas sand. The gross pay of the lower gas sand is 15 meter thick and the sand has average porosity of 17% - 18% and permeability less than 100 md.

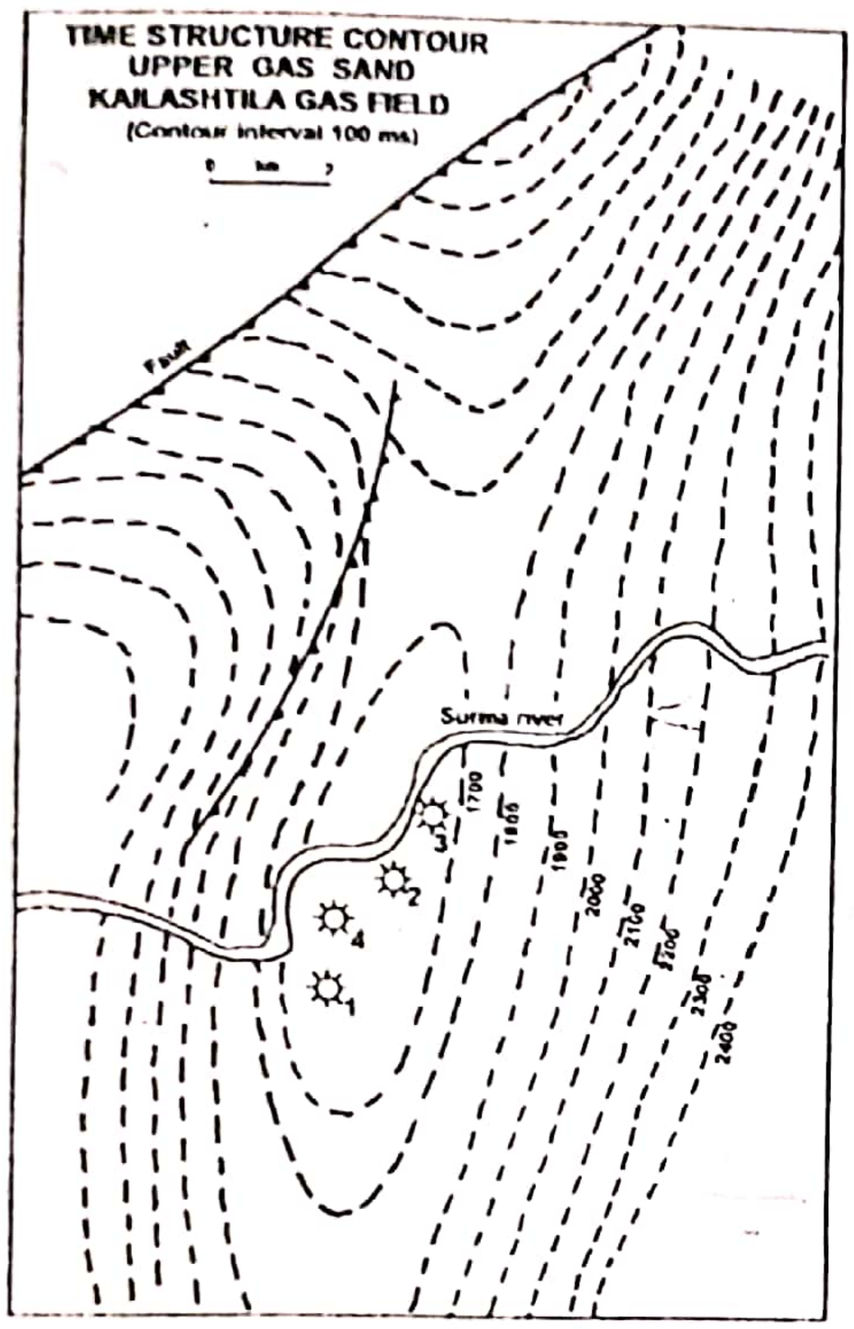
The Upper gas sands originated in high energy beach and barrier bar marginal marine depositional environment. The lower gas sand originated as offshore marine bar in comparatively lower energy environment than the upper gas sand and hence has poorer reservoir qualities than the latter.

3.8.2.3 Gas Reserve: In 1992, IKM consultant estimated the GIIP of Habiganj gas field at 3.66 Tcf with initial recoverable reserve (2P)of 1.89 Tcf. In 2003 HCU-NPD reevaluated the gas field reserve and estimated the GIIP at 5.13 Tcf with initial recoverable reserve (2P) of 3.85 Tcf. Finally in 2011 Petrobangla published a revised estimate of the gas field based on RPS Energy consultant which shows estimated GIIP of 3.68 Tcf and an initial reserve of 2.63 Tcf (Petrobangla 2012).

Gas production from the field started in 1968 and till December 2011 a total of 1.85 Tcf of gas has been produced. By the end of 2012, the field has been producing about 230 mmcfd from 9 wells. Habiganj field is the third largest gas producer in the country. The field is operated by Bangladesh Gas Field Company Ltd (BGFCL), a subsidiary of Petrobangla.

3.8.3 Kailashtila gas field

Kailashtila gas field was discovered by Shell Oil Company in 1962 by the exploratory well Kailashtila-1 located about 12 km southeast of Sylhet town. The field is a gas condensate field and produces significant amount of condensate with gas. The Kailashtila field has been contributing increasingly to the national gas grid over the years since it is brought on stream in 1983.



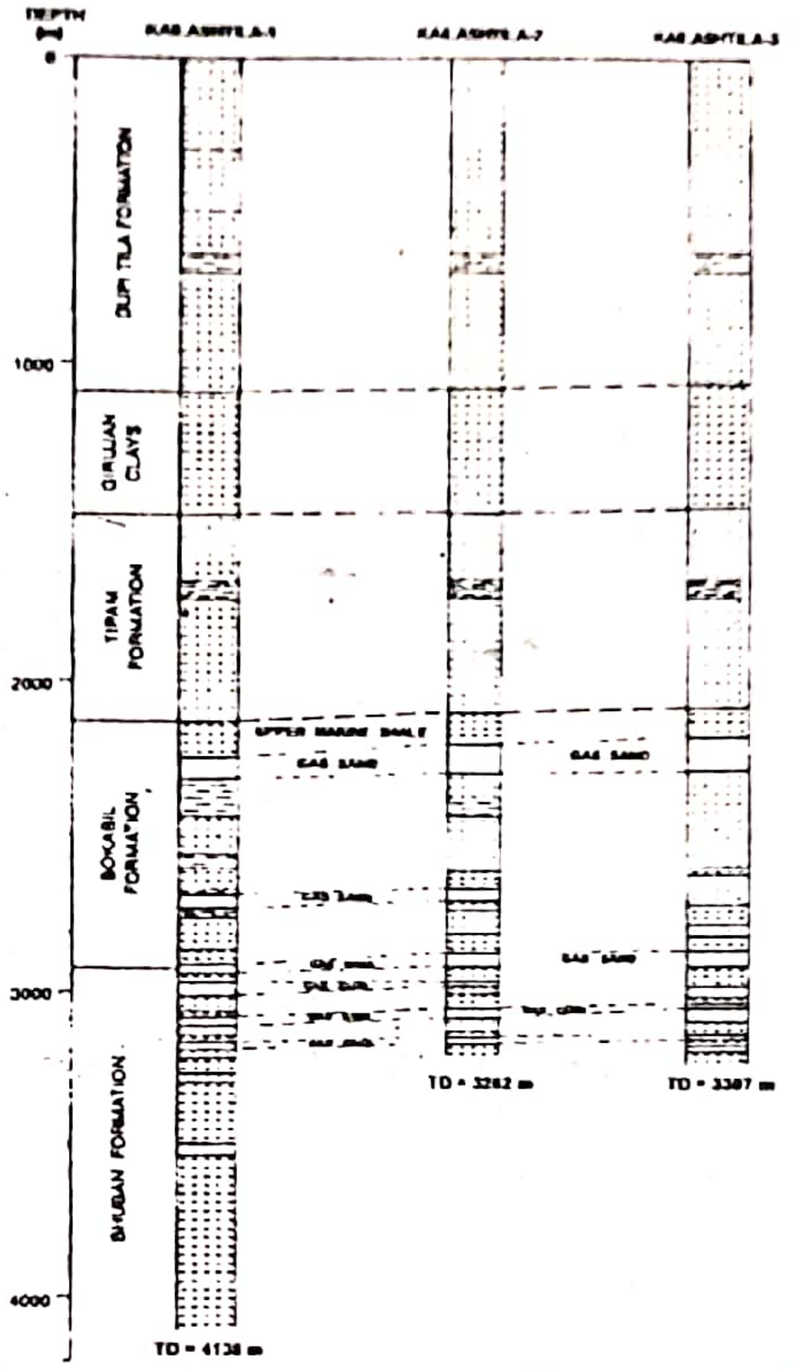


Figure 3.27 Kailashtila gas field: structure contour (left) well litho logs with gas sands (right) (Source: Islam and Hossain 2002; Petrobangla).

3.8.3.1 Structure: The Kailshtila stucture is a north-south trending anticlinal structure located in the Sylhet district. The anticline is 17 km long, 5 km wide, has low relief and is asymmetric in nature with steeper western flank (25°) and gentler eastern flank (11°). Geological and seismic surveys and drillings reveal that the Kailashtila structure has southerly pitched with dip closures to the west, east and south. To the north a fault terminate the structure and separate it from the Sylhet structure (Fig.3.27).

3.8.3.2 Reservoir: There are three main gas zones in the field at depths ranging from about 2280m to 3045m below the surface. The gas sands are referred to as Upper, Middle and Lower gas sands. These are Miocene-Pliocene sands belonging to Bhuban and Bokabil Formations.There has been significant variation of the thicknesses of the gas sands from well to well. For example Upper gas sand shows three fold increase in thickness from well 1 to well 3. The gross pay sand thickness is in the range of 120 m to 150 meter. The poro-perm properties of the sand reservoirs are good to excellent. The reservoir sands were originated as deltaic to marine environment under offshore bar and beach conditions.

3.8.3.3 Gas reserve: The GIIP in this gas field was estimated earlier at 3.65 Tcf with an initial reserve of 2.53 Tcf by IKM in 1992. Later reevaluation by HCU-NPD in 2003 reestimated the GIIP at 2.72 Tcf with initial reserve of 1.93 Tcf. Finally in 2012, Petrobangla, published the latest estimation of GIIP at 3.61 Tcf with initial reserve of 2.76 Tcf, based on the reevaluation of the gas field by RPS Energy consultant.

In addition to gas, the Kailashtila structure has located small amount of oil at deeper horizon. Two oil bearing sands were encountered in well-2 drilled in 1988 between depth of 3086 m and 3225 m. However the sands are rather thin and do not continue to the other wells. The oil pool were therefore considered non commercial. However further appraisal of the oil sand was recommended. Recently Petrobangla announced plan to reevaluate the oil sand in Kailashtila by further drilling.

3.8.4 Bakhrabad gas field

The Bakhrabad gas field is located in Comilla district and is about 35 km from Dhaka city. The gas field area is covered by Meghna river flood plain. The field was discovered in 1968 by Shell Oil Company by the exploratory well Bakhrabad-1. Although initially considered as a large field, rapid decline of pressure and production rate have lately indicated that the gas field may be depleted in near future.

3.8.4.1 Structure: The Bakhrabad gas field is formed in an anticlinal trap. There is no surface expression of the structure and the anticline was delineated by gravity and seismic surveys. The structure was originally defined as a NW-SE running 70 km long trend from Bakhrabad in the south to Narsingdi in the north (Figure 3.28). Subsequently three separate culminations were delineated respectively as south, middle and north. Bakhrabad gas field occupies the south culmination which is structurally the highest part and indicates stronger compression and uplift than its northern counterparts.

Two separate gas discoveries were subsequently made on the middle (Meghna gas field) and north (Narsingdi gas field) culminations respectively.

The Bakhrabad anticline is a near symmetrical fold with flanks dipping in 15°. The gas field is separated from the Meghna gas field culmination in the north by a major fault. There are indications of both transverse as well as flank faults within the Bahkrabad gas field (Figure 3.28).

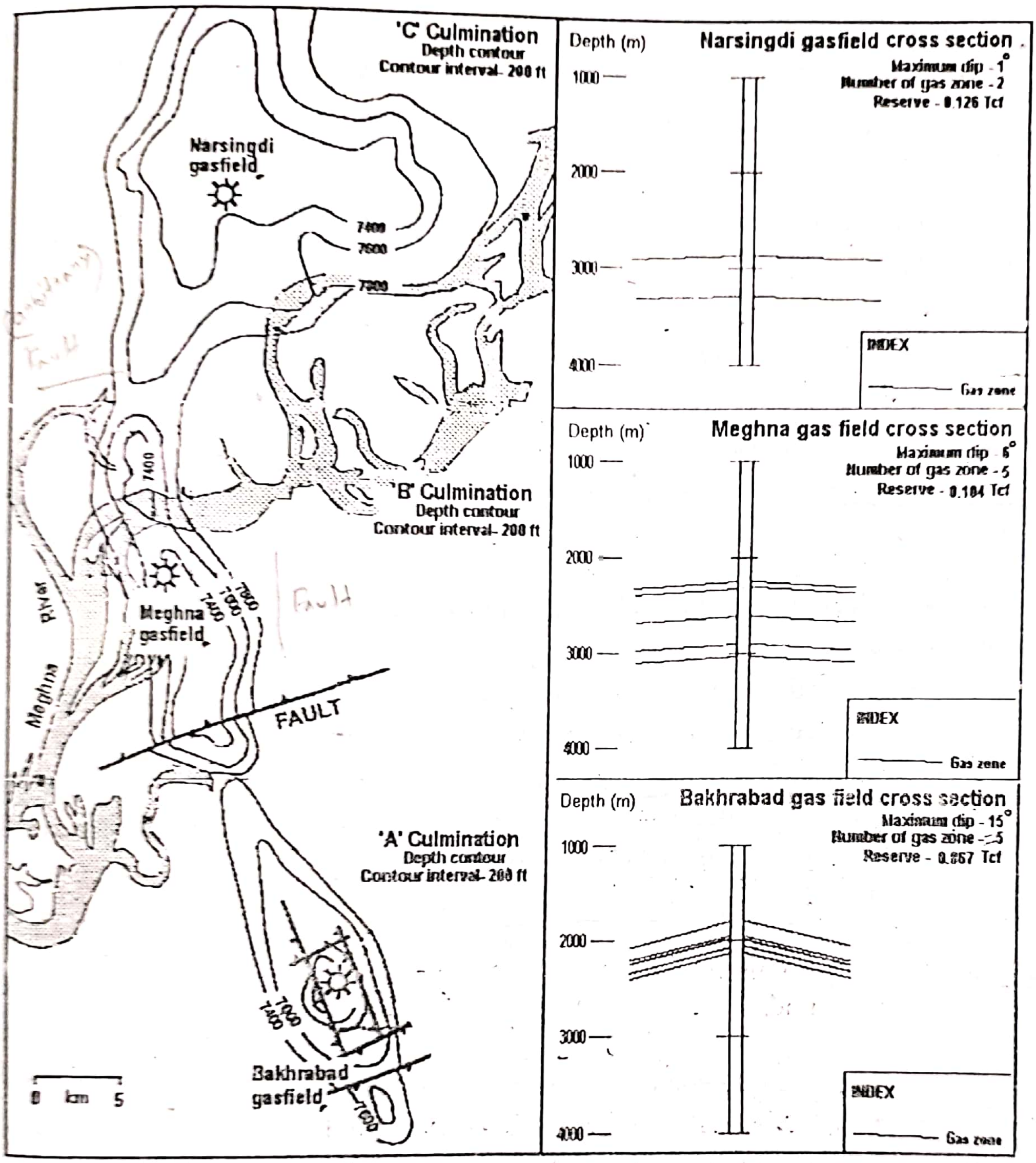


Figure 3.28 Structural contours of Bakhrabad-Meghna-Narsingdi gas fields (left) and schematic cross sections across the respective fields .(right).

