FINAL UPDATED REPORT

On

Bangladesh Petroleum Potential and Resource Assessment 2010

Under

Strengthening of Hydrocarbon Unit in the Energy and Mineral Resources Division (Phase-II)

ADB Grant 0019: GTDP

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For

HYDROCARBON UNIT

Energy and Mineral Resources Division

Government of the People's Republic of Bangladesh

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I. EXECUTIVE SUMMARY

This revision incorporates minor changes in response to Petrobangla's comments received in April 2012.

Gustavson Associates has been commissioned to prepare an update to the estimated resources of Bangladesh as estimated in the 2001 report prepared by the Hydrocarbon Unit of Bangladesh (HCU) and the Norwegian Petroleum Directorate (NPD). We have estimated Prospective and Contingent Resources, according to the guidelines of the Petroleum Resource Management System (PRMS) published by a consortium of world-wide and US-based petroleum professional societies (Appendix A). Five categories of resources were studied:

1. Identified Prospects and Leads
2. Unmapped
3. Shale Gas and Shale Oil
4. Thin Beds
5. Coalbed Methane.

Of these, Identified Prospects and Leads and Unmapped resources are considered conventional resources, Shale Gas and Shale Oil and Coalbed Methane (CBM) are considered unconventional resources, and Thin Beds represent bypassed net pay in conventional fields. The estimated CBM resources are considered Contingent Resources, while all the other resources estimated in this Report are considered Prospective Resources.

The resulting estimates are summarized in Table I-1 below.

Table I-1 Summary of Resource Estimates[1]

	Gas Resources, BCF			Oil/Condensate Resources, MMBO		
Type of Resources	P_{90}	P_{50}	P_{10}	P_{90}	P_{50}	P_{10}
Identified Prospects	41,940	57,013	76,315	0	0	0
Identified Leads	166,442	219,088	279,971	0	0	0
Unmapped	881.2	6080.4	34948.6	3	26	168
Shale Gas and Shale Oil	100,169	234,812	473,278	1,063	2,953	6,733
Thin Beds	0	10,872	27,252	0	0	0
Total Prospective Resources	**309,432**	**527,865**	**891,765**	**1,066**	**2,979**	**6,901**
Coalbed Methane	845	1,040	1,275	0	0	0
Total Contingent Resources	**845**	**1040**	**1275**	**0**	**0**	**0**

These estimates are unrisked. Thus, these probability levels mean that, if the given accumulation is discovered in the future, it has at least a 90% probability of containing recoverable resources equal to or greater than the P_{90} value, and so on. These three levels may also be referred to as the "Low Estimate," "Best Estimate," and "High Estimate." We note that it is extremely unlikely that all of the Prospective Resources will ever actually be discovered.

An analysis has also been made of the risk of discovering the various types of resources. While a risk factor can be assigned to the various prospects and leads and simply multiplied times the estimated quantities discussed above, this ignores the fact that the various prospects, leads, and blocks are largely independent. In other words, the true chance of discovering no gas at all when drilling all 32 mapped prospects is much less than the chance of drilling a dry hole when drilling a single prospect. However, the difference between the results of this simplified risking methodology and a more complex methodology was found to be not material for this group of assets. Thus to be consistent with previous reports, the simple risking methodology has been applied as shown in Table I-2. Thin bed resources and shale oil were not included in this risk

[1] Sums within categories

analysis due to their small impact on the totals. More detail on the risk factors used is included in Section 10 of this Report.

Table I-2 Summary of Risked Gas Resource Estimates[2]

	Gas Resources, BCF		
Type of Resources	**P_{90}**	**P_{50}**	**P_{10}**
Identified Prospects	12,510	19,295	28,259
Identified Leads	21,844	34,057	49,719
Unmapped	65	443	2,548
Shale Gas	4,007	9,392	18,931
Total Prospective Resources	**38,426**	**63,189**	**99,457**
Coalbed Methane	346	426	522
Total Contingent Resources	**346**	**426**	**522**

[2] Sums within categories

1. INTRODUCTION

1.1 GENERAL BACKGROUND

Bangladesh is located in South Asia adjacent to India to the west, north and east, Myanmar to the southeast and the Bay of Bengal. Much of the country has been formed by the alluvium and deltas of the Padma (Ganges), Jamuna (Brahmaputra) and Meghna Rivers and their tributaries (Figure 1-1). The country is considered tropical to sub-tropical. Annual rainfall is more than 250 centimeters. Most of the 144,000 square kilometers that comprise Bangladesh are flat deltaic plains with hilly areas that occur mainly in the east and southeast. The offshore portions of Bangladesh consist of 68,000 square kilometers.

The infrastructure within Bangladesh includes roads, railways, waterways, and air transportation systems (Figure 1-2). The capital of Dhaka is located in the center of the county and the principal port city of Chittagong is located on the eastern side of the Bay of Bengal. The country is served by international air routes. Independence from Pakistan was achieved in 1971. Since then, economic growth has resulted in increased energy needs, which has attracted investment in Bangladesh from International Oil Companies (IOC).

Hydrocarbon exploration has occurred sporadically over the last 100 years in Bangladesh. Early exploration by foreign companies was under the petroleum concession system and post 1974 the production sharing contract. The Petroleum Act of 1974 established Production Sharing Contracts (PSC), which enabled the international petroleum industry to explore for, develop, and produce hydrocarbons used to generate electricity, to power industry, and to power transportation. Twenty three gas fields and one small oil field have been discovered and, as of December 2009, seventeen fields are currently under production. These twenty three gas fields resulted from the drilling of seventy seven exploration wells between 1910 and 2009. A New Model PSC was written in 2008 and is currently being used for all new PSC awards. The Bid Round of 2008 resulted in interest in eight offshore blocks.

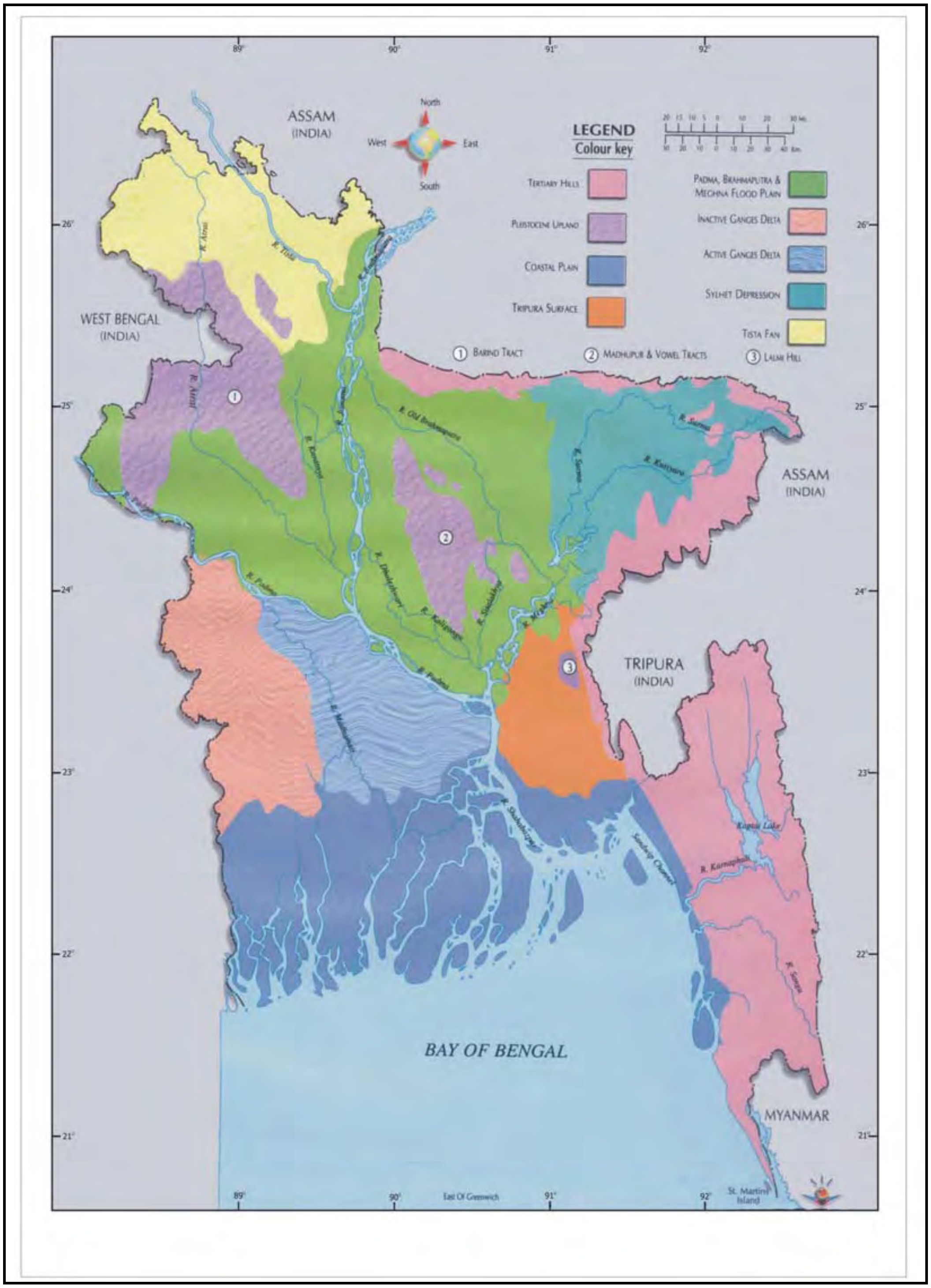

Figure 1-1 Physiographic Map of Bangladesh

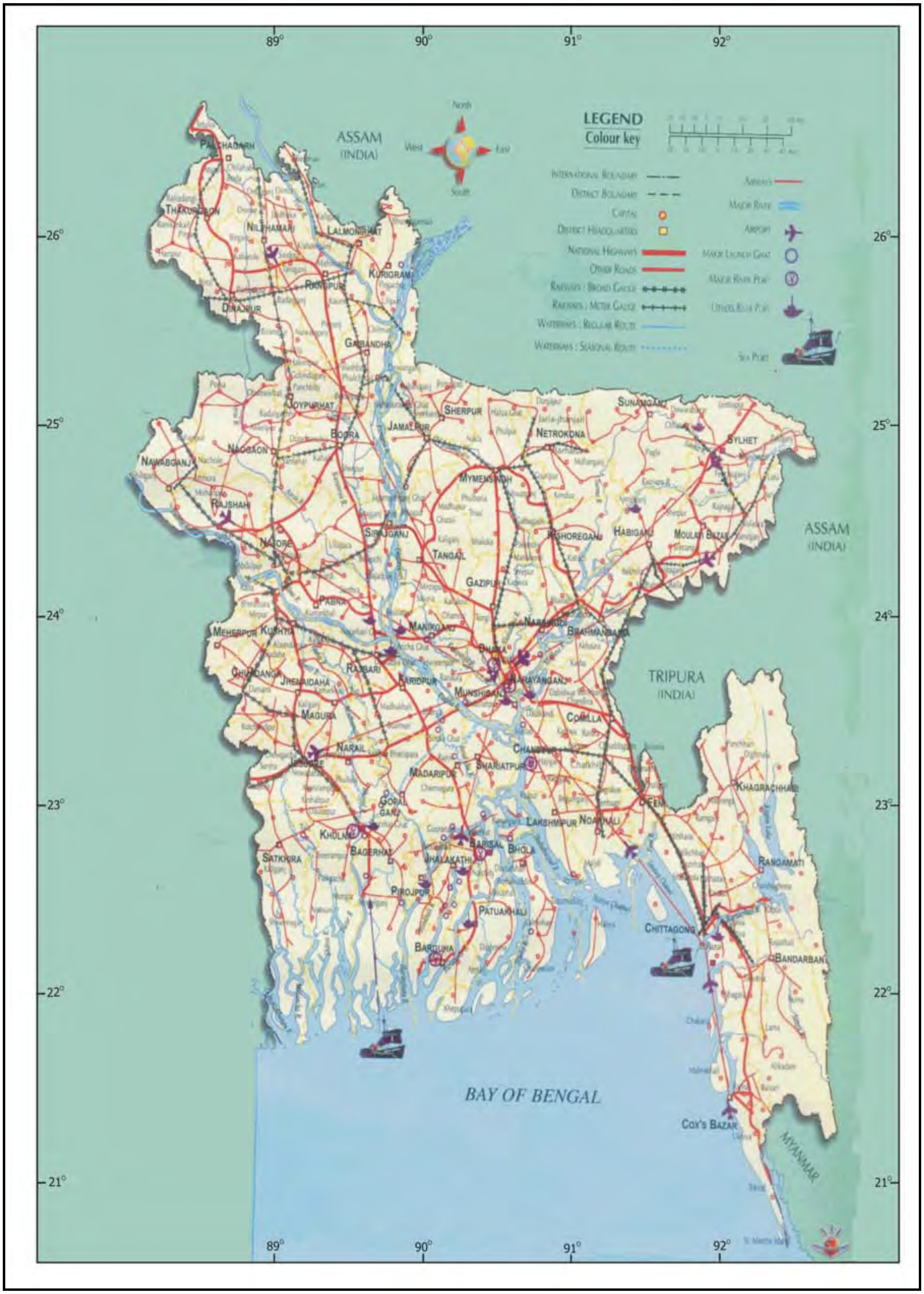

Figure 1-2 Transportation Map of Bangladesh

1.2 CURRENT HYDROCARBON RELATED INFRASTRUCTURE

Bangladesh Mineral, Oil and Gas Corporation (Petrobangla) was created in 1972 to promote and regulate exploration, production, transmission, and distribution of petroleum and minerals within Bangladesh. Bangladesh Mineral Exploration and Development Corporation (BMEDC) was then formed to promote non hydrocarbon mineral resources in Bangladesh. Bangladesh Petroleum Corporation (BPC) was created in 1976 to oversee the downstream portion of the oil and gas industry i.e., importation, refining, and marketing of petroleum products. In 1985 Bangladesh Oil, Gas and Mineral Corporation was formed by the merger of Petrobangla and BMEDC. Then in 1989 a new company, Bangladesh Petroleum Exploration Co. Ltd. (BAPEX) was separated out and assumed the exploration activity of Petrobangla. BAPEX is responsible for exploration and production of hydrocarbon in selected areas of Bangladesh. Currently, Petrobangla operates through ten companies.

1.2.1 Producing Gas Fields

The seventeen gas fields that are producing in Bangladesh account for a total of 1,982.7 Million standard cubic feet per day (MMscf) of gas as of May 6, 2010. This translates to a monthly production rate of just under 60 Billion standard cubic feet per month (Bscf) of gas or 723.7 Bscf/year (0.7 Trillion standard cubic feet per year (Tscf)) [3].

Current production is from fields operated by Petrobangla (through Bangladesh Petroleum Exploration & Production Company Limited (BAPEX), Sylhet Gas Fields Limited (SGFL), and Bangladesh Gas Fields Company Limited (BGFCL), Cairn, Chevron, Niko, and Tullow (as of April 2010). In November 2010 Cairn entered into an agreement with Santos International Holdings to sell all of its holdings in Bangladesh. That agreement was finalized in December 2010.

[3] Energy Bangla website.

BAPEX operates three of these producing gas fields Fenchuganj, Salda Nadi, and Shahbazpur. As of May 6, 2010 BAPEX was producing approximately 39 MMscf/day of gas from these fields.[4]

Bangladesh Gas Fields Co. Ltd. (BGFCL) operates five of the producing gas fields. As of May 6, 2010 BGFCL was producing approximately 715.1 MMscf/day of gas from four of those gas fields while the fifth field, Meghna, is currently nonproducing.

Sylhet Gas Fields Ltd. (SGFL) operates four gas fields. As of May 6, 2010 SGFL was producing approximately 158.4 MMscf/day from those four fields.[5]

The remaining six gas fields are not state owned and as of May 6, 2010 production from these fields totaled approximately 1,072.0 MMscf/day of natural gas.[6] Cairn Energy operated the offshore Sangu gas field through 2010, which is currently producing 36.7 MMscf/day of gas. In September of 2010 Petrobangla signed an amendment to the agreement with Cairn that will allow Cairn and its partners in Block 16, Santos and Halliburton as of 2010, to sell gas to any third party within the country. This is an exception to the policy of gas sales by IOCs that had restricted sales to Petrobangla only[7]. Chevron operates three fields, Jalalabad, Moulavi Bazar, and Bibiyana with total current production of 914.2 MMscf/day of gas. Tullow operates the Bangora field, which is currently producing 121.2 MMscf/day of gas. In 2009 NIKO produced a total of 447,896 MMscf from Feni gas field.

1.2.2 Gas Transmission and Marketing Infrastructure

Gas transportation pipelines, shown in Figure 1-3, carry gas from the fields in Bangladesh to industrial and private customers that are located primarily in the eastern portion of the country. Natural gas is also used to generate electricity, which is then distributed throughout the country. In 2000 a multi-use bridge was completed over the Jamuna River to provide increased access to

[4] Production data from Petrobangla website.
[5] Production data from Petrobangla website.
[6] Production data from Petrobangla website.
[7] Energybangla.com

the western portions of Bangladesh. This access includes a 30-inch gas pipeline that has promoted additional pipeline systems in western Bangladesh. Some of these expansion projects include Nalka to the Baghabari Power Plant in 2001, with a 20-inch pipeline, three network integration projects between 2002 and 2006, and a pipeline to Dhaka in 2007. With predicted increasing demand for natural gas and electricity in Bangladesh, the pipeline system will continue to be important. The estimated total demand for natural gas in 2009 was about 675 Bscf. The total delivered gas through the country's pipeline system for 2009 was approximately 685 Bscf.

There are six companies that market and transport natural gas to different areas of the country, Titas Gas Transmission & Distribution Co. Ltd. (TGTDCL), Bakhrabad Gas Systems Ltd. (BGSL), Jalalabad Gas Transmission & Distribution Company Ltd. (JGTDSL) and Pashimanchal Gas Distribution Co. Ltd. (PGCL), Karnaphuli Gas Distribution Company Ltd. (KGDCL), and Sundarbans Gas Company Ltd (SGCL). SGCL is not distributing any gas as yet. It is a new company established for gas distribution in southwestern Bangladesh.

Titas Gas operates transmission and distribution lines totaling 11,496 kilometers and markets to thirty-one power plants and four fertilizer plants along with other industrial and private customers. Sales of natural gas in the fiscal year 2008-2009 were 474.8455 Bscf.[8]

[8] Petrobangla.org.bd

Figure 1-3 Gas Transmission Network Map of Bangladesh

Bakhrabad markets gas to nine power plants and three fertilizer plants in addition to other industrial and private customers through its 6,246.62 kilometer pipeline network. Sales of natural gas in the fiscal year 2008-2009 were 101.6348 Bscf.[9]

Jalalabad sold gas through its 2,960.21 kilometers pipeline system to nine power plants and one fertilizer plant, in addition to other industrial and private customers, amounting to 43.5471 Bscf in fiscal year 2008-2009.[10]

Pashchimanchal sells gas to areas west of the Jamuna River with a current pipeline network of 970.22 kilometers. It sold 27.68 Bscf of gas to customers in fiscal year 2008-2009[11].

Gas Transmission Co. Ltd. (GTCL) was established to centralize the construction and operation of high-pressure gas transmission pipelines.

1.2.3 Import and Refining of Crude Oil and Petroleum Products

BPC is responsible for the import and refining of crude oil and marketing of petroleum products. The Eastern Refinery Ltd. does the refining in Chittagong. The capacity of the refinery is 40,000 bbl/day, which can meet half the domestic demand of petroleum, oil and lubricants (POL). The refinery also produces about 15,000 tons of liquefied petroleum gas (LPG) annually. Distribution of POL products is carried out through six companies of BPC. BPC also imports refined petroleum products.

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[9] Petrobangla.org.bd

[10] Petrobangla.org.bd

[11] Petrobangla.org.bd

1.2.4 Marketing of LPG

Rupantarito Prakritik Gas Co. Ltd. (RPGCL) extracts LPG from the wet gas stream during natural gas production. LPG Company Ltd. (LPGL) bottles and markets the gas. Annual extraction is 5,000 tons of LPG at their Kailashtila plant[12].

1.2.5 Marketing of Gas for CNG in Vehicles

Compressed natural gas is being promoted by Petrobangla for use in vehicles. To support this alternative fuel use, filling stations for compressed natural gas are being operated by Rupantarito Prakritik Gas Co. Ltd. (RPGCL)[13]. Through July of 2009 there were four hundred sixty-eight of these fueling stations to support the estimated 170,405 vehicles that are run on CNG.[14]

1.2.6 Mining Sector

Petrobangla also has mining companies within its structure. Barapukuria Coal Mining Company Ltd. (BCMCL) produced 37,862.410 metric tons in June 2009, the majority of which was used in a coal fired power station.[15] Maddhapara Granite Mining Company Limited (MGMCL) operates a mine at Madhapara. Markets include domestic construction and the potential for decorative stone for the domestic market[16].

1.3 BLOCK SYSTEM

The Block System for offshore areas has been in effect in Bangladesh since 1974. The first award consisted of six offshore blocks awarded to six companies. These companies then acquired approximately 31,000 kilometers of seismic data with which to explore these blocks.

[12] Petrobangla.org.bd

[13] Petrobangla.org.bd

[14] Petrobangla.org.bd

[15] Etrobangla.org.bd

[16] Petrobangla.org.bd

Seven wells were drilled as a result of this round of awarded blocks. All of the areas had been relinquished by 1978.

The Block System was revised in 1988 when onshore areas were divided into seventeen blocks, numbered 1-15, 22, and 23, and the offshore areas were consolidated into six blocks, numbered 16-21 (Figure 1-4). At this same time, seventeen Reserved Areas or Production Blocks were established around producing gas fields (Figure 1-4).

The current Block System is shown in Figure 1-5. This was the block designation used in the 2008 Offshore Bidding Round and the one that is in effect today. Several onshore blocks have been subdivided into two parts, i.e. A and B, or three parts, i.e. A, B, and C resulting in a total of twenty four onshore blocks. The original six offshore blocks have been further subdivided, by water depth, into a total of thirty blocks. The subdivision of offshore blocks is based roughly on the 2,000 meter isobath. The shallow water blocks include the original Block 17, a portion of original Block 18 and the eight newly designated blocks SS-08-01 through SS-08-08 (Figure 1-5). The new deep water blocks are designated SS-08-09 through SS-09-28 (Figure 1-5).

1.3.1 Onshore Exploration Blocks

The twenty-four onshore block outlines shown in Figure 1-5 include: 1) two BAPEX Blocks (8 and 11) that have been given to the national exploration company for its exclusive use in exploration, 2) Block 7 and part of Block 16 are under current PSC agreements, 3) Blocks 5, 9, 10, 14, and the remainder of 12 and 13 have been relinquished. Portions of Blocks 9, 12, and 13 have been converted to production areas, and 3) fourteen open blocks.

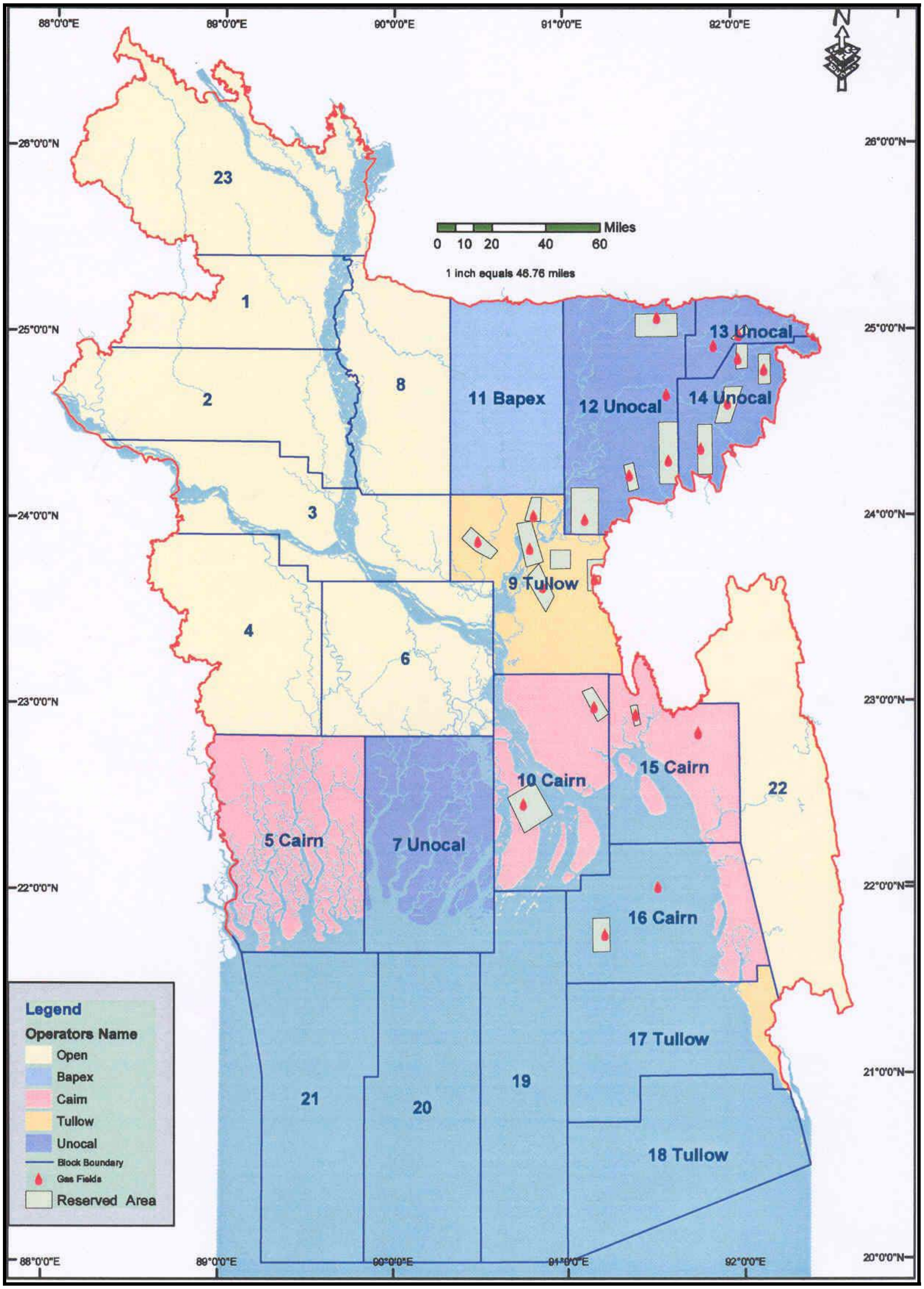

Figure 1-4 Block Map of Bangladesh – 1988 Vintage

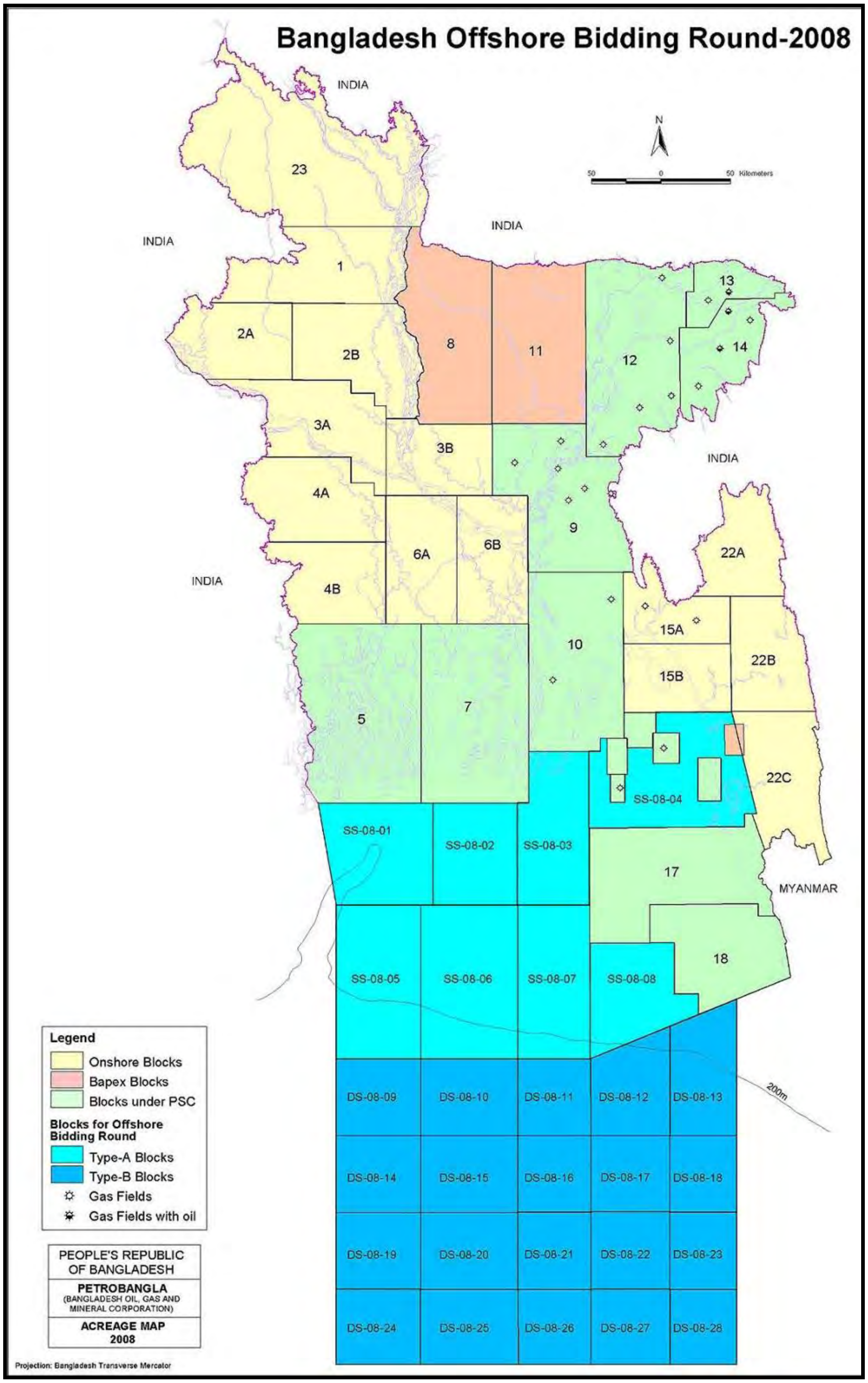

Figure 1-5 Block Map of Bangladesh – Vintage 2008

1.3.2 Offshore Exploration Blocks

The shallow water blocks (shown in light blue in Figure 1-5) are designated SS-08-01 through SS-08-08. The deep water blocks (shown in dark blue in Figure 1-5) are designated DS-08-09 through DS-08-27. These designations were used for the Bangladesh Offshore Bidding Round 2008.

1.3.3 Production Blocks

Exploration blocks contain twenty-three gas fields (Figure 1-4). Two of these gas fields are located offshore in the Bay of Bengal in Block 16 (now within SS-08-04 by the new offshore designation). Other exploration blocks that now contain gas fields are Meghna River Block 10, Blocks 9, 12, 13, 14, and 15 onshore (Figure 1-4)(see 2010 Reserves Report on Petroleum Resource Management recently published as a joint effort of the Hydrocarbon Unit and Gustavson Associates, LLC).

1.3.4 Awarded Blocks

The first six Production Sharing Contracts (PSCs) that were signed with international oil companies after the Petroleum Act of 1974 were with ARCO, Union Oil (UNOCAL), INA-Naftaplin, Bengal Oil Dev. Co. (BODC i.e. Nippon Oil), Ashland and Canadian Superior. These companies acquired geophysical data, drilled seven wells, and relinquished the areas by 1978.

Shell was awarded approximately 13,400 square kilometers in the onshore southeastern part of the country and then in 1986 approximately 13,500 square kilometers in the northwest. These areas are now designated Block 22 and Block 23. Shell had relinquished all of this area by 1988.

After the discovery of oil in 1986 on the Sylhet structure, a PSC was signed with Scimitar Exploration Ltd. in 1987. The concession covered an area in the northeastern part of the country, the current Block 13, but Scimitar's contract was terminated in 1992.

In 1989, Petrobangla held promotional seminars in four cities but no bids were received. Reflection on this unsuccessful promotion resulted in changes in the fiscal policy terms of the PSCs.

In 1993, Petrobangla held a promotional seminar in Houston resulting in the award of four offshore and four onshore blocks to four international oil companies.

Other promotions occurred in 1997, in London and again in Houston. These promotions are known as the 2nd Exploration Bid Round. Petrobangla signed PSCs with the partnership of Chevron, Texaco, and Tullow for Block 9, the partnership of Shell and Cairn for Blocks 5 and 10, and Unocal for Block 7. In each of these agreements BAPEX was a 10% partner under a system of carried interest. There are eight active PSCs covering ten blocks.

The current status of blocks that were held at the date of the previous report is summarized below.

- Block 5: was relinquished in 2009, originally held by the partnership of Shell/Cairn/BAPEX
- Block 7: is held by Chevron. Chevron shot seismic data are drilling a well.[17]
- Block 9: was relinquished except for the portions that hold two gas discoveries, Bangora and Lalmai, by the partnership of Tullow as operator with 30 percent interest, Niko Resources with 60 percent, and Bangladesh Petroleum Exploration and Production Co. The Bangora gas field is currently producing.
- Block 10: was relinquished by the partnership of Shell/Cairn/BAPEX.
- Block 12: was relinquished except for the production area that is operated by Chevron and includes the Bibiyana gas field with 98 percent interest to Chevron.
- Block 13: relinquished except for the production area that is operated by Chevron and includes the Jalalabad gas field with 98 percent interest to Chevron.

[17] Energybangla.com

Block 14: relinquished by Chevron except for the portion that includes the Moulavi Bazar field with 98 percent interest to Chevron.

Block 16: relinquished except for one production area, one contingent gas discovery area, and two exploration areas. In November of 2010 Cairn energy PLC announced that its subsidiary Capricorn Energy Limited entered into a conditional sale and purchase agreement with Santos International Holdings Pty Limited whereas Santos will acquire the entire issued share capital of 37.50 percent in the producing Sangu gas field. Santos will further acquire another 50 percent interest in Block 16 exploration acreage. As Santos will acquire all of the interests of Cairn in Bangladesh they will also assume operatorship of the Sangu gas field. Previously Block 16 was divided into a development area where Cairn held a 37.5 percent interest, Santos a 37.5 percent interest, and HBR Energy a 25 percent working interest in the Sangu gas field, and an exploration area, where Cairn held a 50 percent interest, and Santos a 37.5 percent working interest. The block was formerly held by the partnership of Shell/Cairn.

Block 17: was relinquished in February of 2009 after a seismic survey was shot by the operator Total.

Block 18: was relinquished in February of 2009 by the operator Total. The partnership of Tullow, PTTEP and Oakland, and Rexwood acquired seismic data over the block prior to relinquishment.

In 2008, an Offshore Bidding Round was held. The twenty-eight offshore blocks that were offered at the sale are shown in Figure 1-5. ConocoPhillips submitted tenders on eight of the offshore blocks that were originally offered; however, the government has decided to only permit PSC contracts on two of the blocks (Block 08-10 and Block 08-11). A third offshore block (Block 05) was recommended to be awarded to Tullow.

Information published in March of 2010 suggested that Tullow may receive Block 06 instead of Block 05 due to a territorial dispute over most of Block 05 by India[18]. More recent information suggests that the territorial questions could result in the postponement or suspension of the Block 05 award.[19] ConocoPhillips reportedly is to be awarded offshore PSC for Blocks 08-10 and 08-11 out of their initial selection of Blocks 08-10, 08-11, 08-12, 08-15, 08-16, 08-17, 08-20, and 08-21[20].

These border disputes with India and Myanmar over territorial ownership claims to the offshore Bay of Bengal have created uncertainty about some of the blocks offered by Petrobangla to IOCs, particularly those in the deepwater (Figure 1-5), as well as shallow-water blocks close to the Indian shoreline. The three nations have agreed in principal to talks to resolve the disputes over territorial waters.