3.8.4.2 Reservoirs: Bakhrabad gas reservoirs are sandstones within the Miocene-Pliocene Surma Group unit. There are five major gas sand (pay zones) named as 'B', 'D-upper' 'D-lower', 'G' and 'J' (Choudhury and Gomes 1999). These gas zones lie at depth between 1826 to 2144 meters below surface. The gas sands have porosities in the range of 13% to 26% and permeabilities in the range of 50 md

to 700md. The sands originated as deltaic proximal mouth bar to distal mouth bar deposits, the latter more silty and finer sand reflecting lower energy of depositional environment. The textural difference of the gas sands resulted variations in the reservoir poro-perm properties.

3.8.4.3 Gas reserve: Reserve estimations of the Bakhrabad gas field were initially done by Shell Oil in late sixties and also by DeGolyer and McNaughton in early eighties. These studies suggested that Gas Initially in Place (GIIP) in the field is in the range of 2.78 to 2.90 Tcf. However reappraisal of the gas reserve of the field by IKM in 1992 estimated the GIIP at 1.432 Tcf and an initial reserve of 0.867 Tcf. Finally in 2012, Petrobangla published a re-estimated GIIP of 1.70 Tcf with initial reserve of 1.23 Tcf for the gas field based on the evaluation by RPS Energy consultant.

Gas production from the Bakhrabad field started in 1984. By 1989 there were 8 wells and a steady increase of production. At the end of 1992, gas production rate reached its peak with average of 195 mmcfd. However, by 1994, two of the wells had to be shut down because of excessive pressure drop and water production. This was accompanied by sanding problem, i.e. production of loose sand with the gas flow. Production continued to decrease as further well was shut off. The gas production rate decreased to 50 mmcfd by 1999 and to 35 mmcfd by Jan 2000. In September 2012 the gas field is producing 31 mmcfd gas. Some experts opine that the sanding problem and pressure drop in this gas field resulted due to excessive production rate at some points in time.

Till December 2011, cumulative production of gas from Bakhrabad gas field stood at 0.736 Tcf. It has been suggested that the gas field is on its way to depletion. The Bakhrabad gas field is operated by Bangladesh Gas Field Company Limited.

3.8.5 Meghna gas field

The Meghna gas field is situated 25 kilometer north northwest of Bakhrabad gas field and in close proximity to the Meghna river (Figure 3.28). The gas field was discovered in 1990 by Petrobangla by the exploratory well BK-1. It is a small gas field and has been in production since 1997.

3.8.5.1 Structure: The Meghna gas field is formed by an anticlinal closure. The structure has no surface expression and was delineated by gravity and seismic survey. This is the middle of the three culminations aligned generally along a 70 km long Bakhrabad lineament. (Figure 3.28). The Meghna structure is more gently folded compared to Bakhrabad structure indicating less compression. This is evidenced by 5° to 6° tectonic dip of its flank compared to 15° dip of Bakhrabad flanks. The structural axis of Meghna structure is offset from Bakhrabad axis by 15°. An oblique transverse fault separates the Meghna gas field from the Bakhrabad structure. There is a major longitudinal fault along the eastern flank of the Meghna gas field. The fault is downthrown to the east as shown by the steepening or often displacement of seismic reflector.

3.8.5.2 Reservoir: Meghna gas reservoirs are sandstones belonging to the Surma Group stratigraphic unit of the Miocene-Pliocene age. There are 6 gas sands between the depths of about 2285 m and 2400 m. The gas sands are thin and have limited continuity. Gross and net thickness of all the gas sands of the Meghna gas field are much less than those of the Bakhrabad gas field. The gross thickness of the gas sands is in the range of 40 meter.

The gas sands are medium to fine grained, moderately to well sorted with porosities in the range of 15% to 22%. The gas sands were originated as mouth bar in deltaic environment dominated by river energy regime. Compared to the higher energy beach and barrier bar derived Bakhrabad gas sands, lower energy mouth bar sands of Meghna gas sands are more silty and less clean and thus are generally inferior to Bakhrabad gas sands.

3.8.5.3 Gas reserve: The Gas Initially in Place (GIIP) in the Meghna gas field is estimated at 0.159 Tcf with an initial reserve of 0.103 Tcf. Petrobangla has recently down sized the gas field showing estimated GIIP at 0.12 Tcf with initial reserve of 0.07 Tcf based on study of RPS Energy consultatnt (Petrobangla 2012).

The Meghna gas field is brought under production in 1997. The field has been producing about 4 mmcfd with a single well. By December 2011, the cumulative gas production from the field was 41.8 Bcf (0.0418 Tcf). The gas field is operated by the Bangladesh Gas field Company Limited.

3.8.6 Narsingdi gas field

The Narsingdi gas field is located about 25 km north of Meghna gas field and about 50 km north of Bakhrabad gas field. It was discovered by Petrobangla in 1990 by the well Bk-10. The gas field area is covered by Meghna river flood plain. Narsingdi is a small gas field and has been producing since 1996 from single well.

3.8.6.1 Structure: It is the northernmost culmination or closure along the long Bakhrabad lineament (Figure 3.28). It is structurally the lowest among the three culminations (Bakhrabad-Meghna-Narsingdi) and represents only mild compression. The tectonic dips of the flanks are barely 1° compared to 6° in Meghna and 15° in Bakhrabad structures (Figure 3.28). The axis of Narsingdi structure is offset from Meghna structure by 20° and it is separated from the later by a transverse fault.

The very gentle fold of the structure is likely to have secondary role in pooling or trapping the gas. The gas pooling in this field is more importantly controlled by stratigraphy, i.e. facies changes from sand against shale. In this respect Narsighdi gas field is a structure-stratigarphic combination trap rather than purely structural trap. The pooling of gas is less effective in Narsingdi gas field compared to Meghna and Bakhrabad gas fields.

3.8.6.2 Reservoirs: The reservoirs of the gas field are sandstone belonging to the Surma group stratigraphic unit. There are two gas sands referred to as the Upper sand and Lower sand within the depth range of about 2900m to 3150m. The gross gas sand thickness of the two gas zones is 23 meter. There are four additional gas sands identified in the wireline log but these are too thin and are not considered commercial. The gas sands are very fine to medium grained with average porosities in the range of 15% to 16% and permeabilities in the range of 85 to 150 millidarcy. The gas sands were originated as delta front mouth bar in deltaic environment.

3.8.6.3 Gas reserve: The Narsighdi field has an estimated GIIP of 0.369 Tcf and an initial reserve of 0.277 Tcf (Petrobangla 2012). The gas field has been producing 30 mmcfd from two well by end 2012. The cumulative production till December 2011 was 0.128 Tcf. The gas field is being operated by Bangladesh Gas Field Company limited.

class 6)

3.9 Natural gas production in Bangladesh

Natural gas production in Bangladesh began in 1961 with gas supply from Chattak gas field to Chattak Cement Factory. In 1962, a second gas field, Sylhet, started supplying gas for use as raw material in Fertilizer Factory at Fenchuganj. This was followed by gas supply from Titas gas field to fuel Siddirganj power station. Production of gas has since been steadily increasing with more and more gas field coming on stream. While the cumulative gas produced during the fiscal year 1962 was 3.47 billion cubic feet (Bcf), it rose to 14 Bcf in FY 1970, to 46 Bcf in FY 1980, to 168 Bcf in FY 1990, 331 Bcf in FY 2000 and to 703 Bcf in FY 2010 (Figure 3.29A). The average daily gas production has also recorded an equivalent increase (Figure 3.29B). By end 2012, 25 gas fields are discovered in the country of which 19 are in production (Table 3.17).

Gas is produced by three national gas production companies, Bangladesh gas field company Ltd (BGFCL), Sylhet gas field compny Ltd (SGFCL) and Bangladesh Petroleum exploration company (BPEX) and a group of International oil companies (IOC). Table 3.17 lists the amount of gas produced in a typical day (15 October 2012) by these companies in their respective gas fields. Accordingly BGFCL operates and produces in five gasfields (Titas, Bakhrabad, Habiganj, Narsingdi and Meghna), SGFCL in five gasfields (Sylhet, Kailashtila, Rashidpur and Beanibazar), Bapex in four gas fields (Fenchuganj, Saldanadi, Shahbazpur, Semutang and Sundalpur.) and the IOCs produce from five gasfields(Bibiyana, Sangu, Jalalabad, Moulvibazar and Bangura). The shares of gas produced in the above date by these companies are as follows: BGFCL 33%, SGFCL 7.5%, BAPEX 3.5% and IOCs 56%.

3.9.1 Share of IOC produced gas increases

Until 1998, all gas supplied in the country were produced by national gas production companies BGFCL, SGFCL and Bapex. In 1998, one IOC, the Cairn Energy brought its offshore gas discovery Sangu on stream, thus beginning a new age with both national and international oil companies engaged in gas production. In the following years more IOCs, i.e. Chevron, Tullow and Niko joined as gas producers. The share of IOC produced gas kept on increasing since then (MIS Report, Petrobangla, June 2012). While the national gas companies used to produce 100% of

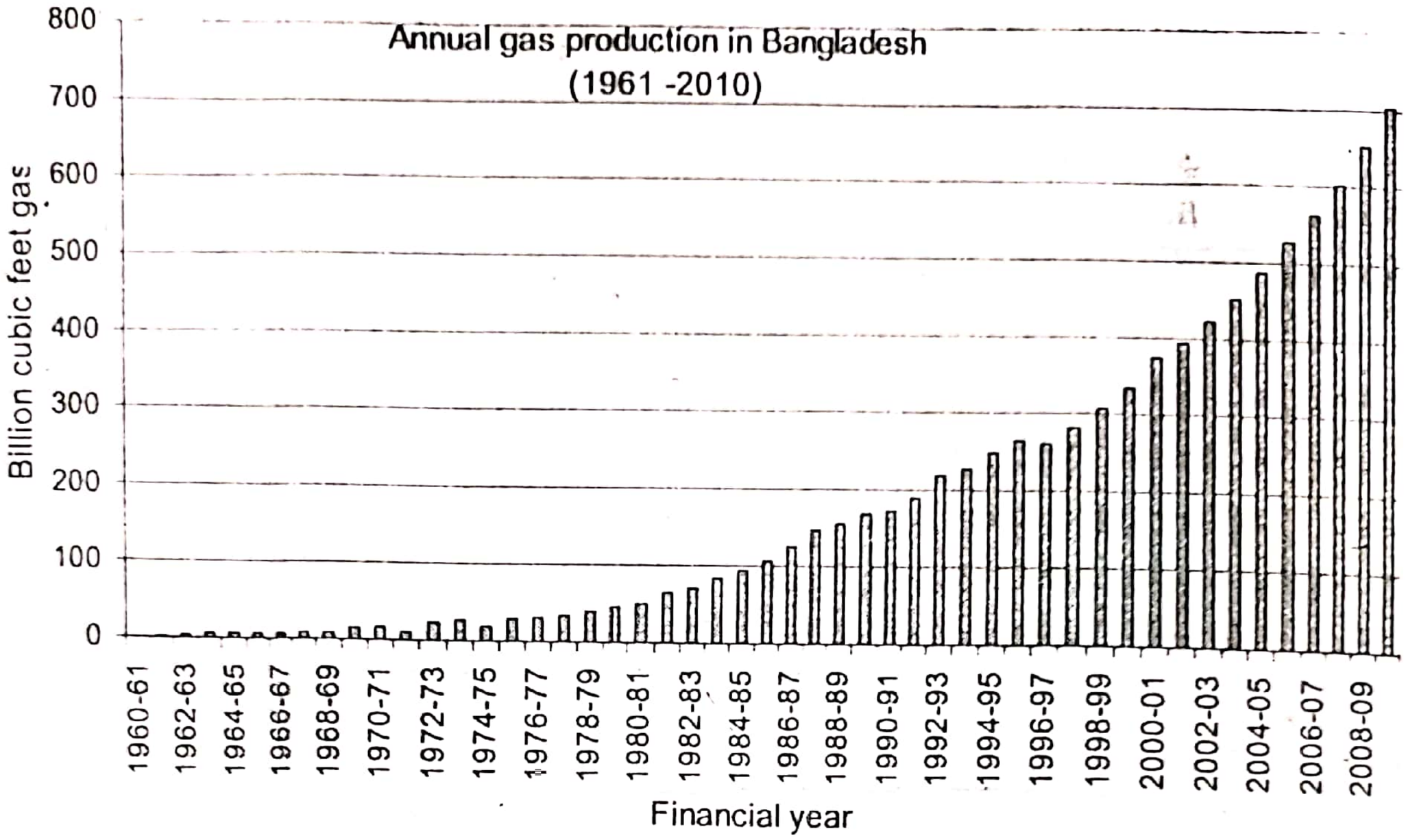


Figure 3.29A Annual Gas Production in Bangladesh (1961-2010)

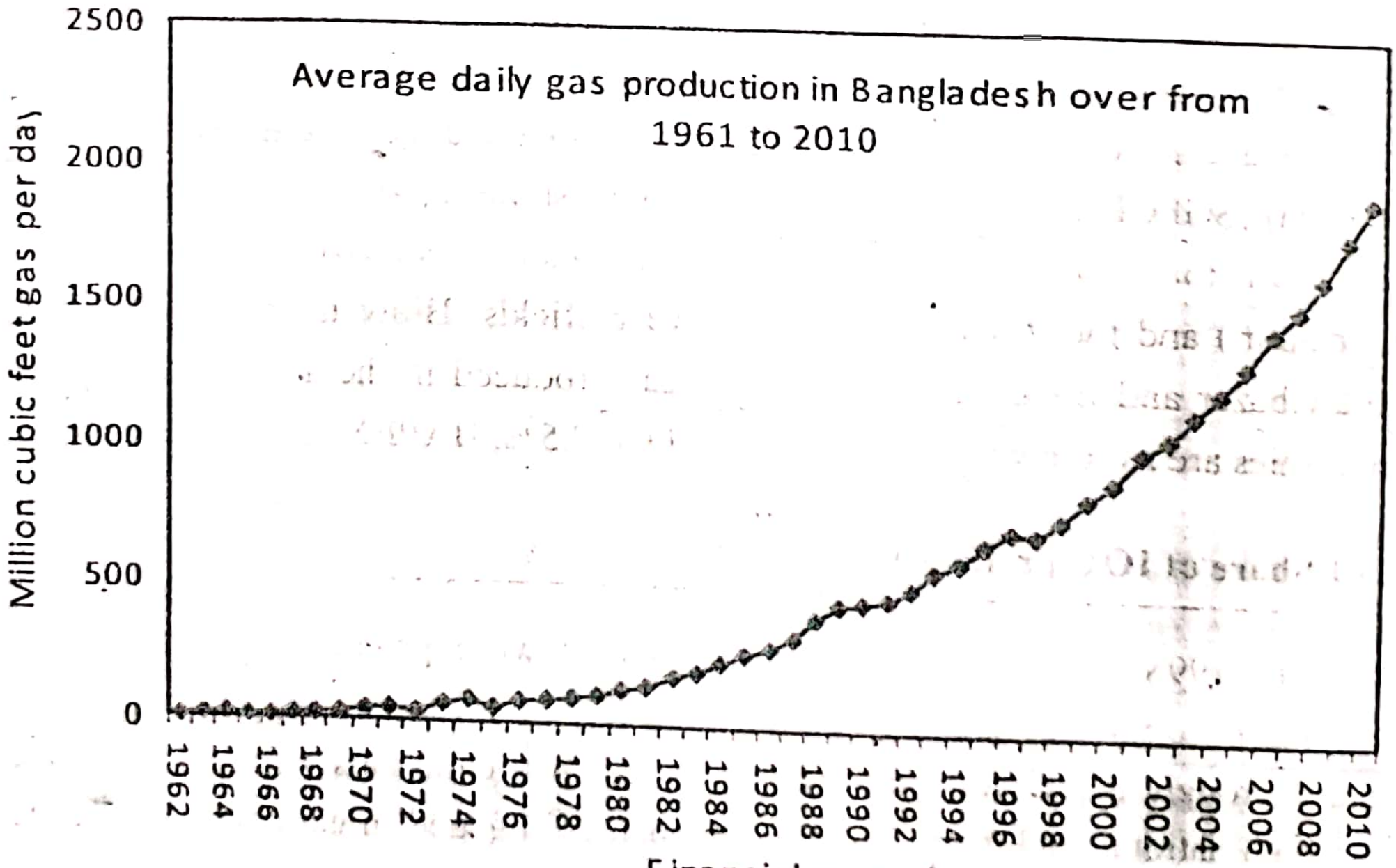


Figure 3.29B Average daily Gas Production in Bangladesh over the period 1961-2010

Table 3.17 Gas production in Bangladesh in a typical day-15 October 2012 (Source Petrobangla)

Operator		Gas field	No. of producing well	Production capacity	Daily gas production (mmcf) 15/10/12	Percentage of total gas production
Petrobangla subsidiaries	Bangladesh Gas Field Company Ltd (BGFCL)	Titas	15	452	451	19.7%
		Bakhrabad	5	33	32	1.3%
		Habiganj	9	240	231	10.1%
		Narsingdi	2	30	30	1.3%
		Meghna	1	11	10	0.4%
	Sylhet Gas Field Company Ltd (SGFCL)	Sylhet	2	11	10	0.4%
		Kailashtila	6	80	97	4.2%
		Rashidpur	4	49	47	2.1%
		Beanibazar	2	14	12	0.5%
	BAPEX	Saldanadi	3	20	17	0.8%
		Fenchuganj	3	40	38	1.8%
		Shahbazpur	2	30	8	0.4%
		Semutang	1	12	9	0.4%
		Sundalpur	1	10	9	0.4
International Oil Company (IOC)	Santos	Sangu	3	-	23	1.0%
	Chevron Corp.	Jalalabad	4	230	233	10.6%
		Bibiyana	12	770	827	36.2%
		Moulvibazar	4	60	101	4.4%
	Tullow Oil	Bangura	4	100	101	4.4%
Total					2287	100%

gas produced in the country prior to 1998, their share came down to 68% (IOCs 32%) in 2005-06, to 55%(IOCs 45%) in 2007-08, and to 47% (IOCs 53%) in 2009-10 (Figure 3.30). The daily gas production data shown in Table 3.17 indicates that in October 2012 the share of gas production by national companies were 44% of the total gas produced and that by IOCs were 56%.

3.9.2 Production rate of Petrobangla wells are lower than IOC wells

A comparison of the rate of gas production from individual wells of national companies (BGFCL, SGFCL and BAPEX) with those of the IOC wells shows that in general the IOC wells produce at much higher rate than the national wells. For example, production from individual wells of Chevron in Bibiyana are up to 80 mmcfd per well whereas the maximum production rate in individual wells of national fields (for example Titas, Habiganj) range from 35 to 40 mmcfd.

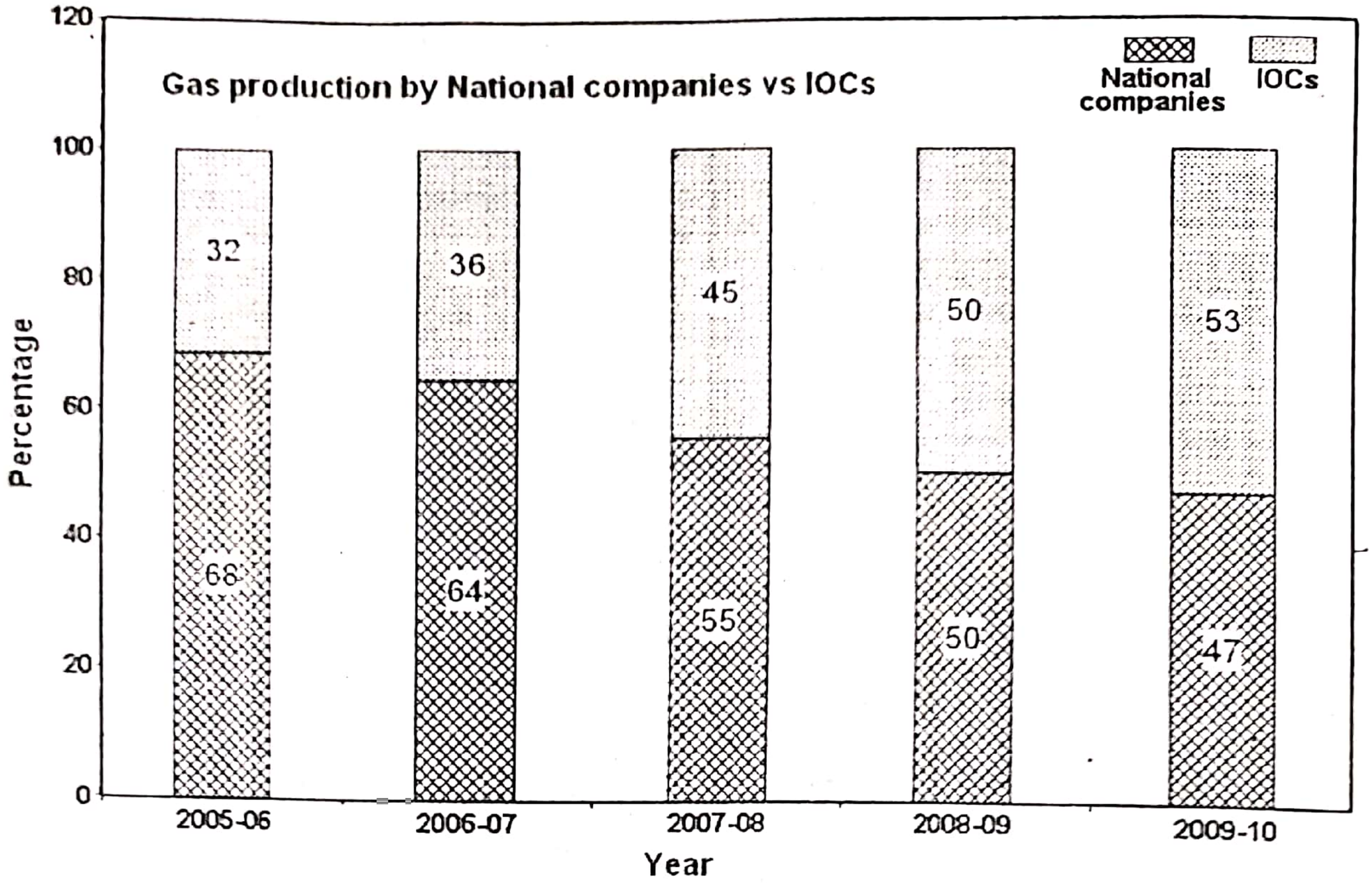


Figure 3.30 Relative percentage of gas produced by National companies versus IOC in Bangladesh over the years (After: Petrobangla).

Yet the fact remains that Titas and Habiganj gas reservoir sands have much better reservoir qualities (porosity-permeability) than those of the IOC gas fields.

In 2010, Hydrocarbon Unit (HCU) under the ministry of power energy and mineral resources has undertaken an ADB sponsored investigation to identify the causes and find remedial method to augment the gas production rates of national wells. MS Schlumberger has been engaged as a consultant to the job. A report submitted at the end of the study has pointedly identified some causes and suggested means to increase the production rate in Petrobangla wells as follows:

✓ i) Intervention in surface equipments: This involves servicing, tuning and replacing certain surface equipments (valve, chokes etc) in order to reduce pressure difference between wellhead and process plant.

✓ ii) Intervention in the borehole to remove flow restriction: The difference between the bottom hole and wellhead flowing pressure in certain wells are higher than it should be, causing restriction to flow capacity. If the restrictions are minimized the wells can produce at higher rate.

Table 3.18 Historical average daily, annual and cumulative gas production in Bangladesh.

Financial Year	Average daily gas production (Million cubic feet)	Annual gas production (Billion cubic feet)	Cumulative gas production (Billion cubic feet)
1961	-	1.0	1
1961-62	8	3.4	4.4
1962-63	13	5.4	9.8
1963-64	19	6.7	16.5
1964-65	16	5.7	22.2
1965-66	16	6.3	28.5
1966-67	19	6.5	35.0
1967-68	22	7.6	42.6
1968-69	27	10.2	52.8
1969-70	38	14.4	67.2
1970-71	46	16.7	83.9
1971-72	33	11.5	95.4
1972-73	66	23.5	118.9
1973-74	77	28.2	147.1
1974-75	52	18.9	166.0
1975-76	79	28.8	194.8
1976-77	88	32.2	227.0.
1977-78	93	34.2	261.2
1978-79	107	39.2	300.4
1979-80	126	45.6	346.0
1980-81	137	50.0	396.0
1981-82	178	64.8	460.8
1982-83	197	72.1	532.9
1983-84	227	83.2	616.1
1984-85	260	95.5	711.6
1985-86	293	105.0	816.6
1986-87	342	120.8	937.4
1987-88	403	147.3	1084.7
1988-89	427	162.0	1246.7
1989-90	460	167.6	1414.3
1990-91	474	172.7	1587.0
1991-92	515	188.3	1775.3
1992-93	578	210.8	1986.1
1993-94	613	223.7	2209.8
1994-95	677	247.1	2456.9
1995-96	729	265.6	2722.5
1996-97	715	260.9	2983.4
1997-98	770	281.9	3265.3
1998-99	841	307.8	3573.1
1999-00	909	331.2	3904.3
2000-01	1019	372.1	4276.4
2001-02	1071	391.5	4667.9
2002-03	1153	421.1	5089.0
2003-04	1238	452.7	5541.7
2004-05	1331	486.6	6028.3
2005-06	1460	532.8	6561.1
2006-07	1542	562.7	7123.2
2007-08	1646	600.8	7724.0
2008-09	1789	653.5	8377.5
2009-10	1926	703.0	9080.5

iii) Use of modern perforator: The national wells were completed in the past with unidirectional 4-6 shot per foot perforator which had low depth of penetration. By using the modern multidirectional perforator with higher penetration depth, better flow efficiency could be achieved allowing higher production rate.

iv) Production tubing size: The national wells use production tubing with diameter 3.5" compared to IOC well production tubing size of 5 inches. Use of greater diameter production tubing would mean greater flow and higher production rate.