Recent gas discoveries and production of those discoveries in offshore blocks D6 and D4 by Reliance Industries Ltd. in Indian waters adjacent to the western deep water blocks of Bangladesh, have strengthened interest in the area as have reported gas discoveries off the Arakan coast of Myanmar[21].

Niko Resources Ltd holds a 60 percent share in Block 9. Niko has a joint venture agreement with BAPX to produce gas from the Feni and Chhatak gas fields.

1.4 EXPLORATION HISTORY

1.4.1 Onshore

Early exploration was based on the presence of oil and gas seeps and mapping conducted by the India Petroleum Prospecting Company. Four wells were drilled between 1908 and 1914. The

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[18] Energybangla.com

[19] Daily-sun.com

[20] Energybangla.com

[21] Gasandoil.com v. 14, issue #16, November 19, 2009

Burma Oil Company drilled two additional exploration wells. No commercial discoveries were made and exploration ceased due to World War II.

The partitioning of Bengal and India in 1947 opened the area to renewed interest. In the period between 1951 and 1971 Standard Vacuum Oil (Stanvac), Pakistan Petroleum Ltd. (PPL) and Pakistan Shell Oil Co (PSOC) drilled a total of twenty exploration wells. During this period seven discoveries were made, Sylhet (1955) and Chhatak (1959) by Pakistan Petroleum Ltd, Rashidpur (1960), Kailas Tila (1962), Titas (1962), Habiganj (1963) and Bakhrabad (1969) by Shell. Shell found five fields with six exploration wells. The Semutang Gas Field was discovered by Oil and Gas Development Corporation (OGDC) of Pakistan.

Since 1971, a total of thirty one additional exploration wells were drilled onshore, bringing the onshore total to fifty seven exploration wells. Out of eleven wells drilled by international oil companies three have been discoveries. Out of sixteen drilled by Petrobangla and BAPEX nine have been discoveries. The oil companies are still focusing on eastern Bangladesh. The most significant recent discoveries have been Bibiyana, Bangora, and Shahbazpur gas fields.

Exploration efforts in Bangladesh after independence in 1971 have been supported by other countries and foreign institutions. Among these were the Union of Soviet Socialist Republics, the Federal Republic of Germany, and the World Bank.

Economic aid was provided in the 1980s by the World Bank for a project by Petrobangla, Hydrocarbon Habitat Study, which identified new prospects and leads across the country and provided a comprehensive hydrocarbon resource evaluation.

1.4.2 Offshore

Drilling in the offshore regions of Bangladesh began in 1969 when PSOC drilled a dry hole offshore of Cox's Bazar. Offshore exploration continued in 1974 with awards of blocks to six international oil companies. Seven wells were drilled as a result of these PSCs and Union Oil (Unocal) reported a gas discovery. Offshore exploration again renewed in 1994 with the award of Blocks 15 and 16 to the partnership of Cairn and Holland Sea Search. This partnership later became Shell and Cairn. The Kutubdia and Sangu gas fields were discovered by Cairn Energy with Royal Dutch/Shell Group (Shell Bangladesh) in 1996 and are located offshore in Block 16 of the Bay of Bengal. The partnership of Rexwood and Okland was awarded Blocks 17 and 18 and drilled a dry hole. A total of five exploratory wells and four development/appraisal wells were drilled in this period. Through the end of 2009, a total of seventeen exploratory wells have been drilled in offshore Bay of Bengal in Bangladesh territorial waters.

2. DATABASES

2.1 SEISMIC DATABASE

Pakistan Petroleum Ltd. initiated seismic data acquisition in Bangladesh in 1955. PPL was active primarily in the greater Sylhet district. SVOC and Shell's seismic campaign started in 1957. In 1963 OGDC started acquisition of seismic data. All these data were singlefold, analogue coverage. Approximately 7,000 kilometers of the pre-1971 seismic data are still available.

Digital multifold seismic data acquisition started in 1978, when Prakla was engaged under the German Technical Assistance Programme. In 1978 Petrobangla also started acquiring multifold analogue seismic data and in 1979 digital data acquisition began. Analogue, multifold seismic data acquisition continued until 1982. During 1986-87 Shell recorded over 1,500 kilometers of multifold data available in the BAPEX Data Center.

From the early nineties on there was an increase in seismic activity when Cairn Energy started acquiring data within Blocks 16 and 17and Occidental in Blocks 12, 13, and 14. Occidental acquired 3-D surveys across both Bibiyana and Moulavi Bazar. Both Okland Oil and United Maridian Corporation (UMC) acquired seismic data. In 2003-2004, Tullow acquired five hundred seventy three line-kilometers of 2-D data across the Bangora-Lalmai Anticline. They also acquired a 3-D survey of their PSC block in 2003.

Additional 3-D surveys have been acquired, are in the process of being acquired, or are proposed both onshore and offshore. NIKO, on behalf of their JV with BAPEX, acquired 3-D surveys across Feni and Chhatak fields. Acquisition of 3-D surveys in underway over Titas, Bakhrabad, Sylhet, Kailas Tila, and Rashidpur fields in order to seismically identify new pay sands and better delineate the areal distribution of existing pay sands.

A list of the seismic data, including 3-D surveys is presented in Table 2-1, and the seismic coverage of Bangladesh is shown in Figure 2-1.

2.2 WELL DATABASE

A total of seventy-five exploration and ninety-six development/appraisal wells have been drilled in Bangladesh. Seventeen of the exploration wells were drilled offshore, five within the Western Shelf and one in the Himalayan Foredeep area. The remaining fifty-one exploration wells were all drilled in the eastern part of the country within the eastern fold belt. The drilling density of exploratory wells is about 1,946 square kilometers/well. Locations of the wells are presented in Figure 2-2 and the exploration wells are listed in Table 2-2.

Most of the well data is archived in the BAPEX Data Center. Development and appraisal well data for the wells drilled by the two production companies of Petrobangla remain with the companies. Well data of the wells drilled by the IOCs from 1996 on are filed with Petrobangla.

2.3 PRODUCTION DATABASE

The production database for Bangladesh resides both in Petrobangla and its affiliated companies, BAPEX, BGFCL, and SGFL as well as in the digital production database maintained by the Hydrocarbon Unit of the Energy and Mineral Resources Division (HCU). Production is recorded by field, by well, and by reservoir and includes gas, condensate, and water. Flowing wellhead pressures (FWHP), important for estimating gas field depletion using a modified material balance approach, are maintained on a well-by-well basis.

Within the HCU database, daily production has been recorded on a field and well basis beginning in about 2005. Prior to that time, historic or vintage gas, condensate, and water production by field, well, and reservoir has been recorded on a monthly basis and is generally available for all fields since production began.

More detailed information and analysis of both historic and current production levels and trends is presented in the 2010 Reserves Report recently published as a joint effort of the Hydrocarbon Unit and Gustavson Associates, LLC.

Table 2-1 Seismic Survey Database of Bangladesh

2-D SURVEYS					
OPERATOR	**PERIOD**	**AREA**	**ENERGY SOURCE**	**LINE Km**	**TYPE OF RECORDING**
OGDC	1963-71	Onshore	Dynamite	971	Single Fold, Analog
Petrobangla	1973-77	Onshore	Dynamite	2065	Single Fold, Analog
Petrobangla	1976-78	Onshore	Dynamite	3606	Single Fold
Petrobangla	1978-82	Onshore	Dynamite	2151	6/12 Fold, Analog
Petrobangla	1979-87	Onshore	Dynamite	3809	12/24 Fold, Digital
Petrobangla	1977-86	Onshore	Dynamite	3658	12 Fold, Digital
Petrobangla	1983-86	Onshore	Dynamite	2646	12/24 Fold, Digital
Petrobangla	1984-86	Onshore	Dynamite	1961	24 Fold, Digital
SGFL	1990-97	Onshore	Dynamite	2587	12/24/30 Fold, Digital
SGFL	2003-09	Onshore	Dynamite	1842	30/60 Fold, Digital
Total				**25,296**	
SVOC	1956-59	Onshore	Dynamite	900	Single Fold, Analog
PSOC	1960-71	Onshore	Dynamite	7600	Single Fold, Analog
INA-Naftaplin	1974-76	Offshore	Aquapulse	2957	24 Fold, Digital
Union Oil	1974-76	Offshore	Airgun / Dynamite	4926	48/24/12/6 Digital
Ashland	1974-76	Offshore	Airgun	5245	12/24 Fold, Digital
ARCO	1974-76	Offshore	Airgun	3242	48 Fold, Digital
BODC	1974-76	Offshore	Airgun	8163	24/48 Fold, Digital
CSO	1974-76	Offshore	Airgun	6536	24 Fold, Digital
Shell	1986-87	Onshore	Dynamite	1506	24 Fold, Digital
Occidental	1995-97	Onshore	Dynamite	2317	Multi Fold, Digital
Cairn / Shell	1996-97	Onshore/ Offshore	Dynamite/ Airgun	2500	Multi Fold, Digital
Okland		Onshore	Airgun / Dynamite	925	Multi Fold, Digital
UMC	1998-99	Onshore	Dynamite	515	Multi Fold, Digital
Tullow	2001-03	Onshore	Dynamite	573	60 Fold, Digital
Unocal	2003-04	Onshore	Dynamite	21	60 Fold, Digital
Chevron	2009	Onshore-Blk 7		1000	
Total				**48,926**	

3-D SURVEYS					
OPERATOR	**PERIOD**	**AREA**	**ENERGY SOURCE**	**AREA Sq. Km.**	**TYPE OF RECORDING**
Occidental	1995-97	Onshore (Bibiyana)	Dynamite	226	3-D
Occidental		Onshore (Moulavi Bazar)			3-D
NIKO (JV)		Onshore (Feni, Chhatak)			3-D
Tullow		Onshore (Bangora)			3-D
Cairn		Offshore (Magnama, Hatiya, and Sangu)			3-D
SGFL		Onshore (Rashidpur?)			3-D
Total					

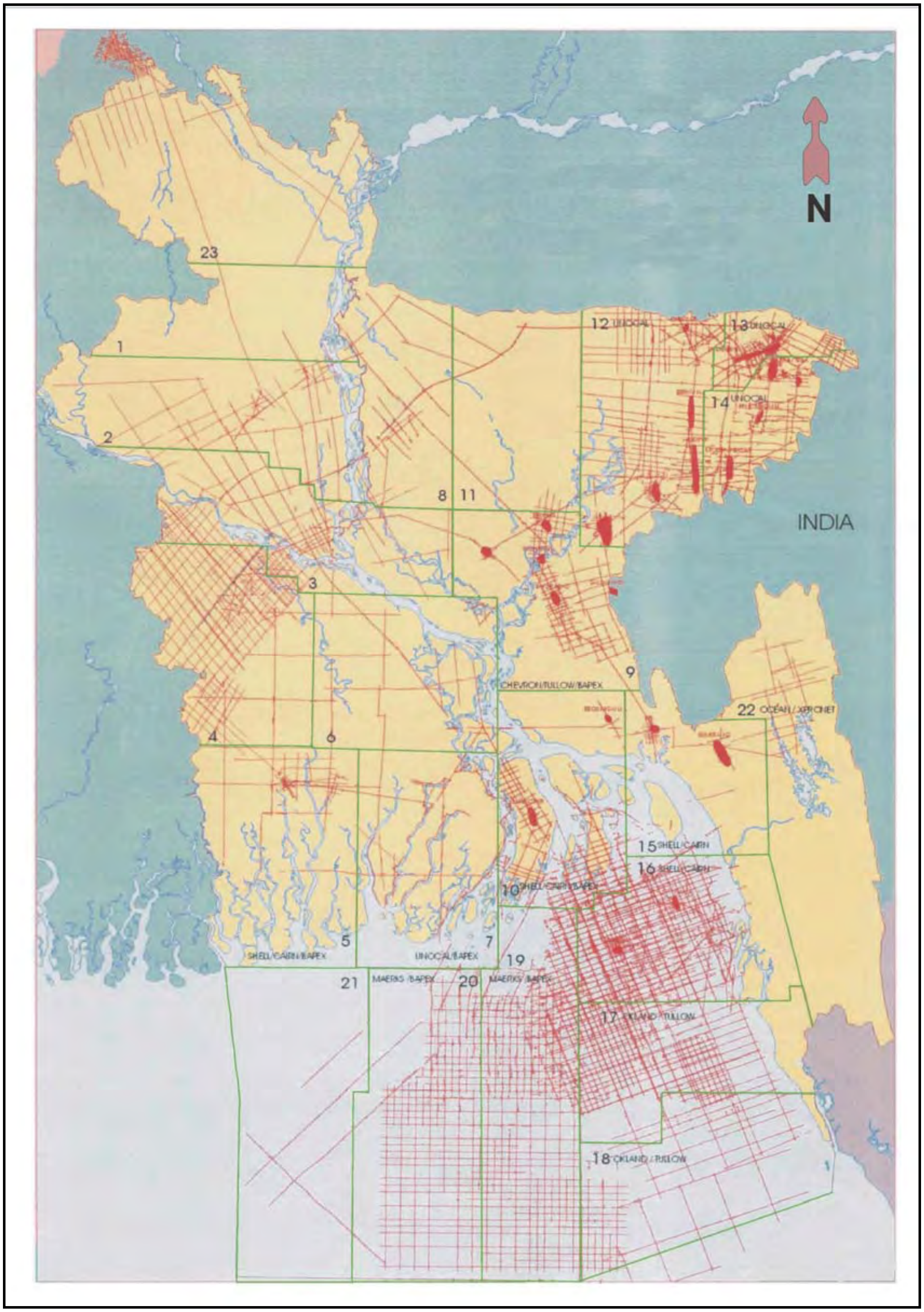


Figure 2-1 Seismic Coverage of Bangladesh

Table 2-2 Exploration Well Database of Bangladesh

UWI	Well Name	Operator	Year	TD (m)	Fm. @ TD	Age	Well Status
ONSHORE							
1	Atgram-1	Petrobangla	1982	4961	Barail	Early Miocene	Dry
2	Bakhrabad-1	Shell	1969	2838	Bhuban	Miocene	Gas Disc.
3	Bangora-1	Tullow	2004	3635	Bhuban	Miocene	Gas Disc.
4	Beani Bazar-1	Petrobangla	1981	4109	Bhuban	Miocene	Gas Disc.
5	Begumganj-1	Petrobangla	1977	3655	Bhuban	Miocene	Gas Disc.
6	Bibiyana-1	Oxy/Unocal	1998	4014	Bhuban	Miocene	Gas Disc.
7	Bogra-1	Stanvac	1960	2187	Basement	Precambrian	Dry
8	Bogra-2	Petrobangla	1989	2100	Chena	Paleocene	Dry
9	Chhatak-1	PPL	1959	2135	Bhuban	Miocene	Gas Disc.
10	Fenchuganj-1	PPL	1960	2438	Bhuban	Miocene	Dry
11	Fenchuganj-2	Petrobangla	1988	4977	Bhuban	Early Miocene	Gas Disc.
12	Feni-1	Petrobangla	1981	3200	Bhuban	Miocene	Gas Disc.
13	Habiganj-1	Shell	1963	3508	Bhuban	Miocene	Gas Disc.
14	Halda-1	Cairn/Shell	1998	4159	Bhuban	Miocene	Dry
15	Hazipur 1	Stanvac	1960	3816	Bhuban	Miocene	Dry
16	Jaldi-1	OGDC	1965	2300	Bhuban	Miocene	Dry
17	Jaldi-2	OGDC	1966	3360	Bhuban	Miocene	Dry
18	Jaldi-3	OGDC	1970	4500	Bhuban	Miocene	Dry
19	Jalalabad-1	Scimitar	1989	2626	Bhuban	Miocene	Gas Disc.
20	Kailas Tila-1	Shell	1962	4139	Bhuban	Miocene	Gas Disc.
21	Kamta-1	Petrobangla	1982	3614	Bhuban	Miocene	Gas Disc.
22	Kapna-1	Oxy/Unocal	1999	3149	Bhuban	Miocene	Dry
23	Kuchma-1	Stanvac	1959	2875	Gondwana	Gondwana	Dry
24	Lalmai-1	PPL	1958	2993	Bhuban	Miocene	Dry
25	Lalmai-2	PPL	1960	4117	Bhuban	Miocene	Dry
26	Lalmai-3	Tullow	2004	2800	Bhuban	Miocene	Gas Disc.
27	Meghna-1 (BK-9)	Petrobangla	1990	3069	Bhuban	Miocene	Gas Disc.
28	Moulavi Bazar-1	Oxy/Unocal	1997	840	Tipam	Pliocene	Dry
29	Moulavi Bazar-2	Oxy/Unocal	1999	3510	Bhuban	Miocene	Gas Disc.
30	Muladi-1	Petrobangla	1976	4732	Bhuban	Miocene	Dry
31	Muladi-2	Petrobangla	1981	4556	Bhuban	Miocene	Dry
32	Narsingdi-1 (BK-10)	Petrobangla	1990	3450	Bhuban	Miocene	Gas Disc.
33	Patharia-1	Bumah	1923	875	Bhuban	Miocene	Dry
34	Patharia-2	Bumah	1933	1047	Bhuban	Miocene	Dry
35	Patharia-3	PPL	1951	1649	Bhuban	Miocene	Oil Show
36	Patharia-4	PPL	1953	830	Bhuban	Miocene	Dry
37	Patharia-5	BAPEX	1992	3438	Bhuban	Early Miocene	Dry
38	Patiya-1	PPL	1953	3102	Bhuban	Miocene	Dry
39	Ratna-1	Oxy/Unocal	1998	3835	Bokabil	Miocene	Dry
40	Rashidpur-1	Shell	1960	3860	Bhuban	Miocene	Gas Disc.
41	Rasulpur-1	Tullow	2003	3295			Dry
42	Salda Nadi-1	BAPEX	1996	2511	Bhuban	Miocene	Gas Disc.
43	Salbanhat-1	Shell	1988	2518	Basement	Precambrian	Dry
44	Semutang-1	OGDC	1969	4088	Bhuban	Miocene	Gas Disc.
45	Shahbazpur-1	BAPEX	1995	3342	Bhuban	Miocene	Gas Disc.
46	Singra-1	Petrobangla	1981	4100	Gondwana	Gondwana	Dry
47	Sitakund-1	IPPC	1910-14	763	Bhuban	Miocene	Oil Shows, P&A
48	Sitakund-2	IPPC	1910-14	n/a	n/a	n/a	Dry
49	Sitakund-3	IPPC	1910-14	n/a	n/a	n/a	Oil Shows, P&A
50	Sitakund-4	BOC	1910-14	1024	Bhuban	Miocene	Oil Shows, P&A
51	Sitakundu-5	Petrobangla	1988	4005	Bhuban	Miocene	Dry
52	Sitapahar-1						
53	Sitapahar-2	Shell	1988	1560	Bhuban	Miocene	Dry
54	Srikail-1	BAPEX	2004	3583	Bhuban	Miocene	Dry
55	Surma-1	Scimatar	1989	2253			Gas Show, P&A
56	Sylhet-1	PPL	1955	2379	Bhuban	Miocene	Gas Disc.
57	Titas-1	Shell	1962	3758	Bhuban	Miocene	Gas Disc.

Table 2-2 Exploration Well Database of Bangladesh (continued)

UWI	Well Name	Operator	Year	TD (m)	Fm. @ TD	Age	Well Status
OFFSHORE							
58	ARCO A-1	ARCO	1976	3903	Bokabil	Late Miocene-Plio.	P&A
59	Bina-1	NA	1976	4095	Bokabil	Late Miocene-Plio.	P&A
60	Bina-2	NA	1976	4294	Bokabil	Late Miocene-Plio.	P&A
61	BODC-1	BODC	1976	4598	Bokabil	Late Miocene-Plio.	P&A
62	BODC-2	BODC	1976	4436	Bokabil	Late Miocene-Plio.	P&A
63	BODC-3	BODC	1978	4488	Bhuban	Late Miocene-Plio.	P&A
64	Cox's Bazar-1	Shell	1969	3698	Bhuban	Late Miocene-Plio.	P&A
65	Kutubdia-1	Union	1976	3508	Bhuban	Late Miocene-Plio.	Gas Disc.
66	Magnama-1	Shell/Cairn	2008	4003	Mega sequence 1	Early Pliocene	Gas Show, P&A
67	Reju-1	Okland	2000	4450		Late Miocene-Plio.	Gas Show, P&A
68	Sangu-1	Cairn	1996	3500	Bhuban	Late Miocene-Plio.	Gas Disc.
69	South Sangu-1	Shell	1999	4664	Bhuban	Late Miocene-Plio.	Gas Shows
70	South Sangu-2	Shell/Cairn	2001	3850			P&A
71	South Sangu-3	Shell/Cairn	2007	3510			Gas Show, P&A
72	Sonadia-1	Cairn	1998	4028	Bokabil	Late Miocene-Plio.	P&A
73	Sandwip East-1	Cairn/Shell	2000	3696	Bokabil	Late Miocene-Plio.	P&A
74	Union 76-1	Union	1976	233			P&A
75	Hatia	Cairn	2008	3850	Mega sequence 1	Early Pliocene	Gas Show, P&A

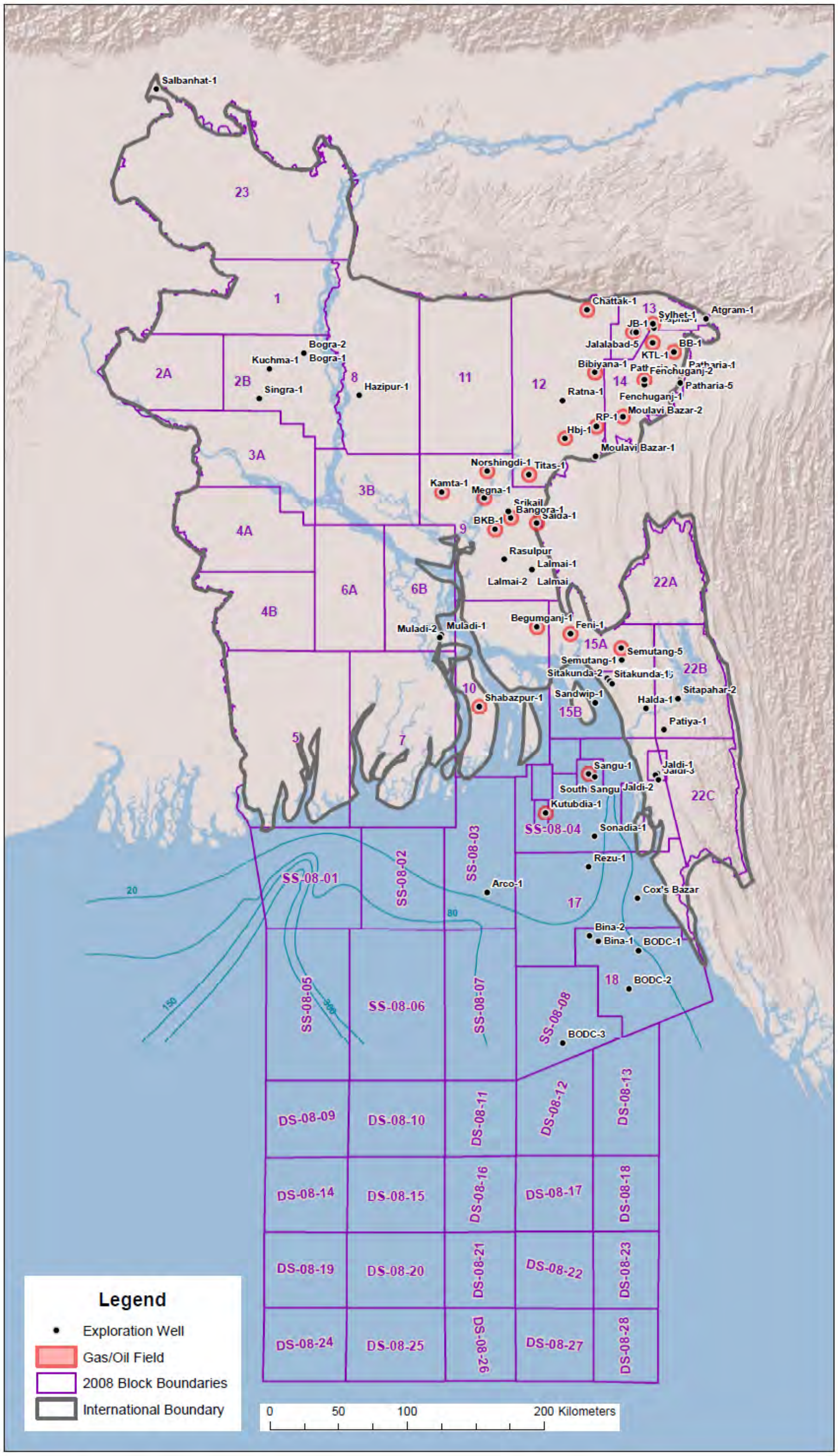


Figure 2-2 Exploratory Well Locations of Bangladesh

3. GEOLOGICAL DEVELOPMENT

3.1 REGIONAL GEOLOGICAL SETTING

The Bengal Basin is located in onshore and offshore Bangladesh and adjacent eastern India. It is part of the India Craton (India tectonic plate) and has been buried by a depocenter formed by the deltas of the Padma (Ganges), Jumuna (Brahmaputra) and Meghan Rivers, which merge to form the Bengal Delta and the Bengal Fan. These rivers are sourced in the Himalayan Mountains to the north that rose from collision of the India plate with the Asia plate, and the Burmese Hills to the east. The current Bengal Fan is the largest submarine fan in the world and has been active from Oligocene through Recent time. The basin includes three geologic regional settings (Imam and Hussain, 2002).

Collision of the India Plate with Asia and the subsequent rotation of the plate to the east have resulted in two of these distinct geologic regions in Bangladesh. The western and northern part of the country, commonly known as the Stable Platform or the Bogra Shelf, is underlain by the shelf margins and rifted basins as part of the India plate, whereas the eastern portion of the country consists of compressional, en echelon fold belts, the Chittagong-Tripura Fold Belt also known as the fold belt, involving thrust faulting and folded sediments, and arc complexes and oceanic crust subduction that developed on the edge of the Eurasian Plate (Imam and Hussain, 2002).

Between these is the third geologic region, the Foredeep, consisting of shallow and deep water deposition. The Foredeep is located on the India plate shelf margin and adjacent oceanic crust, which have been buried by sediments of the Bengal Delta and Fan. The western part the Bengal Foredeep is characterized by an extensional tectonic regime whereas the eastern part is characterized by wrenching and compression of the fold belt. The Tangail-Tripura High further divides the Bengal Foredeep into two sub-basins known as the Surma Sub-Basin (Sylhet Trough) to the north and the Hatia Trough in the south.

These three geologic regions also define the exploration plays that have been developed in Bangladesh and those that have yet to be established and fully explored. Each geologic region has associated with it one or more petroleum systems identified by age, source rock, traps, and reservoir potential. The folded eastern area has been best explored to date but exploration targets may still be present, whereas the western shelf margin areas have very few wells and many undrilled targets. The deep-water deltaic region of the Bengal Delta and Fan is also an under-explored area.

3.2 TECTONIC EVOLUTION

The Indian Plate, Australia, and Antarctica were together as part of East Gondwanaland in the Jurassic (Figure 3-1). As Gondwana began to rift apart, India moved northwest relative to Australia and Antarctica. Sediments over much of the Australian Northwest Shelf basin were sourced from the India Plate as it was adjacent to the region. The India Plate, Australia, and Antarctica later moved as separate plates. The India Plate (greater India) moved rapidly to the north to eventually collide with the Eurasian Plate and rotate counterclockwise. Figures 3-1, 3-2, and 3-3 show the interpretation of these events by Alam et al. (2003). The Bengal Basin covered an area from the Indian Craton to the Shan Massif during Paleocene through Eocene time. Plate collision in Eocene time and the creation of an island arc divided the basin into two basins, Irrawady and Bengal separated by the island arc. The rifted basins and the passive margin of the eastern India Plate are now the West Bengal Basin and the fold belts of eastern Bangladesh are the result of the rotation of the plate and subduction.

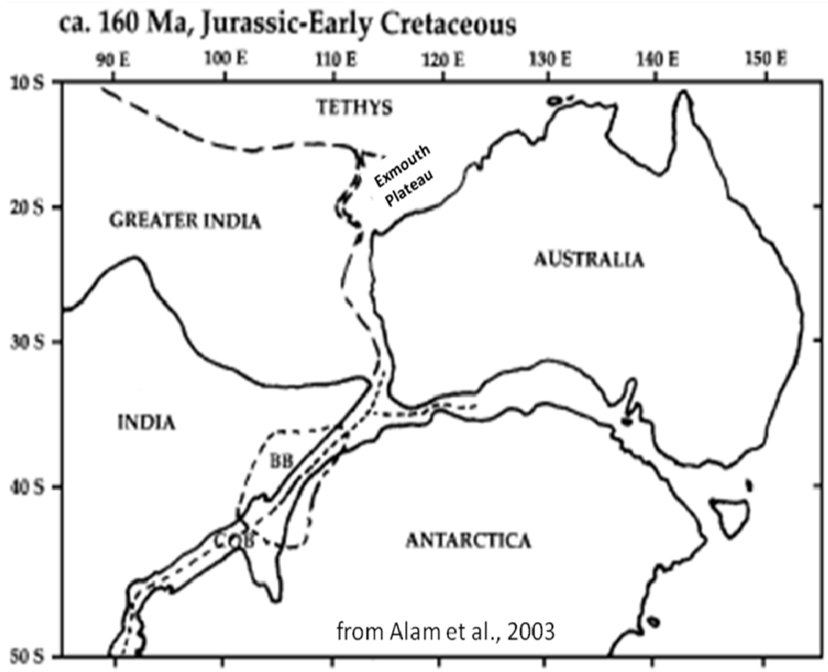


Figure 3-1 Position of continental plates at 160 Ma

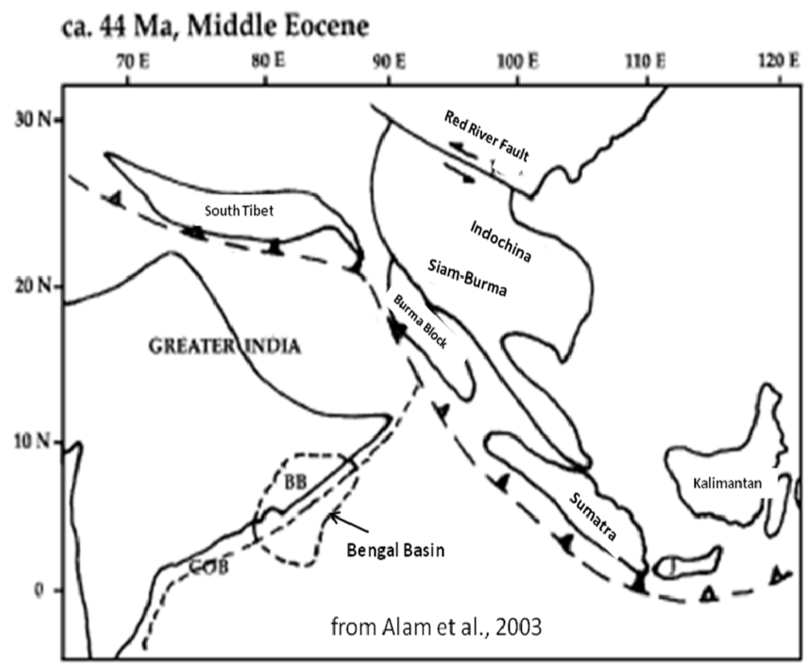


Figure 3-2 Position of continental plates at 44 Ma

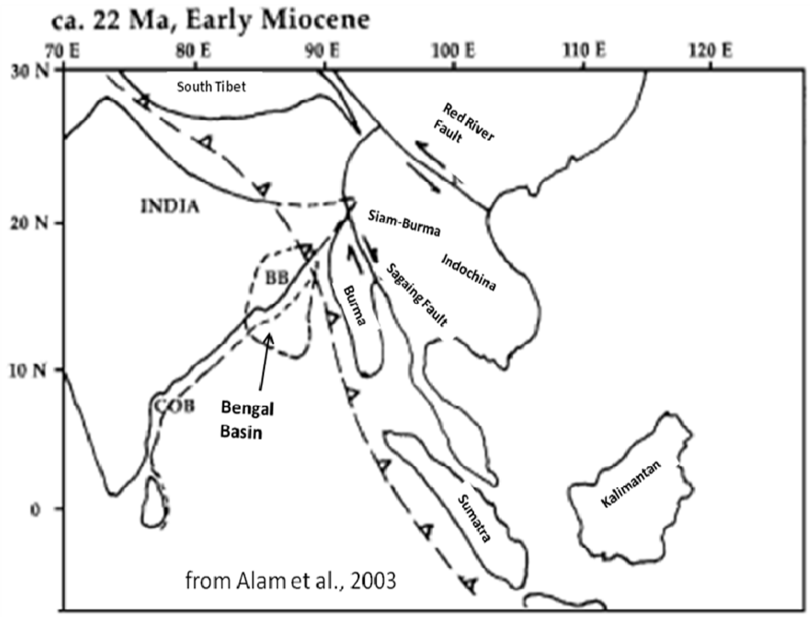


Figure 3-3 Position of continental plates at 22 Ma

3.3 MAJOR STRUCTURAL ELEMENTS

The eastern side of the India Craton that forms western Bangladesh consists of a rifted margin with underlying rift half-graben. This margin then developed into a passive margin with sediments ranging from Permo-Carboniferous to Pleistocene age and, during Eocene time, a carbonate shelf. This area is known as the Bogra Shelf or the Western Shelf. The Bogra Shelf is 60 to 130 kilometers wide with a regional southeast dip. The Hinge Zone estimated the position of attenuated continental crust (Alam et al., 2003). The Barisal-Chandpur Gravity High is located east of the Hinge Zone.

East of the shelf slope is the Foredeep or Central Deep Basin (Alam et al., 2003), which includes the Surma Basin or Trough (Sylhet Trough) and the Haitia Trough. The Surma Trough to the northeast and the Haita Trough to the southeast are separated by the Tangail-Tripura High. The sedimentary successions of the Surma and Hatia Troughs are estimated at approximately fifteen and twenty kilometers thick, respectively.

The Shillong Plateau is oriented west to east and is located to the north of Bangladesh (Figure 3-4). The plateau is a block of Precambrian rocks that has been thrust to the south along the Dauki Fault.

The eastern margin of the foredeep area is oceanic crust overlain by the folded western margin of the fold belt (Figure 3-5).

To the east of Bangladesh are the Burma Hills (Indo-Burma Ranges) that are a complex of folds and thrusts and wrench faults of accreted arc complexes that bound the western side of the Central Burma Basin and the Chindwin Basin. The development of the Burma Hills is a result of subduction of oceanic crust along the Eurasian Plate. The Indo-Burma Ranges region is bounded by the north to south trending Kaladan wrench fault, in front of which the Chittagong-Tripura Fold Belt has developed. The fold belt arches to the west as it trends north to south from the Naga Hills in India south along the eastern side of Bangladesh and into Myanmar. The fold belt is bounded to the west by the Chittagong-Cox's Bazar fault, east of which folding continues, both onshore and offshore where the structures are more gently folded. The sedimentary sequence of the fold belt includes Oligocene through Pleistocene age clastics.

The Rangpur Saddle is a basement high composed of Precambrian rocks that is located between the Indian Craton and the Shillong Plateau and serves to separate the Bengal Basin from the Himalayan Foredeep or Purnea Basin in India. The Himalayan Foredeep contains Paleogene sediments overlain by Neogene continental deposits of the Siwalik Group.

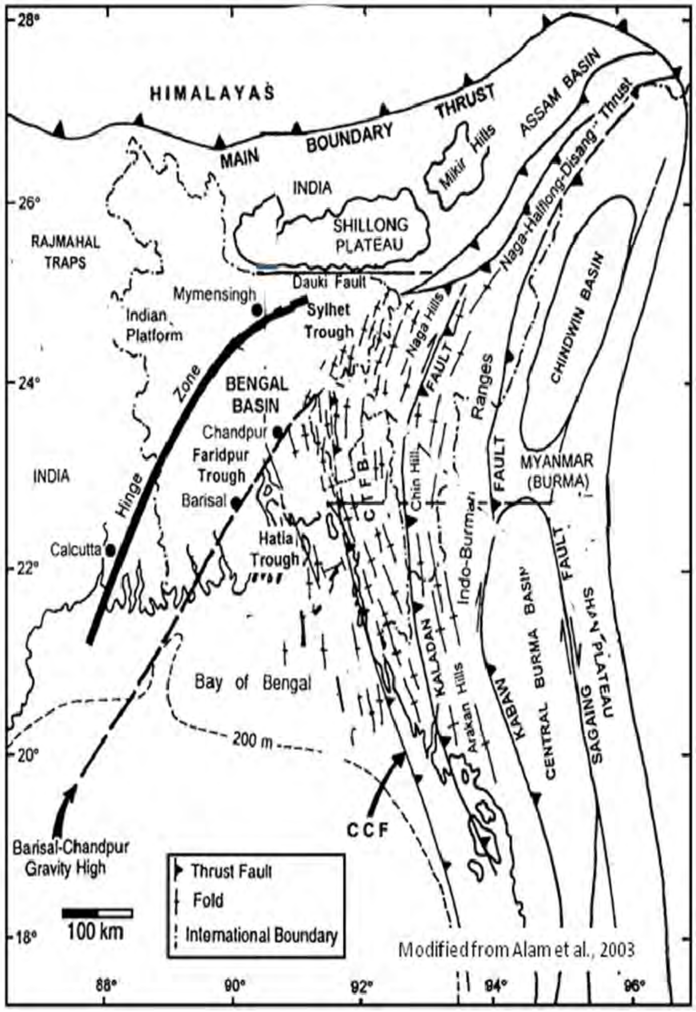


Figure 3-4 Map showing major structural elements

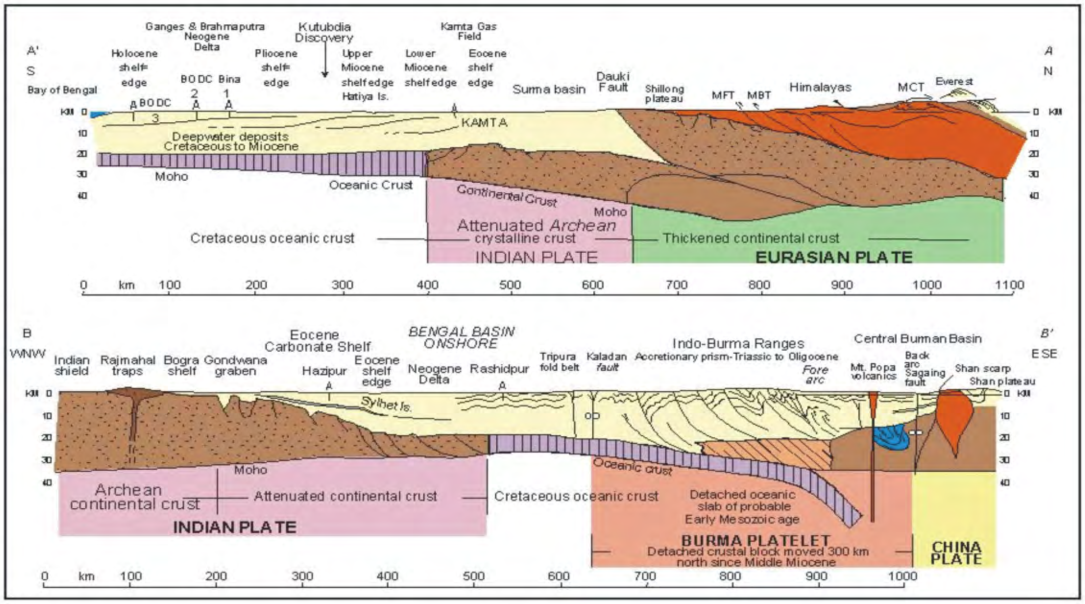


Figure 3-5 General North-South and East-West cross sections

3.4 DEPOSITIONAL HISTORY

The depositional history of the Bengal Basin and Bangladesh is a combination of inherited deposits of the India Plate and other pieces of Gondwanaland, i.e. Tibet and Burma plates, island arcs resulting from plate collisions, and passive margin deposition during drift, collision, rotation of the tectonic plates, and the Ganges-Brahmaputra delta. Deposition was dominated, from approximately Miocene time to the present, by the Ganges-Brahmaputra delta and its Late Oligocene age predecessor. Clastic input shifted with time due to tectonic events that formed basins and changed the drainages of the rivers that contribute to the Ganges-Brahmaputra delta and the Bengal Fan. The source terrains for sediments changed with time from the India Plate to the west to the India Plate and the rising Himalayas to the north and then from the India Plate, the Himalayas and the Burma Plate to the east as the passive margin moved north and collision and rotation of the plate occurred. This is shown well in Figures 3-6 through 3-10.

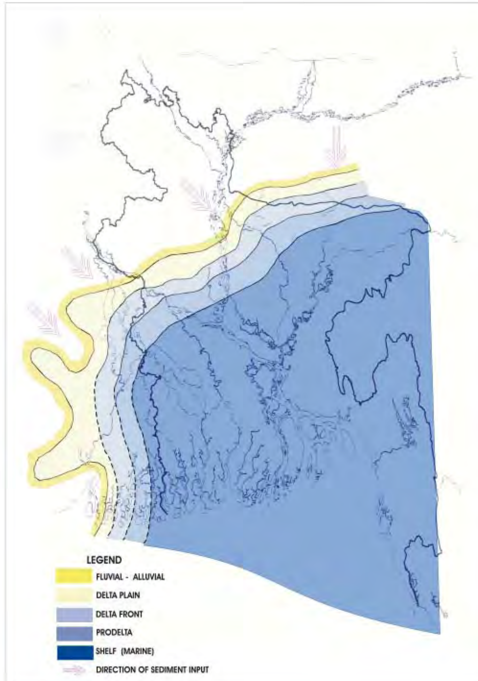


Figure 3-6 Paleogeographic map, Late Cretaceous

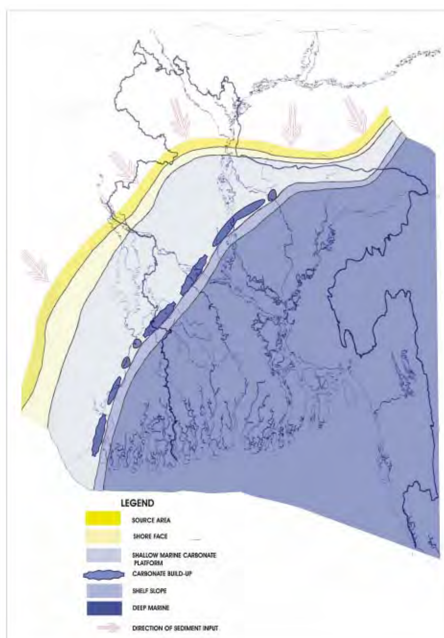


Figure 3-7 Paleogeographic map Middle Eocene

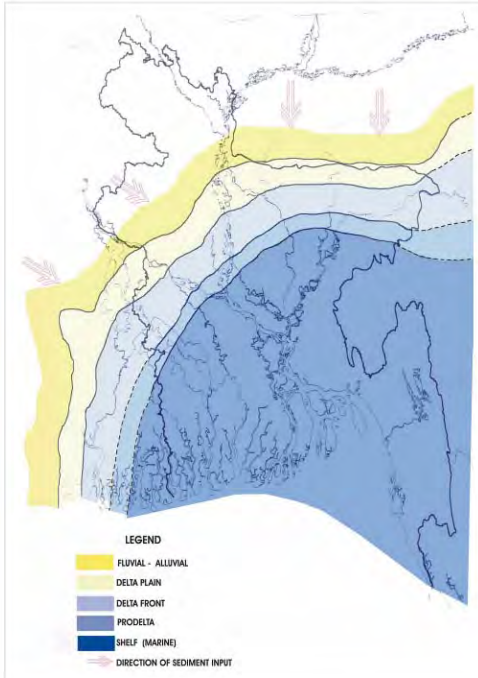


Figure 3-8 Paleogeographic map, Oligocene

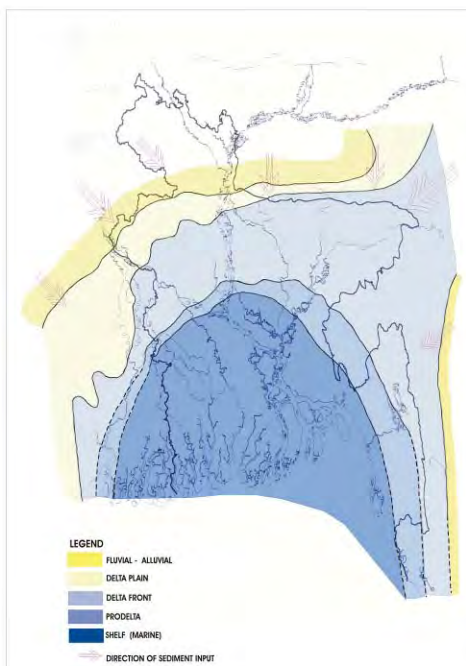


Figure 3-9 Paleogeographic map, Early Miocene

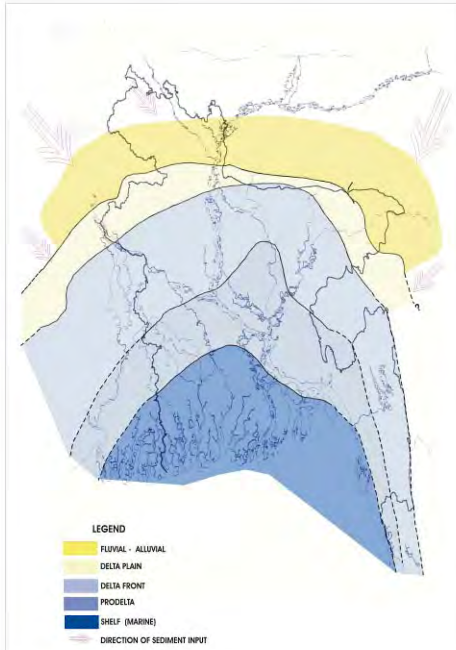


Figure 3-10 Paleogeographic map, Late Miocene

The event chart (Figure 3-11) (Curiale et al., 2003) displays these major tectonic circumstances and the associated depositional settings. Comparisons of the age and names of groups and formations from various sources for both eastern and western Bangladesh are shown in Figure 3-12.

<table>
<tr><th>Carboniferous Permian Triassic</th><th>Jurassic</th><th colspan="3">Cretaceous Paleocene Eocene Oligocene</th><th>Miocene</th><th>Pliocene Pleistocene</th></tr>
<tr><td>Early rifting, formation of half-grabens</td><td>Rifting</td><td colspan="3">Continental separation, breakup unconformity, sea floor spreading.</td><td>Collision. Subduction under Burma. Himalyan Orogeny. Major Himalyan uplift.</td><td>Dauki faulting, Chittagong/Tripura foldbelt, uplift of Shillong block.</td></tr>
<tr><td colspan="3">Synrift-basin deposition</td><td>Drift</td><td>Collision</td><td colspan="2">Collision and rotation</td></tr>
</table>

Figure 3-11 Events chart

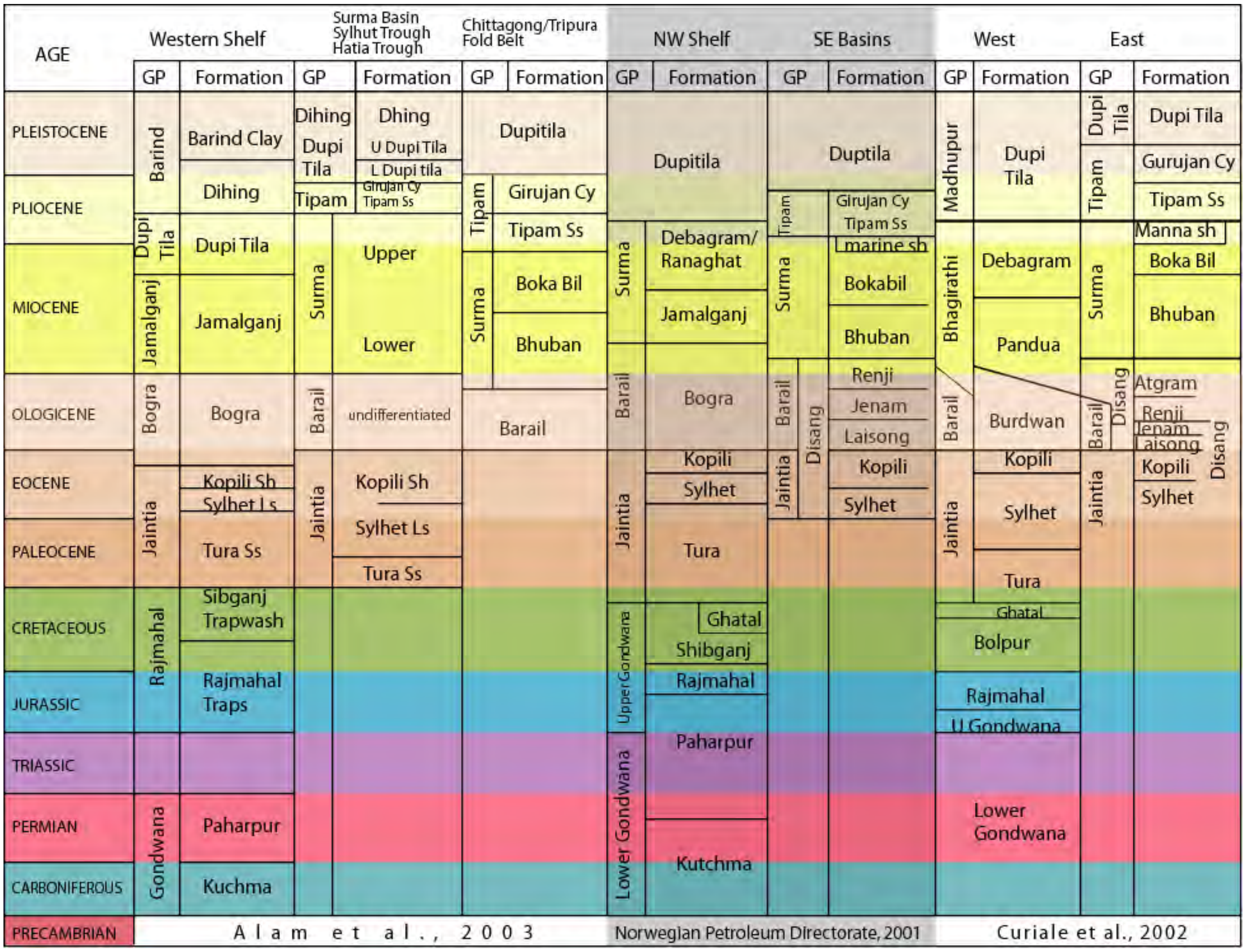


Figure 3-12 Comparison stratigraphic chart

The earliest depositional strata consist of tillite, coal, sandstone, shale and mudstone deposited in half-grabens as syn-rift rocks of the Gondwana Group. Basalt and lava deposited during late rifting to early drift phase comprise the upper units of the Gondwana Group (Figure 3-12).

As separation of the Gondwana continent continued, a passive margin developed on the India Plate in the area that would become the Bengal Basin. On this shelf margin were deposits of fluvial, alluvial, delta plain, and marine shelf that were sourced from the India Craton to the west.

In the Dhananjaypur–A well, drilled in India west of Meherpur in Bangladesh, marine sediments of Cretaceous age were recovered. Similar deposits were drilled in the SME-E well that was drilled offshore just west of the Eocene shelf break. These strata are known as the Dhanajaypur Formation but the geographic extent is not known.

During Middle Eocene time, a carbonate shelf was established by a major marine transgression of the passive margin (Figure 3-7) (Alam et al., 2003). Limestone of the Sylhet Formation covered most of the western shelf area of Bangladesh and the area south of the Shillong Plateau. Sediment influx increased to the shelf and slope building submarine fans.

A relative fall in sea level occurred during Late Eocene resulting in erosion and cutting of channels into the carbonate shelf. The onlapping Kopili Formation represents mudstone deposits of the subsequent transgression.

Seismic interpretation of the shelf during Oligocene time indicates that this was a time of erosion of the shelf edge and slope. Much of the Oligocene strata may have been removed. At the close of Oligocene time evidence of the beginning of collision of the India Plate with Eurasia is represented by strata of the deltaic and marine shelf Barail Group and the equivalent Surma Group in eastern Bangladesh (Figure 3-12) (Alam et al., 2003).

By Early Miocene time, sources for sediments are located to the west, north and east (Figure 3-9). New clastic input from the east confirms collision and rotation against the Burma Plate and the beginning of the Himalayan orogeny (Figure 3-10) (Alam et al., 2003). High sedimentation rates resulted from the Himalayan orogeny. The Miocene shelf was the setting for delta and shallow shelf deposition alternating with erosion and channel cutting during lowstands.

The Ganges-Brahmaputra delta and the Bengal Fan have dominated deposition in Bangladesh beginning in at least Late Oligocene time with the proto delta. Uplift of the Shillong plateau in Pliocene time reorganized the rivers that drained the Himalayas. The Brahmaputra River captured the flow of the Zhangpo River, which had flowed into the China Sea (Curiale et al., 2002). The combined contributions of the Ganges, Brahmaputra, and smaller rivers have built the Ganges-Brahmaputra delta and the Bengal fan filling the basin to an estimated thickness of more than 16 kilometers.

3.5 STRATIGRAPHY

As the tectonic history of Bangladesh varies with the region of the country so does known the stratigraphy. A comparison of the rock groups and formations from different sources and regions is shown in Figure 3-12. This is not an exhaustive comparison of published stratigraphy but illustrates the differences that are apparent between the eastern region of Bangladesh and the western region along with the group and formation names and ages that vary.

3.5.1 Northwestern Shelf and Slope Area

Basement

The western shelf or northwest shelf area is located in northwestern Bangladesh where Precambrian basement has been encountered in wells at approximately 2,500 meters and within the Bogra Shelf area at 2,150 meters. The basement dips generally to the southeast. Basement, where encountered, is comprised of tonalite, diorite, gneiss, schist, and granodiorite (Alam et al., 2003). The basement rocks were faulted and half-grabens formed during rifting.

Gondwana Group

The Gondwana Group rocks are of Permian-Carboniferous to Late Permian age (or through Cretaceous age, NPD, 2001) and form a complex approximately 955 meters thick (Alam et al., 2003), and are known from the India Plate, in India and western Bangladesh. The Gondwana Group was deposited as syn-rift strata in half-grabens formed by rifting and as post-rift drift strata as the continent of Gondwana separated. These strata consist of tillite, shale, sandstone, siltstone, coal, conglomerates, and volcanics associated with rifting. These rocks were encountered in wells in the Bogra Graben and in the Jamalganj area. The Singra-1X well penetrated 1,200 meters of what was interpreted as the Gondwana Group without reaching basement. These rocks were also encountered in the Kutchma well. The rocks encountered in the Kutchma well were correlated with the coal-bearing Early Permian Barakar Stage of Damodar Basin of India. The Gondwana succession encountered in wells drilled in the Jamalganj area has been correlated to the Permian Ranigonj Stage in India.

The Kuchma Formation is at the base of the Gondwana Group (Alam et al., 2003 and NPD, 2001) (Figure 3-12). The Kuchma overlies Precambrian basement across a major unconformity. This formation consists of approximately 490 meters of sandstone, siltstone, mudstone and conglomerate deposited in fluvial to delta plain environments. The coal and tillite at the base represent the end of glaciation of the Gondwana continent and high-latitude cold climate coal deposits that are both similar to those found in southern Africa in equivalent age rocks. Deposition of the Kuchma Formation was followed by another unconformity.

The Paharpur Formation overlies the Kuchma Formation and consists of thick coal and sandstone deposited in fluvial, deltaic, and coal swamp environments. Both of these formations were deposited during early rifting and formation of half-grabens in the area that would later separate the India Plate from the Antarctica Plate and become a passive margin and then western Bangladesh (Alam et al., 2003) (Figure 3-12).

Rajmahal Group

The Rajmahal Group rocks of western Bangladesh are of Jurassic and Cretaceous age and form a complex approximately 840 meters thick (Alam et al., 2003)(some authors include this group in the Gondwana Group, NPD, 2001). The lower formation is the Rajmahal Traps, which are approximately 610 meters thick. The Rajmahal Traps are dominated by several lava flows, but also include variegated siltstones, sandstones and conglomeratic lenses. This formation consists of amygdaloidal basalt, andesite, serpentinized shale, and agglomerate deposited as subaerial lava flows and fluvial to deltaic and shallow marine clastics. These rocks were encountered in the Kutchma and Singra wells.

The overlying Sibganj Trapwash (also known as Ghatal and Bolpur in India) consists of weathering products of the Rajmahal Traps and the granitic India craton in the form of sandstone and clay deposited in fluvial, alluvial and coastal environments (Figure 3-12). These rocks were deposited during late rifting and early drifting phases of the breakup of Gondwana.

Jaintia Group

The Jaintia Group is approximately 735 meters thick and is composed of rocks of Paleocene through Eocene age. The group is divided into the Tura Sandstone, the Sylhet Limestone, and the Kopili Shale (Alam et al., 2003). The Jaintia Group represents onlap of the passive margin that culminated in a maximum transgression during the Middle Eocene forming a carbonate platform followed by an increase in clastic input (Figure 3-12). A relative lowstand eroded the carbonate platform deposits and cut channels in the shelf edge prior to the next transgression, which deposited the overlying and onlapping shale.

The Paleocene to Eocene age Tura Sandstone (Jalangi Formation in India) is composed of coal seams, sandstone, siltstone, and carboniferous mudstone interpreted to have been deposited in deltaic to marine shelf environments.

The Middle Eocene age Sylhet Limestone is from 250 meters to 800 meters thick and represents a major marine transgression of the passive margin and the development of a carbonate shelf (Alam et al., 2003). The Sylhet Limestone has been characterized as a foraminiferal biomicrite (Alam et al., 2003). Seismic data indicate that towards the foredeep the Sylhet Limestone gradually changes to a pelagic mudstone. Deposition of limestone was terminated by a relative fall in sea level at the beginning of Late Eocene.

The Late Eocene age Kopili Shale consists of shale and thin-bedded sandstone with fossiliferous limestone deposited conformably across the Sylhet Limestone shelf. The Kopili Shale varies from 500 meters thick in outcrop in the Assam region of India to 240 meters in Bangladesh to 30 meters in the India West Bengal Basin. The Kopili Formation is considered to have a potential for hydrocarbon generation.

The Jaintia Group may represent Upper Cretaceous through Lower Eocene strata of the Therria Subgroup. The Therria is described as a sequence that includes that includes reworked trapwash, massive sandstones and interbedded shales, coals and sands. The subgroup contains both deltaic and marine strata in proximal and distal depositional settings. This subgroup is known mainly from the Assam Valley, India. The Therria Subgroup term is not frequently used in Bangladesh. It correlates with the top of the Sibganj Trapwash and the Tura Sandstone in Figure 3-12.

Bogra Group

The Oligocene age Bogra Group is also known as the Baril Group and consists of the Bogra Formation (also known as Memari and Burdwan in West Bengal Basin, and the Barail Formation in the Assam region, India) (Figure 3-12). The group is approximately 165 meters thick and consists of siltstone, sandstone, and carbonaceous shale (Alam et al., 2003). The Bogra Formation was deposited in deltaic to marine shelf environments. In Bangladesh the Bogra Formation is encountered in the Bogra, Kutchma and Singra wells.

The time equivalent rocks in the Sylhet Trough are known as the Barail Formation and, combined with the underlying Jaintia Group, reach a thickness of 7,200 meters (Figure 3-12). The Barail Group equivalent is also recognized in the subsurface of the Chittigong-Tripura Fold Belt in eastern Bangladesh. Here it is known as the Surma Group. The Surma Group is of Oligocene to Miocene age and in the fold belt consists of the Bhuban Formation and the Boka Bil Formation (Figure 3-12). This group represents deposition in shelf, nearshore, and tidal depositional environments (Alam et al., 2003). Alam et al. (2003) propose renaming this group into the Mirinja Group, above the Middle Miocene unconformity, and the Sitapahar Group below.

Jamalganj Group

The Early to Middle Miocene age Jamalganj Group and Formation (also known as Pandua Formation in West Bengal Basin, India) occurs in western Bangladesh and was deposited on an unconformity on the Bogra Formation. This strata is also known as the Surma Group and the Bhagriathi Group (Figure 3-12). The Jamalganj Formation is approximately 415 meters thick in Bangladesh and more than 1,500 meters thick in the West Bengal Basin, India and has been encountered in several wells drilled in the shelf area of Bangladesh (Alam et al., 2003). These rocks are interpreted to have been deposited in deltaic and marine shelf environments and consist of shale, sandstone, and siltstone.

Dupi Tila Group

The overlying Late Miocene to Early Pliocene age Dupi Tila Group and Formation (also known as Debagram and Ranaghat in the West Bengal Basin, India) is a series of claystone, siltstone, sandstone, and gravel approximately 280 meters thick in western Bangladesh (Alam et al., 2003). Correlative rocks in the Surma Basin would include the upper Surma Group and in eastern Bangladesh the Boka Bill Formation of the Surma Group, the Tipam Sandstone of the Tipam Group (NPD, 2001; Curiale et al., 2002) (Figure 3-12). These rocks are interpreted to have been deposited in fluvial and deltaic depositional environments. The Dupi Tila is bounded both at the base and at the top by unconformities.

Barind Group

The Late Pliocene to Pleistocene age Barind Group in the western Bangladesh area (also known as the Dupitila Group and the Dupi Tila Formation of the Madhupur Group) (Figure 3-12) consists of the Dihing Formation and the Barind Clay (Alam et al., 2003). The Dihing Formation is composed of redbeds of sand and clay in strata that measure approximately 150 meters thick. The presence of silicified wood also characterizes the Dihing Formation. The formation is interpreted to have been deposited in fluvial and alluvial settings. The Barind Clay is approximately 50 meters thick and is composed of yellow to red clay, silty clay, and silty sand.

Overlying these rocks is Holocene age alluvium in western Bangladesh.

3.5.2 Eastern Basinal Area

The stratigraphic nomenclature of eastern Bangladesh is similar to western Bangladesh from Paleocene or Eocene time and younger (Figure 3-12). Older strata have not been drilled. The area of the Sylhet Trough has been described separately by Alam et al. (2003) (Figure 3-12). This stratigraphic succession will be treated within the eastern Bangladesh descriptions.

Jaintia Group

The Jaintia Group contains the Tura Sandstone, the Sylhet Limestone, and the Kopili Shale and is of Paleocene and Eocene age across Bangladesh. The Jaintia Group is recognized by Alam et al. (2003) in the Sylhet Trough but not in the fold belt. The Sylhet Limestone and the underlying Tura Sandstone are the oldest known strata in eastern Bangladesh (Figure 3-12) (Alam et al., 2003). The Tura Sandstone in the Sylhet Trough area is described as poorly sorted sandstone with mudstone and fossiliferous marl. The formation is 170 to 360 meters thick and has been interpreted as having been deposited in shallow marine to marine settings (Alam et al., 2003). These strata crops out on the southern side of the Shillong Plateau. Descriptions of the Sylhet Limestone from the Khasi Hills in India recognize three limestone units interbedded with two sandstone units. This limestone is generally grey, medium grained, hard, massive and rich in foraminifera. The 40 to 90 meter thick Eocene age Kopili Formation or Kopili Shale crops out near the northern border of Bangladesh. In outcrop and where encountered in wells, the Kopili consists of gray to black shale that can be calcareous or fossiliferous and interbedded with sandstone and fossiliferous limestone.

Barail Group

The term Barail Group (Bogra Group by Alam et al. in western Bangladesh) has been applied to strata of Oligocene age in both western and eastern Bangladesh (Figure 3-12). These strata outcrop near the Dauki Fault where they range in thickness from 800 to 1600 meters (Alam et al., 2003). The group can be divided into the Laisong, Jenam, and Renji Formations with a total thickness estimated at 4,000 to 6,000 meters. These strata consist of tide-dominated shelf sandstones and shales in the Eocene shelf area in the west and marine fan facies to the east. Distal marine fan facies interpretations are supported by seismic data (NPD, 2001). The Barial Group in central and eastern Bangladesh may be mainly argillaceous (Worm, 1998).

Surma Group

The Surma Group is interpreted to range from Late Oligocene to Early Pliocene age however; it is usually placed entirely in the Miocene in eastern Bangladesh (Figure 3-12). The thickness ranges from 3,500 meters near Cachar, India, to 6,000 meters near the coast in Arakan, and from 5,500 to 6,000 meters in the Surma Trough. The strata crop out near Sylhet and in the Chittagong Hills. This group is divided into the Bhuban and the Boka Bil Formations. The Bhuban Formation consists of sandstones, siltstones, shaly sandstones, shales, and conglomerates deposited in deltaic to shallow marine environments. The overlying Bokabil Formation consists of generally argillaceous shales, siltstones, and sandstones. The marine shale that is the youngest strata in the Surma Group, informally called the Upper Marine Shale, is the seal rock in several gas fields in the Surma Trough area.

Tipam Group

The Tipam Group is variously interpreted as being of Late Miocene to Early Pleistocene age (Figure 3-12). The group is divided into the Tipam Sandstone and the Girujan Clay. The Tipam Sandstone consists of conglomerate, coarse-grained, cross-bedded sand and pebbly sand. Coal, carbonized wood, and petrified tree fragments are common within the sandstone. The environment of deposition is interpreted as braided fluvial streams. The Girujan Clay conformably overlies the Tipam Sandstone (Figure 3-12) and consists of red, brown, purple, and blue mottled clays interpreted to have been deposited as lacustrine and fluvial overbank deposits.

Dupi Tila Group

The Dupi Tila (Dupitila) Group and Formation is of Late Pliocene and Pleistocene age. It includes two units: the lower one, which is composed of poorly consolidated sandstones representing deposition in channel and floodplain settings; and the upper one, which is composed of silty sandstones frequently containing coal and petrified wood fragments, and mottled clay horizons.

Pleistocene subaerial deposits of the Dihing Formation have been identified locally (Figure 3-12).

4. SOURCE ROCKS

Source rocks that are mature and capable of generating hydrocarbons have been identified in Eocene and Miocene strata in Bangladesh (Curiale et al., 2002; Hossain et al., 2009; Shamsuddin and Khan, 1991; Manzur Ahmed et al., 1991; Ismal and Shamsuddin, 1991; Islam and Rahman, 2009). Source rocks from Gondwana Group strata have also been identified (Frielingsdorf et al., 2009). The potential source rocks in Bangladesh were compiled and summarized by Curiale et al. (2002) and are presented in Table 4-1.

Table 4-1 Comparison of source rock data, modified from Curiale et al., 2002

Age	Unit	Sample	TOC (%)	Other
Pliocene/late Miocene	Tipam, Boka Bil, U Bhuban	Beani Bazaar-1 well, Rashidpur-3 well	0.2-1.5	HI 104-225 mg/g
Mid-Miocene	L Bhuban	Adamtila-1 well (India)	1.76 (avg)	2-3 mg/g (avg), Rock-Eval S2
Mid-Miocene-Oligocene	Atgram, Renji, U Jenam?	Atgram-1 well plus wells in Surma Basin	0.4-1.2	HI to 155 mg/g, marginally mature
Oligocene	U Jenam	outcrop	1.4-2.7	HI 121-166 mg/g, up to 0.15% extractable hydrocarbons
Eocene/Paleocene	Kopili, Cherra	outcrop	up to 16	gas prone
Tertiary	Undifferentiated	Titas-1 well	0.45-3.60	100% humic organic matter
Mesozoic	Gondwana	surface and subsurface	up to 60	gas prone

Gas, condensate, and oil are present in the Bengal Basin of Bangladesh. Two phases of hydrocarbon generation have occurred. The first phase took place just prior to break up during the Jurassic involving strata of the Gondwana Group and the second and current phase beginning in Paleocene with burial of source rocks in the Sylhet Trough (Surma Basin) and the Hatia Trough.

4.1 SOURCE ROCK POTENTIAL

Source rock studies have indicated that there are two primary areas that contain strata that are within the hydrocarbon generating window. One is to the south of the Shillong Plateau and corresponds to the Surma Basin or Sylhet Trough and the other is south of the Tangail-Tripura High corresponding to the Hatia Trough (Curiale et al., 2002; Ismail and Shamsuddin, 1991; Shamsuddin and Khan, 1991). Within these two "kitchen" areas the early mature gas generation window is in the lower portion of the Bokabil Formation. In addition to these hydrocarbon "kitchen" areas, western Bangladesh contains half-grabens located on the rifted margin of the India Plate that contain Gondwana strata that are mature for hydrocarbons. Studies have also predicted the presence of mature oil windows in Paleocene through Eocene age strata along the Bogra Shelf (Anglo Scandinavian Petroleum Group, 1988). These strata could be both oil and gas prone.

Analysis of outcrop samples of the Barakar (L. Permian) and Ranigonj (U. Permian) Formations of the Gondwana Group strata in India indicates that both of these formations are excellent potential source rocks. In Tihki #1 well in India, the total organic carbon content (TOC) of the Barakar Formation ranges from 1.75 percent to 17.9 percent and that of the Ranigonj Formation ranges from 2.79 percent to 17.08 percent. The Gondwana strata in Bangladesh consist of coal and coaly shale sequences that are rich in Type III organic matter. Humic Type III organic matter is generally gas-prone; however, oil is also generated from coals rich in liptinite in many basins. Gondwana strata potential source rocks have TOC values up to 60 percent (Curiale et al., 2002). Data from the Chandkuri-1 well west of Bangladesh in India indicates that in this area Gondwana source rocks entered the oil window in Oligocene to Miocene time and may still be within the oil window.

Mudrocks of the Eocene age Jaintia Group and the Oligocene age Barail Group from the Sylhet Trough contain kerogen derived from land plants that could generate condensate and oil. The TOC values from samples of these strata were 1.0 percent to 1.6 percent (Zakir Hossain, et al., 2009).

A recent study and modeling of the Kuchma, Singra, and Hazipur wells in northern and western Bangladesh predicted a significant hydrocarbon (predicted to be gas) generation phase for Gondwana strata from Late Triassic through Early Jurassic time (Frielingsdorf et al., 2008). Uplift then occurred as a result of the continental breakup. Another phase of hydrocarbon generation is predicted from these well modeling results in appropriately buried Gondwana strata, particularly basinward of the "hinge zone", from Late Miocene to present day (Frielingsdorf et al., 2008). Gondwana half-grabens are well imaged on seismic data; however, the presence and distribution of the potential source rocks among the half-grabens is not known.

Samples of Cretaceous age strata from two wells in West Bengal contain TOC values of 1.04 percent to 1.5 percent. This suggests that the adjacent Natore-Pabna area of western Bangladesh could contain Cretaceous age source rocks capable of generating hydrocarbons.

Paleocene to Eocene strata, particularly the Kopili Formation with TOC values of 5 percent and the Cherra unit with TOC values of 16 percent, have the potential to be source rocks (Curiale et al., 2002). Wells in the Eocene shelf area within the India portion of the West Bengal Basin have encountered oil in Lower Oligocene sandstone reservoirs. Samples from the West Bengal Basin and from wells on the Eocene shelf in Bangladesh of the Eocene age Kopili Shale indicate this marine shale has fair to good source rock potential in the area. These strata are considered gas-prone with TOC values up to 16 percent however, oil may also be generated. Where sampled, the Kopili Shale is immature but would be expected to mature down dip to the southeast. Analysis by ONGC also suggests an increasing TOC content toward the basin. The transgressive, Kopili Shale covers a large area of the eastern Eocene shelf and the Assam and Surma valleys. The Kopili Shale is known to be a source rock in the Assam area of India and could therefore be a source rock for adjacent northeastern and eastern Bangladesh. This source rock has potential to generate oil and gas.