3.9.3 Augmentation of gas production

In the context of the present gas supply deficit (about 500 mmcfd in mid 2012), many energy experts believe that the present gas crisis is more of a reflection of the inability to exploit the available gas reserves rather than the lack of it. There are several lines of actions that are being suggested by the expert in order to achieve augmentation of gas production in the existing gas fields in the country (Elahi 2010). These are:

i) Production augmentation in individual wells: As explained in the earlier section (3.9.2) the gas production from individual national wells may be increased by adopting certain simple ways and means which would involve minimum costs. These include intervention in the surface equipments, intervention in borehole to remove flow restriction, use of modern perforators and change of the production tubing for higher diameter tubing. The fact that most of the national wells were completed many years ago and has not since been readjusted or recompleted with modern and more efficient gears means that most of the national wells remain relatively lesser performer than their potentials.

ii) Work over of suspended well: There are several wells where production have been suspended due to depletion of the gas in the completed zone, or due to water handling problem and/or other mechanical problems. These wells may be brought into stream by recompleting in new zones and fixing any other problem by work over at minimum cost and time.

iii) Drilling appraisal/development wells: Most of the producing gas fields operated by national companies are yet to come to a mature stage of development.

For example one of the oldest one, Titas, produces from 1968 years (> 40 years from now) and still has the southern part of the field undeveloped as of 2012. While Titas has drilled 16 wells in forty years, the Bibiyana, operated by Chevron and being smaller than Titas has drilled 16 wells in the first 5 years of its production history. This means Bibiyana is eight time faster than Titas in developing the gas. This is one case which testifies that the development of gas fields have more potential than its present position and far more gas may be extracted by simply adopting a more serious development plans in the national gas fields.

3.9.4 Near future gas production forecast: Rise and then fall

Ever since gas production began in the country in 1962, the average daily production kept on growing keeping pace with the growing national demand. The average daily production of gas has increased from about 8 million cubic feet per day (mmcfd) in financial year 1962 to 38 mmcfd in 1970, 126 mmcfd in 1980, 460 mmcfd in 1990, 909 mmcfd in 2000 and 1926 mmcfd in 2010 (Table 3.19, Figure 3.29B). The daily gas production data provided in Table 3.17 shows a cumulative daily production of 2287 mmcfd on 15 October 2012.

Will the average daily production keep on increasing with the line of increasing demand in the near to long term future? There has been some production forecast on near to medium term future which are based on some practical assumption. These assumptions take into accounts the possible increase in production in the existing fields as well as the possible increase in production from expected new discoveries (JICA 2011). There have been three cases forecasted and include (Figure 3.31):

i) Government's case (high case) in which production will reach peak at about 3900 mmcfd in 2017 and thereafter will decrease gradually,

ii) PSMP case 1 (base case) the production will peak at about 3320 mmcfd in 2017 and thereafter will decline gradually, and

iii) PSMP case 2 (low case) in which production will peak at about 2700 mmcfd in 2017 and will decline thereafter.

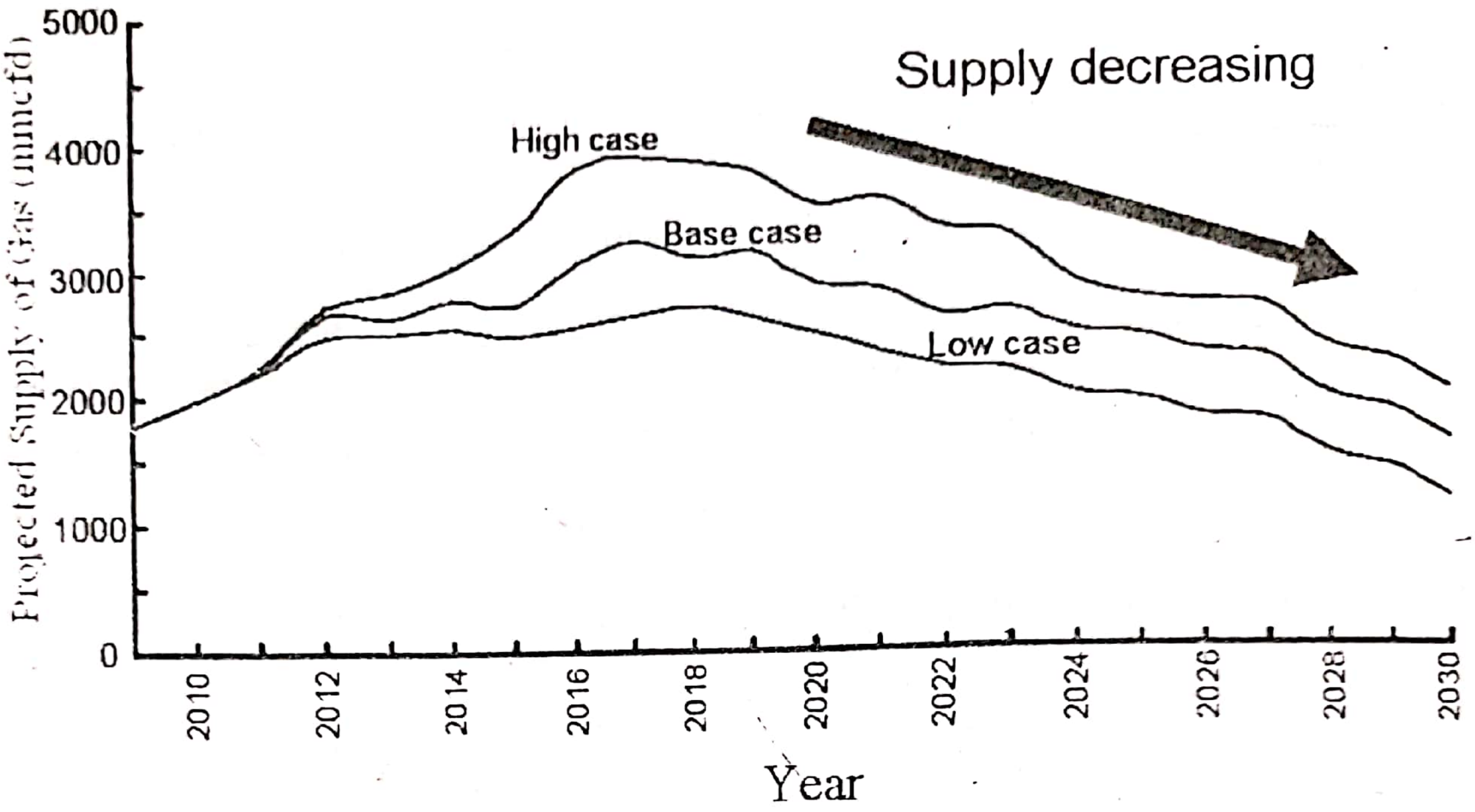


Figure 3.31 Projected gas supply in Bangladesh in near to medium term future – a rise and then fall (Source: JICA 2012)

In each of the above case, gas production is forecasted to increase till around the year 2017 and will gradually decrease thereafter. Beyond that point the gap between demand and supply will continue to grow wider and the supply will never ever reach demand again. The balance in energy supply would have to be met by other primary energy source like coal.

3.10 Utilization of natural gas in Bangladesh

Natural gas in Bangladesh is used as fuel as well as feedstock for fertilizer production. It is the predominant fuel for power generation in the country. In FY 2010, power generation plants and industry combined together use about 73% of the total gas produced (Figure 3.32).

Remaining 17% of the produced gas is used in fertilizer production, domestic, commercial and CNG sector including a 4% system loss (Petrobangla 2011). Although prospect of natural gas as an export commodity was debated during 2001-2002, this was not found viable. Instead, the government has been actively looking into the possibility of gas import either by pipeline or in the form of LNG. The role of natural gas in the economic development remains prime during 2010-2011, but the forecast into near to medium term future suggests that the country will lose

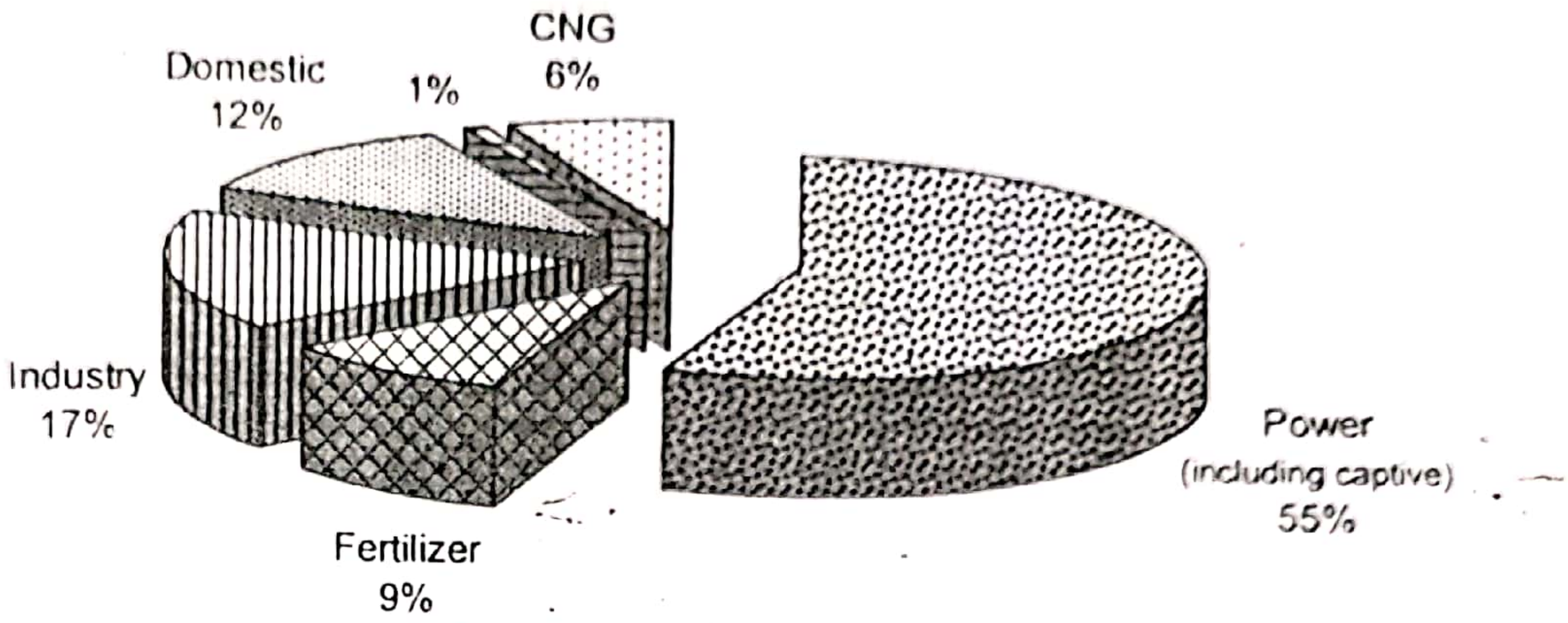


Figure 3.32 Sectoral use of gas in Bangladesh -2010-11.

its natural gas based mono-energy status and the share of other energy will inevitably increase to make a balanced energy mix.

3.10.1 Electricity generation:

For more than a decade power plants have been the largest users of natural gas in the country. In the financial year 2010-11, power generation (including captive power) consumed 395 Bcf gas, i.e. 55% of the total gas consumed in the country in that year (Figure 3.32). This records an average daily gas consumption of 1082 mmcfd. The decade wise data base shows that gas consumption for power generation has increased from 1.10 Tcf in the decade 1991-2000 to 2.65 Tcf in the next decade (2001-2010), more than double in successive decade (Table 3.19). During the period from 2005 to 2010, the annual growth rate of gas use in electricity range from 4% to 12%.

In FY 2009 and FY 2010, about 88% of the electricity generated in the country came from gas based power plants (Ministry of Finance 2012). Since then, the acute gas crisis in the country failed to totally meet the gas demand in the power plants and this reduced the share of gas in power generation. At the same time, electricity demand kept on growing and thus made the situation even worse.

To combat the crisis, the government has allowed establishment of many oil based rental power plants on a temporary basis. This has increased the share of

Table 3.19 Sector wise and total gas consumption in successive 10 year periods from 1961 to 2010 (Source: Petrobangla).

	Gas consumption (Trillion cubic feet)				
Period of:	*1961 to 1970*	*1971 to1980*	*1981 to1990*	*1991 to 2000*	*2001to 2010*
Power	0.009	0.102	0.432	1.104	2.652
Fertilizer	0.049	0.129	0.359	0.756	0.848
Others	0.009	0.048	0.276	0.630	1.675
Total consumption	0.067	0.279	1.067	2.490	5.175

oil in electricity generation from 6% in FY 2009 to 12% in FY 2011 (Ministry of Finance, GOB, 2012) making the generation cost excessively high with negative impact on national economy. It is expected that the share of oil for power generation will peak in FY 2013 with 22% of power generation shared by oil when share of gas will come down to 74% (Ministry of Finance GOB 2012). This will be followed by gradual increase, once again, of gas share and fall of oil share in power generation till 2016 when the share of oil will come down to the previous level of 6% (Ministry of Finance GOB 2012).

However, it has been projected both by the government and international consultant JICA that supply of gas thereafter i.e. from 2017 onward, will take a downward trend and gas will no longer be the sole primary fuel for meeting country's energy need. From this point onward coal is expected to take major share of energy supply along with gas. As a consequence the share of gas in power generation is projected to decrease to 54% in 2020, 36% in 2025 and 25% in 2030 according to the Power sector master plan or PSMP 2011 (JICA 2011).

The above projection pictures the near future as a new age in energy mix of the country whereby fuel diversification for electricity generation is inevitable. It may be concluded that the heyday of natural gas use for electricity generation in Bangladesh is over and the future will bring alternative energy source like coal to fill the gap created by natural gas shortage.