The Oligocene age Jenam Shale is considered to be a significant source rock for hydrocarbons in the Bengal Basin and one of the major sources of oil in the Assam area of India and the fold belt of Bangladesh. Analysis of the Jenam Shale indicates TOC ranging from 1.4 percent to 2.7 percent and HI of 121 to 166 mg/g from the lower Jenam and 0.4 percent to 1.2 percent and HI up to 155 mg/g from the upper Jenam (Curiale et al., 2002). The Jenam Formation and the Rangpani Clay unit are source rocks with both oil and gas potential. Where sampled in the Atgram-IX well at depths of 4,740 meters to 4,980 meters, the Jenam consisted of dark gray silty and sandy shales with TOC ranging from 0.6 percent to 1.6 percent but is only marginally mature at the Atgram-IX well location.

The Miocene Bhuban Shale is well developed in the Bengal Basin. These strata extend to the fold belt of eastern Bangladesh. The source rock potential is low due to TOC values ranging from 0.2 percent to 0.7 percent and gas is the predicted hydrocarbon from this strata. Locally the TOC value reaches 1.76 percent within the Lower Bhuban Formation in the Adamtila well in India. Rock-Eval pyrolysis indicates possible liquid hydrocarbon source rock potential at this location.

5. RESERVOIR ROCKS

Middle to Late Miocene age sandstones are the primary producing reservoir rocks in Bangladesh and are known mostly from wells drilled in the fold belt. These reservoir rocks include the upper Miocene to Pliocene Boka Bil Formation and the middle Miocene Bhuban Formation (Curiale et al., 2002; Islam, 2009). The Bhuban Formation produces gas at the Titas Gas Field where the formation represents deposition in prodelta, delta front, paralic and minor marine environments (Islam, 2009). These reservoir rocks consist of fine- to medium-grained quartz sandstones with siltstone interbeds. Porosity ranges from 5 percent to 28 percent and consists of primary and secondary porosity. Horizontal permeability ranges from 0.5 mD to 490 mD (Islam, 2009). In other fields in the fold belt, porosity of the reservoir rocks ranges from 15 percent to 33 percent and permeability from 20 mD to 330 mD with permeability found as high as 4 darcies. The depositional environments of these reservoir rocks include fluvial, tidal channel, coastal plain and shallow marine settings.

The equivalent age sequence on the western shelf area may be more argillaceous. Seismic data indicate that the sequence is extensively channeled, which may cut out some potential reservoir strata and add channel fill as a potential reservoir rock.

The Lower-Middle Miocene reservoir rock strata in eastern Bangladesh has been sampled at depths of 2,500 meters to 3,500 meters resulting in sandstone conventional core porosity measurements ranging from 10 percent to 23 percent. Porosity at shallower depths ranges from 20 percent to 30 percent.

In the western shelf area potential reservoir rocks were deposited in delta front to inner shelf depositional environments. Porosity values of these rocks, measured from conventional core samples, range from 5 percent to 28 percent. The Middle Miocene sequence is absent in many areas in western Bangladesh due to a widespread erosional unconformity.

Other potential reservoir rocks have been encountered in wells drilled in Bangladesh and India.

Syn-rift sandstones of the Jurassic through Carboniferous age Gondwana Group are potential reservoir rocks. These reservoirs are fine- to coarse-grained sandstones deposited in alluvial, fluvial, deltaic, and shallow marine depositional environments. These rocks are restricted half-grabens of the rifted margin of the India Plate.

The Paleocene age Tura Sandstone that has been encountered in the Singra well and the Kutchma well in the area of the western shelf is a potential reservoir rock. Porosity is fair to good, from less than 12 percent to 27 percent.

The platform carbonates and the carbonate buildups that comprise the Sylhet Limestone of the Eocene age shelf are potential reservoir rocks. The platform facies was drilled in a few wells on the western shelf and found to have porosity ranging from tight to approximately 18 percent. Porosity enhancement is due to dolomitisation and karstification. This alteration along with possible fracturing would increase the porosity and permeability of this potential reservoir. Sandstone interbedded with the Sylhet Limestone are producing reservoirs in the Assam area of India suggesting an additional potential reservoir for exploration in Bangladesh.

Sandstones and shales of the Oligocene age Barail Group were drilled in wells in the western shelf region and the northern Surma Basin. The sandstone porosity ranges from 10 percent to as much as 18 percent.

6. PETROLEUM SYSTEMS

The petroleum system is based on a single source rock or source strata (as well as can be known) and the hydrocarbon accumulations associated with that source. The system can be known, hypothetical, or speculative. The resulting petroleum system is the sum of several factors that act together to enable the accumulation of conventional hydrocarbons. Factors affecting conventional hydrocarbon accumulations include source rock (a rock layer in the region that has sufficient organic content to provide for hydrocarbons), maturation (the burial of the source rock sufficient to generate hydrocarbons from the organic material within the source rock), reservoir rock (one or more rock layers that has sufficient porosity and permeability to store hydrocarbons), trap (the structural or stratigraphic configuration that involves the reservoir rock and where migrated hydrocarbons reside), seal (a layer that is impermeable to hydrocarbon and prevents the hydrocarbon from escaping the trap), migration (the path of movement of the generated hydrocarbons from the source rock to a trap), and timing (the events must occur in the correct order to create and preserve a hydrocarbon accumulation). Evaluation of this group of factors is termed "basin analysis". The formal presentation of this type of analysis has been developed into the "petroleum system" by Magoon (1988) and Magoon and Dow (1994) and subsequent refinements.

In Bangladesh, a Tertiary Composite Total Petroleum System has been described by the U. S. Geological Survey (2001) and a Jenam-Bhuban Boka Bil Petroleum System by Curiale et al. (2002). Using the convention set forth by Magoon and the USGS, the first name is the source rock separated by a dash from the reservoir or reservoirs that hold hydrocarbons sourced by that particular source rock. Composite systems are where no particular source rock has yet been geochemically matched with discovered hydrocarbons.

Bangladesh has been divided into two regions in some schemes and three regions in other schemes. Division into two regions results in the western province, which consists of extensional continental rifting followed by passive margin and partially covered by Tertiary deltaics (includes the western Hatia Trough), and the eastern province, which consists of oceanic crust and distal passive margin partially covered by Tertiary deltaics and then folded (includes the Surma Basin or Sylhet Trough). Division into three regions results in the Stable Shelf, Central Deep Basin (the Sylhet Trough and the Hatia Trough), and the Chittagong-Tripura Fold Belt (Alam, et al., 2003).

Curiale et al., (2002) developed a petroleum system events chart for the Surma basin, Bangladesh. The authors showed the Kopili and Jenam formations as source rock, burial continuous since the middle of the Oligocene, seals within the Kopili and Jenam formation and the Miocene age Bhuban and Boka Bil formations, reservoir rocks from the Eocene age Sylhet Formation up through the Miocene age Boka Bil Formation, trap formation in the Pliocene and Pleistocene, oil generation from late Eocene through middle Oligocene, and gas generation from middle Oligocene to the present.

Another petroleum system was described for northwest Bangladesh (Frielingsdorf et al., 2008) that combined Paleozoic age Lower Gondwana coal, Kopili shale, Jenam shale, and Boka Bil Formation source rocks with Sylhet Limestone and Bhuban/Boka Bil reservoirs.

6.1 WESTERN PETROLEUM PROVINCE

Three petroleum systems are suggested within the western province area; the Gondwana composite petroleum system, the Bogra Shelf petroleum system, and the Western Delta petroleum system.

6.1.1 Gondwana Petroleum System

The hypothetical Gondwana composite petroleum system is located on the rifted margin of the India Plate, now the northwestern part of Bangladesh. Syn-rift coal-bearing sequences located in half-grabens are the probable source rocks. Individual coal seams are up to 45 meters thick. Additional speculative source rocks that would be expected in this tectonic setting would be oil-prone lacustrine shales. As the half-grabens were buried by a passive margin setting, potential traps and reservoir rocks would be expected in Carboniferous through Late Cretaceous age strata and perhaps Tertiary strata. Initial hydrocarbon generation during Early Jurassic time was followed by uplift and cooling (Frielingsdorf et al., 2008). Uplift that reached a maximum in middle Cretaceous time had the potential to remove reservoir rocks and breach traps and cooling may have halted hydrocarbon generation. These rocks are now again within the hydrocarbon generation window so that traps and reservoirs of Late Neogene age could hold hydrocarbons sourced by Gondwana rocks. Fault block traps would be expected in the syn-rift basins whereas stratigraphic traps in erosional remnants, channels, or stratigraphic pinchouts would be expected targets in this region.

6.1.2 Bogra Shelf Petroleum System

The hypothetical Paleocene to Eocene age Bogra Shelf petroleum system includes parts of the western shelf and the slope area of the Bengal Foredeep. The system is located in a passive margin setting of the India Plate. Deposition of clastic and carbonate strata included in this system took place from Late Cretaceous through Late Eocene time. The Paleocene age Cherra Shale and the Eocene age Kopili Formation, both part of the Jaintia Group, are dominantly gas-prone with TOC values up to 16 percent (Curiale, et al., 2002). Oil shows have been noted in limestone strata of the Golf Green-1 well in West Bengal and from the Ichapur well indicating an active oil generating petroleum system in the area, which could be based on the Kopili Shale as the source rock. Stratigraphic traps and carbonate build-ups would be expected along this shelf and shelf margin as exploration targets. Potential reservoir rocks include the Tura Formation, Sylhet Limestone and other clastic strata. The Kopili shale and Oligocene through Miocene regional shales could be seals for the hydrocarbon accumulations.

6.1.3 Western Delta Petroleum System

The western delta area is located southeast of the Bogra paleo shelf edge in the Bengal Foredeep and the western part of the Hatia Trough. Source rocks are Oligocene through Miocene age strata of the Barail Group and the Surma Group. One of the source rocks that has been specifically identified as mature in the Hatia Trough is the Bhuban Formation (Shamsuddin and Khan, 1991; Curiale et al., 2002). This strata is generating hydrocarbons that are expected to migrate up-dip to the west, where the system is unproved, as they have to the east, where the petroleum system is proven. Gas and liquids are both possible from this widespread shale. Early Miocene through Pliocene age stratigraphic traps in delta front and slope fan complexes are expected exploration targets. Growth faulting associated with deltaic deposition will add fault traps to the target inventory.

6.2 EASTERN FOLD BELT PETROLEUM PROVINCE

In eastern Bangladesh gas and liquids have been commercially produced since the 1950s, proving the existence of petroleum systems in this area. Three areas have proven reserves; the Surma petroleum system, the east delta petroleum system, and the southeastern offshore petroleum system.

6.2.1 Surma Petroleum System

The northeastern area of Bangladesh is characterized by a petroleum system based on the Oligocene age Jenam Formation as a gas-prone and liquid-prone source rock. Hydrocarbon accumulations have been found primarily in the Oligocene to Miocene age Bhuban and Boka Bil Formations of the Surma Group (Curiale et al., 2002). The strata is mature in the Surma Trough (Sylhet Trough) and is migrating vertically and horizontally to charge the traps (Shamsuddin and Khan, 1991). The traps are primarily anticlines and faulted anticlines. Combination anticlines with draped channels have also been proven. Other stratigraphic traps and deeper horizons may be possible future targets.

6.2.2 East Delta – Hill Tract Petroleum System

The mature source rock in the east delta area has been identified as the Miocene Bhuban Formation (Curiale et al., 2002). These strata are mature in the Hatia Trough. Migration is into the fold belt to the east and the Tangail-Tripura High to the north. Migration out of this “kitchen” (Hatia Trough) has also been predicted to the west as reviewed above. Proven reservoir rocks are primarily Miocene and Pliocene age sandstones deposited in fluvial, nearshore and offshore depositional environments. Traps include anticlines and channels incorporated into anticlines. Additional exploration targets would include stratigraphic traps and deeper reservoirs.

6.2.3 Southeastern Offshore Petroleum System

This area contains a proven petroleum system that includes the offshore southern and western portion of the fold belt and the offshore portions of the Hatia Trough. The source rock is the Bhuban Formation that is mature in the Hatia Trough, and perhaps the Kopili Formation. The traps are a combination of relaxed folded anticlines of the western part of the fold belt and growth faults related to the delta. Reservoir rocks include Miocene and Pliocene age deltaic sandstones, and deep-water clastics. Stratigraphic traps may also prove to be an exploration target.

7. HYDROCARBON HABITAT

7.1 CONVENTIONAL TRAP TYPES AND PLAYS

All of the conventional trap types, structural and stratigraphic, are expected to be present in Bangladesh. Anticlines are concentrated in the tectonically compressional eastern portion of the region and have been proven to contain commercial quantities of hydrocarbons in Bangladesh. Carbonate build-ups are concentrated along the Eocene shelf edge of the passive margin of the India Plate and have yet to be well explored. Other structural and stratigraphic trap types will be located throughout the region.

The trap types that are proven and expected include:

- Anticlines
- Fault closures or fault traps
- Rollovers and normally faulted anticlines
- Carbonate platforms, carbonate build ups, carbonate debris fans
- Prograding delta plays
- Channels, incised valleys and erosional remnants ("buried hills"), and other stratigraphic plays
- Gondwana fault block, stratigraphic, and inversion plays

Of these plays, perhaps the most significant, is the combined stratigraphic/structural trap, found to be productive in the Chittagong-Tripura Fold Belt, where reservoirs of limited areal extent that were deposited in various depositional settings are draped over anticlines. These reservoirs include marine, marginal marine, deltaic, and fluvial sandstones. These numerous additional targets should initially be explored for within the currently productive areas where exploration and production infrastructure already exists. These additional targets include deeper or shallower reservoirs (thin bedded reservoirs in productive fields are discussed elsewhere in this report) and down dip reservoirs that occur off-structure. These drilling targets could be identified with 3D seismic data.

Additional stratigraphic targets would be expected in deposits of prograding deltas, turbidites, basin-floor-fans, channels, incised valleys, erosional remnants, shallow marine and marginal marine settings. These stratigraphic targets would be associated with Paleocene through Miocene age rocks of the Bogra Shelf, Oligocene through Miocene age rocks of the delta, and Miocene and Pliocene age deposits associated with the younger delta and southeastern shelf margins.

7.1.1 Anticlines

The eastern portion of Bangladesh is characterized by anticlines due to the compressional tectonic regime resulting from plate subduction that has been discussed above. The Chittagong-Tripura Fold Belt, or eastern fold belt, trends NE-SW in the northeast then arcs around to trend NW-SE in the southeast. The belt extends from northeast Bangladesh south through Myanmar and offshore into the Bay of Bengal. This belt developed from Miocene to Recent time. Folding intensity and steepness decrease from east to west. Folding occurs on a detachment fault in Oligocene age shales. Many of the anticlines are also faulted. Most of the fields and exploration targets that involve anticlines in Bangladesh are considered four-way closures.

Combination stratigraphic and structural traps have been drilled in the fold belt of Bangladesh. These consist of sand bodies of limited extent, usually channels, which have been involved in the folding. In this case the exploration target may be off to one side of the structural closure and be partially stratigraphically controlled.

In the fold belt, most proven reservoirs are Miocene age to Early Pliocene age delta front to outer shelf sandstones of the Surma Group. Other potential reservoirs are under-explored. Gas and condensate are the primary products from the fold belt but oil seeps, shows, and minor oil production indicate oil discoveries in Miocene age strata may be possible.

7.1.2 Fault Closures

Downthrown fault closures in the fold belt may trap hydrocarbons. An example of this type of trap is the Chhatak East downthrown fault closure. It has yet to be drilled even though the upthrown block (Chhatak West) was drilled as a gas discovery. More of this kind of potential structural trap undoubtedly exist in the fold belt.

Simple fault traps would also be expected in the syn-rift plays of western Bangladesh where potential reservoir sandstone is faulted against basement as discussed below. And as expansion faulting along the shelf margins of both eastern and western Bangladesh.

7.1.3 Rollovers and Normal Faults

Over steepened or rolled over anticlines occur in the fold belt of eastern Bangladesh. Normal faulting also occurs. Both of these features act to create additional traps and compartmentalize reservoirs in anticlines.

7.1.4 Carbonate Platforms and Build-Ups

An Early to Middle Eocene age carbonate platform is present in northwestern Bangladesh resulting in deposition of the Sylhet Limestone. Possible stratigraphic exploration targets associated with the carbonate platform include carbonate reefs or build-ups along the shelf edge as well as carbonate debris fans and debris flows into the basin. The trend of the carbonate build ups have been mapped using seismic data and subsurface data. Both oil and gas sourced by shales of the Jalangi Group can be expected.

7.1.5 Prograding Delta Plays

Prograding deltas of Cretaceous through Recent age can be found in all regions of Bangladesh. Stratigraphic traps associated with deltas are common in Bangladesh and should be important exploration targets along and combined with structure. The delta plays of the Ganges-

Bramaputra delta located onshore and offshore in the Bay of Bengal have yet to be fully explored and may hold significant reserves. These plays include growth faults and rollovers associated with growth faulting, stratigraphic pinch-outs, channel cuts, erosional remnants, along shore sand bodies, and deep-water clastics.

7.1.5.1 Turbidites

Turbidites or deep-water clastics, or gravity/density flows form submarine fans along continental shelves and slopes and are proven hydrocarbon reservoirs throughout the world.

7.1.5.2 Pinch-Outs

Proximal deltaic deposits are generally of limited extent and form discreet stratigraphic traps. These include offshore bars that are generally oriented parallel to the shoreline and lowstand erosional channels that are generally oriented perpendicular to the shoreline.

7.1.6 Channels, Incised Valleys and Buried Hills

The seismic data indicates that the Miocene section is highly channelized. This erosion has left stratigraphic targets in the form of erosional remnants (buried hills), incised valley fill, and sand-filled reservoir channels or shale-filled sealing channels.

7.1.7 Gondwana Plays

Gondwana plays are located in western Bangladesh in the area where half-grabens formed by continental rifting underlie the western shelf region. The syn-rift sedimentary section was deposited from Permian through Carboniferous time. The primary play expected in this tectonic and sedimentary setting is the fault trap. Stratigraphic plays and inversion structures are also common targets associated with half-grabens. Plays also may be present that are located under the breakup unconformity or other major unconformity where these unconformities represent seals to hydrocarbon migration.

7.2 UNCONVENTIONAL PLAYS AND BYPASSED PAYS

A conventional gas accumulation can generally be identified as a discrete pool having definable areal limits imposed by an underlying fluid contact and overlying seal (caprock). The conventional gas system typically consists of a permeable rock reservoir with a trapping mechanism dominated by hydrodynamic, or buoyancy, forces (Elloitt, 2008). In contrast, unconventional gas accumulations tend to be contained within low-permeability reservoirs having ill-defined boundaries. Such gas systems are generally not buoyancy-driven and are commonly independent of structural and stratigraphic traps (Law and Curtis, 2002).

The classification of conventional and unconventional hydrocarbon systems is an informal practice that can cause confusion in a global context. Distinctions between conventional and unconventional resources in the United States were primarily based on the economics of resource development. Subeconomic or marginally economic gas resources such as coalbed methane, shale gas, and tight (low-permeability) gas sands were considered by most exploration geologists as unconventional. These gas systems are now economically viable resources in many countries, and some exploration companies no longer refer to them as unconventional but refer to them now as resource plays.

In many countries outside North America, concepts of some types of unconventional gas resources, such as basin-centered gas systems, are not known or are poorly understood. In Bangladesh, unconventional gas plays, specifically coalbed methane and fractured shale gas, were not considered in the 2001 resource report. Continuing technological advances and increasing understanding of reservoir characteristics now allows exploration geologists to consider low-permeability (<0.1 md) sandstones and self-sourcing reservoirs such as coal and shale as potential resources.

This section includes a discussion of bypassed pays. Bypassed pays are actually conventional hydrocarbon systems that have not been recognized mainly because of their thinness. Beds of hydrocarbon-bearing sandstones may be thinner than the vertical resolution of standard downhole logging devices. Logging tools that lack the capability to resolve resistivity values for the individual beds of sand and shale record an average resistivity measurement over the thinly bedded sequence.

7.2.1 Gondwana Coalbed Methane (CBM) [“Resource” Play]

Coal beds (containing greater than 50 percent by volume of carbonaceous material) are self-sourcing reservoirs in which gas is stored within the coal matrix, primarily in an adsorbed state and, secondarily in micropores and fractures as free gas or solution gas in water (Rice, 1993; Yee, and others, 1993). Important reservoir parameters that control gas resource potential and economic producibility include thermal maturity, maceral composition, gas content, coal thickness, fracture density and permeability, burial history, and hydrologic setting (Ayers, 2002). Natural gas in coal is generated by biogenic and thermogenic processes, which can be identified by isotopic composition (Rice, 1993).

Gas migration through CBM reservoirs proceeds by a combination of diffusion and fluid (Darcy) flow mechanisms. Gas molecules on surfaces of micropores (<2 nm) and mesopores (2–50 nm) diffuse through the coal matrix. The matrix permeability of coal is too low for commercial gas production. Fluid flow to gas wells in coalbeds is through the natural fractures, or cleats. Cleats are systematic, orthogonal fracture systems that commonly are perpendicular to bedding. Cleat permeability is controlled by fracture density (spacing), aperture width and openness, extent, and connectivity. Permeability generally decreases with depth due to overburden stress (Mavor and Nelson, 1997; Ayers, 2002).

Coalbed reservoirs may be normally (hydrostatically) or abnormally pressured. At the usual pressures encountered in producing coalbed reservoirs in the (150 to 1,200 meters deep), coal can store more adsorbed gas than typical sandstone can store in primary pores (Nolde and Spears, 1998; Ayers, 2002). The cleat systems of coal beds at depth are typically filled with water. Gas production (desorption) from the reservoir generally begins when a pressure differential develops at the coal matrix/cleat interface by withdrawing water from the reservoir (dewatering).

The evaluation of coal and coaly shales that might contribute to a coalbed methane play is done with multiple boreholes where whole core is taken during drilling with special equipment to preserve the gas content of the rock. Testing of the core involves desorbing the rock in a pressure vessel for several months and recording the volume of gas released. The production potential of a coalbed methane play is usually evaluated using a five-spot drilling program. This consists of a group of four wells that are drilled in a square with a fifth well in the center. Water is then produced from the wells (dewatering) for up to two years in order to draw down the formation water and allow the gas to be produced primarily from the center well. The core testing and well testing will determine the practicality of the potential coalbed methane play.

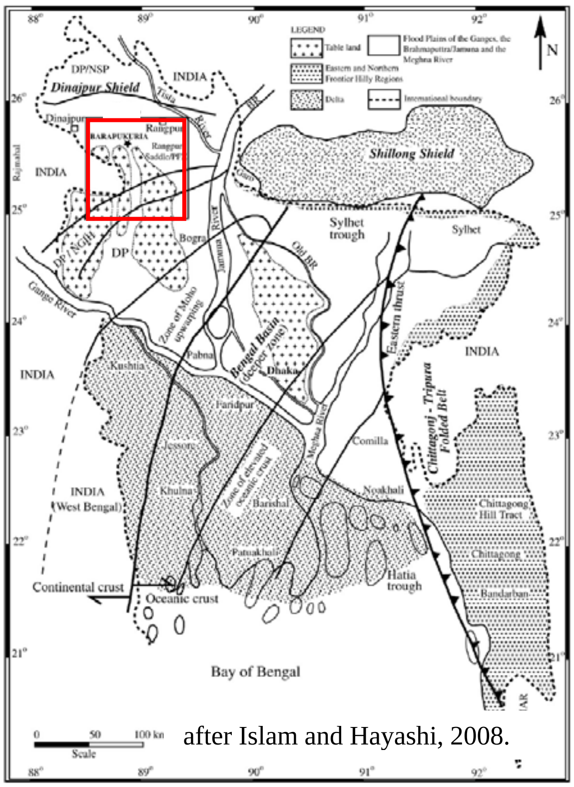
In addition to coalbed methane production play alone, coalbed methane can be produced ahead of more traditional coal mining. In this way both the gas, which can be a hazard to the mining operations, and the coal are able to be exploited.

Coal in Bangladesh that has been considered for this report is located in the northwestern part of the country, where isolated deposits have been discovered in Gondwana (Permo-Carboniferous) intracratonic structural basins (grabens) on the Bogra shelf (Figure 7-1). The coal-bearing rocks of the Gondwana Group are unconformably overlain by Miocene-Pliocene and younger deposits and are not exposed at the surface.

Figure 7-1 Map showing coal provinces in adjacent India and Bangladesh (red box)

The coal district northwestern portion of Bangladesh has been known for decades (Table 7-1 and Figure 7-2). The Bangladesh coal deposits are generally similar to coals in other Gondwana basins in Australia and southern Africa, and are considered analogous to nearby Gondwana coal deposits located in the Rajmahal hills and Damodar valley of eastern India (Figure 7-1).

Occurrences of coal have been identified in other locations in Bangladesh in addition to the coal district in the northwest (Akhtar, 2000) (Figure 7-3).



after Islam and Hayashi, 2008.

Figure 7-2 Map of Bangladesh showing the location of the coal mining area in red

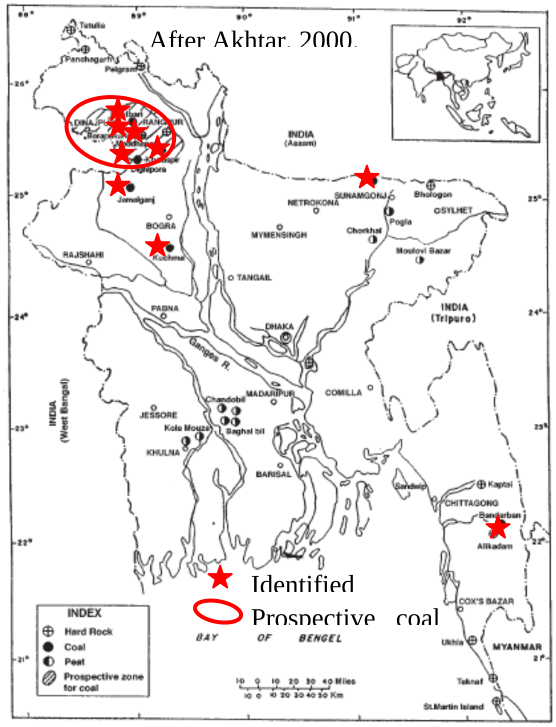


Figure 7-3 Map showing location of potential coal resources in Bangladesh

Table 7-1 General Information for Major Coal Deposits in Bangladesh

Coal Field (District)	Year of Discovery	Reported Area (km^2)	Aggregate Coal Thickness Range (m)	Number of Coal Beds	Depth of Coal Range (m)	Coal Rank	In-situ Coal Resources (million tonnes)
Barapukuria (Dinajpur)	1985[3]	5.16[2]	40.3-83.0[2]	6[2]	118-518[2]	HVB Bituminous[2]	377[2]
Dinghipara (Dinajpur)	1995[1]	5[8]	61.38[8] (Avg)	5[8]	328-422[1]	Bituminous[1]	483[6]
Jamalganj (Bogra)	1962[5]	11.7[5]	18.59-99.49[5]	7[5]	641-1,158[5]	HVB to HVA Bituminous[5]	1,053[6]
Khalaspir (Rangpur)	1989[4]	12.26[1]	42.30-61.00[1,4]	8[8]	257-615[2,4]	Bituminous[1]	828[2]
Phulbari (Dinajpur)	1997[1]	6[6]	38.41[1] (Avg)	8[8]	120-350[6]	Bituminous[1]	426[2]

[1] Akhtar, 2000
[2] Islam and Hayashi, 2008
[3] Norman, 1992
[4] Hossain and others, 2002
[5] Imam and other, 2002
[6] Islam, 2009
[7] Elahi, 1995
[8] Ghose, 2009

Five known coal basins (Barapukuria, Dighipara, Jamalganj, Khalaspir, and Phulbari) are considered potential CBM plays for this report (Figure 7-4). Table 7-1 provides general information about these coal basins. Insufficient information is available to evaluate the CBM resources for coal deposits reported at Kuchma and Maddhapara (Akhtar, 2000).

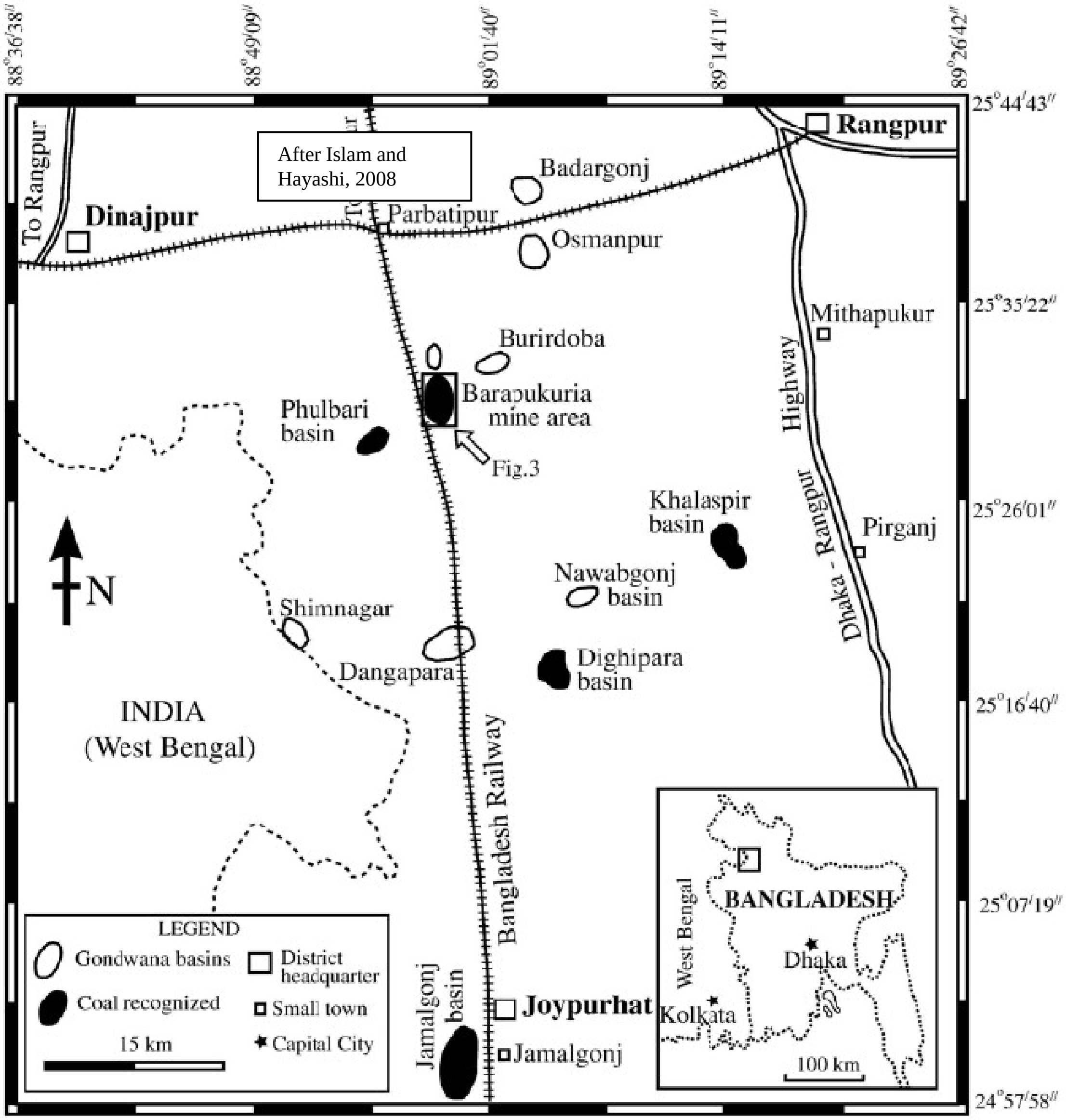


Figure 7-4 Map showing Gondwana coal deposits identified for mining

This report considers resources for the areas of Barakupuria, Dighipara, Jamalganj, Khalaspir and Phulbari shown on Figure 7-4 from published information. Gas content is reported on a dry ash-free basis[22] (DAF). Areas reported in Table 7-1 reflect those as reported in published documents. Gustavson relied on published data for coal deposit areas at Khalaspi, Jamalganj, and Dighipara and has used this data in the resource calculations. Gustavson digitized maps of the coal deposits and has used the resulting areas in the resource calculations for deposits at Barakupuria, and Phulbari.

At Barakupuria five coal seams have been considered in the resource estimate with minimum content (m^3/ton) of 6.51 (DAF), maximum of 12.68 (DAF), and median of 9.60 (DAF). The average total coal thickness is 67.04 meters and the area is 7.2 km^2.

Five coal seams have been considered in the resource estimate at Dighipara using a minimum gas content of 6.00 m^3/ton (DAF), a maximum of 16.00 m^3/ton (DAF), and a median of 11.00 m^3/ton (DAF), based on analogs from coals in India (Peters, 2000 and Rao, 2004). The average total coal thickness is 61.38 meters and the area is 5 km^2.

At Jamalganj seven coal seams have been considered in the resource estimate with an average total thickness of 79.18 meters and an area of 11.7 km^2. Gas contents are based on data from measured gas contents in India (Rao, 2004 and Imam et al. 2002) and range from a minimum of 4.00 m^3/ton (DAF), to a maximum of 12.80 m^3/ton (DAF), with a median of 8.40 m^3/ton (DAF), assuming a density of 1.49 g/cm3.

Eight coal seams have been considered in the resource estimate at Khalaspir with an average total thickness of 42.97 meters and an area of 6.2 km^2. Gas contents were estimated using measured gas content from India (Peters, 2000 and Rao, 2004) giving a minimum of 6.0 m^3/ton (DAF), a maximum of 16.0 m^3/ton (DAF), and a median of 11.00 m^3/ton (DAF).

[22] A basis for gas content determination whereby the air-dry weight is corrected for “non-coal” components, including residual moisture and ash. Gas Research Institute, 1995, A Guide to Determining Coalbed Gas Content.

At Phulbari, eight coal seams have been considered in the resource estimate with an average total thickness of 52.45 meters in an area of 12.4 km^2. Gas content was based on gas content measurements from India (Peters, 2000 and Rao, 2004) and assigned values of 6.00 m^3/ton (DAF) minimum, 16.00 m^3/ton (DAF) maximum, and 11.00 m^3/ton median (DAF).

7.2.2 Fractured Shale Gas "Resource" Play

Shale-gas systems are self-sourcing continuous-type accumulations characterized by widespread gas saturation, subtle trapping mechanisms, seals of various lithologies, and short hydrocarbon migration distances (Curtis, 2002). Hydrocarbons in shale reservoirs are stored as free gas in natural fractures and intergranular porosity, as gas sorbed onto kerogen and clay-particle surfaces, and/or as gas dissolved in kerogen and bitumen. The gas may be biogenic, thermogenic, or combined biogenic-thermogenic in origin.

In the United States, shale formations that produce commercial quantities of gas exhibit a wide range in values of five key parameters: thermal maturity, sorbed-gas fraction, reservoir thickness, total organic carbon content (TOC), and volume of gas-in-place. A TOC of 0.5 percent is considered the minimum cutoff for hydrocarbon generation in shale (Boyer et al., 2006). Organic material (kerogen) derived from terrestrial plants typically generates dry gas (methane). This would be considered gas-prone kerogen. Shales characterized by oil-prone kerogen or mixed oil-prone and gas-prone kerogen that is thermally overmature and in the "gas window" also produces shale gas in the United States. Thermal maturity, determined by vitrinite reflectance, pyrolysis (Tmax), or other methods, is an indicator of burial depth and hydrocarbon generation. High maturation values ($Ro>1.5\%$) indicate the presence of predominantly dry gas (Boyer et al., 2006).

The degree of natural fracture development in an otherwise low-matrix-permeability shale reservoir is a controlling factor in gas producibility. Economic production generally requires enhancement of the low matrix permeability (<0.001 Darcey) of gas shale reservoirs (Hill and Nelson, 2000). Well completion practices employ hydraulic fracturing and other common or specialized technology to access the natural fracture system and to create new fractures.

Shale gas plays are based on source rocks that have long been established as source rocks for conventional accumulations in the areas where they occur. These source rocks have histories of minor production from the source rock interval in vertical wells. Advances in technology in the areas of hydraulic fracturing and horizontal drilling have enabled the petroleum industry to target these shale gas plays and shale oil plays very effectively. These plays are produced from wellbores that are termed horizontals or laterals. The well is drilled vertically through the source rock then kicked off and drilled within the source rock interval and parallel to the strata. A lateral well can extend horizontally for two to more than three kilometers from the vertical well and the surface location. The well is then perforated and hydraulically fractured within the target strata all along the length of the lateral portion of the well. Drilling this way, parallel to the strata and entirely within the strata, exposes more of the target strata to the well bore increasing flow rates and recovery making this type of play economic.

In Bangladesh, there will necessarily be a longer lead time to identify and exploit potential shale gas resources then for conventional hydrocarbon resources. This lead time will involve the gathering of existing data from any logs, cores, geochemical testing, hydrocarbon typing, surface sampling, and subsurface maps. The available data will need to be analyzed with respect to the five key parameters mentioned above. An approach can then be developed to supplement the existing data and identify the most likely potential target and target area.

Increased exploration for conventional targets in undrilled or poorly explored areas of Bangladesh can add to the information necessary for the future of shale gas exploration. Sampling and testing of these new wells should be done in order to identify, locate, qualify, and quantify potential shale gas intervals.

Source rocks that may be exploited for shale gas in Bangladesh are not well known. Potential shale gas plays in Bangladesh include the organic-rich shales of Eocene, Oligocene, and Miocene age that have been considered source rocks for conventional gas fields in the Surma Basin, eastern fold belt, and Bengal Foredeep (USGS, 2001). The settings of these shales are described here.

Regional basin development and sedimentation is a result of tectonic drifting and collision of the Indian and Eurasian plates beginning in Tertiary Time (Curiale et al., 2002). Drift sediments consist of Cretaceous–Eocene distal deltaic (shallow) to shelf or slope (deep) marine deposits that lie unconformably on upper Paleozoic–Mesozoic Gondwana graben deposits of mainly continental origin. The poorly sorted sandstones, mudstones, and shales of the Paleocene/Eocene Jaintia Group (Cherra/Tura and Kopili units) formed at this time (Hossain et al., 2009).

Early collision sedimentation was contemporaneous with the beginning of continental collision (Oligocene to late Miocene), when initial uplift of the Himalayan and Indo-Burman Ranges occurred. Sediments deposited at this time in the eastern fold belt and Surma Basin range in thickness from 10 to 15 kilometers and were deposited in shallow marine and deltaic environments. This part of the stratigraphic section includes shales of the Barail Group/Jenam Formation. These rocks are currently at depths of 4 to 8 kilometers below surface (Ahmed et al., 1991).

Late collision sediments include the upper Bhuban and Bokabil Formations and overlying Tipam and Dupi Tila Formations. Sedimentation was contemporaneous with the major phase of continental collision (late Miocene–Holocene), when the main uplift of the Himalayan and Indo-Burman ranges occurred. Sediments accumulated in fluvial-deltaic to estuarine environments during the late Miocene–Pliocene, accompanied by extensive channeling and sediment reworking. The organic-rich shales and siltstones of the Bhuban Formation were deposited during this phase.

Thus, there are areas that would warrant investigation for shale gas potential within the mature shales in the Bogra Slope area, the Surma Basin, the Hatia Trough and the Fold Belt (Figure 7-5).

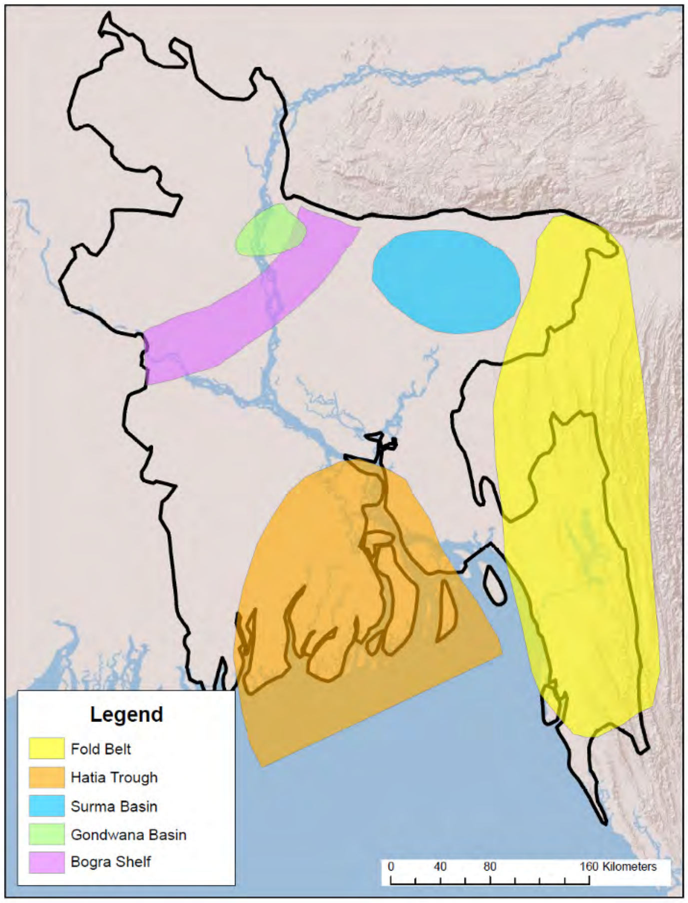


Figure 7-5 Map showing potential shale gas plays in Bangladesh

The Late Eocene age Kopili Shale and the Late Cretaceous through Early Eocene age Therria Subgroup are predicted to be in the oil window from 3,050 meters to 5,500 meters in an area parallel to the Hinge Zone (Anglo Scandinavian Petroleum Group, 1988). The Kopili Shale may be an oil-prone shale and thus the possibility of a shale oil play also exists. Oil-prone shale would be in the oil window beginning at a vitrinite reflectance value of between 0.5 and 0.6 with peak oil generation at a value of 0.6 (Figure 7-6). Shales in the Therria Subgroup may be gas-prone and would be mature at slightly deeper depths. The wet gas generation peak is at 1.0 percent on the vitrinite reflectance scale and the dry gas generation peak is at 1.20 percent on the vitrinite reflectance scale (Figure 7-6). Shales in the Surma Basin would be expected to be mature at approximately 6,000 to 8,000 meters, and in the onshore portions of the Hatia Trough at from 5,400 to 10,000 meters. The Jenam Shale could be a potential shale gas target in the region of the Fold Belt where it would be expected to be mature at approximately 6,500 meters depth (Curiale et al., 2002 and Ismail and Shamsuddin, 1991).

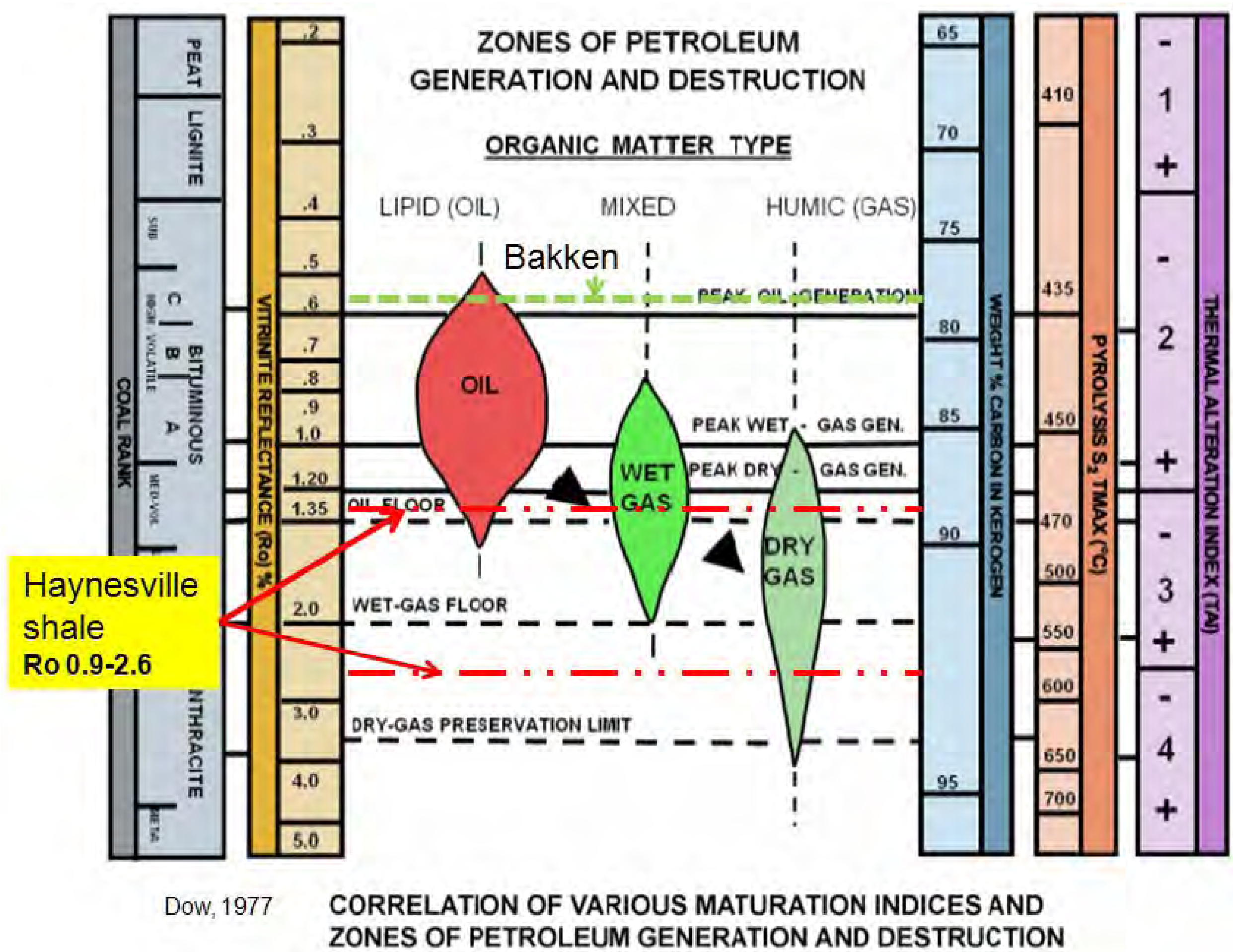


Figure 7-6 Petroleum generation chart

Comparing the shale gas plays in the United States to the potential in Bangladesh we look at source rock data from various authors that were compiled by Curiale, et al. (2002) and data for shale gas plays in the United States (Table 7-2 and Table 7-3). The deepest production in the United States is the Haynesville play, which may be most similar in depth to what could be expected in Bangladesh. Production in the Haynesville play is from approximately 3,200 vertical meters in wells with 1,850 meter lateral sections that are artificially fraced. Haynesville

TOC ranges from 0.5 to 4.0 percent[23]. Technically Recoverable Resources estimated by the U.S. Department of Energy, (2009) from publicly available sources was estimated at 251 Tscf from an estimated basin area of more than 23,000 square kilometers in the Haynesville play. Comparatively, source rock data from identified potential source rocks in Bangladesh range from 0.2 to 16 percent TOC (Curiale, et al., 2002).

Table 7-2 Summary of shale gas areas in Bangladesh

	Bogra Shelf		Surma Basin	Hatia Trough	Fold Belt
	Late Cretaceous-Early Eocene Therria Subgroup	oil prone Late Eocene Kopili Sh	pre-Miocene shales to Early Miocene	pre-Miocene shales	Pre-Miocene shales Jenam Shale Kopili Sh
Estimated area km2	8,421	8,421	7,706	33,553	23,000
Depth	3,200	3,000	5,000	5,000	3,000 to 6,000
Gross Thickness meters	120 to 350	240	90 plus	90 to 240	240
TOC%	0.6	up to 16	most 0.5 up to 1.5	0.5 up to 1.5	1.4 to 2.7 possibly 4.5[24]
Geothermal Gradient	3 degrees C/100m	3 degrees C/100m	1.8 degrees C/100m	1.8 degrees C/100m	

[23] U.S. Department of Energy, 2009

[24] www.dghindia.org

In comparison to other shale gas plays, the size of the areas that could be investigated for shale gas potential in Bangladesh are 8,421 square kilometers in the shelf area, 7,706 square kilometers in the Surma basin, over 33,553 square kilometers in the Hatia trough area, and more than 23,000 square kilometers in the fold belt area (Figure 7-5).

Table 7-3 Comparison of United States shale gas plays, U. S. Department of Energy

Gas Shale Basin	Barnett	Fayetteville	Haynesville	Marcellus	Woodford	Antrim	New Albany
Estimated Basin Area, square miles	5,000	9,000	9,000	95,000	11,000	12,000	43,500
Depth, ft	6, 500 - 8,500[82]	1,000 - 7,000[83]	10,500 - 13,500[84]	4,000 - 8,500[85]	6,000 - 11,000[86]	600 - 2,200[87]	500 - 2,000[88]
Net Thickness, ft	100 - 600[89]	20 - 200[90]	200[91] - 300[92]	50 - 200[93]	120 - 220[94]	70 - 120[95]	50 - 100[96]
Depth to Base of Treatable Water[#], ft	~1200	~500[97]	~400	~850	~400	~300	~400
Rock Column Thickness between Top of Pay and Bottom of Treatable Water, ft	5,300 - 7,300	500 - 6,500	10,100 - 13,100	2,125 - 7650	5,600 - 10,600	300 - 1,900	100 - 1,600
Total Organic Carbon, %	4.5[98]	4.0 - 9.8[99]	0.5 - 4.0[100]	3 - 12[101]	1 - 14[102]	1 - 20[103]	1 - 25[104]
Total Porosity, %	4 - 5[105]	2 - 8[106]	8 - 9[107]	10[108]	3 - 9[109]	9[110]	10 - 14[111]
Gas Content, scf/ton	300 - 350[112]	60 - 220[113]	100 - 330[114]	60 - 100[115]	200 - 300[116]	40 - 100[117]	40 - 80[118]
Water Production, Barrels water/day	N/A	N/A	N/A	N/A	N/A	5 - 500[119]	5 - 500[120]
Well spacing, acres	60 - 160[121]	80 - 160	40 - 560[122]	40 - 160[123]	640[124]	40 - 160[125]	80[126]
Original Gas-In-Place, tcf[127]	327	52	717	1,500	23	76	160
Technically Recoverable Resources, tcf[128]	44	41.6	251	262	11.4	20	19.2

NOTE: Information presented in this table, such as Original Gas-in-Place and Technically Recoverable Resources, is presented for general comparative purposes only. The numbers provided are based on the sources shown and this research did not include a resource evaluation. Rather, publically available data was obtained from a variety of sources and is presented for general characterization and comparison. Resource estimates for any basin may vary greatly depending on individual company experience, data available at the time the estimate was performed, and other factors. Furthermore, these estimates are likely to change as production methods and technologies improve.

Mcf = thousands of cubic feet of gas
scf = standard cubic feet of gas
tcf = trillions of cubic feet of gas
# = For the Depth to base of treatable water data, the data was based on depth data from state oil and gas agencies and state geological survey data.
N/A = Data not available

7.2.3 Thin-Bed Analysis – Bypassed Thin Sandstone Pays

Thin-bed or interlaminated pay has been studied in the Bibiyana Field. The possibility of thin-bed pay in other fields has been considered in this report as a resource of Bangladesh. Existing fields can be examined for this additional pay and evaluation of new wells should include a thin-bed analysis.

There are three possible methods for determining potential thin-bed pays in existing fields. One method would be to use modern resistivity modeling software, such as RT-mod to analyze existing data. This processing would be used to identify the thin beds and to calculate the true resistivity of theses beds. The second method would be to run modern cased-hole saturation tools such as the RST, reservoir saturation tool in existing wells. The data would then be processed to identify potential pay in the thin beds. The Third would be to drill new wells in each existing field. These new wells would be logged with mico-resistivity tools to determine the presence of these thin beds. Additionally, these new wells should be logged with standard logging tools using high resolution sampling (2.54 mm or 0.10 inch sampling rate) to determine the presence of thin-bed pays.

Since the possibility exists of the presence of thin-bed pay in new fields, proper logging needs to be done to identify this potential pay as each field is discovered.

Some of the reservoir intervals within the lower Bokabil and underlying Bhuban Formations consist of thin-bed, interlaminated pay consisting of thin alternations of reservoir-quality sands and non-reservoir shales. These intervals were identified by thin-bed logging tools, in particular the STAR tool, a micro-resistivity device. These pays at Bibiyana, with thickness between 5 cm and 30 cm, represent over 60 percent of the net pay in the first two wells, as documented in Unocal's Evaluation Report of July 2000 (Table 4).

Similar pays may be present in the older gas fields that were only logged with older tools that averaged or "smeared out" log characters of thin-bedded pays. These types of thin-bedded reservoir sequences show up as low-resistivity "shale" zones on older resistivity logs with larger detector spacings. A comparison of logs and perforated intervals in some of these older fields with Bibiyana would enable calculation of Contingent Resources in the older fields based on analogy to the percentage of total pay that would have been overlooked at Bibiyana if thin bed logging tools had not been run there. While all the intervals analyzed by Unocal in the first two Bibiyana wells had some thinly bedded pay, the intervals with the largest percentages of pay that could potentially have been overlooked in other fields are the BB65, BB10/15, and BH30/60. If the intervals were perforated anyway in the older fields, such resources would already be included in the reserves.

There are three possible methods for determining potential thin bed pays in these fields (Table 7-4). One would be to use modern resistivity modeling software, such as RT-mod. This processing would be used to identify the thin beds and to calculate the true resistivity of theses beds. Second method would be to run modern cased-hole saturation tools such as the RST, reservoir saturation tool. Then process the data to identify potential pay in the thin beds. The Third method would be to drill new wells in each field. Then log these new wells with mico-resistivity tools to determine the presence of these thin beds. Additionally, log these new wells with standard logging tools using high resolution sampling to determine the presence of thin bed pays

Table 7-4 Log Analysis Summary, Bibiyana Field

	conventional logs		Thin-bed logs		% Pay recognized with conventional logs
Zone	Top	Net Pay, m (tvd)	Top	Net Pay, m (tvd)	
BB60	2840	21.6	2630	32	67.5%
BB65	2906	6.6	2701	36.1	18.3%
BB70	3037	24	2831	57.9	41.5%
BH10/15	3224	9.8	3018	58.6	16.7%
BH20/25	3398	47.6	3194	69	69.0%
BH30/60	3898	12.8	3466	70.5	18.2%
Total		122.4		324.1	37.8%

8. FIELDS AND DISCOVERIES

8.1 PRESENT PRODUCTION

The seventeen gas fields that are producing in Bangladesh account for a total of 1,982.7 MMscf/day of gas as of May 6, 2010. This translates to a monthly production rate of just under 60 Bscf/month or 723.7 Bscf/year (0.7 Tscf/yr.).

Current production is from Petrobangla (through Bangladesh Petroleum Exploration & Production Company Limited (BAPEX), Sylhet Gas Fields Limited (SGFL), and Bangladesh Gas Fields Company Limited (BGFCL), Cairn, Chevron, Niko, and Tullow (as of April 2010).

8.2 PRODUCTION HISTORY

More detailed information and analysis of both historic and current production levels and trends is presented in the companion 2010 Reserves Report recently published as a joint effort of the Hydrocarbon Unit and Gustavson Associates, LLC.

9. RESOURCE CLASSIFICATION

9.1 2001 REPORTING OF BANGLADESH RESOURCES

In 2001, the Hydrocarbon Unit Ministry of Energy and Mineral Resources Government of the Peoples Republic of Bangladesh (HCU) and the Norwegian Petroleum Directorate (NPD) conducted a study titled Bangladesh Petroleum Potential and Resource Assessment 2001. This report estimated undiscovered risked recoverable resources for the minimum case at 19 Tscf, for the mean at 42 Tscf, and for the maximum at 64 Tscf.

9.2 PETROLEUM RESOURCE MANAGEMENT SYSTEM (PRMS)

The Petroleum Resource Management System (PRMS) was published jointly in 2007 by the Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE). This system defines both reserves and resources, including Contingent and Prospective Resources, and the reserve categories of Proved, Probable, and Possible. The relationship among these categories is illustrated in Figure 9-1 below.

Reserves, as defined under PRMS are "those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions" (SPE/WPC/AAPG/SPEE, 2007). Reserves must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. "Commercial" in this context denotes a commitment to develop the reserves within a reasonable time frame. "Remaining" means that volume of reserves that has not yet been produced and still is contained in the reservoir. Hydrocarbon accumulations that do not meet these criteria are classified as resources.

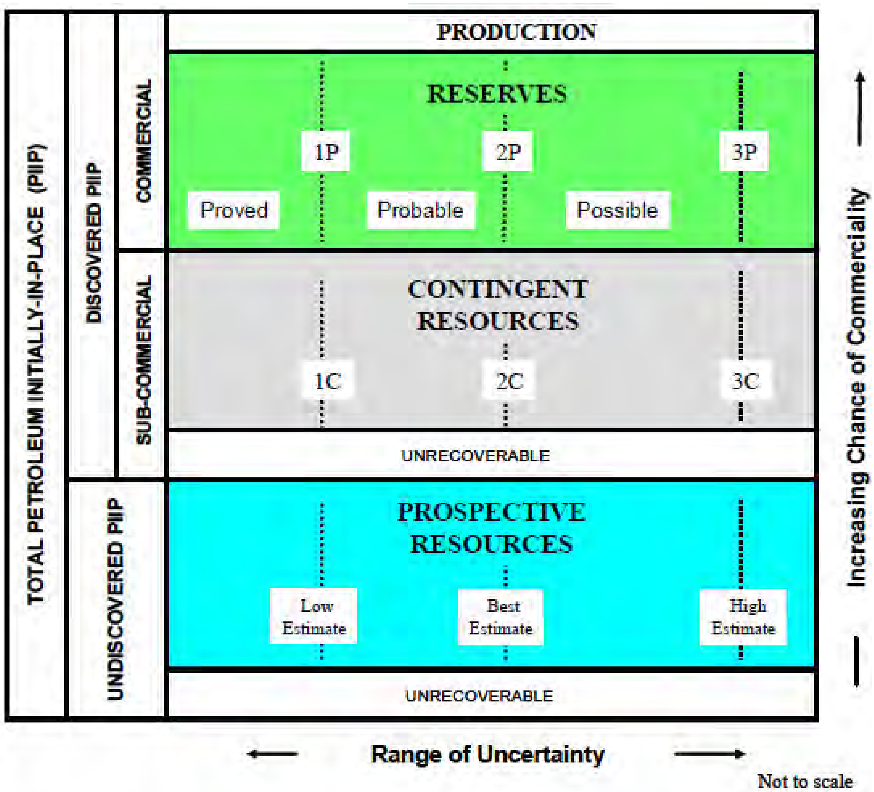


Figure 9-1 PRMS Resource Classification Framework
(SPE/WPC/AAPG/SPEE, 2007)

Resources may be classified as Contingent or Prospective. "Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality." (SPE/WPC/AAPG/SPEE, 2007)

"Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development." (SPE/WPC/AAPG/SPEE, 2007) A more complete description of the PRMS system is included as Appendix A to this report.

9.3 SYSTEM USED IN THIS REPORT

For this report, we use the PRMS Resource Classification Framework as developed and jointly adopted by the Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE). We have categorized the resources as Contingent or Prospective. We present resources at three certainty levels: P_{90}, P_{50}, and P_{10}. The resource estimates presented in this Report are not risked. Thus, these probability levels mean that, if the given accumulation is discovered in the future, it has at least a 90% probability of containing recoverable resources equal to or greater than the P_{90} value, and so on. These three levels may also be referred to as the "Low Estimate," "Best Estimate," and "High Estimate." We note that it is extremely unlikely that all of the Prospective Resources will ever actually be discovered.

10. ASSESSMENT OF UNDISCOVERED RESOURCES

10.1 PREVIOUS ASSESSMENT STUDIES

Several resource assessment studies and reports have been produced on the hydrocarbon resources of Bangladesh, either independently by different governmental agencies or jointly with Petrobangla. This includes two of the most recent resource assessments by the U.S. Geological Survey in cooperation with Petrobangla and the assessment performed independently by Bangladesh’s experts under the administration of the Hydrocarbon Unit of the Ministry of Energy and Mineral Resources (NPD, 2001). The latter two studies were published in 2001.

In 1986 Bangladesh Oil Gas and Mineral Corporation conducted a study titled “*Habitat of Hydrocarbons in Bangladesh*”, under Hydrocarbon Habitat Study Project (HHSP) with the technical support of WellDrill UK Ltd. All geological basins, both onshore and offshore Bangladesh, were included. This study identified prospects and leads in eastern and western Bangladesh and assigned “Possible” gas resources of 42.8 Tscf. Leads and prospects identified on a portion of the western shelf (8,000 square kilometers) accounted for about 16.4 Tscf of these resources. The western shelf area was futher broken down into play types with assigned resources as follows: reef plays, 14.8 Tscf; “buried hill” plays, 1.14 Tscf; amplitude anomaly plays, 0.5 Tscf; slope pinch-out plays, 0.5 Tscf. This study suggested that amplitude anomalies were good oil targets. Twenty prospects were identified in anticlines of the fold belt and assigned a resource potential of 22 Tscf. As of 2001, eight of these prospects had been drilled with six discoveries made. The HHSP estimated resources for these prospects at 7.8 Tscf. Post-discovery reserve estimates of six out of these eight structures is approximately 3 Tscf. Two of the prospects were dry.

This study estimated “Possible” oil reserves associated with identified exploration leads in Bangladesh at 764.9 Million barrels (MMbbl). The HHSP study resulted in the creation of twenty-three PCS blocks and promotional packages that were offered to the oil industry for evaluation.

Another report was prepared in 1986 by BOGMC/WellDrill/(ODA) for the same area of the hinge zone. This report identified twenty-one prospects and three leads using 2,646 kilometers of 2D seismic data. The total potential recoverable oil and gas resources of the twenty-one prospects were estimated at 7.5 Tscf gas and 1.38 Billion barrels (Bbbl) oil. Three of these prospects were recommended for drilling and none had been drilled as of the date of the NPD report in 2001.

A third report was prepared in 1986 by the German Geological Advisory Group in Petrobangla. This report estimated the risk-discounted reserves (50 % probability) of ten gas fields at 7.179 Tscf gas and 394 MMbbl condensate. This report also estimated the risk-discounted reserves (50 percent probability) of nine prospects at 1.758 Tscf gas and 45.383 MMbbl liquid including 34.053 MMbbl oil. Six of the prospects were drilled resulting in five gas discoveries. The pre-spud risk discounted recoverable reserves (50 percent probability) of these five discoveries was 1.54 Tscf gas and 3.95 MMbbl liquid including 2.54 MMbbl oil estimated for Jalalabad. Recoverable reserves estimated for these five discoveries was 1.7 Tscf gas as reported by NPD (2001).

The Anglo-Scandinavian Petroleum Group conducted a study on the hydrocarbon potential of the Mymensingh area (PSC Blocks 8 and 11) in 1988. A number of structural and stratigraphic leads were identified based on limited seismic and well data. Nine of these leads were assessed. A total of 2.5 Bbbl and 7.07 Tscf were assigned to these nine leads.

Bangladesh Study Group conducted a joint technical study on “Hydrocarbon Potential of Bangladesh” in the later parts of 1989 and early 1990. The study group included Trend International Ltd., Idemitsu Oil Development Co. Ltd, Repsol Exploration Indonesia and Eurafrep S.A. The study goals were to evaluate the hydrocarbon potential of the offered blocks and outline those most prospective to be considered for bidding. The study concluded that the fold belt of eastern Bangladesh is the only area that has been well explored and that the remainder of the county is generally unexplored. The study assessed oil and gas potential of all individual onshore blocks (except 13 and 14) based on geological and geophysical criteria such as the potential for oil versus gas, reservoir quality, seals, and the number and type of plays in each block. One hundred thirty leads and prospects were assessed using Monte Carlo simulation resulting in minimum potential recoverable resources of 62 Tscf, maximum 340 Tscf, and mean 112 Tscf.

In 1997, Maersk Olie OG estimated recoverable oil and gas for five identified lead areas in Blocks #19 and 20 in the Bay of Bengal as part of their evaluation of offered tracts in the Second Bidding Round. Their best estimate for the five leads was 15.3 Tscf and 1,043 MMbbl oil recoverable.

In 1998, the Federal Institute for Geoscience and Mineral Resources (BGR) conducted a study on energy resources of the world. In the report, resource potential of Bangladesh was estimated at 26 Tscf including discovered reserve of 14 Tscf. The oil potential of Bangladesh was estimated at 60 million tons and oil reserve was estimated at 1 million tons.

In 1999, a study was completed by Shell Bangladesh Exploration and Development B.V., "*Gas Resource Estimation – Managing Risk*". This study concluded the risked success volume of gas for Bangladesh was approximately 38 Tscf.

In 2000, Unocal Corporation produced a report called "*Bangladesh Resource Assessment*". This report summarized existing technical database and knowledge of petroleum systems and divided the hydrocarbon resources in Bangladesh into three categories: 1. Field Discoveries; 2. Field Growth; and 3. New Field Discoveries. The Field Discoveries category consists of proven and probable reserve estimates of 16.1 Tscf for the twenty-two existing gas fields, and excluded condensate as published by Petrobangla. The Field Growth category includes additional probable reserve estimates of 11.8 Tscf. The New Field Discoveries category consists of a mean resource estimate of 13.2 Tscf for the potential reserves derived from currently identified leads and prospects from selected blocks that Unocal evaluated. The total of these three categories is conservatively estimated at 41.1 Tscf, not including condensate potential.

In January of 2001, the United States Geological Survey (USGS) and Petrobangla concluded a study titled "*Cooperative Assessment of Undiscovered Natural Gas Resources of Bangladesh*" in which countrywide estimates of technically recoverable, undiscovered resources or "New Field

Discoveries" were made. This study estimated a range of a minimum case of 8.4 Tscf to a maximum case of 65.7 Tscf with a mean of 32.1 Tscf for the total potential of "New Field Discoveries". This study did not include gas accumulation less than 42 Bscf of gas or offshore fields beyond 200 meter water depth. The study also did not consider additional potential (field growth) reserves within the existing fields.

In 2001, the Hydrocarbon Unit Ministry of Energy and Mineral Resources Government of the Peoples Republic of Bangladesh (HCU) and the Norwegian Petroleum Directorate (NPD) conducted a study titled Bangladesh Petroleum Potential and Resource Assessment 2001. This report estimated undiscovered risked recoverable resources for the minimum case at 19 Tscf, for the mean at 42 Tscf, and for the maximum at 64 Tscf.

A comparison of previous resource assessments arranged chronologically is shown in Table 10-1. A more detailed comparison of the probabilistic results of the two 2001 resource estimates made by the USGS/Petrobangla and HCU/NPD studies, respectively, is shown in Table 10-2.

Table 10-1 Comparison of Previous Resource Assessments (Tscf)

Estimated by	Year	Resource Min.	Resource Mean	Resource Max.	Resource Rec.	Area	No of Prospect / Lead	Remarks
HHSP	1986			42.8		Eastern+Western (excluded offshore)	44 Prospects + Reef plays (Hinge zone)	Unrisked
ODA	1986				7.55	Greater Kustia and part of Jessore (8000sq.km)	21 Prospects 3 Leads	Unrisked Recoverable
GGAG	1986	5.04 0.95	6.24 1.76	7.75 3.33	5.23 1.76	Mostly in eastern part.	9 Prospects	Unrisked Recoverable Risked Recoverable
Anglo-Scandinavian	1988				7.07	Mymensing, Blocks # 8 & 11	9 Leads	
Bangladesh Study Group	1989	62	112	340		Excluded Blocks # 13 & 14 and offshore	130 Leads and Prospects	Unrisked Recoverable
Maersk Olie OG	1997				15.3 + 1043 MMBO	Block # 19 & 20	5 Leads	Unrisked Recoverable
Shell	1999	20		40		Entire country.		Risked Recoverable
Unocal	2000	5.3	13.2	22.6		Block # 11,12,13,14,7,& 20		Risked Recoverable
USGS / Petrobangla[1]	2001	8.4	32.1	65.7		Entire country (up to 200m water depth)		Risked Recoverable
HCU / NPD[2]	2001	19	42	64		Entire country	95 Prospects, 92 Leads; 214 occurrences (P50)	Risked Recoverable

[1] USGS used P95, P50, and P5 for prob. estimates of Min., Mean, and Max. confidence levels

[2] HCU-NPD used P90, P50, and P10 for prob. estimates of Min., Mean, and Max. confidence levels

Table 10-2 Comparison of USGS/Petrobangla and HCU/NPD 2001 Resource Estimates (Tscf)

Study	P_{95}	P_{90}	Mean	P_{50}	P_{10}	P_{05}
HCU/NPD	15	19	42	42	64	71
USGS - PETROBANGLA	9	-	32	31	-	66

10.2 PRESENT ASSESSMENT STUDY

10.2.1 Assessment Method

Various assessment methods were used for the various types of resources included in this report. These are described in the following sections.

10.2.1.1 Identified Prospects and Leads

For the identified prospects and leads, Gustavson's local Consultants reviewed all available data and maps, and prepared a list of 182 prospects and leads included as Appendix B. This list was reviewed, and prospects and leads removed which were no longer prospective due to either the prospect having been drilled and a discovery made, having had seismic data acquired analysis of which showed that the area no longer looked prospective, or the prospect was drilled with unfavorable results. Additional input was received from Petrobangla and the other national companies regarding additional prospects that should be eliminated based on additional data acquisition or drilling results. This reduced the number of prospects and leads to 140, 32 prospects and 108 leads. Ranges of input reservoir parameters for volumetric probabilistic resource estimates for each of these prospects and leads were prepared by Gustavson's geologists and engineers based on data from existing fields in Bangladesh or other appropriate analogs. The pressure regime was defined based on the map below (Figure 10-1), which shows the location and indicated pressure gradients, when available, for wells drilled in Bangladesh exhibiting pressure gradients higher than 0.75 psi/ft (2.46 psi/m). The depth at which an elevated pressure gradient was encountered is also shown on this figure. For each block, prospects deeper than nearby indicated depths to high pressure gradients were assigned pressure gradients ranging from 0.7 to 0.8 psi/ft. Shallower prospects and all prospect areas west of the westernmost wells shown on Figure 10-1 were assigned pressure gradients close to normal.