3.10.2 Fertilizer production

In the financial year 2010-11, the fertilizer sector consumed about 63 Bcf of gas, i.e. 9% of the total gas consumed in the country that year. The fertilizer sector used to be the second largest user of gas after power generation. However, the gas supply in this sector decreased from 25% of the total produced gas in FY 2000 to 16% in FY 2007 and to 13% in FY 2008. Since then, because of the continued gas crisis, gas supply to the fertilizer industry has further decreased to 9% in FY 2011. It has been projected that the restriction of gas supply to fertilizer factories will continue till 2013 and thereafter the gas supply will be increased.

The main fertilizer produced in Bangladesh is urea for which gas is used as raw material as well as for fuel for processing and generating its utilities. There are at present seven fertilizer factories with total maximum gas demand of about 289 mmcfd (Table 3.20). From Petrobangla source it is known that the supply of gas to fertilizer industry has its ups and downs in 2012; for example, against a maximum demand of 289 mmcf, the gas supply to fertilizer factories were 60 to 70 mmcfd during June and July of that year while it increased to 217 mmcfd in October, (Petrobangla, Marketing div 2012).

Table 3.20 Maximun gas demand in the fertilizer factories and supply on 15 Oct 2012 (Source: Petrobangla, Prod. & Market Div 2012)).

Plant	*Year commissioned*	*Maximum gas demand per day (mmcfd)*	*Gas supply on 15 October 2012 (mmcfd)*
Natural gas fertilizer factory, Fenchuganj	1961	18	16
Urea fertilizer factory, Ghorasal	1970	45	39
Zia fertilizer factory,Ashuganj	1981	52	52
Polash Urea fertilizer factory,Ghorasal	1986	14	13
Chittagong Urea fertilizer Factory ,Rangunua	1987	52	10
Jamuna fertilizer factory,Jamalpur	1991	45	37
Karnaphuli fertilizer factory (KAFCO)	1994	63	50
Total		289	217

3.10.3 Industrial sector

The industrial sector has been the second largest consumer of gas since 2007. During FY 20010-11 this sector consumed 121 Bcf gas, about 17% of the total gas consumed that year (Figure 3.32). During the period from 2005 to 2010, the annual growth of gas use in industrial sector range from 13% to 22%.

The industrial sector, for this discussion, includes all industrial activities except fertilizer. In the industrial sector gas is used in variety of different processes i.e. in industrial furnaces, boiler, smelter, dryer and others. Major industrial units in Bangladesh include cement, paper, fiber, sugar, metal processing, leather, export processing zone etc. Small to medium consumers in industrial sectors include ceramics, glass, foundry, dye work and food processing factories etc. Industries previously (pre-1980s) using furnace oil, diesel or other liquid, switched over to gas as availability allows them to do so. Gas demand for industry has therefore grew steadily after 1981.

3.10.4 Domestic and commercial sectors

Domestic consumers use gas as a cooking fuel mainly. The sector consumed about 73 Bcf of gas in FY 2010, i.e. 12% of the total gas produced in the country that year. This recorded an average daily consumption of 238 mmcf gas. The domestic use of gas has been growing at an annual rate of 6% to 11% during the period from 2005 to 2010, with a 9% annual growth during the year 2010. However, it may be mentioned that nationwide, only a small population living in metropolitan cities has access to domestic commercial natural gas in the country.

The commercial consumption accounts for about 1% of the total gas consumed in the country. Commercial gas consumption during FY 2010 was about 8 Bcf. This recorded an average daily consumption of about 22 mmcf gas. This sector includes hotel, restaurant, hospitals, school, universities, office buildings, shopping mall and other commercial units. The commercial use of gas grew at an average rate of about 2% during 1991-2000.

3.10.5 Automobile/Vehicle Fuel (CNG)

Because of the fact that natural gas is cleaner and environmentally friendly fuel, its uses as an alternative fuel in place of gasoline or diesel to run automobiles have attracted much attention over the world. In several cities of the world compressed natural gas (CNG) run car is becoming more and more common.

In Bangladesh, CNG as a vehicle fuel was introduced around 1985. By 2010, about 25% of the one million vehicles were running on CNG across the country (Hossain 2010). In the FY 2010 CNG vehicles consumed 38 Bcf gas or 5% of the total gas consumed during that time. This recorded a daily consumption of about 103 mmcf of gas.

A rapid growth of CNG as transport fuel was forecasted as the government placed the program in its priority list. In 2002, the government appointed Gas Utilization Committee had forecasted gas demand for CNG vehicles by the year 2010 assuming three conversion scenario i.e. low, medium and high. A low conversion scenario with 50,000 CNG vehicle requiring 50 mmcf per day or 18 Bcf (0.018 Tcf) per year; a medium conversion scenario with 75,000 CNG vehicle requiring 75 mmcf per day or 27 Bcf per year and a high conversion scenario with 100,000 CNG vehicle requiring 98 mmcf per day or 36 Bcf per year (National Committe for gas Utilization 2002). In reality, by the year 2010, the use of CNG exceeded the high case scenario of the 2002 forecast and the actual use of CNG stood at 103 million cubic feet of gas per day or 38 Bcf per year.

3.10.6 LPG (Propane plus Butane)

Liquefied Petroleum gas (LPG) is a mixture of propane (C_3H_8) and butane (C_4H_8) bottled and marketed in cylinder. These two components has special property of becoming liquid at atmospheric temperature if lightly compressed (80 to 110 psi pressure) and revert to gases when pressure is sufficiently reduced. Advantage is taken of this property to transport and store these products in liquid state. It is an easy alternative to pipeline gas (methane) and has been used as fuel in domestic cooking and commercial uses, specially where pipeline network is not available. LPG is a colorless, odorless and heavier than air in vapor state. A sulfur based chemical is added to give it a smell so that a small leak can be detected.

methane - CH_4
ethane - C_2H_6
propane - C_3H_8
butane - C_4H_{10}

Some petroleum observers opine that pipeline supply of natural gas for domestic and commercial user in small towns is already a bad economic choice in Bangladesh and it would be more appropriate to replace pipeline supply of natural gas by LPG in these places (Saleque 2003). LPG is a safe and clean fuel and it is also used to run automobile in many countries. It is produced either from wet natural gas in NGL fractional plant or in the crude oil refinery as a by product.

LPG is used as cooking fuel in urban Bangladesh where pipeline networks are mostly absent. However the percentage of households using LPG is small compared to other form of cooking fuel. Looking at the broad picture, more than 70% of the households of the country, are rural and uses firewood and biomass with few using kerosene. In urban and semi-urban areas, around six million houses predominantly use wood/biomass and kerosene as cooking fuel, followed by about two million households who use pipe line natural gas. LPG has a small share of less than a million household living in urban and semi urban areas (Rahman and Hussain 2009). The gas crisis of 2010s means that more and more urban households should depend on LPG for domestic cooking.

The annual demand of LPG in the country has increased from 300 thousand metric tons in 2003 to about 500 thousand metric tons in 2012 (Fianace Ministry, GOB, 2012). There are three sources from which LPG is made available in the country at present (Table 3.21). These are i) NGL fractionation plant in Kailashtila gas field, producing about 7850 ton/year LPG. The natural gas liquid (NGL) that is separated out from methane is piped to the fractionation plant which produces LPG, motor spirit and kerosene from the liquid received, the LPG being the most important product, ii) crude oil refinery in Chittagong producing 13200 ton/year LPG as a by product of oil refining process and iii) government and private agencies importing 100 thousand ton/year LPG (Fianace Ministry, GOB, 2011).

Thus the total supply of LPG in the country by 2012 is about 121 thousand ton/year against a demand of 500 thousand ton/year (Table 3.21). The government has planned to reduce the gap between demand and supply by increasing the import of LPG in the country. The government has taken up a project to establish an import based LPG storage and bottling plant with a capacity of 100 thousand in Mongla,

Table 3.21 Status of LPG market in Bangladesh. (2012).

Sources of LPG	*Amount (Ton per year)*
(NGL) Kailashtila fractionation plant,, Golapganj	7850
(Crude) Eastern refinery Ltd, Chittagong	13200
(import) Import by private sectors	100,000
Total supply	121,050

Bageghat. A second import based LPG bottling plant is also planned to be establish in Chittagong under public-private partnership.

3.10.7 Gas export option rejected –Import contemplated

In October 2001. the Unocal Corporation, one of the IOCs working in Bangladesh submitted a gas export and pipeline development proposals to the Bangladesh government. The proposal was aimed at pipeline gas export from Bibiyana gas field in northeast Bangladesh, to the markets in the Delhi area, India. Bibiyana gas field was discovered by the same company in 1998. Under the pipeline gas export project, Bibiyana gas would be transported via a 1350 kilometer long 30 inch diameter pipeline to be constructed. A length of 350 km of the pipeline would be located within Bangladesh and the remaining 1000 km in India according to the Unocal proposal.

Unocal proposed that 500 million cubic feet of gas per day would be supplied from Bibiyana gas field to the Indian border. The 350 km Bangladesh section of the pipeline would be built by a consortium including Bangladeshi interests. The gas would then be taken to be transported to Delhi via the Indian section of the pipeline that would be built by Indian consortium.

For the proposed 20 year gas export project, supplying 500 million cubic feet of gas per day means the project would require a total of about 3.6 Tcf of gas. Unocal emphasized that India has a large gas market and Bangladesh should utilize the

window of opportunity to sell its gas. Unocal estimated that the shortfall in gas demand along the HBJ pipeline in India is expected to increase from 955 mmcfd in 2005 to 7000 mmcfd by 2020. The major consumers of the imported gas in Indian side would be the power and fertilizer sectors. Unocal proposed that the financing and construction of the pipeline could be expected to complete in four years with the 'first gas' anticipated to begin flowing in the fourth year.

The gas export proposal stirred up debates among government officials, national experts and politicians in Bangladesh. While some Bangladeshi business interests and bureaucrats tried to lobby in support of the gas export, vast majority of the population including the national experts, civil society, academicians and politicians strongly opposed the gas export proposal.

The opponents of gas export argue that Bangladesh do not have enough natural gas reserve to meet its future domestic demand. Ten years after the proposal was rejected, the arguments against gas export remain valid to date. The following points may be high lighted:

✓ i) Gas is the most important energy source in the country contributing about 70% of the total commercial energy consumed in 2009; the country's overwhelming dependence on gas is evidenced from the fact that about 90% of the electricity generated here was based on gas fired power plant during that time. The present gas reserve will not allow this gas dominance to continue and it has been projected that gas share in meeting primary energy need will continue to decrease from as soon as 2016 or 2017.

ii) Petrobangla forecasted that the country's future gas demand is about 8.86 Tcf from 2011-2020 and about 13.05 Tcf from 2021 to 2030. With about 16 Tcf of remaining gas reserve as of December 2011, there is no option of contemplating gas export. The country should embark on a rigorous exploration program to increase its gas reserve toward achieving a gas security for 50 years.

iii) Assessment of the undiscovered gas resource of Bangladesh suggests a 95% possibility of finding about 8.2 Tcf or 50% possibility of finding 32.1 Tcf of yet undiscovered gas in Bangladesh over the next 30 years (USGS-Petrobangla 2001).

This assessment does not lent support to a notion of 'floating on gas' or 'tremendous prospect' for the country.

iv) Bangladesh does not have good oil prospect according to the recent geological studies (USGS-Petrobangla 2001). The contribution of coal to the total energy mix in the country is about 4%. This is likely to increase as national coal production is likely to increase, but the role of gas as a prime fuel in the country will not change in short term future.

v) Kaptai hydroelectric plant is the only one of its kind in Bangladesh and contributes to a small part of total electricity generation. The scope of establishing any further major hydroelectric plant in the country is nil, considering the social, political and economic fallout of Kaptai hydroelectric project. (?)

vi) The take off point for solar or other alternative energy (wind, wave etc) source becoming easily available worldwide will be delayed very significantly as suggested by scientists. The world will not see an alternative energy source like solar energy becoming easily and widely available before 2060. In 2010, the solar energy contribution to electricity generation is only about 1% of the total electricity produced in the country, too low to make an impact nationwide.

vii) In conclusion, it may be mentioned that the present plan to combat the energy crisis involves diversification of energy mix. This is an inevitable consequence of gas shortage and the fact that gas is unable to play required role as single predominant source of primary energy in the country. While the country is now actively implementing ways to import coal for power generation, realistic planning for gas import from a cost effective source is a second choice Bangladesh contemplates.

3.10.8 LNG option -A costly venture

Liquefied Natural Gas (LNG) is produced when natural gas is artificially liquefied by refrigerant at super low temperature of minus 160° centigrade. LNG technology is developed for long distance transportation and export and import of natural gas via ocean tanker similar to oil tanker. Large scale investment is required

to build an LNG plant. Furthermore, LNG operation requires infrastructure for delivery, transportation tanker and receiving terminals.

In the 2008 PSC agreement between the government and the international oil companies (IOC), gas export via LNG was an option given to the companies. For a LNG operation to be commercially viable, Bangladesh needs to have the capability of dedicating at least 6 Tcf of gas for the purpose. It will also require an investment of about US $6 billion. However, considering the fact that the country has about 16 Tcf of natural gas (2P reserve) remaining in 2012 and that the country's dependence on pipeline natural gas for power and fertilizer and other industries is overwhelming, dedicating 6 Tcf of gas for LNG export purpose is not considered a rational option.

On the contrary, Bangladesh is recently implementing a plan to import LNG from gas rich middle east country Qatar with which preliminary agreement has been signed for the purpose. Bangladesh plans to import 500 mmcfd gas in the form of LNG from Qatar. There is no problem of this venture on the supply side because Qatar is one of the most gas rich country in the world with gas reserve of about 900 Tcf. But the question is whether Bangladesh can afford a very costly LNG?

Industry experts opine that LNG will be too costly for Bangladesh to consume. LNG price in the international market is in the range of $13 to $14 per Mcf which is more than four times higher than the IOC gas Bangladesh purchase ($3 per Mcf). Furthermore the infrastructure that is required for LNG import include floating storage and regasification unit (import terminal), subsea and over land gas pipe lines to transport the gas from floating terminal to the consumers. These are being planned to be built in and off the Moheshkhali Island for which massive investment will be required.

3.11 Future gas demand projection

Ever since gas consumption began in the country in 1962, the demand of gas kept on growing. While the average daily gas demand and supply in FY 1970 was 38 million cubic feet (mmcf), this has increased to 126 mmcf in FY 1980, 460 mmcf in FY 1990 and to 909 mmcf in FY 2000. Since 2001 the annual rate of growth of gas demand has been 8%. to 10% By 2005 the demand outpaced the supply and a gas

shortfall set in the gas sector. By the beginning of 2012, the gas demand was recorded at 2500 mmcf per day against a gas production rate of about 2000 mmcf per day, setting a shortfall of about 500 mmcf per day.

How would the gas demand grow in short term and long term future? There has been several future gas demand projection made at several point in time and by several agencies. Obviously none of these are full proof because of the fact that energy demand projection or the gas demand projection for that matter, of a developing nation is a difficult task. This is because the economic growth, which is the main driver for energy growth is very difficult to predict. It is more so when demand projection is considered for a long term rather than short term basis.

3.11.1 Daily gas demand projection upto 2025 (Petrobangla GSMP 2006)

In 2006 the gas sector master plan (GSMP) was prepared by Petrobangla/World Bank consultant (Wood Mcanzee) in which future gas demand (per day) projection upto 2025 was made for three cases depending on different GDP growth assumption. These are Case A (assumes GDP growh in continuation of current i.e. 2006 trend), Case B (assumes GDP growth upto 7%- consistent with govrernment's proverty reduction plan) and Case C (assume GDP growth upto 9%).

The demand projection of case B of GSMP and that of Petrobangla almost matches except for the latter end of the forecasting period where case B diverges to higher level. However none of the above two forecast matches with the actual gas demand, so far these can be judged (2006 to 2011).

On the other hand, a comparison shows that case C projection has very close match with the actual demand for the same period. For example, Case C demand projection of 1785 mmcfd at end fiscal 2009 matches well with actual demand of 1791mmcfd at end fiscal 2009; also case C demand projection of 2500 mmcfd at begining 2012 matches with actual demand of 2500 mmcfd at beginning 2012 (Fig 3.33).

According to case C demand projection, the daily gas demands are expected to reach about 3050 mmcfd begining 2015, about 4800 mmcfd begining 2020 and about 7400 mmcfd begining 2025 (Fig 3.33).

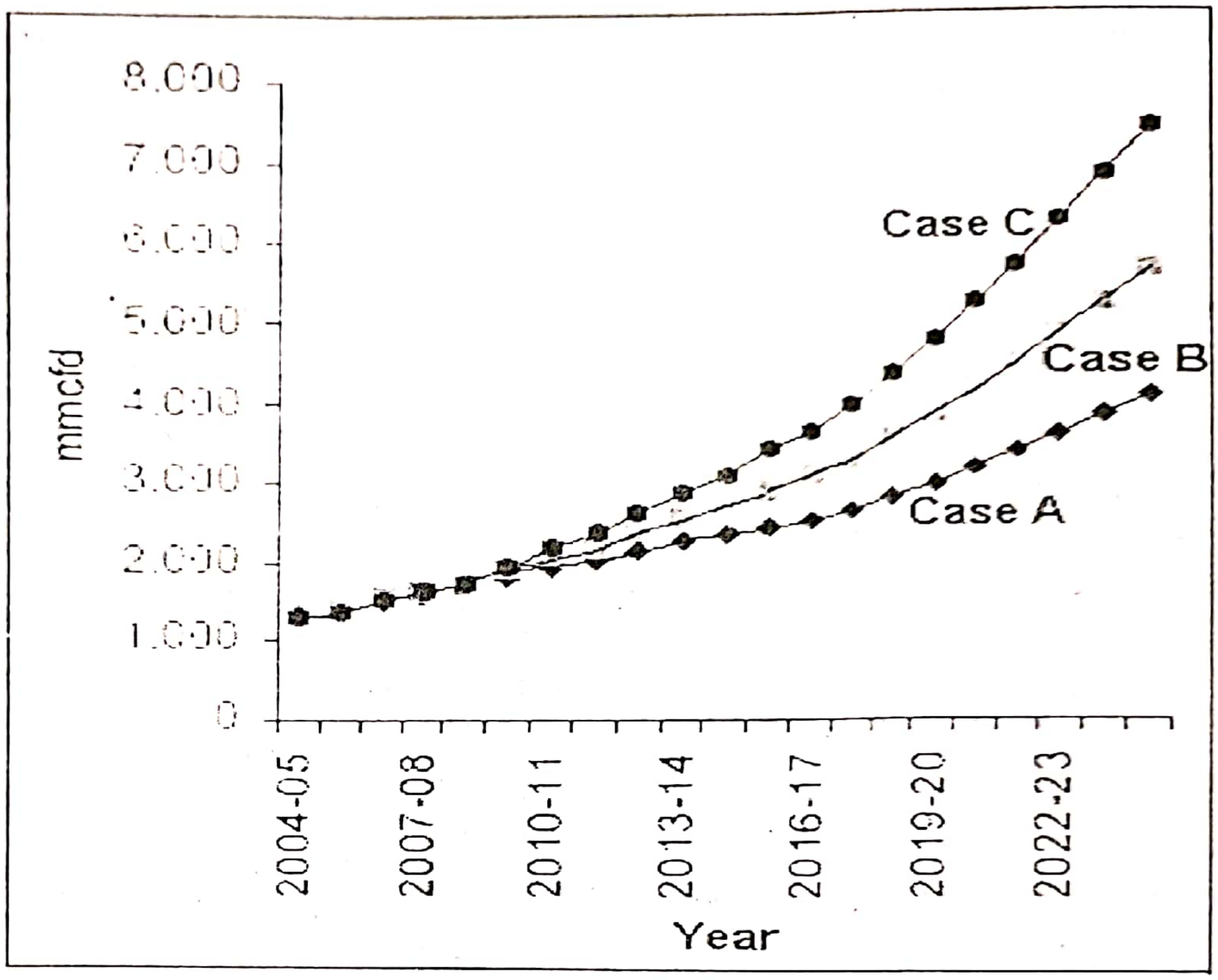


Figure 3.33 Gas demand projection upto year 2025 (Source: Petrobangla)

3.11.2 Year-wise gas demand projection upto 2016 (Finance Ministry,GOB)

The Ministry of Finance, government of Bangladesh has published a road map for power and energy sectors in which sector wise gas demand and the total yearly demands of the country has been projected to 2016 (GOB 2012). It has shown that while the actual gas demand in financial year (FY) 2011 was 714 billion cubic feet (the actual production being 709 Bcf), the projected gas demand in the FY 2013 would be 1061 Bcf. And this will increase to 1222 Bcf in FY 2014, to 1335 Bcf in FY 2015 and to 1453 Bcf in FY 2016. This projection envisages an yearly gas demand growth rate of 8% to as much as 15%.

3.11.3 Decade-wise gas demand projection upto 2050

3.11.3.1 Sectoral demand analysis by Petrobangla (2001): Projection based on disaggregated or sectoral demand analysis is relatively simple method though laborious and time consuming. Petrobangla made a gas demand projection for a fifty years period for the country using this methodology (Khan 2001).

Petrobangla's future gas demand projection was based on sectoral demand analysis as per the data received from the gas consumer authorities (Bangladesh Power Development Board or BPDB, Bangladesh Chemical Industries Corporation and other industrial and commercial sectors) to which it requested for their growth projection and consequent projected gas requirements (Khan 2001). Gas demand projection was made individually for each sector i.e. power, fertilizer, industries, commercial and domestic for ten year intervals from 2001 to 2050.

According to above, the country's total gas demand was projected at 4.84 Tcf for the period 2001-2010 (in reality the gas consumed during the period 2001-2010 was 5.12 Tcf), 8.86 Tcf for the period 2011-2020 , 13.05 Tcf for the period 2021-2030 , 16.9 Tcf for the period 2031-2040 and 19.31 Tcf for the period 2041-2050. In other words, the cumulative gas demand for the fifty years from 2001-2050 has been projected at 62.9 Tcf (Khan 2001).

3.11.3.2 Energy Intensity Analysis by National Committee (2002): Projection based on energy intensity (EI) of the economy is a more . complicated but more suitable method for high commercial energy consuming countries. The National Committee for Gas Demand and Reserve (2002) has adopted this methodology to project the country's natural gas demand for a 50 years period. Energy Intensity, by definition, is the ratio of commercial energy consumption (toe) and the GDP. For gas-demand projections for next fifty years, the Committee opted for a range of GDP growth rates i.e. 3%, 4.55% (business as usual), 6% and 7%. According to the Committee, the usefulness of several scenario is that one can get a picture of the energy requirement, given a level of economic performance.

Taking the 4.55% GDP growth model, the national Committee projected a gas demand of 4.7 Tcf for 2001-2010, 8.8 Tcf for 2011-2020, 14.2 Tcf for 2021-2030, 18.9 Tcf for 2031-2040 and 22.4 Tcf for 2041-50. This means a cumulative gas demand of about 69 Tcf in 50 years from 2001 to 2050 (National Committee for gas demand and reserve 2002).

3.12 Gas well blow out accidents

A 'blow out' is simply the blowing up and destruction of the drilling rig and associated installations due to sudden, violent and uncontrolled flow of fluids i.e. water, gas or oil, from underneath the surface. Such accident is accompanied, in most cases, by fire and lead to damage of properties and often loss of lives. Oil or gas zone or overpressured water bearing rock layer in the subsurface. if penetrated by drilling pipe, may cause forceful flow of fluid into the drilling pipe. This fluid may come up to the surface and kick the rig floor violently causing a blow out. It is therefore customary to maintain a proper mud circulation through the drill pipe during drilling in order to counter any fluid flow from the formation into the drill hole. This is done by increasing the mud weight whenever such force is expected or encountered in the subsurface. Any delay or failure to maintain such a circulation may cause fatal blow out in a gas or oil well.

In Bangladesh there have been some cases of gas well blow out. Among these, the Sylhet-1 gas well blow out, the Moulvibazar-1 (Magurchara) gas well blow out and Chattak-2 (Tengratila) gas well blowout are well known.

3.12.1 Sylhet Well Blow out: Accident that bleeds gas till date

The Sylhet-1 exploratory well was drilled in 1955 by PPL. The well was drilled to a depth of 2379 meter and encountered gas. After casing was set, the well blew out of control, ignited and destroyed the rig. A large crater was formed into which the rig sank. Subsequently the crater was filled with water creating a large pond which is still present today and vents gas from the subsurface into the air in the form of bubbles. The gas bubbles catch fire on ignition. The site attracts people as a tourist spot.

A second well, Sylhet-4 had a similar blow out fate when drilled to only 314 m below surface (Table 3.22). The well was abandoned. Gas broke through to the surface close-by and is still venting out today from fissures in the well site and nearby hillside (porapahar) often catching fire.

Table 3.22 Blow outs wells (bold) in Sylhet gas field (Source: Petrobangla).

Well	Spud date	Total depth	Status
Sylhet-1	26-1-1955	2379	**Blow out** Rig sunk into the crater. Gas seepage continues till date through water filled crater.
Sylhet-2	24-5-1956	2818	Plugged and Abandoned
Sylhet-3	6-5-1957	1675	Gas well
Sylhet-4	11-4-1962	314	**Blow out** Gas seepage continues till date through fissures in the adjacent hill sides (*Pora Pahar*)
Sylhet-5	14-2-1963	574	Observation well
Sylhet-6	6-5-1964	1406	Gas well
Sylhet-7	12-6-1986	2065	Oil well

3.12.2 Moulvibazar-1 (Magurchara) well blowout – A case of misadventure

A more dangerous and bigger gas well blow out took place in 1997 in Moulvibazar district when Moulvibazar -1 well (also known as Magurchara well) was blown out due to violent and uncontrolled flow of gas. It was an exploratory well drilled by Occidental/Unocal Oil Company in Moulvibazar anticline east of Rashidpur gas field. The accident resulted in total destruction of drilling rig and associated installations, damage to the environment and loss of natural gas and human properties. Large amount of gas was lost into the air not only through the well but also through the fractures formed in the ground surrounding the well.

The Margurchara well targeted to drill to a depth of about 3400 m below the surface. The well drilled through a loosely consolidated sand layer known as Tipam Sandstone Formation in shallow subsurface and then through a consolidated shale layer known as Upper Marine Shale or UMS (Figure 3.34). The driller did not set a casing in the loose Tipam Sand unit above the UMS.