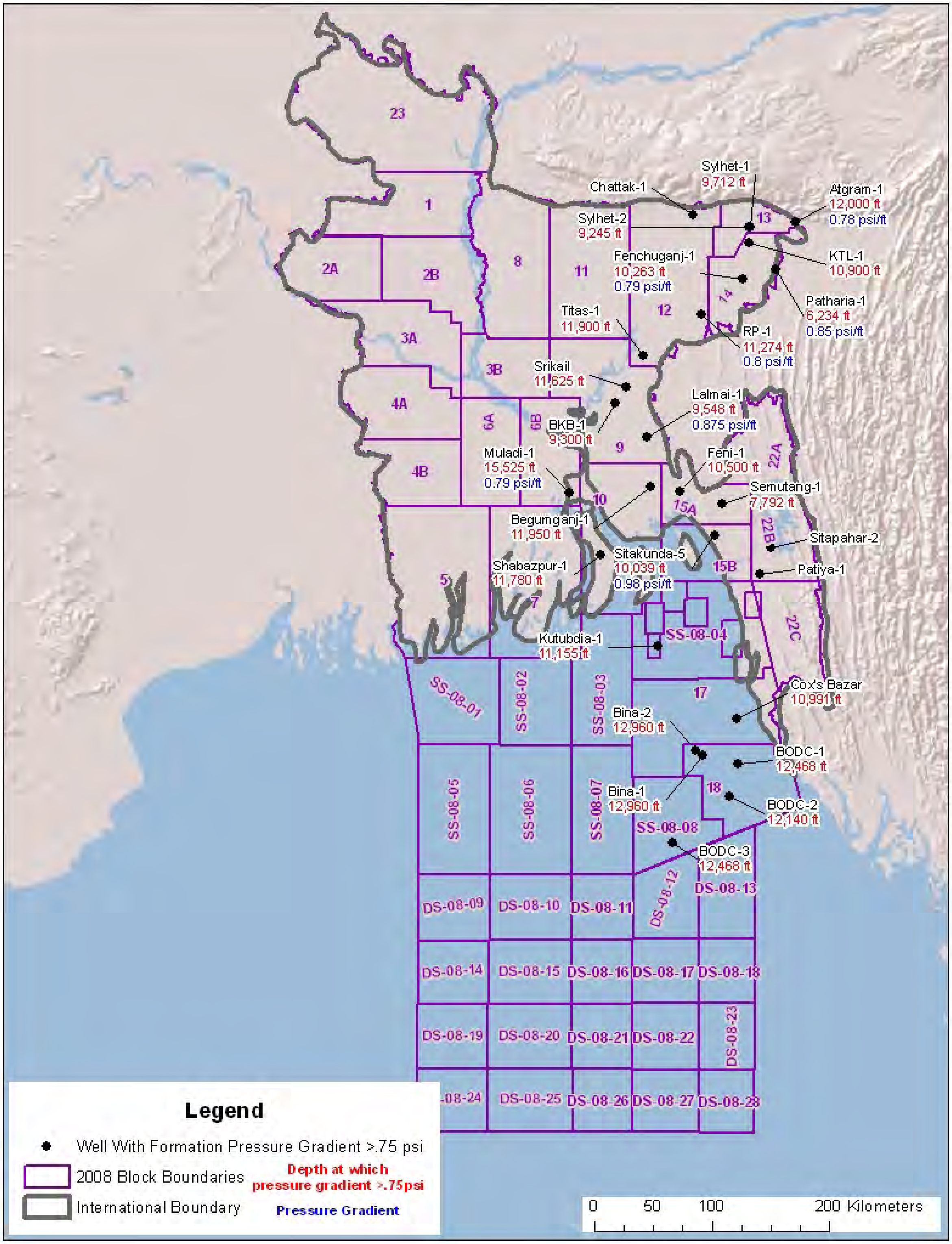


Figure 10-1 Map Showing Wells with High Pressure Gradients

The prospects and leads were each divided into two groups: those located in the Eastern Foldbelt and those located in other areas. Some blocks contain both prospects and leads classified as Eastern Foldbelt and not in the foldbelt.

Resources were calculated by prospect and for the total of all prospects by block.

10.2.1.2 Unmapped Resources

The next type of resources evaluated herein is additional prospective resources from conventional accumulations that have not yet been identified as being in a specific prospect or lead. This evaluation built on the foundation of the resource estimate report prepared by the USGS in 2001. This assessment divided the country into six Assessment Areas:

1. The Surma Basin assessment unit;
2. Easternmost Extremely Folded assessment unit;
3. High-Amplitude Faulted Anticlines assessment unit;
4. Moderately Folded Anticlines assessment unit;
5. Western Slope assessment unit;
6. Western Platform assessment unit.

These areas are shown on Figure 10-2. The approach used by the USGS was to assign to each assessment unit a triangular distribution for the likely number of fields to be discovered, and lognormal distribution for the likely size of fields to be discovered. These same distributions were used for the current Study. Because these distributions represented all undiscovered resources, in the current Study the number of mapped prospects and leads already assigned to that assessment unit were subtracted from the number of discoveries from the USGS distribution. Because maps showing the exact location of each prospect and lead were not available to Gustavson, when blocks were split between assessment areas, the number of prospects and leads in those blocks were apportioned into the assessment areas roughly proportionally to the area of the block within each assessment area. For example, half of Block 3's prospects and leads were assigned to the Western Slope area and half to the Western Platform area. Some areas had a maximum number of discoveries in the distribution smaller than the number of mapped prospects and leads in that area: those areas were assigned no unmapped resources in this Study.

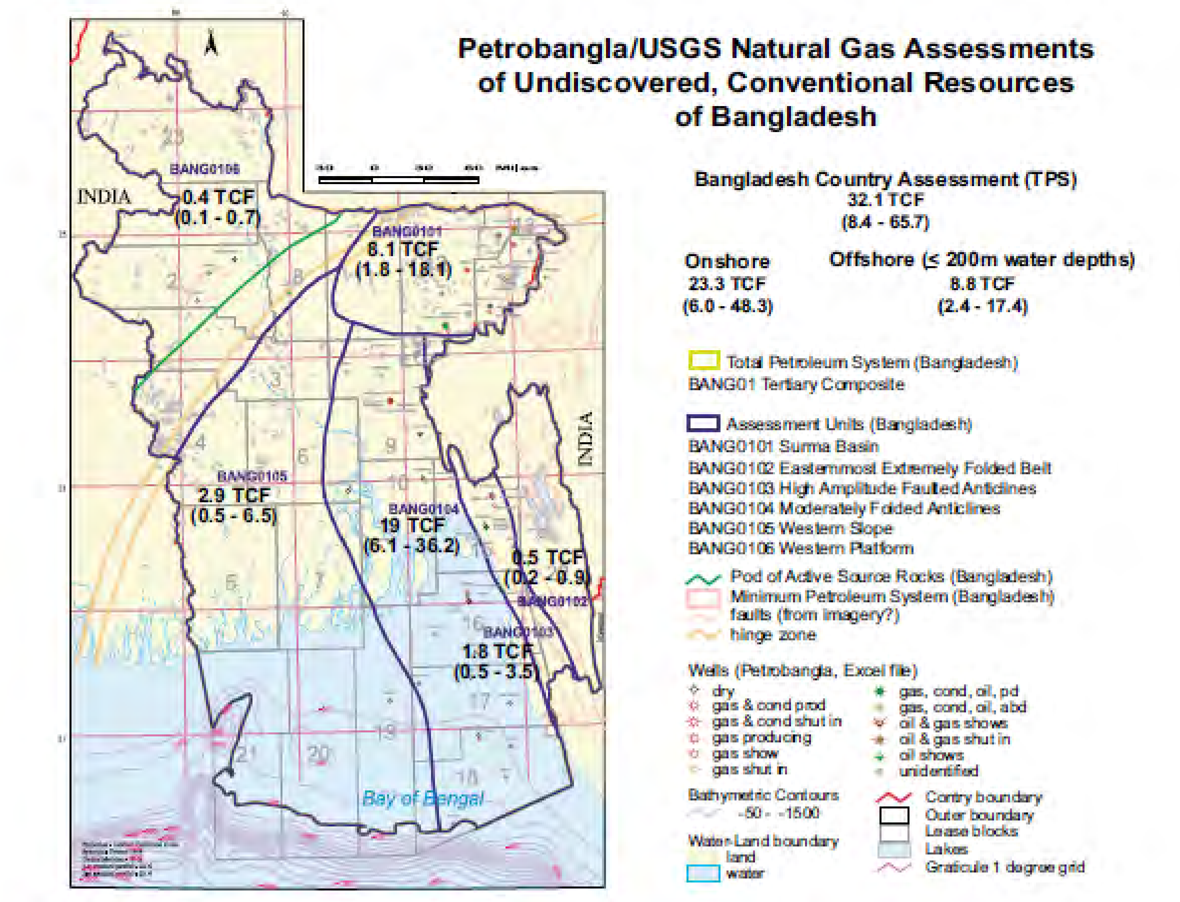


Figure 10-2 Map Showing Assessment Areas for Unmapped Resources
(from USGS, 2001. Numbers shown are USGS's estimates)

10.2.1.3 Coalbed Methane

All available data were compiled for the five major coal fields in Bangladesh, and used to characterize the coalbed methane (CBM), by coal seam, in each coal field. For this analysis, the area of each coal seam was determined from existing maps. This was taken as a constant. A distribution for the thickness of each seam was established based on existing maps or data. These two parameters establish the volume of coal in each seam. Then the density of each coal seam and the CBM content in standard cubic feet per ton of coal were estimated. Multiplying these parameters by the volume of coal yields CBM in place. A range of recovery factors was based on Gustavson's experience with various CBM plays in the US. The CBM in these coal fields is considered to be Contingent Resources, since the presence of the coal and gas in the coal has been established, but insufficient data are available to establish whether or not this CBM will be commercially producible.

10.2.1.4 Shale Gas / Shale Oil

The next type of resources estimated in this Study is gas and oil contained in naturally fractured shale formations. The methodology used for these estimates is based on selecting values of reserves per acre-foot of shale volume from analogous shale plays in the US, and multiplying these by the potentially productive volume of shales in Bangladesh. For the oil-prone shales in the Bogra Shelf area, the Bakken shale was selected as the best analog. For the other, gas-prone shales in Bangladesh, the Haynesville shale was selected as the best analog. A triangular distribution was used for the area of each shale play, with the maximum set at the total area of the shale expected to be thermally mature, and the most likely and minimum areas set at 50% and 20% of this area, respectively. These smaller areas reflect the likelihood that not 100% of the shale is likely to be sufficiently naturally-fractured to enable economic production.

Condensate content was assumed to be similar to that seen in the producing fields in Bangladesh.

10.2.1.5 Thin Beds

The final type of resources estimated in this Study is resources contained in thin beds that may be present but bypassed in existing gas fields. The basis for this assessment is data available from Bibiyana Field from logs specifically designed to be able to measure the properties of thin layers of sandstone interbedded with shales. As discussed previously, that data indicated that almost two-thirds of the pay intervals in the first two wells drilled at Bibiyana were thin beds.

To quantify this estimate, we began with the reserve distributions prepared in Gustavson's most recent report for the HCU. (Gustavson, 2010) Then a distribution was set up for a potential percentage increase in reserves due to bypassed thin bed pays, ranging from zero to 165%

increase. A 20% chance was assigned of no increase in reserves. The distributions were multiplied together to estimate Prospective Resources contained in bypassed thin beds field by field.

10.2.2 Mapped Undiscovered Resources (Hypothetical Resources)

Included here are those identified Prospects and Leads that have been included in the calculation of resources. These are listed in Appendix B. The table in Appendix B was provided using the pre 2008 exploration block numbers and post 2008 exploration block numbers. The 2008 block numbering is shown on Figure 1-5 and can be compared to the pre 2008 block numbering as shown on Figure 1-4. The 2008 block numbers are also used below in Figure 10-3.

The database used in the previous report was not available from HCU. Gustavson Associates and HCU contacted the Norwegian Petroleum Directorate in order to obtain their copy of this database but received no reply. Therefore only the information that was available in print was examined. Much of the supporting data and documentation was not available. A new map was generated using the prospect/lead spreadsheet in Appendix B (Figure 10-3). This figure has no locations noted for prospects and leads where there were no specific locations that could be represented.

Trends can be seen in Figure 10-3. A band of prospects and leads is seen running from Block 4A northeast through Block 8. These prospects and leads are generally associated with the shelf and shelf edge of the Bogra Shelf. They include carbonate platform and build up targets and lowstand erosional remnants called “buried hills”.

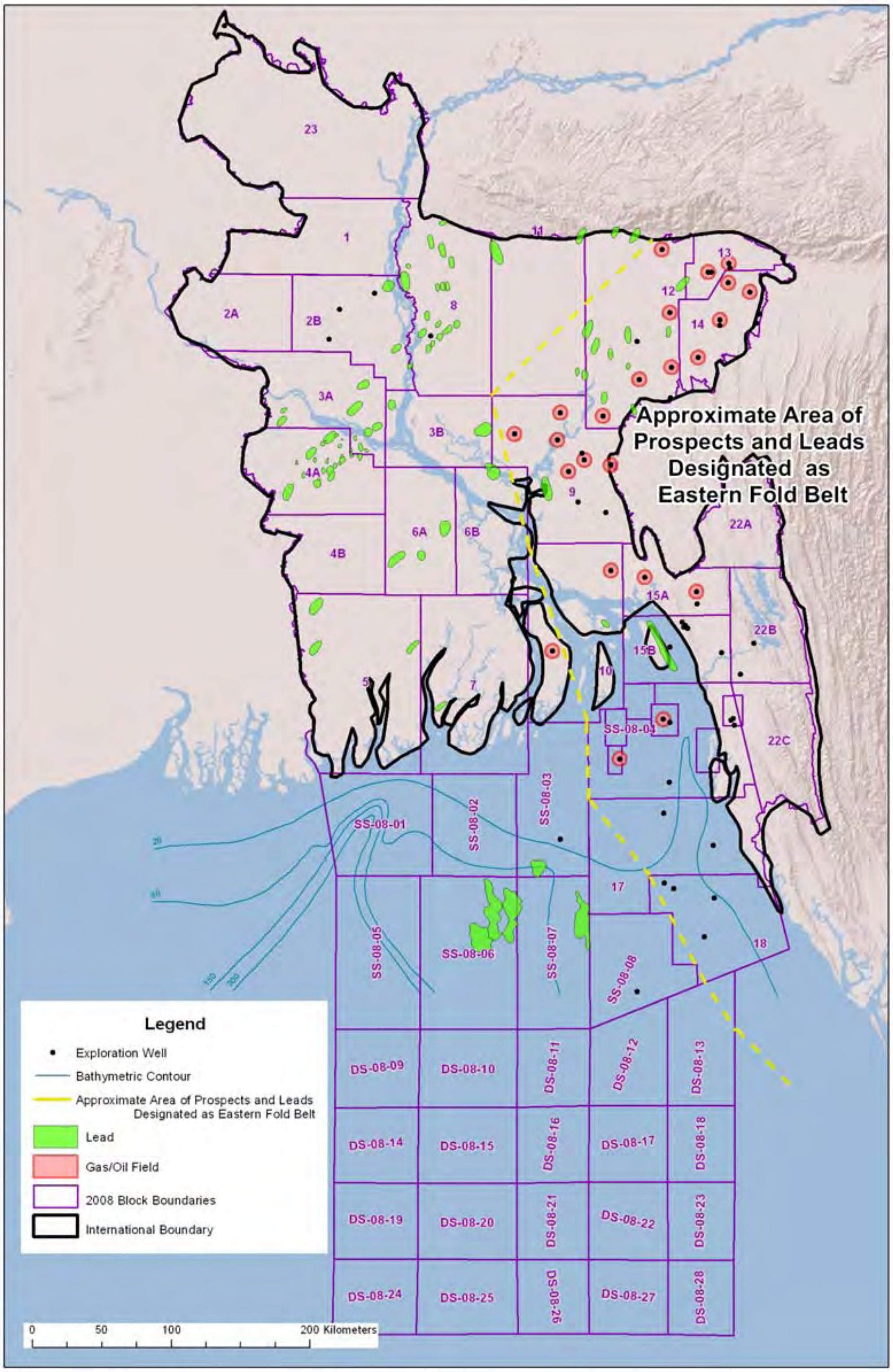


Figure 10-3 Mapped Prospects and Leads and Discovered Fields

Hydrocarbon accumulations in Bangladesh Blocks 1, 2, 3, 4, 5, 8, and the west portions of 6 would be reasonably expected to be sourced by strata of the Gondwana Group and/or lower Eocene as well as Oliogocene strata. There is coal present in the Gondwana Group that could source oil and/or gas, however, to date, there is no evidence of a rift-basin lacustrine shale that could source oil. Rift half-grabens underlie the Bogra Shelf area and could be identified as areas of exploration and source rock kitchens as much of this strata is mature (Frielingsdorf et al., 2008). Hydrocarbon accumulations in these blocks would generally be expected to include oil-prone source rocks such as the Eocene age Kopili Shale and oil and gas prone source rocks within the Cretaceous through Oligocene age strata. Migration of generated hydrocarbons could occur to a lesser extent from mature Oligocene age strata of the Surma/Sylhet Trough and the Hatia Trough through long range migration.

Hydrocarbon accumulation in Blocks 11, 12, 13, 14, 9, and possibly the eastern side of Block 3 would be expected to be sourced by Oligocene age Jenam Formation and possibly Miocene age Bhuban Formation source rocks that would be oil and gas prone. The Eocene age Kopili Formation and Cherra unit may also contribute in certain areas. Migration of the generated hydrocarbons would be updip and lateral in all directions from the Surma/Sylhet Trough to accumulate primarily in Miocene age reservoir rocks and vertically along faults.

Hydrocarbon accumulations in Blocks 6, 7, 8, parts of 9, 10, 15, 16, 17, 18, 19, 20, and 21 would be expected to be sourced by Miocene age Bhuban Formation source rocks that would be gas and condensate prone. The possibility of oil in this region is indicated by oil seeps onshore. Migration of the hydrocarbons would be updip and lateral in all directions from the Hatia Trough and locally into Miocene age and younger reservoir rocks.

10.2.2.1 Block 2

Block 2 in the northwestern part of Bangladesh bordering India, is characterized by six leads that are classified as being in the Bogra Shelf Province/Play. Two of the leads were drilled in 1959, Kuchma-1, and in 1960, Bogra-1 resulting in oil shows from sandstones in the Late Cretaceous through Early Eocene age Therria sub group. The interpretation of these wells is that they are located at the oil/water contact of the respective structures and should be given further study.

The Singra-1 well is also located on Block 2 and encountered gas shows in Lower Gondwana group strata. This indicates the possibility of hydrocarbon accumulations sourced by Gondwana source rocks within Block 2. The Kopili Shale, source rock in the Assam Valley, isn't well developed where encountered by the Bogra-1, Kuchma-1, and Singra-1 wells instead it is more argillaceous and deltaic in this area.

Leads also include carbonate reservoirs of the Sylhet limestone in the southeastern portion of Block 2 along the area of reef development near the Eocene age shelf edge.

10.2.2.2 Block 3

Block 3 is located to the south of Blocks 2 and 8 and borders India on the west. This block is the location of fourteen identified leads classified as being part of the Bogra Shelf Province/Play and the Madhupur High Province/Play. Seven of these leads target the Eocene age Sylhet limestone in a carbonate buildup or a carbonate platform setting. Two are described as anticlines along the Madhupur High and five are described as buried hills situated along the Bogra Shelf hinge line. The term "buried hills" has been used in previous reports. These targets appear as erosional remnants on seismic data.

10.2.2.3 Block 4

Block 4 is located to the south of Block 3 and borders India on the west. This block contains twenty-three leads classified as being part of the Bogra Shelf Province/Play and the Bogra Shelf hinge line. Six of these leads target the Eocene age Sylhet limestone in a carbonate buildup or a carbonate platform setting. Sixteen are classified as "buried hills" (erosional remnants) and one is described as a wedge out or truncation.

10.2.2.4 Block 5

Block 5 is located to the south of Block 3, borders India on the west, and includes the western part of the shoreline of Bangladesh and shallow waters. This block contains three leads classified as being in the Western Delta Province/Play. All three are located in the northern half of the block and are described as anticlines.

10.2.2.5 Block 6

Block 6 is located to the south of Block 3 and east of Block 4. This block contains four leads classified as being in the Western Delta Province/Play. All four are described as anticlines with closure in middle Miocene or late Miocene age strata or both. Two other leads were identified by the Bangladesh Study Group on the eastern side of Block 6 and were classified as being in the Eastern fold belt province/play.

10.2.2.6 Block 7

Block 7 is located south of Block 6 and east of Block 5 and includes part of the shoreline of Bangladesh and shallow waters. This block contains four leads and one prospect with targets in middle Miocene age strata classified as being in the Western Delta Province/Play.

10.2.2.7 Block8

Block 8, in the northwest portion of Bangladesh, is characterized by twenty-four leads that are classified as being in the Bogra Shelf Province/Play.

Block 8 contains the Hazipur -1 well drilled to a depth of 3,816 meters. Oil shows occurred in this well below the Late Oligocene Unconformity at approximately 3,100 meters in sandstones of the Barail Group. This well encountered Barail Group sandstones up to 30 meters thick interspersed with shales. The sandstone sequences have measured log porosity of 18 to 24 percent. The analog is within producing oil fields in the Upper Assam Valley of India where Barail Group sandstone reservoirs up to 30 meters thick contain waxy oil.

Underlying a portion of Block 8 is the Gondwana mature basin area. There is a possibility of hydrocarbon accumulations in the Gondwana Group as seen by oil and gas shows in the Singra, Kuchma, and Bogra wells that were drilled in Block 2.

10.2.2.8 Block 9

Block 9 is located east of Block 3 and borders India on the east. This block contains two prospects classified in the Modhupur Tripura High Province/Play. Both target anticlines with late Oligocene to early Miocene age strata. This block also contains three leads and two prospects described as in the Eastern fold belt province and classified as anticlines.

10.2.2.9 Block 10

Block 10 is located to the east of Blocks 6 and 7 and includes part of the shoreline and shallow waters. This block contains two prospects classified in the Southern Delta Province/Play. Both target anticlines with late Miocene age strata. One has been a discovery and is now classified as the Shahbajpur field. Another anticline within this block is classified as being in the Eastern Fold Belt and has been confirmed by seismic.

10.2.2.10 Block 11

Block 11 is located to the east of Block 8 and is bordered to the north by the Shillong Plateau. This block contains six leads and one prospect.

10.2.2.11 Block 12

Block 12 is located in northern Bangladesh just south of the Shillong Plateau and east of Block 11. Eleven leads and prospects were identified on the block resulting in the discovery of the Bibiyana gas field on one of these locations. The one remaining undrilled lead and one remaining undrilled prospect are in the Surma Basin Province/Play and target middle to late Miocene age strata and one anticline described as being in the Eastern fold belt.

10.2.2.12 Block 13

Block 13 is located in the far northeast portion of Bangladesh, is classified as being in the Eastern fold belt province, and contains two leads that are anticlines or fault closures.

10.2.2.13 Block 14

Block 14 is located just to the south of Block 13 and is classified in the lead and prospect list as in the Eastern fold belt province. Faulted closures are the trap type for these six leads that target primarily pre-Miocene strata.

10.2.2.14 Block 15

Block 15 is located just east of Block 16 in eastern Bangladesh and includes coastal areas and shallow offshore areas. The nine prospects considered in this report on this block are described as anticlines or faulted anticlines.

10.2.2.15 Block 16

Block 16 is located along the eastern shoreline of the Bay of Bengal both offshore and onshore. This area is in the fold belt. One prospect has been identified consisting of an anticline in the Hatiya Trough Province/Play. This location, designated as Sonadia, was drilled to 4,028 meters by Cairn. Nine other prospects are classified as being in the Eastern fold belt and are described as anticlines, or a combination of anticline and stratigraphic trap.

10.2.2.16 Block 17

Block 17 is located offshore in the Bay of Bengal with the eastern edge onshore. Two prospects have been identified on the block, which aren't classified as being in the fold belt. A further four leads and five prospects are in the block and are classified as being in the Eastern fold belt. These are described as three-way and four-way closures.

10.2.2.17 Block 18

Block 18 is located offshore the southeastern tip of Bangladesh. Five prospects identified have all been drilled. The results of the drilling include reported oil and gas shows in three of the wells, BODC-1, BINA-1, and BINA-2. There are one lead and three prospects identified as in the Eastern fold belt that are described as four-way closures or faulted anticlines.

10.2.2.18 Block 19

Block 19 is located offshore in the Bay of Bengal west of Blocks 17 and 18. Two leads and one prospect were identified by Maersk in 1997 in this part of the Western Delta-Offshore Province/Play. These targets are described as “buried hills” (erosional remnants) with the main reservoir targets being sandstones within the Pliocene and upper Miocene deltaic sequences.

10.2.2.19 Block 20

Block 20 is located offshore in the Bay of Bengal west of Block 19. Three leads are located in this block and classified as “buried hills” in the Western Delta-Offshore Province/Play. All three are identified by Maersk Olie and were described as erosional remnants in Pliocene and upper Miocene marine strata.

10.2.2.20 Block 22

Block 22 is located in the eastern side of the Bay of Bengal and contains twelve leads described as faulted anticlines and classified as being in the Eastern fold belt.

All resources estimated for identified prospects and leads are summarized by block in Table 10-3. Note that the summations by area and total represent the mathematical sum of the P_{90}, P_{50}, and P_{10} values for the blocks, and not the probability levels from a distribution of the totals. The only statistical parameter of a probability distribution that adds to the parameter for the distribution of the total is the mean. The sum of the P_{90} values, as shown here, will actually have a probability higher than 90%, while the sum of the P_{10} values will have a probability less than

10%. The prospects and leads were divided into two groups: those located in the Eastern Foldbelt and those located in other areas. Several blocks straddle the boundary between the Eastern Foldbelt and the other area: 10, 11, 12, and 17. Separate estimates are presented for the two parts of these blocks.

Table 10-3 Summary of Resources in Identified Prospects and Leads

	Prospects				Leads			
Block	**P_{90}**	**P_{50}**	**P_{10}**	**# of Pros-pects**	**P_{90}**	**P_{50}**	**P_{10}**	**# of Leads**
Eastern Foldbelt 9					965	1,392	1,934	3
Eastern Foldbelt 10	99	130	165	1				
Eastern Foldbelt 11	2,015	2,592	3,299	1				
Eastern Foldbelt 12	1,013	1,310	1,667	1				
Eastern Foldbelt 13					1,305	1,647	2,029	2
Eastern Foldbelt 14					19,548	22,955	26,707	6
Eastern Foldbelt 15	2,838	3,423	4,113	5				
Eastern Foldbelt 16	10,126	13,448	18,596	11				
Eastern Foldbelt 17	5,243	6,441	7,657	4	2,828	3,836	5,043	3
Eastern Foldbelt 18	3,443	4,464	5,487	3				
Eastern Foldbelt 22					38,075	43,257	48,661	11
Subtotal, E. Foldbelt	***24,777***	***31,807***	***40,984***	***26***	***62,721***	***73,087***	***84,374***	***25***
2					4,047	5,602	7,622	4
3					17,726	24,689	32,607	14
4					17,468	24,376	32,460	23
6					8,618	10,592	12,908	4
7	2,120	2,985	4,045	1	1,109	1,517	2,015	2
8					18,157	23,742	30,177	24
10	279.2	428.7	611.0	1				
11	2,815	4,942	7,502	1	6,663	9,398	12,587	6
12	1,358	2,081	3,125	1	1,762	2,221	2,785	1
17	10,591	14,769	20,049	2				
19					7,643	13,128	19,757	2
20					20,528	30,736	42,679	3
Subtotal, Other	***17,163***	***25,205***	***35,332***	***6***	***103,721***	***146,001***	***195,597***	***83***
Total, Identified	**41,940**	**57,013**	**76,315**	**32**	**166,442**	**219,088**	**279,971**	**108**

More details on the results of these estimates are included in Appendix C, and information on the input data and distributions is included in Appendix D.

10.2.3 Unmapped Resources (Speculative Resources)

Appendix B contains unmapped leads that have been included in this report. In addition to the prospects and leads that have been mapped and shown on Figure 10-1, unmapped resources are discussed by exploration block in section 10.2.3. Bangladesh has multiple active petroleum systems based on potential source rocks ranging in age from Cretaceous through Miocene and widely distributed across the country that would support the accumulation of hydrocarbons in any competent conventional trap.

The additional unmapped Prospective Resources estimated as part of this Study are summarized by Assessment Area in Table 10-4.

Table 10-4 Summary of Unmapped Resources

	Prospective Gas Resources, Billions of Cubic Feet			Prospective Oil/Condensate Resources, MMBO		
Assessment Area	P_{90}	P_{50}	P_{10}	P_{90}	P_{50}	P_{10}
Surma Basin	0	1,065	8,279	0.0	4.2	40.1
Eastern Foldbelt	0	0	30	0.0	0.0	0.1
Faulted Anticlines	268	873	2,707	0.9	3.9	14.2
Folded Anticlines	613	4,143	23,933	1.9	18.3	113.2
Western Slope	0	0	0	0.0	0.0	0.0
Western Platform	0	0	0	0.0	0.0	0.0
Sum	**881**	**6,080**	**34,949**	**2.8**	**26.4**	**167.6**

As discussed in Section 10.2.3, the totals presented in this table are arithmetic sums of the estimates above. More details on the results of these estimates are included in Appendix C, and information on the input data and distributions is included in Appendix D.

10.2.4 Coalbed Methane Resources

The total CBM resources estimated as part of this Study are summarized in Table 10-5

Table 10-5 Summary of CBM Resource Estimates

Coal Field	Contingent Gas Resources, Billions of Cubic Feet		
	P_{90}	P_{50}	P_{10}
Phulbari	254	296	341
Khalaspir	189	236	298
Jamalganj	249	317	399
Dighipara	82	103	130
Barakupuria	71	88	107
Sum	**845**	**1,040**	**1,275**

As discussed in Section 10.2.3, the totals presented in this table are arithmetic sums of the estimates above. More details on the results of these estimates are included in Appendix C, and information on the input data and distributions is included in Appendix D.

10.2.5 Shale Gas / Shale Oil Resources

Shale gas resources were estimated by major shale deposit. Shale oil resources were estimated for the oil-prone shales in the Bogra Shelf area. These estimates are summarized in Table 10-6.

Table 10-6 Summary of Shale Gas and Shale Oil Resources

Shale Gas Area	Prospective Gas Resources, BCF			Prospective Oil/Condensate Resources, MMBO		
	P90	P50	P10	P90	P50	P10
Bogra Slope Oil	357	970	2,241	758	1,927	4,006
Bogra Slope Gas	13,672	34,255	73,137	44	147	414
Surma Basin	8,834	20,681	41,471	27	91	239
Hatia Trough	37,992	94,853	202,155	118	419	1,140
Eastern Foldbelt	39,314	84,053	154,274	116	369	934
Sum	**100,169**	**234,812**	**473,278**	**1,063**	**2,953**	**6,733**

As discussed in Section 10.2.3, the totals presented in this table are arithmetic sums of the estimates above. More details on the results of these estimates are included in Appendix C, and information on the input data and distributions is included in Appendix D.

10.2.6 Thin Bed Resources

Prospective Resources contained in thin beds with bypassed pay at existing fields are summarized in Table 10-7.

Table 10-7 Summary of Thin Bed Resources

Field	Prospective Gas Resources, BCF		
	P_{90}	P_{50}	P_{10}
Bakhrabad	0	611	1,521
Bangora	0	288	695
Beanibazar	0	61	159
Fenchuganj	0	123	339
Habiganj	0	1,311	3,195
Jalalabad	0	593	1,531
Kailash	0	1,220	3,015
Moulavi	0	406	1,064
Narshingdi	0	98	255
Rashidpur	0	1,438	3,676
Salda	0	118	322
Sangu	0	323	792
Shahbazpur	0	122	300
Sylhet	0	171	440
Titas	0	3,516	8,575
Chattak	0	204	591
Feni	0	44	163
Kamta	0	16	49
Meghna	0	25	75
Begumganj	0	14	74
Kutubdia	0	21	53
Semutang	0	149	368
Sum	**0**	**10,872**	**27,252**

As discussed in Section 10.2.3, the totals presented in this table are arithmetic sums of the estimates above. More details on the results of these estimates are included in Appendix C, and information on the input data and distributions is included in Appendix D.

10.3 RISKING

Risk factors were assigned to the various types of resources considering the amount of knowledge and various geologic factors as summarized in Table 10-8.

Table 10-8 Summary of Risk Factors Used

	Trap &Seal	Reservoir	Source	Timing	Overall Probability of Success (POS)
Identified Prospects					
Foldbelt	0.7	0.9	0.95	0.9	0.5387
Other	0.5	0.6	0.5	0.6	0.0900
Identified Leads					
Foldbelt	0.5	0.9	0.95	0.9	0.3848
Other	0.45	0.6	0.5	0.6	0.0810
Unmapped	0.45	0.6	0.6	0.45	0.0729
CBM	0.8	0.8	0.8	0.8	0.4096
		Reservoir	Source	Maturation	
Shale Gas		0.2	0.4	0.5	0.0400

Simple multiplication of these risk factors times the estimated unrisked resource volumes result in the values shown in Table 10-9.

Table 10-9 Summary of Risked Gas Resource Estimates

	Gas Resources, BCF		
Type of Resources	**P_{90}**	**P_{50}**	**P_{10}**
Identified Prospects	12,510	19,295	28,259
Identified Leads	21,844	34,057	49,719
Unmapped	65	443	2,548
Shale Gas	4,007	9,392	18,931
Total Prospective Resources	**38,426**	**63,189**	**99,457**
Coalbed Methane	346	426	522
Total Contingent Resources	**346**	**426**	**522**

10.4 COMPARISON OF CURRENT ESTIMATES WITH 2001 ESTIMATES

Because the resource estimates presented in the 2001 HCU/NPD report were generally risked, we are comparing our risked estimates with those risked estimates. Any company evaluating future exploration of any of the resource areas described herein would certainly have their own perceptions of the risks of the various plays, and would apply their own risk factors in their evaluations. Additionally, presenting unrisked estimates enables an overall understanding of the potential for future exploration and development in Bangladesh without limiting it to subjective risk factors. For these purposes, the unrisked estimates presented in Section 10.2 should be used. These unrisked estimates should not be construed as volumes that would ultimately be realized in total.

However, for the purpose of comparison with the 2001 estimates, in this section we are presenting our estimates of resources for the Mapped Prospects and Leads and Unmapped Resources with the application of risk factors similar to those that we are able to infer were applied in the preparation of the estimates presented in the 2001 report. These comparisons are shown in Table 10-10 below. The resources estimated by Gustavson for thin beds and unconventional resource types are not included in these comparisons, since these types of resources were not included in the previous estimates.

Table 10-10 Comparison of Risked Resource Estimates

	Gas Resources, TCF		
Study	**P_{90}**	**P_{50}**	**P_{10}**
HCU/NPD			
Identified Prospects	11	17	24
Unmapped and Leads	8	25	40
This Study			
Identified Prospects	13	19	28
Unmapped And Leads	22	35	52

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12. ABBREVIATIONS

BAPEX	Bangladesh Petroleum Exploration Co. Ltd
BCMCL	Barapukuria Coal Mining Company Ltd
BGFCL	Bangladesh Gas Fields Co. Ltd
BGR	Federal Institute for Geoscience and Mineral Resources
BGSL	Bakhrabad Gas Systems Ltd
BMEDC	Bangladesh Mineral Exploration and Development Corporation
BODC	Bengal Oil Dev. Co. (i.e. Nippon Oil)
BPC	Bangladesh Petroleum Corporation
Bscf	Billion standard cubic feet
Bscf/month	Billion standard cubic feet per month
Bscf/yr	Billion standard cubic feet per year
CBM	Coalbed Methane
CNG	Compressed Natural Gas
DAF	Dry ash free
FWHP	Flowing Wellhead Pressures
GGAG	German Geological Advisory Group
GTCL	Gas Transmission Co. Ltd
HCU	Hydrocarbon Unit of the Energy and Mineral Resources Division
HHSP	Hydrocarbon Habitat Study Project
IOC	International Oil Companies
JGTDSL	Jalalabad Gas Transmission & Distribution System
LPG	Liquefied Petroleum Gas
MGMCL	Maddhapara Granite Mining Company Limited
MMscf	Million standard cubic feet
MMscf/day	Million standard cubic feet per day
NPD	Norwegian Petroleum Directorate
OGDC	Oil and Gas Development Corporation
Petrobangla	Bangladesh Mineral, Oil and Gas Corporation
PGCL	Pashimanchal Gas Distribution Co. Ltd

POL	Petroleum, Oil and Lubricants
PPL	Pakistan Petroleum Ltd
PSC	Production Sharing Contracts
PSOC	Pakistan Shell Oil Co.
RPGCL	Rupantarito Prakritik Gas Co. Ltd
SGFL	Sylhet Gas Fields Ltd
Shell Bangladesh	Royal Dutch/Shell Group
Stanvac	Standard Vacuum Oil
SVOC	Standard Vacuum Oil Company
TGTDCL	Titas Gas Transmission & Distribution Co. Ltd
TOC	Total Organic Carbon Content
Tscf	Trillion standard cubic feet
Tscf/yr	Trillion standard cubic feet per year
UMC	United Meridian Corporation
UNOCAL	Union Oil
USGS	United States Geological Survey

APPENDIX A

Petroleum Resource Management System (PRMS)

World Petroleum Council

Petroleum
Resources Management
System

Sponsored by:

Society of Petroleum Engineers (SPE)
American Association of Petroleum Geologists (AAPG)
World Petroleum Council (WPC)
Society of Petroleum Evaluation Engineers (SPEE)

Table of Contents

Petroleum Resources Management System

Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

International efforts to standardize the definitions of petroleum resources and how they are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), SPE published definitions for all Reserves categories in 1987. In the same year, the World Petroleum Council (WPC, then known as the World Petroleum Congress), working independently, published Reserves definitions that were strikingly similar. In 1997, the two organizations jointly released a single set of definitions for Reserves that could be used worldwide. In 2000, the American Association of Petroleum Geologists (AAPG), SPE, and WPC jointly developed a classification system for all petroleum resources. This was followed by additional supporting documents: supplemental application evaluation guidelines (2001) and a glossary of terms utilized in resources definitions (2005). SPE also published standards for estimating and auditing reserves information (revised 2007).

These definitions and the related classification system are now in common use internationally within the petroleum industry. They provide a measure of comparability and reduce the subjective nature of resources estimation. However, the technologies employed in petroleum exploration, development, production, and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with other organizations to maintain the definitions and issues periodic revisions to keep current with evolving technologies and changing commercial opportunities.

This document consolidates, builds on, and replaces guidance previously contained in the 1997 Petroleum Reserves Definitions, the 2000 Petroleum Resources Classification and Definitions publications, and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources"; the latter document remains a valuable source of more detailed background information, and specific chapters are referenced herein. Appendix A is a consolidated glossary of terms used in resources evaluations and replaces those published in 2005.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that this document will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

This SPE/WPC/AAPG/SPEE Petroleum Resources Management System document, including its Appendix, may be referred to by the abbreviated term "SPE-PRMS" with the caveat that the full title, including clear recognition of the co-sponsoring organizations, has been initially stated.

1.0 Basic Principles and Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project's economic feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide and sulfur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term "resources" as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional."

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

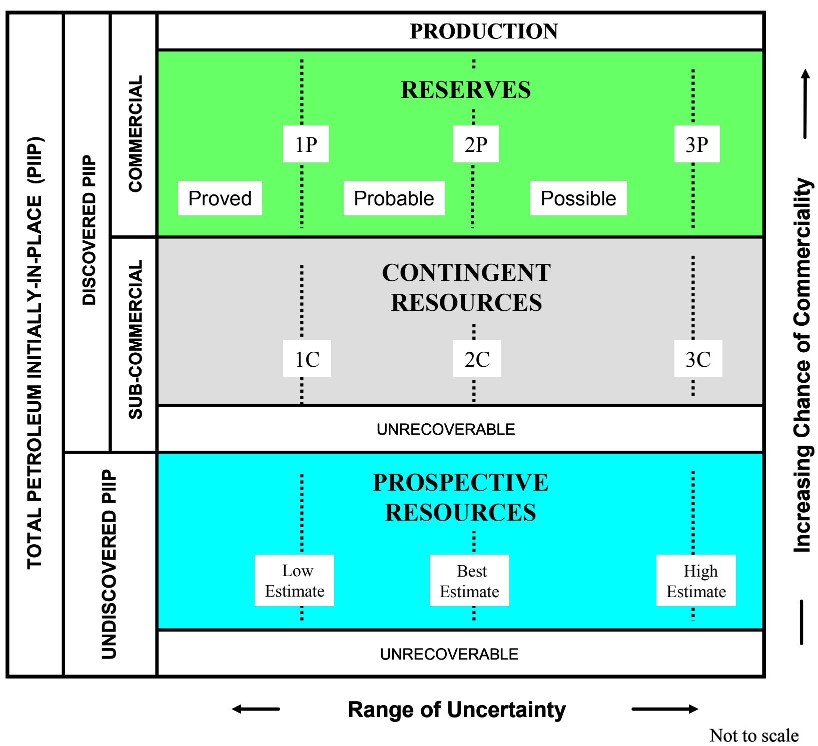


Figure 1-1: Resources Classification Framework.

The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of Commerciality, that is, the chance that the project that will be developed and reach commercial producing status. The following definitions apply to the major subdivisions within the resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

DISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Production Measurement, section 3.2).

Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

RESERVES are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

CONTINGENT RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

UNRECOVERABLE is that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Estimated Ultimate Recovery (EUR) is not a resources category, but a term that may be applied to any accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable under defined technical and commercial conditions plus those quantities already produced (total of recoverable resources).

In specialized areas, such as basin potential studies, alternative terminology has been used; the total resources may be referred to as Total Resource Base or Hydrocarbon Endowment. Total recoverable or EUR may be termed Basin Potential. The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." When such terms are used, it is important that each classification component of the summation also be provided. Moreover, these quantities should not be aggregated without due consideration of the varying degrees of technical and commercial risk involved with their classification.

1.2 Project-Based Resources Evaluations

The resources evaluation process consists of identifying a recovery project, or projects, associated with a petroleum accumulation(s), estimating the quantities of Petroleum Initially-in-Place, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on its maturity status or chance of commerciality.

This concept of a project-based classification system is further clarified by examining the primary data sources contributing to an evaluation of net recoverable resources (see Figure 1-2) that may be described as follows:

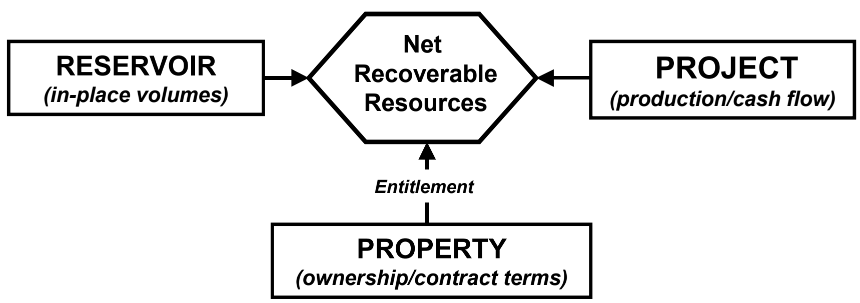


Figure 1-2: Resources Evaluation Data Sources.

- The Reservoir (accumulation): Key attributes include the types and quantities of Petroleum Initially-in-Place and the fluid and rock properties that affect petroleum recovery.

- The Project: Each project applied to a specific reservoir development generates a unique production and cash flow schedule. The time integration of these schedules taken to the project's technical, economic, or contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to Total Initially-in-Place quantities defines the ultimate recovery efficiency for the development project(s). A project may be defined at various levels and stages of maturity; it may include one or many wells and associated production and processing facilities. One project may develop many reservoirs, or many projects may be applied to one reservoir.

- The Property (lease or license area): Each property may have unique associated contractual rights and obligations including the fiscal terms. Such information allows definition of each participant's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations.

In context of this data relationship, “project” is the primary element considered in this resources classification, and net recoverable resources are the incremental quantities derived from each project. Project represents the link between the petroleum accumulation and the decision-making process. A project may, for example, constitute the development of a single reservoir or field, or an incremental development for a producing field, or the integrated development of several fields and associated facilities with a common ownership. In general, an individual project will represent the level at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for that project.

An accumulation or potential accumulation of petroleum may be subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resource classes simultaneously.

In order to assign recoverable resources of any class, a development plan needs to be defined consisting of one or more projects. Even for Prospective Resources, the estimates of recoverable quantities must be stated in terms of the sales products derived from a development program assuming successful discovery and commercial development. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be largely based on analogous projects. In-place quantities for which a feasible project cannot be defined using current, or reasonably forecast improvements in, technology are classified as Unrecoverable.

Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on a forecast of the conditions that will exist during the time period encompassed by the project’s activities (see Commercial Evaluations, section 3.1). “Conditions” include technological, economic, legal, environmental, social, and governmental factors. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms, and taxes.

The resource quantities being estimated are those volumes producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Reference Point, section 3.2.1). The cumulative production from the evaluation date forward to cessation of production is the remaining recoverable quantity. The sum of the associated annual net cash flows yields the estimated future net revenue. When the cash flows are discounted according to a defined discount rate and time period, the summation of the discounted cash flows is termed net present value (NPV) of the project (see Evaluation and Reporting Guidelines, section 3.0).

The supporting data, analytical processes, and assumptions used in an evaluation should be documented in sufficient detail to allow an independent evaluator or auditor to clearly understand the basis for estimation and categorization of recoverable quantities and their classification.

2.0 Classification and Categorization Guidelines

To consistently characterize petroleum projects, evaluations of all resources should be conducted in the context of the full classification system as shown in Figure 1-1. These guidelines reference this classification system and support an evaluation in which projects are “classified” based on their chance of commerciality (the vertical axis) and estimates of recoverable and marketable quantities associated with each project are “categorized” to reflect uncertainty (the horizontal axis). The actual workflow of classification vs. categorization varies with individual projects and is often an iterative analysis process leading to a final report. “Report,” as used herein, refers to the presentation of evaluation results within the business entity conducting the assessment and should not be construed as replacing guidelines for public disclosures under guidelines established by regulatory and/or other government agencies.

Additional background information on resources classification issues can be found in Chapter 2 of the 2001 SPE/WPC/AAPG publication: "Guidelines for the Evaluation of Petroleum Reserves and Resources," hereafter referred to as the "2001 Supplemental Guidelines."

2.1 Resources Classification

The basic classification requires establishment of criteria for a petroleum discovery and thereafter the distinction between commercial and sub-commercial projects in known accumulations (and hence between Reserves and Contingent Resources).

2.1.1 Determination of Discovery Status

A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons.

In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. Estimated recoverable quantities within such a discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves. Where in-place hydrocarbons are identified but are not considered currently recoverable, such quantities may be classified as Discovered Unrecoverable, if considered appropriate for resource management purposes; a portion of these quantities may become recoverable resources in the future as commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:

- Evidence to support a reasonable timetable for development.
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria:
- A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.
- Evidence that the necessary production and transportation facilities are available or can be made available:
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.

To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

2.1.3 Project Status and Commercial Risk

Evaluators have the option to establish a more detailed resources classification reporting system that can also provide the basis for portfolio management by subdividing the chance of commerciality axis according to project maturity. Such sub-classes may be characterized by standard project maturity level descriptions (qualitative) and/or by their associated chance of reaching producing status (quantitative).

As a project moves to a higher level of maturity, there will be an increasing chance that the accumulation will be commercially developed. For Contingent and Prospective Resources, this can further be expressed as a quantitative chance estimate that incorporates two key underlying risk components:

- The chance that the potential accumulation will result in the discovery of petroleum. This is referred to as the "chance of discovery."
- Once discovered, the chance that the accumulation will be commercially developed is referred to as the "chance of development."

Thus, for an undiscovered accumulation, the "chance of commerciality" is the product of these two risk components. For a discovered accumulation where the "chance of discovery" is 100%, the "chance of commerciality" becomes equivalent to the "chance of development."

2.1.3.1 Project Maturity Sub-Classes

As illustrated in Figure 2-1, development projects (and their associated recoverable quantities) may be sub-classified according to project maturity levels and the associated actions (business decisions) required to move a project toward commercial production.

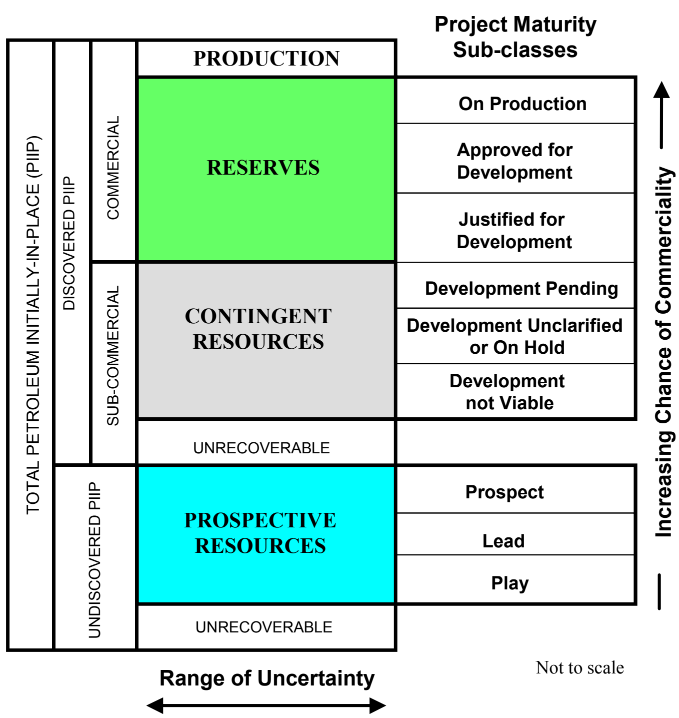


Figure 2-1: Sub-classes based on Project Maturity.

Project Maturity terminology and definitions have been modified from the example provided in the 2001 Supplemental Guidelines, Chapter 2. Detailed definitions and guidelines for each Project Maturity sub-class are provided in Table I. This approach supports managing portfolios of opportunities at various stages of exploration and development and may be supplemented by associated quantitative estimates of chance of commerciality. The boundaries between different levels of project maturity may be referred to as "decision gates."

Decisions within the Reserves class are based on those actions that progress a project through final approvals to implementation and initiation of production and product sales. For Contingent Resources, supporting analysis should focus on gathering data and performing analyses to clarify and then mitigate those key conditions, or contingencies, that prevent commercial development.

For Prospective Resources, these potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under appropriate development projects. The decision at each phase is to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity where a decision can be made to proceed with exploration drilling.

Evaluators may adopt alternative sub-classes and project maturity modifiers, but the concept of increasing chance of commerciality should be a key enabler in applying the overall classification system and supporting portfolio management.

2.1.3.2 Reserves Status

Once projects satisfy commercial risk criteria, the associated quantities are classified as Reserves. These quantities may be allocated to the following subdivisions based on the funding and operational status of wells and associated facilities within the reservoir development plan (detailed definitions and guidelines are provided in Table 2):

- Developed Reserves are expected quantities to be recovered from existing wells and facilities.
  - Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.
  - Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.
- Undeveloped Reserves are quantities expected to be recovered through future investments**.**

Where Reserves remain undeveloped beyond a reasonable timeframe, or have remained undeveloped due to repeated postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay (see Determination of Commerciality, section 2.1.2) is justified, a reasonable time frame is generally considered to be less than 5 years.

Development and production status are of significant importance for project management. While Reserves Status has traditionally only been applied to Proved Reserves, the same concept of Developed and Undeveloped Status based on the funding and operational status of wells and producing facilities within the development project are applicable throughout the full range of Reserves uncertainty categories (Proved, Probable and Possible).

Quantities may be subdivided by Reserves Status independent of sub-classification by Project Maturity. If applied in combination, Developed and/or Undeveloped Reserves quantities may be identified separately within each Reserves sub-class (On Production, Approved for Development, and Justified for Development).

2.1.3.3 <u>Economic Status</u>

Projects may be further characterized by their Economic Status. All projects classified as Reserves must be economic under defined conditions (see Commercial Evaluations, section 3.1). Based on assumptions regarding future conditions and their impact on ultimate economic viability, projects currently classified as Contingent Resources may be broadly divided into two groups:

- Marginal Contingent Resources are those quantities associated with technically feasible projects that are either currently economic or projected to be economic under reasonably forecasted improvements in commercial conditions but are not committed for development because of one or more contingencies.

- Sub-Marginal Contingent Resources are those quantities associated with discoveries for which analysis indicates that technically feasible development projects would not be economic and/or other contingencies would not be satisfied under current or reasonably forecasted improvements in commercial conditions. These projects nonetheless should be retained in the inventory of discovered resources pending unforeseen major changes in commercial conditions.

Where evaluations are incomplete such that it is premature to clearly define ultimate chance of commerciality, it is acceptable to note that project economic status is "undetermined." Additional economic status modifiers may be applied to further characterize recoverable quantities; for example, non-sales (lease fuel, flare, and losses) may be separately identified and documented in addition to sales quantities for both production and recoverable resource estimates (see also Reference Point, section 3.2.1). Those discovered in-place volumes for which a feasible development project cannot be defined using current, or reasonably forecast improvements in, technology are classified as Unrecoverable.

Economic Status may be identified independently of, or applied in combination with, Project Maturity sub-classification to more completely describe the project and its associated resources.

2.2 Resources Categorization

The horizontal axis in the Resources Classification (Figure 1.1) defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project. These estimates include both technical and commercial uncertainty components as follows:

- The total petroleum remaining within the accumulation (in-place resources).
- That portion of the in-place petroleum that can be recovered by applying a defined development project or projects.
- Variations in the commercial conditions that may impact the quantities recovered and sold (e.g., market availability, contractual changes).

Where commercial uncertainties are such that there is significant risk that the complete project (as initially defined) will not proceed, it is advised to create a separate project classified as Contingent Resources with an appropriate chance of commerciality.

2.2.1 Range of Uncertainty

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution (see Deterministic and Probabilistic Methods, section 4.2).

When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately (see Category Definitions and Guidelines, section 2.2.2).

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

2.2.2 Category Definitions and Guidelines

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods. (see "2001 Supplemental Guidelines," Chapter 2.5). In many cases, a combination of approaches is used.

Use of consistent terminology (Figure 1.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Commercial Evaluations, section 3.1).

Table III presents category definitions and provides guidelines designed to promote consistency in resource assessments. The following summarizes the definitions for each Reserves category in terms of both the deterministic incremental approach and scenario approach and also provides the probability criteria if probabilistic methods are applied.

- Proved Reserves are those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

- Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

- Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves, which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

Based on additional data and updated interpretations that indicate increased certainty, portions of Possible and Probable Reserves may be re-categorized as Probable and Proved Reserves.

Uncertainty in resource estimates is best communicated by reporting a range of potential results. However, if it is required to report a single representative result, the "best estimate" is considered the most realistic assessment of recoverable quantities. It is generally considered to represent the sum of Proved and Probable estimates (2P) when using the deterministic scenario or the probabilistic assessment methods. It should be noted that under the deterministic incremental (risk-based) approach, discrete estimates are made for each category, and they should not be aggregated without due consideration of their associated risk (see "2001 Supplemental Guidelines," Chapter 2.5).

2.3 Incremental Projects

The initial resource assessment is based on application of a defined initial development project. Incremental projects are designed to increase recovery efficiency and/or to accelerate production through making changes to wells or facilities, infill drilling, or improved recovery. Such projects should be classified according to the same criteria as initial projects. Related incremental quantities are similarly categorized on certainty of recovery. The projected increased recovery can be included in estimated Reserves if the degree of commitment is such that the project will be developed and placed on production within a reasonable timeframe.

Circumstances where development will be significantly delayed should be clearly documented. If there is significant project risk, forecast incremental recoveries may be similarly categorized but should be classified as Contingent Resources (see Determination of Commerciality, section 2.1.2).

2.3.1 Workovers, Treatments, and Changes of Equipment

Incremental recovery associated with future workover, treatment (including hydraulic fracturing), re-treatment, changes of equipment, or other mechanical procedures where such projects have routinely been successful in analogous reservoirs may be classified as Developed or Undeveloped Reserves depending on the magnitude of associated costs required (see Reserves Status, section 2.1.3.2).

2.3.2 Compression

Reduction in the backpressure through compression can increase the portion of in-place gas that can be commercially produced and thus included in Reserves estimates. If the eventual installation of compression was planned and approved as part of the original development plan, incremental recovery is included in Undeveloped Reserves. However, if the cost to implement compression is not significant (relative to the cost of a new well), the incremental quantities may be classified as Developed Reserves. If compression facilities were not part of the original approved development plan and such costs are significant, it should be treated as a separate project subject to normal project maturity criteria.

2.3.3 Infill Drilling

Technical and commercial analyses may support drilling additional producing wells to reduce the spacing beyond that utilized within the initial development plan, subject to government regulations (if such approvals are required). Infill drilling may have the combined effect of increasing recovery efficiency and accelerating production. Only the incremental recovery can be considered as additional Reserves; this additional recovery may need to be reallocated to individual wells with different interest ownerships.

2.3.4 Improved Recovery

Improved recovery is the additional petroleum obtained, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural reservoir performance. It includes waterflooding, secondary or tertiary recovery processes, and any other means of supplementing natural reservoir recovery processes.

Improved recovery projects must meet the same Reserves commerciality criteria as primary recovery projects. There should be an expectation that the project will be economic and that the entity has committed to implement the project in a reasonable time frame (generally within 5 years; further delays should be clearly justified).

The judgment on commerciality is based on pilot testing within the subject reservoir or by comparison to a reservoir with analogous rock and fluid properties and where a similar established improved recovery project has been successfully applied.

Incremental recoveries through improved recovery methods that have yet to be established through routine, commercially successful applications are included as Reserves only after a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program, where the response provides support for the analysis on which the project is based.

These incremental recoveries in commercial projects are categorized into Proved, Probable, and Possible Reserves based on certainty derived from engineering analysis and analogous applications in similar reservoirs.

2.4 Unconventional Resources

Two types of petroleum resources have been defined that may require different approaches for their evaluations:

- Conventional resources exist in discrete petroleum accumulations related to a localized geological structural feature and/or stratigraphic condition, typically with each accumulation bounded by a downdip contact with an aquifer, and which is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water. The petroleum is recovered through wellbores and typically requires minimal processing prior to sale.

- Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and that are not significantly affected by hydrodynamic influences (also called "continuous-type deposits"). Examples include coalbed methane (CBM), basin-centered gas, shale gas, gas hydrates, natural bitumen, and oil shale deposits. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, massive fracturing programs for shale gas, steam and/or solvents to mobilize bitumen for in-situ recovery, and, in some cases, mining activities). Moreover, the extracted petroleum may require significant processing prior to sale (e.g., bitumen upgraders).

For these petroleum accumulations that are not significantly affected by hydrodynamic influences, reliance on continuous water contacts and pressure gradient analysis to interpret the extent of recoverable petroleum may not be possible. Thus, there typically is a need for increased sampling density to define uncertainty of in-place volumes, variations in quality of reservoir and hydrocarbons, and their detailed spatial distribution to support detailed design of specialized mining or in-situ extraction programs.

It is intended that the resources definitions, together with the classification system, will be appropriate for all types of petroleum accumulations regardless of their in-place characteristics, extraction method applied, or degree of processing required.

Similar to improved recovery projects applied to conventional reservoirs, successful pilots or operating projects in the subject reservoir or successful projects in analogous reservoirs may be required to establish a distribution of recovery efficiencies for non-conventional accumulations. Such pilot projects may evaluate both extraction efficiency and the efficiency of unconventional processing facilities to derive sales products prior to custody transfer.

3.0 Evaluation and Reporting Guidelines

The following guidelines are provided to promote consistency in project evaluations and reporting. "Reporting" refers to the presentation of evaluation results within the business entity conducting the evaluation and should not be construed as replacing guidelines for subsequent public disclosures under guidelines established by regulatory and/or other government agencies, or any current or future associated accounting standards.

3.1 Commercial Evaluations

Investment decisions are based on the entity's view of future commercial conditions that may impact the development feasibility (commitment to develop) and production/cash flow schedule of oil and gas projects. Commercial conditions include, but are not limited to, assumptions of financial conditions (costs, prices, fiscal terms, taxes), marketing, legal, environmental, social, and governmental factors. Project value may be assessed in several ways (e.g., historical costs, comparative market values); the guidelines herein apply only to evaluations based on cash flow analysis. Moreover, modifying factors such contractual or political risks that may additionally influence investment decisions are not addressed. (Additional detail on commercial issues can be found in the "2001 Supplemental Guidelines," Chapter 4.)

3.1.1 Cash-Flow-Based Resources Evaluations

Resources evaluations are based on estimates of future production and the associated cash flow schedules for each development project. The sum of the associated annual net cash flows yields the estimated future net revenue. When the cash flows are discounted according to a defined discount rate and time period, the summation of the discounted cash flows is termed net present value (NPV) of the project. The calculation shall reflect:

- The expected quantities of production projected over identified time periods.
- The estimated costs associated with the project to develop, recover, and produce the quantities of production at its Reference Point (see section 3.2.1), including environmental, abandonment, and reclamation costs charged to the project, based on the evaluator's view of the costs expected to apply in future periods.
- The estimated revenues from the quantities of production based on the evaluator's view of the prices expected to apply to the respective commodities in future periods including that portion of the costs and revenues accruing to the entity.
- Future projected production and revenue related taxes and royalties expected to be paid by the entity.
- A project life that is limited to the period of entitlement or reasonable expectation thereof.
- The application of an appropriate discount rate that reasonably reflects the weighted average cost of capital or the minimum acceptable rate of return applicable to the entity at the time of the evaluation.

While each organization may define specific investment criteria, a project is generally considered to be "economic" if its "best estimate" case has a positive net present value under the organization's standard discount rate, or if at least has a positive undiscounted cash flow.

3.1.2 Economic Criteria

Evaluators must clearly identify the assumptions on commercial conditions utilized in the evaluation and must document the basis for these assumptions.

The economic evaluation underlying the investment decision is based on the entity's reasonable forecast of future conditions, including costs and prices, which will exist during the life of the project (forecast case). Such forecasts are based on projected changes to current conditions; SPE defines current conditions as the average of those existing during the previous 12 months.

Alternative economic scenarios are considered in the decision process and, in some cases, to supplement reporting requirements. Evaluators may examine a case in which current conditions are held constant (no inflation or deflation) throughout the project life (constant case).

Evaluations may be modified to accommodate criteria imposed by regulatory agencies regarding external disclosures. For example, these criteria may include a specific requirement that, if the recovery were confined to the technically Proved Reserves estimate, the constant case should still generate a positive cash flow. External reporting requirements may also specify alternative guidance on current conditions (for example, year-end costs and prices).

There may be circumstances in which the project meets criteria to be classified as Reserves using the forecast case but does not meet the external criteria for Proved Reserves. In these specific circumstances, the entity may record 2P and 3P estimates without separately recording Proved. As costs are incurred and development proceeds, the low estimate may eventually satisfy external requirements, and Proved Reserves can then be assigned.

While SPE guidelines do not require that project financing be confirmed prior to classifying projects as Reserves, this may be another external requirement. In many cases, loans are conditional upon the same criteria as above; that is, the project must be economic based on Proved Reserves only. In general, if there is not a reasonable expectation that loans or other forms of financing (e.g., farm-outs) can be arranged such that the development will be initiated within a reasonable timeframe, then the project should be classified as Contingent Resources. If financing is reasonably expected but not yet confirmed, the project may be classified as Reserves, but no Proved Reserves may be reported as above.

3.1.3 Economic Limit

Economic limit is defined as the production rate beyond which the net operating cash flows from a project, which may be an individual well, lease, or entire field, are negative, a point in time that defines the project's economic life. Operating costs should be based on the same type of projections as used in price forecasting. Operating costs should include only those costs that are incremental to the project for which the economic limit is being calculated (i.e., only those cash costs that will actually be eliminated if project production ceases should be considered in the calculation of economic limit). Operating costs should include fixed property-specific overhead charges if these are actual incremental costs attributable to the project and any production and property taxes but, for purposes of calculating economic limit, should exclude depreciation, abandonment and reclamation costs, and income tax, as well as any overhead above that required to operate the subject property itself. Operating costs may be reduced, and thus project life extended, by various cost-reduction and revenue-enhancement approaches, such as sharing of production facilities, pooling maintenance contracts, or marketing of associated non-hydrocarbons (see Associated Non-Hydrocarbon Components, section 3.2.4).

Interim negative project net cash flows may be accommodated in short periods of low product prices or major operational problems, provided that the longer-term forecasts must still indicate positive economics.

3.2 Production Measurement

In general, the marketable product, as measured according to delivery specifications at a defined Reference Point, provides the basis for production quantities and resources estimates. The following operational issues should be considered in defining and measuring production. While referenced specifically to Reserves, the same logic would be applied to projects forecast to develop Contingent and Prospective Resources conditional on discovery and development. (Additional detail on operational issues that impact resources estimation can be found in the "2001 Supplemental Guidelines," Chapter 3.)

3.2.1 Reference Point

Reference Point is a defined location(s) in the production chain where the produced quantities are measured or assessed. The Reference Point is typically the point of sale to third parties or where custody is transferred to the entity's downstream operations. Sales production and estimated Reserves are normally measured and reported in terms of quantities crossing this point over the period of interest.

The Reference Point may be defined by relevant accounting regulations in order to ensure that the Reference Point is the same for both the measurement of reported sales quantities and for the accounting treatment of sales revenues. This ensures that sales quantities are stated according to their delivery specifications at a defined price. In integrated projects, the appropriate price at the Reference Point may need to be determined using a netback calculation.

Sales quantities are equal to raw production less non-sales quantities, being those quantities produced at the wellhead but not available for sales at the Reference Point. Non-sales quantities include petroleum consumed as fuel, flared, or lost in processing, plus non-hydrocarbons that must be removed prior to sale; each of these may be allocated using separate Reference Points but when combined with sales, should sum to raw production. Sales quantities may need to be adjusted to exclude components added in processing but not derived from raw production. Raw production measurements are necessary and form the basis of engineering calculations (e.g., production performance analysis) based on total reservoir voidage.

3.2.2 Lease Fuel

Lease fuel is that portion of produced natural gas, crude oil, or condensate consumed as fuel in production and lease plant operations.

For consistency, lease fuel should be treated as shrinkage and is not included in sales quantities or resource estimates. However, some regulatory guidelines may allow lease fuel to be included in Reserves estimates where it replaces alternative sources of fuel and/or power that would be purchased in their absence. Where claimed as Reserves, such fuel quantities should be reported separately from sales, and their value must be included as an operating expense. Flared gas and oil and other losses are always treated as shrinkage and are not included in either product sales or Reserves.

3.2.3 Wet or Dry Natural Gas

The Reserves for wet or dry natural gas should be considered in the context of the specifications of the gas at the agreed Reference Point. Thus, for gas that is sold as wet gas, the volume of the wet gas would be reported, and there would be no associated or extracted hydrocarbon liquids reported separately. It would be expected that the corresponding enhanced value of the wet gas would be reflected in the sales price achieved for such gas.

When liquids are extracted from the gas prior to sale and the gas is sold in dry condition, then the dry gas volume and the extracted liquid volumes, whether condensate and/or natural gas liquids, should be accounted for separately in resource assessments. Any hydrocarbon liquids separated from the wet gas subsequent to the agreed Reference Point would not be reported as Reserves.

3.2.4 Associated Non-Hydrocarbon Components

In the event that non-hydrocarbon components are associated with production, the reported quantities should reflect the agreed specifications of the petroleum product at the Reference Point. Correspondingly, the accounts will reflect the value of the petroleum product at the Reference Point. If it is required to remove all or a portion of non-hydrocarbons prior to delivery, the Reserves and production should reflect only the residual hydrocarbon product.

Even if the associated non-hydrocarbon component (e.g., helium, sulfur) that is removed prior to the Reference Point is subsequently and separately marketed, these quantities are not included in petroleum production or Reserves. The revenue generated by the sale of non-hydrocarbon products may be included in the economic evaluation of a project.

3.2.5 Natural Gas Re-Injection

Natural gas production can be re-injected into a reservoir for a number of reasons and under a variety of conditions. It can be re-injected into the same reservoir or into other reservoirs located on the same property for recycling, pressure maintenance, miscible injection, or other enhanced oil recovery processes. In such cases, assuming that the gas will eventually be produced and sold, the gas volume estimated as eventually recoverable can be included as Reserves.

If gas volumes are to be included as Reserves, they must meet the normal criteria laid down in the definitions including the existence of a viable development, transportation, and sales marketing plan. Gas volumes should be reduced for losses associated with the re-injection and subsequent recovery process. Gas volumes injected into a reservoir for gas disposal with no committed plan for recovery are not classified as Reserves. Gas volumes purchased for injection and later recovered are not classified as Reserves.

3.2.6 Underground Natural Gas Storage

Natural gas injected into a gas storage reservoir to be recovered at a later period (e.g., to meet peak market demand periods) should not be included as Reserves.

The gas placed in the storage reservoir may be purchased or may originate from prior production. It is important to distinguish injected gas from any remaining native recoverable volumes in the reservoir. On commencing gas production, its allocation between native gas and injected gas may be subject to local regulatory and accounting rulings. Native gas production would be drawn against the original field Reserves. The uncertainty with respect to original field volumes remains with the native reservoir gas and not the injected gas.

There may be occasions, such as gas acquired through a production payment, in which gas is transferred from one lease or field to another without a sale or custody transfer occurring. In such cases, the re-injected gas could be included with the native reservoir gas as Reserves. The same principles regarding separation of native resources from injected quantities would apply to underground oil storage.

3.2.7 Production Balancing

Reserves estimates must be adjusted for production withdrawals. This may be a complex accounting process when the allocation of production among project participants is not aligned with their entitlement to Reserves. Production overlift or underlift can occur in oil production records because of the necessity for participants to lift their production in parcel sizes or cargo volumes to suit available shipping schedules as agreed among the parties. Similarly, an imbalance in gas deliveries can result from the participants having different operating or marketing arrangements that prevent gas volumes sold from being equal to entitlement share within a given time period.

Based on production matching the internal accounts, annual production should generally be equal to the liftings actually made by the participant and not on the production entitlement for the year. However, actual production and entitlements must be reconciled in Reserves assessments. Resulting imbalances must be monitored over time and eventually resolved before project abandonment.

3.3 Resources Entitlement and Recognition

While assessments are conducted to establish estimates of the total Petroleum Initially-in-Place and that portion recovered by defined projects, the allocation of sales quantities, costs, and revenues impacts the project economics and commerciality. This allocation is governed by the applicable contracts between the mineral owners (lessors) and contractors (lessees) and is generally referred to as "entitlement." For publicly traded companies, securities regulators may set criteria regarding the classes and categories that can be "recognized" in external disclosures.

Entitlements must ensure that the recoverable resources claimed/reported by individual stakeholders sum to the total recoverable resources; that is, there are none missing or duplicated in the allocation process. (The "2001 Supplemental Guidelines," Chapter 9, addresses issues of Reserves recognition under production-sharing and non-traditional agreements.)

3.3.1 Royalty

Royalty refers to payments that are due to the host government or mineral owner (lessor) in return for depletion of the reservoirs by the producer (lessee/contractor) having access to the petroleum resources.

Many agreements allow for the lessee/contractor to lift the royalty volumes and sell them on behalf of, and pay the proceeds to, the royalty owner/lessor. Some agreements provide for the royalty to be taken only in-kind by the royalty owner. In either case, royalty volumes must be deducted from the lessee's entitlement to resources. In some agreements, royalties owned by the host government are actually treated as taxes to be paid in cash. In such cases, the equivalent royalty volumes are controlled by the contractor who may (subject to regulatory guidance) elect to report these volumes as Reserves and/or Contingent Resources with appropriate offsets (increase in operating expense) to recognize the financial liability of the royalty obligation.

Conversely, if a company owns a royalty or equivalent interest of any type in a project, the related quantities can be included in Resources entitlements.

3.3.2 Production-Sharing Contract Reserves

Production-Sharing Contracts (PSCs) of various types replace conventional tax-royalty systems in many countries. Under the PSC terms, the producers have an entitlement to a portion of the production. This entitlement, often referred to as "net entitlement" or "net economic interest," is estimated using a formula based on the contract terms incorporating project costs (cost oil) and project profits (profit oil).

Although ownership of the production invariably remains with the government authority up to the export point of the project, the producers may take title to their share of the net entitlement at that point and may claim that share as their Reserves.

Risked-Service Contracts (RSCs) are similar to PSCs, but in this case, the producers are paid in cash rather than in production. As with PSCs, the Reserves claimed are based on the parties' net economic interest. Care needs to be taken to distinguish between an RSC and a "Pure Service Contract." Reserves can be claimed in an RSC on the basis that the producers are exposed to capital at risk, whereas no Reserves can be claimed for Pure Service Contracts because there are no market risks and the producers act as contractors.