Just below the UMS, the well encountered a gas zone at a depth of about 800 meters from the surface. After drilling to a depth of 840 meter as a vertical well, the

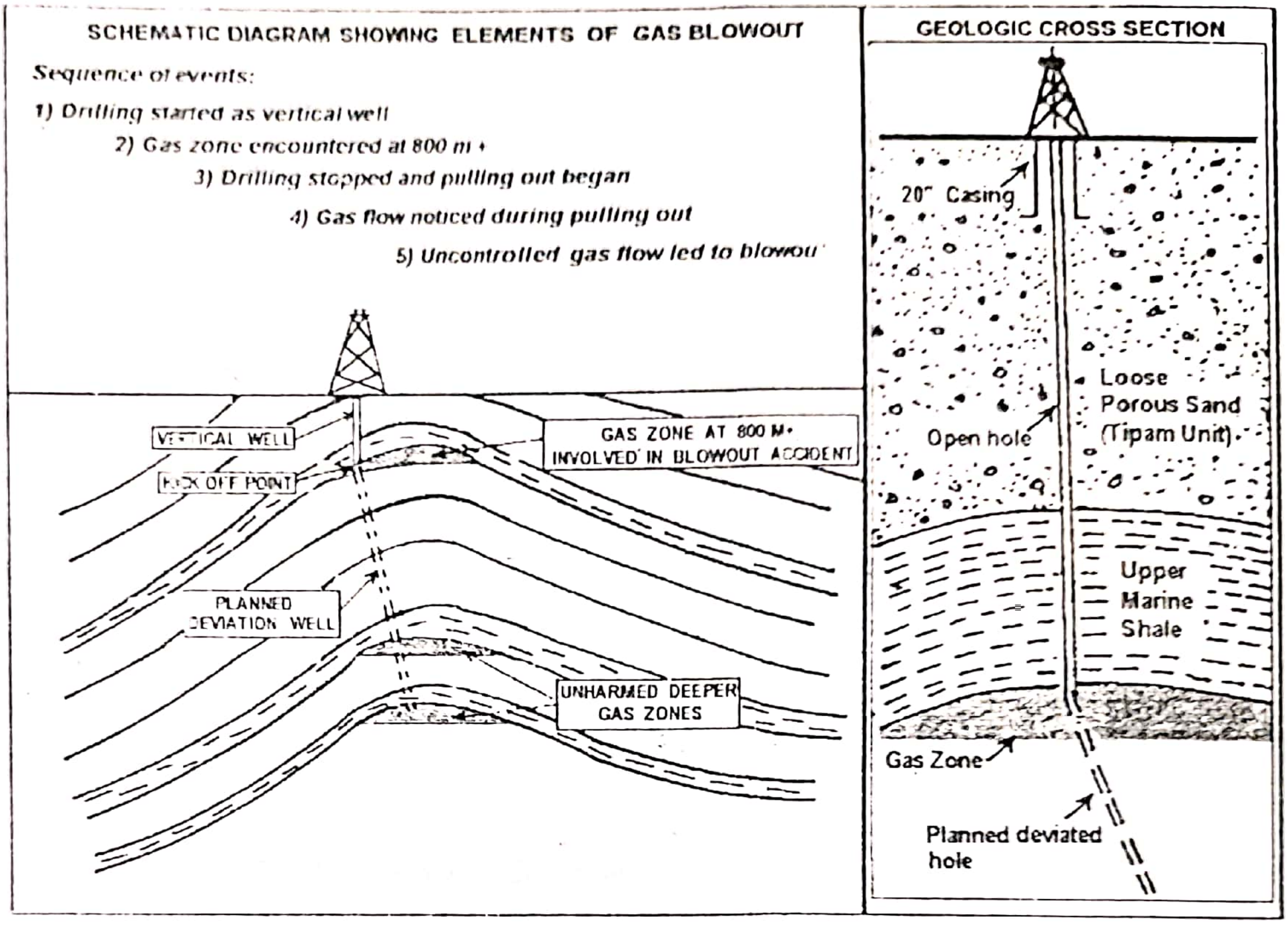


Figure 3.34 Schematic diagram to demonstrate the Magurchara blowout events (left) and a section through subsurface rock sequence (right).

drillers stopped drilling and started to pull out the drill pipes in order to make arrangement for well deviation from its vertical path. It was during the pulling out operation that gas from the gas zone below rushed into the drill hole and forced its way up which eventually caused the blow out of the well.

As the gas was gushing out, it was lit by fire that burned down all in and around the wellhead including properties and forest. A large crater was created into which the rig and associated machineries sank as it was filled with water. In addition to the drill hole, gas was bubbling up through several points in the ground outside and surrounding the well through newly created fractures and fissures No loss of live was reported however.

Following an investigation by a government appointed committee of experts, it was concluded that the blow out was caused by negligence on part of the drillers and the committee held the drilling company responsible. Following observations were made by the Committee in favor of its conclusion with respect to the blow out event :

i) With initial sign of a gas onrush, the driller failed to counter the flow by effectively circulating required heavy mud down the drill pipe, a conventional practice to handle a blow out in an initial stage.

ii) The well was not cased to the drilled depth (a cased well is one in which the hole is permanently isolated from surrounding by putting a hollow pipe into the hole). Instead, it was drilled as an open hole through the loose and porous sand units called Tipam Sandstone Formation (Figure 3.33). As the gas rushed up through this open hole, it found its way and entered into the surrounding loose sand layer beyond the confine of the hole. This is the reason why the gas flow could not be stopped even by closing the well head at the surface by Blow Out Preventer (BOP), a conventional last attempt to handle a blow out. The gas spread through the loose Tipam Sand layer in the underground, fracture it and flowed outside the drill hole. Eventually the fractures served as conduits for gas which escaped to the surface at several points outside the drill hole.

iii) The drillers attempted to make deviation of the well from its vertical path from a point in the subsurface that was near or within a gas zone. To make the necessary well adjustments for the deviation, the pulling out of drill pipes were carried out. But pulling out of drill pipes from or near the gas zone made the situation vulnerable for gas flowing up through the pipe. This is an example of how vulnerable a well could be to blow out if pulling out is made from a gas zone.

The inquiry Committee has reported that an estimated 245 Bcf of gas was damaged and lost in the blow out incidence. The government accordingly claimed a compensation of $685 million to Occidental Oil Company. This was not realized till date. The company has since left Bangladesh after handing over the gas block to Unocal Corporation. Subsequently Chevron Corp took over the gas block.

3.12.3 Chattak-2 (Tengratila) well blowout – Irresponsible or inaptitude

A severe blowout of well occurred in Chattak gas field on 8 January 2005 while Niko Resources Company was drilling a development well Chattak-2 (also known as Tengratila well) at Tengratila in Sunamganj district. In a similar event to that of Magurchara well blowout of 1997, the accident happened because of uncontrolled flow of gas and fire causing complete destruction of drilling rig and associated

installations. Large amount of gas escaped and lost into the air, not only through the well but also through the fractures in the ground surrounding the well.

As the cause of the blowout incidence is investigated by the government appointed Committee of experts. preliminary report has pointed out the following factors supposedly responsible for the Chattak-2 well blowout (Imam 2005).

At a relatively shallow depth, the well drilled through the loosely consolidated sand unit (Tipam Sandstone Formation) and then through a consolidated shale unit (Upper Marine Shale or UMS). The drillers did not set casing in the loose sand unit. The well encountered a gas zone below the UMS. After drilling to a depth of 807 meters, drillers began pulling out of the drill pipes. This made a swabbing effect on the gas zone and gas entered the hole and forced its way up. The gas flow was not contained by mud circulation, nor could the gas flow stop by blow out preventer (BOP). As the gas rushed its way up, it found the loose sand unit (Tipam Sands) uncased and open and this allowed the gas to enter and spread through the loose sand unit. This causes fractures in the sand unit through which the gas rushed up to the surface at several points outside and surrounding the borehole.

Two factors may have been most responsible for the accident: i) keeping the loose sand (Tipam Sand Unit) unprotected by not setting a casing and ii) pulling out from the gas zone while the sand above remained uncased and unprotected. These are the same factors responsible for the blowout of Magurchara well in Moulvibazar gas field in 1997. The drilling operators at Chattak-2 (Tengratila) well apparently did not take into account the well history of the ill fated Magurchara well while designing and planning the well.

The blow out accident in Tengratila well gave rise to one of the most controversial case involving high ups in the government. The sensational case involves the state minister of Energy in Bangladesh and foreign oil company Niko Resources, the latter tried in a Canadian court and convicted for indulging bribery in Bangladesh. Niko Resources was fined US$9 million by the court in the above case (Box 3.3).

Box 3.3 JV deal with Niko Resources for Chattak gas field development – The scandal:

Chattak gas field was discovered in 1959 and started producing in 1961. After the independence of Bangladesh it was operated by Petrobangla. In 1985, the gas production from the single well was suspended. Considering the simple geologic and geographic set up plus the already developed infrastructure, it was expected that Petrobangla would drill further wells to resume gas production from the field.

Bangladesh (Bapex) signed a MOU in 1999 and a joint venture (JV) agreement in 2001 with Niko Resources Ltd. in order to produce gas and develop Chattak gas field. The JV contract gave rise to a number of questions by which it was implied that normal working procedures were breached and national interest sacrificed during the period the contract was signed. The following points were keys to the questions.

1) Chattak was declared as marginal gas field, though the reserve of the field was estimated at 256 billion cubic feet gas. Observers pointed out that while several other fields with lesser reserves have been on production by national companies, the declaration of Chattak as marginal field was unaccepted by any standard and was done exclusively to justify JV with Niko Resources.

2) The JV with Niko resources was unsolicitated and based on personal interest of some 'patrons'. This was done at a period when international oil companies were invited to participate in oil gas exploration through competitive biddings. Niko had previously failed to qualify in competitive bid for exploration block in Bangladesh.

3) In addition to the Chattak gas field (geologically Chattak west) Niko Resources was also awarded an undrilled but prospective adjacent exploration block (Chattak east), to the dismay of the other foreign oil companies who were engaged in competitive bidding for exploration blocks.

With the above irregularities in the back stage, Niko Resources signed the JV contract and and started drilling its first well (Tengratila) in Chattak gas field in January 2005. However, the matter flared up when Niko accidentally blew up its first well Tengratila in January 2005, causing destruction of rig, loss of gas and people's properties and contaminated the environment (Figure 3.34). A second blow up by Niko, i.e. that of the relief well in June 2005 in the same field made the situation worse.

Bangladesh's claim for loss of 9 billion cubic feet of gas due to the accident was strongly contested by many local experts who claimed that the total gas of the affected reservoir, estimated at 110 billion cubic feet, should be taken as the lost gas. This is because the reservoir gas, although did not totally escaped into the air (part of the gas did), were scattered into the uncased sandy layer (Tipam Formation) above the reservoir and formed many pockets meaning that these were no more producible (Figure 3.34).

The row over compensation claim by the Bangladesh made another twist in the JV affair when the media exposed a bribery deal Niko offered to the Bangladesh State minister for Energy and Power in exchange of favour with respect to compensation claim. This had cost the State minister his job. Eventually Niko Resources, a Canadian company was tried in a Canadian court in Calgary and fined $9 million dollar for fraud and bribery in the Bangladesh gas deal.

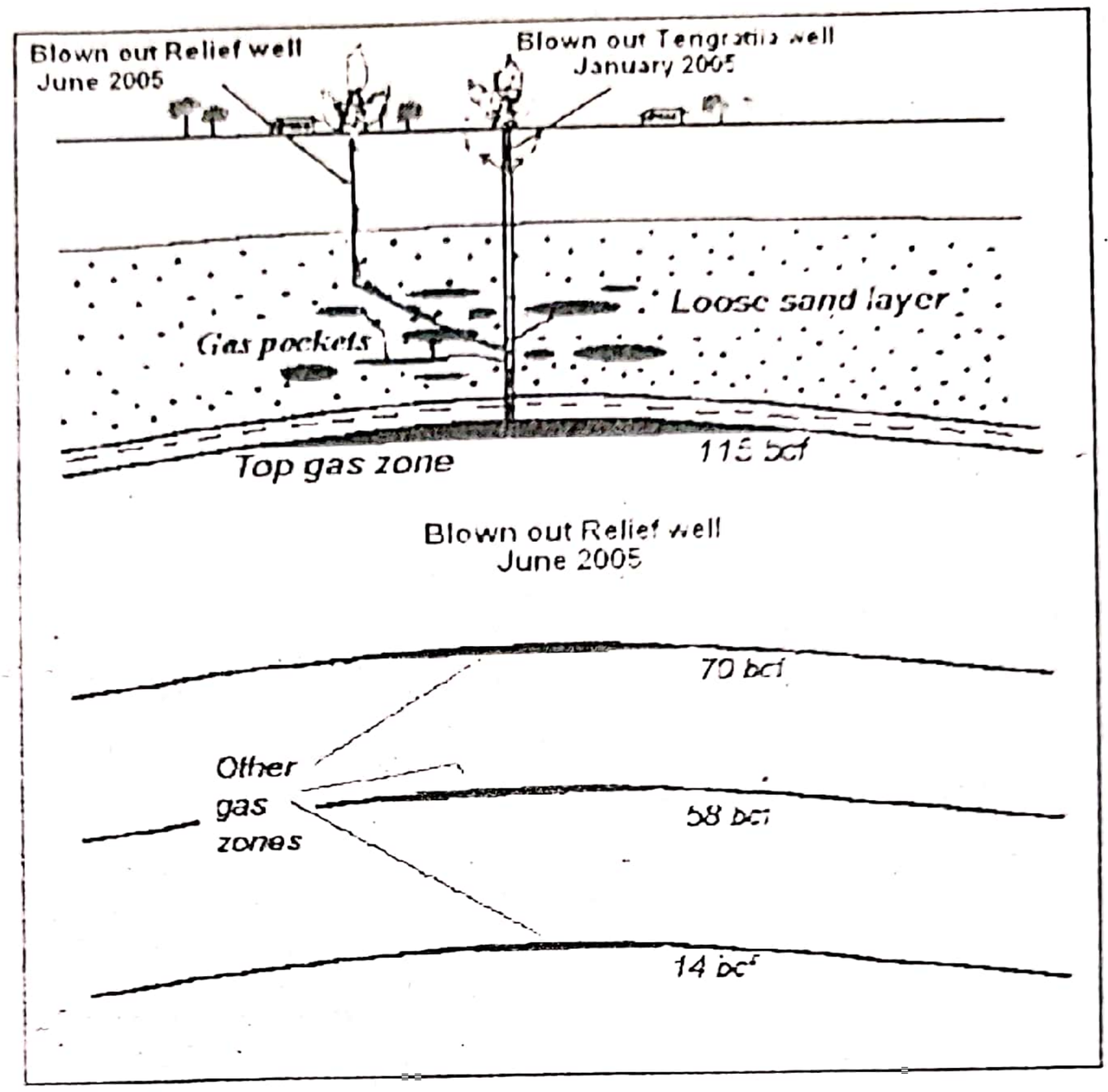


Figure 3.35 Schematic cross section of Chattak gas field with the Tengratila blown out wells.

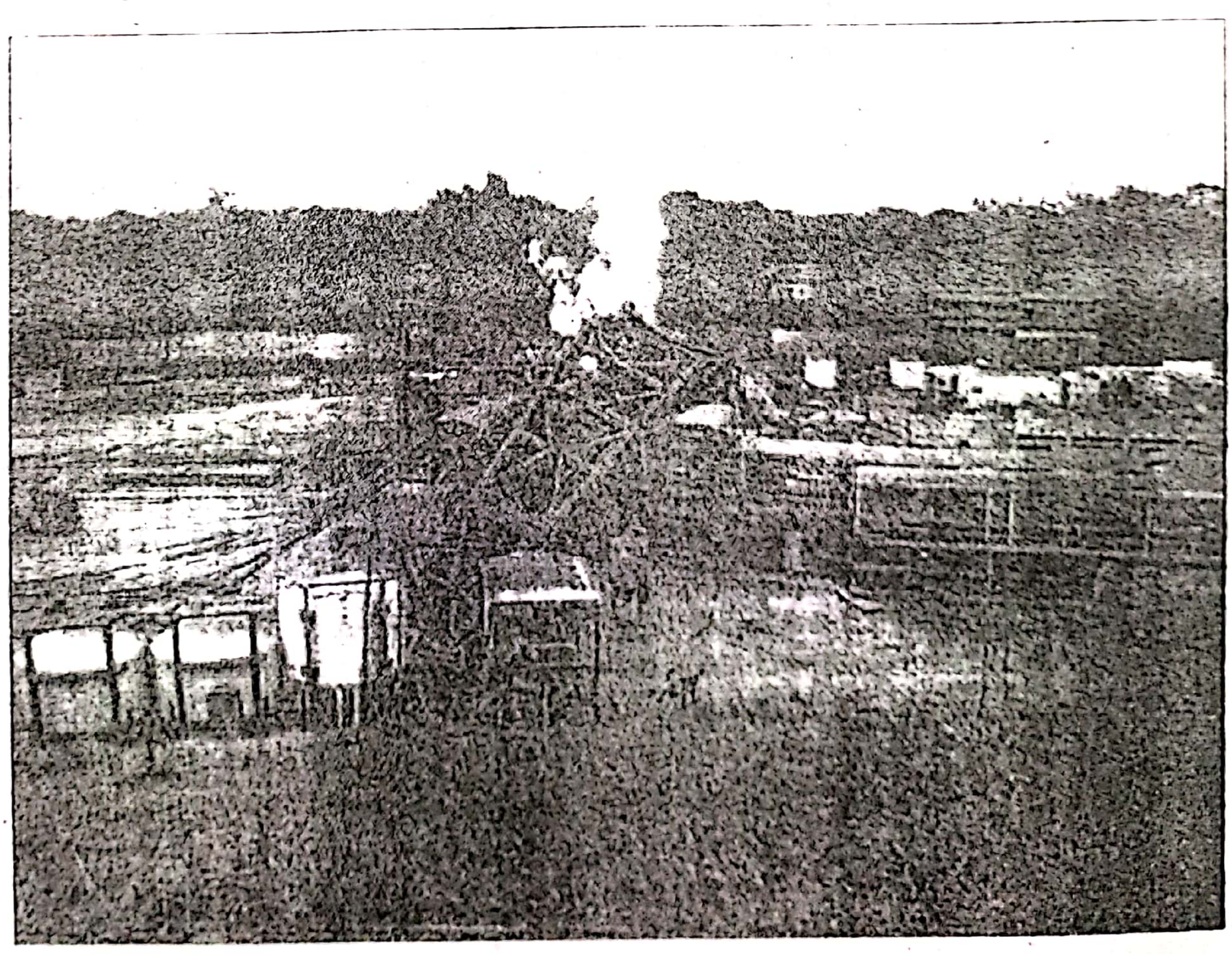


Plate 3.7 Tengratila blown out (January 2005) well in Chattak gas field.

3.13 Unconventional natural gas

3.13.1 Bacterial (Biogenic) Gas in Bangladesh

Occurrences of bacterial gas, also known as biogenic gas, formed from organic matter by the bacterial action rather than heat, are reported at shallow depths within the Recent sediments in many parts of Bangladesh plain. These occurrences are found to be small pockets of gas rather than commercial accumulation of any kind. These are encountered while hand operated tube well or shallow and deep irrigation water wells are drilled.

Discharge of gas in these wells do not necessarily critically interfere with tube well operation, but reduces hydraulic efficiency of pumping. In some cases, however, the occurrences of such pocket gas have been the limiting factor for water well developments. Sudden discharge of gas may cause disruption to drilling operation and there are reports of drilling failure from different parts of Bangladesh (Ahmed et al 1998). During recent years, these are more widely reported because of increasing number of tube wells sunk in the country. Bacterial gas in Bangladesh has been reported from different depths ranging from 10 meter to 100 meter below surface, but most of these occur at depths more than 30 meters. The gas is essentially methane (CH_4) with virtually no higher hydrocarbon and with some carbon dioxide (5 % or more). It is recognized by flammable ignition character.

Among the well documented reports of the occurrences of bacterial gas are those of Comilla-Brahmanbaria, Noakhali-Lakhsmipur in the SE, Tarail thana of Kishoreganj, different thanas of Greater Sylhet in the NE, Maksudpur and Boalmari thanas of Faridpur, Mohamadpur thana of Magura, parts of Satkhira, Barguna, Dacope thana of Khulna in SW, and Manda thana of Naogaon in the NW (Ahmed et al 1998). Bacterial gas is reported sporadically across the deltaic and fluvial plain of the country. Few areas has been studied in detail.

Ahmed et al (1998) reported result of a detail study of the bacterial gas in Comilla region based on water well data. They suggested that gas occurrence as a constraint to water well development is more pronounced in the Meghna deltaic plain in SE Bangladesh. The sedimentary sequences in which the gas occurs are fluvio-deltaicin nature and has been dated as Recent (Holocene) by radioactive dating.

The Recent fluvio-deltaic sediments in which bacterial gas occurs vary in thickness from tens of meter in the north to a few hundred meters in the south. The sediments are brought in by Brahmaputra-Ganges-Meghna river system and are composed of sand, silt and clay. The Recent sands are medium to dark gray and may be differentiated from Pleistocene or older sands which are usually brown to reddish brown. The Recent clays are often rich in organic matter and are associated with peat in some areas.

It has been seen that in the broad fluvio-deltaic system, the estuarine environment is more suitable for organic matter preservation and thus deposits more organic rich sediments and therefore generates more biogenic gas. It has also been observed that areas marked by high groundwater salinity generate more bacterial gas than other parts of the country (Ahmed et al 1998).

3.13.2 Coal Bed Methane

Coal Bed methane (CBM) refers to the methane gas that occurs within coal beds lying underground. Methane is produced during coalification process that transforms plant materials into coal in response to burial. The methane thus produced is stored mostly (about 90%) as adsorbed gas held by molecular attraction on coal particles. It occurs in less amount (about 10%) as free gas in micropores in coal and as dissolved gas in water within pores. The mode of occurrence of CBM is different from that of conventional natural gas in that it is originated and stored in the same rock, i.e. coal. It is therefore known as unconventional natural gas.

Historically, CBM has been considered as a safety hazard in underground coal mine because of explosion and accidents associated with it. Lately, however, technology has developed to commercially extract the CBM from coal bed by drilling wells, thus making it a significant energy resource. Most of the developments of CBM have been taking place in USA over the last few decades.

The CBM industry in USA, starting in 1978 with only 12 wells, has in excess of 7000 producing wells in 2000 (Warshaw 2001). The USA annual production of CBM has increased from 300 billion cubic feet in 1991 to 1100 billion cubic feet in 1997, the latter accounting 6% of the total natural gas produced in that country that year (Stevens 1999). A number of coal rich countries including China, India, UK, Russia,

Poland and Australia are actively engaged in developing CBM. Among the prerequisite condition for CBM prospecting are large coal reserve, high methane content in coal seam, greater thickness, moderate depth of burial and high permeability of coal seam. Development of CBM is different from that of conventional natural gas as pointed out below:

i) In conventional wells, little or no water is produced with the gas initially. This is quite opposite in case of CBM production. Since most coal seams are highly saturated with water, the water must be pumped prior to economic gas production. Dewatering by pumping causes a pressure decline and allows the methane to be released from the coal surface. A proper disposal system must be available for the water pumped to the surface.

ii) In conventional natural gas well, gas production is initially high and typically decline with time steadily. In a typical CBM well, gas production is initially low with water production relatively high. As the dewatering process continues, rate of gas production usually increase. Through time, the three phases of CBM production are initial dewatering phase, stable production phase and final decline phase.

iii) Hydraulic fracture is not usual in conventional gas production from porous rock reservoirs. But due to relatively low permeability of the coal seams, hydraulic fracturing is used to induce gas production in CBM well.

iv) In conventional gas well, gas is produced at high pressure and generally does not need compressor. In case of CBM, the gas is produced at very low pressure (less than 10 psi) and it needs to be compressed in order to transmit in commercial gas pipeline.

The major coalfields of Bangladesh lie in the Bogra-Dinajpur-Rangpur area in the northwestern part of the country. Due to comparatively high depths of the coal layers, conventional coal mining is not suitable in certain coalfields (Jamalganj). Prospecting for coal bed methane for such fields is an alternative option which may well be economically profitable.

Considering the prerequisite factors for CBM development, Jamalganj coalfield is considered a viable candidate for CBM prospecting in Bangladesh. The Jamalganj

coalfield has the largest coal reserve in Bangladesh. Some of the coal seams are very thick and there are evidences of high methane content in the coal. Also the coal seams in Jamalganj field lie within the optimum depth range for CBM development. In chapter 5 (coal), a detail description of the Jamalganj coalfield has been given including the prospect of CBM development in the field (section 5.2.7.6).

All the gas fields in Bangladesh occur in the eastern half of the country and prospect of finding conventional natural gas in the western part is low from geological point of view. The gap or disparity of gas consumption and the industrial development between the east and western part of the country is too obviously related to the easy availability of gas in the east. Development of CBM in the coalfields of the northwest Bangladesh could somewhat help to lessen the above gap or disparity.

3.13.3 Shale gas – The new frontier

Shale gas refers to the natural gas that is extracted from shale underground. This is known as unconventional gas due to the fact that gas can not be produced from shale with conventional method because shale has too little permeability (the property that allows gas to flow through the rock). Late technological advances have enabled gas prospectors to produce gas from shale by fracturing the rock, thus creating artificial permeability. In conventional method, gas is produced from permeable rocks like sandstone and limestone, into which the gas migrates and accumulates from shale source rock by geologic process.

Can all shale produce gas? Shale can generates gas when it is rich in organic matter and attained thermal maturity through burial temperature. For shale gas to be viable, the shale must also have to be sufficiently brittle and rigid to maintain fractures when such artificial fracturing procedure is applied. The process of hydraulic fracturing involves drilling hole into the shale that contain the gas, then pumping in vast quantities of water mixed with sand and chemicals. This opens up tiny fissures and induce permeability in the otherwise dense impermeable shale, thus allowing the gas to escape. Horizontal drilling with lateral extent up to 3000m may create maximum borehole surface area in contact with shale.

Over the last two decades two major technologies - horizontal drilling and hydraulic fracturing enabled the shale gas to be commercially produced. United

States has been the leader in producing and developing shale gas. In 1996, shale gas production in USA accounted for only 1.6% of the total gas production; by 2006 the shale gas contribution was 6% and by 2011 about 20% of the total gas produced in USA was shale gas. However, in other countries shale gas exploration and exploitation program remains in testing ground as of 2011. Large shale gas resources are estimated in China, Australia, Canada and in some European countries, but these are not matched with actual production activities.

There has been too little work or information on the prospect of shale gas in Bangladesh. From a geological point of view it may be mentioned that the deep basin area of Bangladesh has huge thickness of alternating shale and sandstone of Miocene-Pliocene age in the subsurface, but the shale are mostly lean or poor in organic-matter. Also the thermal maturity of the Mio-Pliocene shale is not enough to generate significant gas. Therefore the prospect of shale gas in deep basin areas in the eastern part of Bangladesh is generally not considered good, although a conclusive comment on the issue can not be made at this stage. The shelf part (the Bogra shelf) of the Basin, in the northwest has some stratigraphic horizons like Kopili shale which are relatively rich in organic matter and these may have attained thermal maturity towards the hinge zone to generate gas. The Bogra shelf area may be more suitable to be taken as a test case for shale gas evaluation in Bangladesh.

There has been some environmental concern over the development of shale gas. Target shales are buried under aquifer and if the cement casing around the well is not adequate, then the process of drilling and fracturing can release chemicals into the aquifer and contaminate it. The water chemical mixer returns to surface where it can also contaminate the land.

Shale gas tends to cost more to produce because of the expenses of hydraulic fracture treatment required to produce the gas and also because of horizontal drilling. These factors along with the environmental concerns with shale gas development make some experts skeptic about the future of this unconventional gas resource.

3.13.4 The gas hydrate – Into the future

Gas hydrate is an ice like solid formed from a mixture of water and natural gas. In a molecular level gas hydrates consists of gas molecules 'surrounded by' or 'caged

within' crystal structure of water molecules. Gas hydrates forms and is stable only in a very low temperature and high pressure environmemt. Gas hydrates occur in two discrete geologic situations because these settings have pressure-temperature conditions within the hydrate stability field: i) beneath deep ocean floor and ii) beneath permafrost in polar region.

One cubic feet of gas hydrate at reservoir pressure and temperature yields about 160 cubic feet of gas at atmospheric pressure and temperature. The amount of gas hydrate world wide is estimated to be far greater than the entire world's conventional natural gas resources.

Till date there is no commercial production of gas hydrate in the world. There has been several multi-national research project looking into the gas hydrate resource base and prospects of its exploitation. The USA research program pursues a goal of producing natural gas from gas hydrate by 2015. Researches are also underway in Japan, Canada, India, United Kingdom, Russia, Germany and some other countries. Seven organizations from five countries carried out a joint research and development program of gas hydrate in 2002 known as ``Mallik 2002 Gas hydrate research program` and attempted the first gas production test. Although success of the test proved gas hydrate can be a potential gas reserve, the difficulty of heat transport from well to the formation in deep water limited the productivity and formed a technical challenge.

India has been seriously working for the development of gas hydrates under the "Indian Gas Hydrate Program" (NGHP), in association with USGS. Extensive studies under the program has located significant gas hydrate bearing marine sediments in deep ocean off Krishna-Godavari Basin, Mahanadi Basin and the offshore Andaman Islands (Jamaluddin 2010). There has been no known work done on the gas hydrate resource potential in the deep ocean off Bangladesh coast.