Unlike traditional royalty-lease agreements, the cost recovery system in production-sharing, risk-service, and other related contracts typically reduce the production share and hence Reserves obtained by a contractor in periods of high price and increase volumes in periods of low price. While this ensures cost recovery, it introduces a significant price-related volatility in annual Reserves estimates under cases using "current" economic conditions. Under a defined "forecast conditions case," the future relationship of price to Reserves entitlement is known.

The treatment of taxes and the accounting procedures used can also have a significant impact on the Reserves recognized and production reported from these contracts.

3.3.3 Contract Extensions or Renewals

As production-sharing or other types of agreements approach maturity, they can be extended by negotiation for contract extensions, by the exercise of options to extend, or by other means.

Reserves should not be claimed for those volumes that will be produced beyond the ending date of the current agreement unless there is reasonable expectation that an extension, a renewal, or a new contract will be granted. Such reasonable expectation may be based on the historical treatment of similar agreements by the license-issuing jurisdiction. Otherwise, forecast production beyond the contract term should be classified as Contingent Resources with an associated reduced chance of commercialization. Moreover, it may not be reasonable to assume that the fiscal terms in a negotiated extension will be similar to existing terms.

Similar logic should be applied where gas sales agreements are required to ensure adequate markets. Reserves should not be claimed for those quantities that will be produced beyond those specified in the current agreement or reasonably forecast to be included in future agreements.

In either of the above cases, where the risk of cessation of rights to produce or inability to secure gas contracts is not considered significant, evaluators may choose to incorporate the uncertainty by categorizing quantities to be recovered beyond the current contract as Probable or Possible Reserves.

4.0 Estimating Recoverable Quantities

Assuming that projects have been classified according to their project maturity, the estimation of associated recoverable quantities under a defined project and their assignment to uncertainty categories may be based on one or a combination of analytical procedures. Such procedures may be applied using an incremental (risk-based) and/or scenario approach; moreover, the method of assessing relative uncertainty in these estimates of recoverable quantities may employ both deterministic and probabilistic methods.

4.1 Analytical Procedures

The analytical procedures for estimating recoverable quantities fall into three broad categories: (a) analogy, (b) volumetric estimates, and (c) performance-based estimates, which include material balance, production decline, and other production performance analyses. Reservoir simulation may be used in either volumetric or performance-based analyses. Pre- and early post-discovery assessments are typically made with analog field/project data and volumetric estimation. After production commences and production rates and pressure information become available, performance-based methods can be applied. Generally, the range of EUR estimates is expected to decrease as more information becomes available, but this is not always the case.

In each procedural method, results are not a single quantity of remaining recoverable petroleum, but rather a range that reflects the underlying uncertainties in both the in-place volumes and the recovery efficiency of the applied development project. By applying consistent guidelines (see Resources Categorization, section 2.2.), evaluators can define remaining recoverable quantities using either the incremental or cumulative scenario approach. The confidence in assessment results generally increases when the estimates are supported by more than one analytical procedure.

4.1.1 Analogs

Analogs are widely used in resources estimation, particularly in the exploration and early development stages, when direct measurement information is limited. The methodology is based on the assumption that the analogous reservoir is comparable to the subject reservoir regarding reservoir and fluid properties that control ultimate recovery of petroleum. By selecting appropriate analogs, where performance data based on comparable development plans (including well type, well spacing and stimulation) are available, a similar production profile may be forecast.

Analogous reservoirs are defined by features and characteristics including, but not limited to, approximate depth, pressure, temperature, reservoir drive mechanism, original fluid content, reservoir fluid gravity, reservoir size, gross thickness, pay thickness, net-to-gross ratio, lithology, heterogeneity, porosity, permeability, and development plan. Analogous reservoirs are formed by the same, or very similar, processes with regard to sedimentation, diagenesis, pressure, temperature, chemical and mechanical history, and structural deformation.

Comparison to several analogs may improve the range of uncertainty in estimated recoverable quantities from the subject reservoir. While reservoirs in the same geographic area and of the same age typically provide better analogs, such proximity alone may not be the primary consideration. In all cases, evaluators should document the similarities and differences between the analog and the subject reservoir/project. Review of analog reservoir performance is useful in quality assurance of resource assessments at all stages of development.

4.1.2 Volumetric Estimate

This procedure uses reservoir rock and fluid properties to calculate hydrocarbons in-place and then estimate that portion that will be recovered by a specific development project(s). Key uncertainties affecting in-place volumes include:

- Reservoir geometry and trap limits that impact gross rock volume.
- Geological characteristics that define pore volume and permeability distribution.
- Elevation of fluid contacts.
- Combinations of reservoir quality, fluid types, and contacts that control fluid saturations.

The gross rock volume of interest is that for the total reservoir. While spatial distribution and reservoir quality impact recovery efficiency, the calculation of in-place petroleum often uses average net-to-gross ratio, porosity, and fluid saturations. In more heterogeneous reservoirs, increased well density may be required to confidently assess and categorize resources.

Given estimates of the in-place petroleum, that portion that can be recovered by a defined set of wells and operating conditions must then be estimated based on analog field performance and/or simulation studies using available reservoir information. Key assumptions must be made regarding reservoir drive mechanisms.

The estimates of recoverable quantities must reflect uncertainties not only in the petroleum in-place but also in the recovery efficiency of the development project(s) applied to the specific reservoir being studied.

Additionally, geostatistical methods can be used to preserve spatial distribution information and incorporate it in subsequent reservoir simulation applications. Such processes may yield improved estimates of the range of recoverable quantities. Incorporation of seismic analyses typically improves the underlying reservoir models and yields more reliable resource estimates. [Refer to the "2001 SPE Supplemental Guidelines" for more detailed discussion of geostatistics (Chapter 7) and seismic applications (Chapter 8)].

4.1.3 Material Balance

Material balance methods to estimate recoverable quantities involve the analysis of pressure behavior as reservoir fluids are withdrawn. In ideal situations, such as depletion-drive gas reservoirs in homogeneous, high-permeability reservoir rocks and where sufficient and high quality pressure data is available, estimation based on material balance may provide very reliable estimates of ultimate recovery at various abandonment pressures. In complex situations, such as those involving water influx, compartmentalization, multiphase behavior, and multilayered or low-permeability reservoirs, material balance estimates alone may provide erroneous results. Evaluators should take care to accommodate the complexity of the reservoir and its pressure response to depletion in developing uncertainty profiles for the applied recovery project.

Computer reservoir modeling or reservoir simulation can be considered a sophisticated form of material balance analysis. While such modeling can be a reliable predictor of reservoir behavior under a defined development program, the reliability of input rock properties, reservoir geometry, relative permeability functions, and fluid properties are critical. Predictive models are most reliable in estimating recoverable quantities when there is sufficient production history to validate the model through history matching.

4.1.4 Production Performance Analysis

Analysis of the change in production rates and production fluids ratios vs. time and vs. cumulative production as reservoir fluids are withdrawn provides valuable information to predict ultimate recoverable quantities. In some cases, before decline in production rates is apparent, trends in performance indicators such as gas/oil ratio (GOR), water/oil ratio (WOR), condensate/gas ratio (CGR), and bottomhole or flowing pressures can be extrapolated to an economic limit condition to estimate reserves.

Reliable results require a sufficient period of stable operating conditions after wells in a reservoir have established drainage areas. In estimating recoverable quantities, evaluators must consider complicating factors affecting production performance behavior, such as variable reservoir and fluid properties, transient vs. stabilized flow, changes in operating conditions, interference effects, and depletion mechanisms. In early stages of depletion, there may be significant uncertainty in both the ultimate performance profile and the commercial factors that impact abandonment rate. Such uncertainties should be reflected in the resources categorization. For very mature reservoirs, the future production forecast may be sufficiently well defined that the remaining uncertainty in the technical profile is not significant; in such cases, the "best estimate" 2P scenario may also be used for the 1P and 3P production forecasts. However, there may still be commercial uncertainties that will impact the abandonment rate, and these should be accommodated in the resources categorization.

4.2 Deterministic and Probabilistic Methods

Regardless of the analytical procedure used, resource estimates may be prepared using either deterministic or probabilistic methods. A deterministic estimate is a single discrete scenario within a range of outcomes that could be derived by probabilistic analysis.

In the deterministic method, a discrete value or array of values for each parameter is selected based on the estimator's choice of the values that are most appropriate for the corresponding resource category. A single outcome of recoverable quantities is derived for each deterministic increment or scenario.

In the probabilistic method, the estimator defines a distribution representing the full range of possible values for each input parameter. These distributions may be randomly sampled (typically using Monte Carlo simulation software) to compute a full range and distribution of potential outcome of results of recoverable quantities (see "2001 Supplemental Guidelines," Chapter 5, for more detailed discussion of probabilistic reserves estimation procedures). This approach is most often applied to volumetric resource calculations in the early phases of an exploitation and development projects. The Resources Categorization guidelines include criteria that provide specific limits to parameters associated with each category. Moreover, the resource analysis must consider commercial uncertainties. Accordingly, when probabilistic methods are used, constraints on parameters may be required to ensure that results are not outside the range imposed by the category deterministic guidelines and commercial uncertainties.

Deterministic volumes are estimated for discrete increments and defined scenarios. While deterministic estimates may have broadly inferred confidence levels, they do not have associated quantitatively defined probabilities. Nevertheless, the ranges of the probability guidelines established for the probabilistic method (see Range of Uncertainty, section 2.2.1) influence the amount of uncertainty generally inferred in the estimate derived from the deterministic method.

Both deterministic and probabilistic methods may be used in combination to ensure that results of either method are reasonable.

4.2.1 Aggregation Methods

Oil and gas quantities are generally estimated and categorized according to certainty of recovery within individual reservoirs or portions of reservoirs; this is referred to as the "reservoir level" assessment. These estimates are summed to arrive at estimates for fields, properties, and projects. Further summation is applied to yield totals for areas, countries, and companies; these are generally referred to as "resource reporting levels." The uncertainty distribution of the individual estimates at each of these levels may differ widely, depending on the geological settings and the maturity of the resources. This cumulative summation process is generally referred to as "aggregation."

Two general methods of aggregation may be applied: arithmetic summation of estimates by category and statistical aggregation of uncertainty distributions. There is typically significant divergence in results from applying these alternative methods. In statistical aggregation, except in the rare situation when all the reservoirs being aggregated are totally dependent, the P90 (high degree of certainty) quantities from the aggregate are always greater than the arithmetic sum of the reservoir level P90 quantities, and the P10 (low degree of certainty) of the aggregate is always less than the arithmetic sum P10 quantities assessed at the reservoir level. This "portfolio effect" is the result of the central limit theorem in statistical analysis. Note that the mean (arithmetic average) of the sums is equal to the sum of the means; that is, there is no portfolio effect in aggregating mean values.

In practice, there is likely to be a large degree of dependence between reservoirs in the same field, and such dependencies must be incorporated in the probabilistic calculation. When dependency is present and not accounted for, probabilistic aggregation will overestimate the low estimate result and underestimate the high estimate result. (Aggregation of Reserves is discussed in Chapter 6 of the "2001 Supplemental Guidelines.")

The aggregation methods utilized depends on the business purpose. It is recommended that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property, or project level. Results reporting beyond this level should use arithmetic summation by category but should caution that the aggregate Proved may be a very conservative estimate and aggregate 3P may be very optimistic depending on the number of items in the aggregate. Aggregates of 2P results typically have less portfolio effect that may not be significant in mature properties where the statistical median approaches the mean of the resulting distribution.

Various techniques are available to aggregate deterministic and/or probabilistic field, property, or project assessment results for detailed business unit or corporate portfolio analyses where the results incorporate the benefits of portfolio size and diversification. Again, aggregation should incorporate degree of dependency. Where the underlying analyses are available, comparison of arithmetic and statistical aggregation results may be valuable in assessing impact of the portfolio effect. Whether deterministic or probabilistic methods are used, care should be taken to avoid systematic bias in the estimation process.

It is recognized that the monetary value associated with these recoveries is dependent on the production and cash flow schedules for each project; thus, aggregate distributions of recoverable quantities may not be a direct indication of corresponding uncertainty distributions of aggregate value.

4.2.1.1 Aggregating Resources Classes

Petroleum quantities classified as Reserves, Contingent Resources, or Prospective Resources should not be aggregated with each other without due consideration of the significant differences in the criteria associated with their classification. In particular, there may be a significant risk that accumulations containing Contingent Resources and/ or Prospective Resources will not achieve commercial production.

Where the associated discovery and commerciality risks have been quantitatively defined, statistical techniques may be applied to incorporate individual project risk estimates in portfolio analysis of volume and value.

Table 1: Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project "chance of commerciality" can be said to be 100%. The project "decision gate" is the decision to initiate commercial production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project "decision gate" is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

Class/Sub-Class	**Definition**	**Guidelines**
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity's assumptions of future prices, costs, etc. ("forecast case") and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project "decision gate" is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to "On Hold" or "Not Viable" status. The project "decision gate" is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.

Class/Sub-Class	**Definition**	**Guidelines**
Development Unclarified or on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a re-classification of the project to "Not Viable" status. The project "decision gate" is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project "decision gate" is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2: Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Developed Reserves are expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.
Developed Producing Reserves	Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.	Improved recovery reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Undeveloped Reserves	Undeveloped Reserves are quantities expected to be recovered through future investments:	(1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3: Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that: • The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive. • Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Category	Definition	Guidelines
Possible Reserves	Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	(See above for separate criteria for Probable Reserves and Possible Reserves.)	The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Appendix A: Glossary of Terms Used in Resources Evaluations

Originally published in January 2005, the SPE/WPC/AAPG Glossary has herein been revised to align with the 2007 SPE/WPC/AAPG/SPEE Petroleum Resources Management System document. The glossary provides high-level definitions of terms use in resource evaluations. Where appropriate, sections and/or chapters within the 2007 and/or 2001 documents are referenced to best show the use of selected terms in context.

TERM	Reference	DEFINITION
1C	2007 - 2.2.2	Denotes low estimate scenario of Contingent Resources.
2C	2007 - 2.2.2	Denotes best estimate scenario of Contingent Resources.
3C	2007 - 2.2.2	Denotes high estimate scenario of Contingent Resources.
1P	2007 - 2.2.2	Taken to be equivalent to Proved Reserves; denotes low estimate scenario of Reserves.
2P	2007 - 2.2.2	Taken to be equivalent to the sum of Proved plus Probable Reserves; denotes best estimate scenario of Reserves.
3P	2007 - 2.2.2	Taken to be equivalent to the sum of Proved plus Probable plus Possible Reserves; denotes high estimate scenario of reserves.
Accumulation	2001 - 2.3	An individual body of naturally occurring petroleum in a reservoir.
Aggregation	2007 - 3.5.1 2001 - 6	The process of summing reservoir (or project) level estimates of resource quantities to higher levels or combinations such as field, country or company totals. Arithmetic summation of incremental categories may yield different results from probabilistic aggregation of distributions.
Approved for Development	2007 - Table I	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is underway.
Analogous Reservoir	2007 - 3.4.1	Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery.
Assessment	2007 - 1.2	See Evaluation.
Associated Gas		Associated Gas is a natural gas found in contact with or dissolved in crude oil in the reservoir. It can be further categorized as Gas-Cap Gas or Solution Gas.
Barrels of Oil Equivalent (BOE)	2001 - 3.7	See Crude Oil Equivalent.
Basin-Centered Gas	2007 - 2.4	An unconventional natural gas accumulation that is regionally pervasive and characterized by low permeability, abnormal pressure, gas saturated reservoirs and lack of a down-dip water leg.

Behind-Pipe Reserves	2007 - 2.1.3.1	Behind-pipe reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to the start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Best Estimate	2007 - 2.2.2 2001 - 2.5	With respect to resource categorization, this is considered to be the best estimate of the quantity that will actually be recovered from the accumulation by the project. It is the most realistic assessment of recoverable quantities if only a single result were reported. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
Bitumen	2007 - 2.4	See Natural Bitumen.
Buy Back Agreement		An agreement between a host government and a contractor under which the host pays the contractor an agreed price for all volumes of hydrocarbons produced by the contractor. Pricing mechanisms typically provide the contractor with an opportunity to recover investment at an agreed level of profit.
Carried Interest	2001 - 9.6.7	A carried interest is an agreement under which one party (the carrying party) agrees to pay for a portion or all of the pre-production costs of another party (the carried party) on a license in which both own a portion of the working interest.
Chance	2007 - 1.1	Chance is 1- Risk. (See Risk)
Coalbed Methane (CBM)	2007 - 2.4	Natural gas contained in coal deposits, whether or not stored in gaseous phase. Coalbed gas, although usually mostly methane, may be produced with variable amounts of inert or even non-inert gases. (Also termed Coal Seam Gas, CSG, or Natural Gas from Coal, NGC)
Commercial	2007 - 2.1.2 and Table 1	When a project is commercial, this implies that the essential social, environmental and economic conditions are met, including political, legal, regulatory and contractual conditions. In addition, a project is commercial if the degree of commitment is such that the accumulation is expected to be developed and placed on production within a reasonable time frame. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.
Committed Project	2007 - 2.1.2 and Table 1	Projects are committed only when it can be demonstrated that there is a firm intention to develop them and bring them to production. Intention may be demonstrated with funding/financial plans and declaration of commerciality based on realistic expectations of regulatory approvals and reasonable satisfaction of other conditions that would otherwise prevent the project from being developed and brought to production.

Completion		Completion of a well. The process by which a well is brought to its final classification—basically dry hole, producer, injector, or monitor well. A dry hole is normally plugged and abandoned. A well deemed to be producible of petroleum, or used as an injector, is completed by establishing a connection between the reservoir(s) and the surface so that fluids can be produced from, or injected into, the reservoir. Various methods are utilized to establish this connection, but they commonly involve the installation of some combination of borehole equipment, casing and tubing, and surface injection or production facilities.
Completion Interval		The specific reservoir interval(s) that is (are) open to the borehole and connected to the surface facilities for production or injection, or reservoir intervals open to the wellbore and each other for injection purposes.
Concession	2001 - 9.6.1	A grant of access for a defined area and time period that transfers certain entitlements to produced hydrocarbons from the host country to an enterprise. The enterprise is generally responsible for exploration, development, production, and sale of hydrocarbons that may be discovered. Typically granted under a legislated fiscal system where the host country collects taxes, fees, and sometimes royalty on profits earned.
Condensate	2001 - 3.2	Condensates are a mixture of hydrocarbons (mainly pentanes and heavier) that exist in the gaseous phase at original temperature and pressure of the reservoir, but when produced, are in the liquid phase at surface pressure and temperature conditions. Condensate differs from natural gas liquids (NGL) on two respects: (1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities; and (2) NGL includes very light hydrocarbons (ethane, propane, butanes) as well as the pentanes-plus that are the main constituents of condensate.
Conditions	2007 - 3.1	The economic, marketing, legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated (also termed Contingencies).
Constant Case	2007 - 3.1.1	Modifier applied to project resources estimates and associated cash flows when such estimates are based on those conditions (including costs and product prices) that are fixed at a defined point in time (or period average) and are applied unchanged throughout the project life, other than those permitted contractually. In other words, no inflation or deflation adjustments are made to costs or revenues over the evaluation period.
Contingency	2007 - 3.1 and Table 1	See Conditions.
Contingent Project	2007 - 2.1.2	Development and production of recoverable quantities has not been committed due to conditions that may or may not be fulfilled.
Contingent Resources	2007 - 1.1 and Table 1	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are a class of discovered recoverable resources.
Continuous-Type Deposit	2007 - 2.4 2001 - 2.3	A petroleum accumulation that is pervasive throughout a large area and which is not significantly affected by hydrodynamic influences. Such accumulations are included in Unconventional Resources. Examples of such deposits include "basin-centered" gas, shale gas, gas hydrates, natural bitumen and oil shale accumulations.

Conventional Crude Oil	2007 - 2.4	Crude oil flowing naturally or capable of being pumped without further processing or dilution (see Crude Oil).
Conventional Gas	2007 - 2.4	Conventional Gas is a natural gas occurring in a normal porous and permeable reservoir rock, either in the gaseous phase or dissolved in crude oil, and which technically can be produced by normal production practices.
Conventional Resources	2007 - 2.4	Conventional resources exist in discrete petroleum accumulations related to localized geological structural features and/or stratigraphic conditions, typically with each accumulation bounded by a downdip contact with an aquifer, and which is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water.
Conveyance	2001 - 9.6.9	Certain transactions that are in substance borrowings repayable in cash or its equivalent and shall be accounted for as borrowings and may not qualify for the recognition and reporting of oil and gas reserves.
Cost Recovery	2001 - 9.6.2, 9.7.2	Under a typical production-sharing agreement, the contractor is responsible for the field development and all exploration and development expenses. In return, the contractor recovers costs (investments and operating expenses) out of the gross production stream. The contractor normally receives payment in oil production and is exposed to both technical and market risks.
Crude Oil	2001 - 3.1	Crude oil is the portion of petroleum that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric conditions of pressure and temperature. Crude oil may include small amounts of non-hydrocarbons produced with the liquids but does not include liquids obtained from the processing of natural gas.
Crude Oil Equivalent	2001 - 3.7	Converting gas volumes to the oil equivalent is customarily done on the basis of the nominal heating content or calorific value of the fuel. There are a number of methodologies in common use. Before aggregating, the gas volumes first must be converted to the same temperature and pressure. Common industry gas conversion factors usually range between 1 barrel of oil equivalent (BOE) = 5,600 standard cubic feet (scf) of gas to 1 BOE = 6,000 scf. (Many operators use 1 BOE = 5,620 scf derived from the metric unit equivalent 1 m^3 crude oil = 1,000 m^3 natural gas). (Also termed Barrels of Oil Equivalent.)
Cumulative Production	2007 - 1.1	The sum of production of oil and gas to date (see also Production).
Current Economic Conditions	2007 - 3.1.1	Establishment of current economic conditions should include relevant historical petroleum prices and associated costs and may involve a defined averaging period. The SPE guidelines recommend that a 1-year historical average of costs and prices should be used as the default basis of “constant case” resources estimates and associated project cash flows.
Cushion Gas Volume		With respect to underground natural gas storage, Cushion Gas Volume (CGV) is the gas volume required in a storage field for reservoir management purposes and to maintain adequate minimum storage pressure for meeting working gas volume delivery with the required withdrawal profile. In caverns, the cushion gas volume is also required for stability reasons. The cushion gas volume may consist of recoverable and non-recoverable in-situ gas volumes and injected gas volumes.
Deposit	2007 - 2.4	Material laid down by a natural process. In resource evaluations, it identifies an accumulation of hydrocarbons in a reservoir (see Accumulation).

Deterministic Estimate	2007 - 3.5	The method of estimation of Reserves or Resources is called deterministic if a discrete estimate(s) is made based on known geoscience, engineering, and economic data.
Developed Reserves	2007 - 2.1.3.2 and Table 2	Developed Reserves are expected to be recovered from existing wells including reserves behind pipe. Improved recovery reserves are considered "developed" only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Developed Reserves may be further sub-classified as Producing or Non-Producing.
Developed Producing Reserves	2007 - 2.1.3.2 and Table 2	Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	2007 - 2.1.3.2 and Table 2	Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are also those expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Development Not Viable	2007 - 2.1.3.1 and Table 1	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential. A project maturity sub-class that reflects the actions required to move a project towards commercial production.
Development Pending	2007 - 2.1.3.1 and Table 1	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. A project maturity sub-class that reflects the actions required to move a project towards commercial production.
Development Plan	2007 - 1.2	The design specifications, timing and cost estimates of the development project including, but not limited to, well locations, completion techniques, drilling methods, processing facilities, transportation and marketing. (See also Project.)
Development Unclarified or On Hold	2007 - 2.1.3.1 and Table 1	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. A project maturity sub-class that reflects the actions required to move a project toward commercial production.
Discovered	2007 - 2.1.1	A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons. In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. (See also Known Accumulations.)

Discovered Petroleum Initially-in-Place	2007 - 1.1	Discovered Petroleum Initially-in-Place is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. Discovered Petroleum Initially-in-Place may be subdivided into Commercial, Sub-Commercial, and Unrecoverable, with the estimated commercially recoverable portion being classified as Reserves and the estimated sub-commercial recoverable portion being classified as Contingent Resources.
Dry Gas	2001 - 3.2	Dry Gas is a natural gas remaining after hydrocarbon liquids have been removed prior to the reference point. The dry gas and removed hydrocarbon liquids are accounted for separately in resource assessments. It should be recognized that this is a resource assessment definition and not a phase behavior definition. (Also called Lean Gas.)
Dry Hole	2001 - 2.5	A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.
Economic	2007 - 3.1.2 2001 - 4.3	In relation to petroleum Reserves and Resources, economic refers to the situation where the income from an operation exceeds the expenses involved in, or attributable to, that operation.
Economic Interest	2001 - 9.4.1	An Economic Interest is possessed in every case in which an investor has acquired any Interest in mineral in place and secures, by any form of legal relationship, revenue derived from the extraction of the mineral to which he must look for a return of his capital.
Economic Limit	2007 - 3.1.2 2001 - 4.3	Economic limit is defined as the production rate beyond which the net operating cash flows (after royalties or share of production owing to others) from a project, which may be an individual well, lease, or entire field, are negative.
Entitlement	2007 - 3.3	That portion of future production (and thus resources) legally accruing to a lessee or contractor under the terms of the development and production contract with a lessor.
Entity	2007 - 3.0	Entity is a legal construct capable of bearing legal rights and obligations. In resources evaluations this typically refers to the lessee or contractor, which is some form of legal corporation (or consortium of corporations). In a broader sense, an entity can be an organization of any form and may include governments or their agencies.
Estimated Ultimate Recovery (EUR)	2007 - 1.1	Those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom.
Evaluation	2007- 3.0	The geosciences, engineering, and associated studies, including economic analyses, conducted on a petroleum exploration, development, or producing project resulting in estimates of the quantities that can be recovered and sold and the associated cash flow under defined forward conditions. Projects are classified and estimates of derived quantities are categorized according to applicable guidelines. (Also termed Assessment.)

Evaluator	2007 - 1.2, 2.1.2	The person or group of persons responsible for performing an evaluation of a project. These may be employees of the entities that have an economic interest in the project or independent consultants contracted for reviews and audits. In all cases, the entity accepting the evaluation takes responsibility for the results, including Reserves and Resources and attributed value estimates.
Exploration		Prospecting for undiscovered petroleum.
Field	2001 - 2.3	An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impermeable rock, laterally by local geologic barriers, or both. The term may be defined differently by individual regulatory authorities.
Flare Gas	2007 - 3.2.2 2001 - 3.1	Total volume of gas vented or burned as part of production and processing operations.
Flow Test	2007 - 2.1.1	An operation on a well designed to demonstrate the existence of moveable petroleum in a reservoir by establishing flow to the surface and/or to provide an indication of the potential productivity of that reservoir (such as a wireline formation test).
Fluid Contacts	2007 - 2.2.2	The surface or interface in a reservoir separating two regions characterized by predominant differences in fluid saturations. Because of capillary and other phenomena, fluid saturation change is not necessarily abrupt or complete, nor is the surface necessarily horizontal.
Forecast Case	2007 - 3.1.1	Modifier applied to project resources estimates and associated cash flow when such estimates are based on those conditions (including costs and product price schedules) forecast by the evaluator to reasonably exist throughout the life of the project. Inflation or deflation adjustments are made to costs and revenues over the evaluation period.
Forward Sales	2001 - 9.6.6	There are a variety of forms of transactions that involve the advance of funds to the owner of an interest in an oil and gas property in exchange for the right to receive the cash proceeds of production, or the production itself, arising from the future operation of the property. In such transactions, the owner almost invariably has a future performance obligation, the outcome of which is uncertain to some degree. Determination as to whether the transaction represents a sale or financing rests on the particular circumstances of each case.
Fuel Gas	2007 - 3.2.2	See Lease Fuel.
Gas Balance	2007 - 3.2.7 2001 - 3.10	In gas production operations involving multiple working interest owners, an imbalance in gas deliveries can occur. These imbalances must be monitored over time and eventually balanced in accordance with accepted accounting procedures.

Gas Cap Gas	2001 - 6.2.2	Gas Cap Gas is a free natural gas which overlies and is in contact with crude oil in the reservoir. It is a subset of Associated Gas.
Gas Hydrates	2007 - 2.4	Gas hydrates are naturally occurring crystalline substances composed of water and gas, in which a solid water lattice accommodates gas molecules in a cage-like structure, or clathrate. At conditions of standard temperature and pressure (STP), one volume of saturated methane hydrate will contain as much as 164 volumes of methane gas. Because of this large gas-storage capacity, gas hydrates are thought to represent an important future source of natural gas. Gas hydrates are included in unconventional resources, but the technology to support commercial production has yet to be developed.
Gas Inventory		With respect to underground natural gas storage, "gas inventory" is the sum of Working Gas Volume and Cushion Gas Volume.
Gas/Oil Ratio	2007 - 3.4.4	Gas to oil ratio in an oil field, calculated using measured natural gas and crude oil volumes at stated conditions. The gas/oil ratio may be the solution gas/oil , symbol R_s; produced gas/oil ratio, symbol R_p; or another suitably defined ratio of gas production to oil production.
Gas Plant Products		Gas Plant Products are natural gas liquids (or components) recovered from natural gas in gas processing plants and, in some situations, from field facilities. Gas Plant Products include ethane, propane, butanes, butanes/propane mixtures, natural gasoline and plant condensates, sulfur, carbon dioxide, nitrogen, and helium.
Gas-to-Liquids (GTL) Projects		Gas-to-Liquids projects use specialized processing (e.g., Fischer-Tropsch synthesis) to convert natural gas into liquid petroleum products. Typically, these projects are applied to large gas accumulations where lack of adequate infrastructure or local markets would make conventional natural gas development projects uneconomic.
Geostatistical Methods	2001 - 7.1	A variety of mathematical techniques and processes dealing with the collection, methods, analysis, interpretation, and presentation of masses of geoscience and engineering data to (mathematically) describe the variability and uncertainties within any reservoir unit or pool, specifically related here to resources estimates, including the definition of (all) well and reservoir parameters in 1, 2, and 3 dimensions and the resultant modeling and potential prediction of various aspects of performance.
High Estimate	2007 - 2.2.2 2001 - 2.5	With respect to resource categorization, this is considered to be an optimistic estimate of the quantity that will actually be recovered from an accumulation by a project. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.
Hydrocarbons	2007 - 1.1	Hydrocarbons are chemical compounds consisting wholly of hydrogen and carbon.

Improved Recovery (IR)	2007 - 2.3.4	Improved Recovery is the extraction of additional petroleum, beyond Primary Recovery, from naturally occurring reservoirs by supplementing the natural forces in the reservoir. It includes waterflooding and gas injection for pressure maintenance, secondary processes, tertiary processes and any other means of supplementing natural reservoir recovery processes. Improved recovery also includes thermal and chemical processes to improve the in-situ mobility of viscous forms of petroleum. (Also called Enhanced Recovery.)
Injection	2001 - 3.5 2007 - 3.2.5	The forcing, pumping, or free flow under vacuum, of substances into a porous and permeable subsurface rock formation. Injected substances can include either gases or liquids.
Justified for Development	2007 - 2.1.3.1 and Table 1	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting and that there are reasonable expectations that all necessary approvals/contracts will be obtained. A project maturity sub-class that reflects the actions required to move a project toward commercial production.
Kerogen		The naturally occurring, solid, insoluble organic material that occurs in source rocks and can yield oil upon heating. Kerogen is also defined as the fraction of large chemical aggregates in sedimentary organic matter that is insoluble in solvents (in contrast, the fraction that is soluble in organic solvents is called bitumen). (See also Oil Shales.)
Known Accumulation	2007 - 2.1.1 2001 - 2.2	An accumulation is an individual body of petroleum-in-place. The key requirement to consider an accumulation as "known," and hence containing Reserves or Contingent Resources, is that it must have been discovered, that is, penetrated by a well that has established through testing, sampling, or logging the existence of a significant quantity of recoverable hydrocarbons.
Lead	2007 - 2.1.3.1 and Table 1	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect. A project maturity sub-class that reflects the actions required to move a project toward commercial production.
Lease Condensate		Lease Condensate is condensate recovered from produced natural gas in gas/liquid separators or field facilities.
Lease Fuel	2007 - 3.2.2	Oil and/or gas used for field and processing plant operations. For consistency, quantities consumed as lease fuel should be treated as shrinkage. However, regulatory guidelines may allow lease fuel to be included in Reserves estimates. Where claimed as Reserves, such fuel quantities should be reported separately from sales, and their value must be included as an operating expense.
Lease Plant		A general term referring to processing facilities that are dedicated to one or more development projects and the petroleum is processed without prior custody transfer from the owners of the extraction project (for gas projects, also termed "Local Gas Plant").
Liquefied Natural Gas (LNG) Project		Liquefied Natural Gas projects use specialized cryogenic processing to convert natural gas into liquid form for tanker transport. LNG is about 1/614 the volume of natural gas at standard temperature and pressure.
Loan Agreement	2001 - 9.6.5	A loan agreement is typically used by a bank, other investor, or partner to finance all or part of an oil and gas project. Compensation for funds advanced is limited to a specified interest rate.

Low/Best/High Estimates	2007 - 2.2.1, 2.2.2	The range of uncertainty reflects a reasonable range of estimated potentially recoverable volumes at varying degrees of uncertainty (using the cumulative scenario approach) for an individual accumulation or a project.
Low Estimate	2007 - 2.2.2 2001 - 2.5	With respect to resource categorization, this is considered to be a conservative estimate of the quantity that will actually be recovered from the accumulation by a project. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
Lowest Known Hydrocarbons	2007 - 2.2.2.	The deepest occurrence of a producible hydrocarbon accumulation as interpreted from well log, flow test, pressure measurement, or core data.
Marginal Contingent Resources	2007 - 2.1.3.3	Known (discovered) accumulations for which a development project(s) has been evaluated as economic or reasonably expected to become economic but commitment is withheld because of one or more contingencies (e.g., lack of market and/or infrastructure).
Measurement	2007 - 3.0	The process of establishing quantity (volume or mass) and quality of petroleum products delivered to a reference point under conditions defined by delivery contract or regulatory authorities.
Mineral Interest	2001 - 9.3	Mineral Interests in properties including (1) a fee ownership or lease, concession, or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest; (2) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and (3) those agreements with foreign governments or authorities under which a reporting entity participates in the operation of the related properties or otherwise serves as producer of the underlying reserves (as opposed to being an independent purchaser, broker, dealer, or importer).
Monte Carlo Simulation	2001 - 5 2007 - 3.5	A type of stochastic mathematical simulation that randomly and repeatedly samples input distributions (e.g., reservoir properties) to generate a resulting distribution (e.g., recoverable petroleum volumes).
Natural Bitumen	2007 - 2.4	Natural Bitumen is the portion of petroleum that exists in the semisolid or solid phase in natural deposits. In its natural state, it usually contains sulfur, metals, and other non-hydrocarbons. Natural Bitumen has a viscosity greater than 10,000 milliPascals per second (mPa.s) (or centipoises) measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural viscous state, it is not normally recoverable at commercial rates through a well and requires the implementation of improved recovery methods such as steam injection. Natural Bitumen generally requires upgrading prior to normal refining. (Also called Crude Bitumen.)
Natural Gas	2007 - 3.2.3 2001 - 6.6, 9.4.4	Natural Gas is the portion of petroleum that exists either in the gaseous phase or is in solution in crude oil in natural underground reservoirs, and which is gaseous at atmospheric conditions of pressure and temperature. Natural Gas may include some amount of non-hydrocarbons.

Natural Gas Inventory		With respect to underground natural gas storage operations "inventory" is the total of working and cushion gas volumes.
Natural Gas Liquids	2007 - A13 2001 - 3.2, 9.4.4	Natural Gas Liquids (NGL) are a mixture of light hydrocarbons that exist in the gaseous phase and are recovered as liquids in gas processing plants. NGL differs from condensate in two principal respects: (1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGL includes very light hydrocarbons (ethane, propane, butanes) as well as the pentanes-plus that are the main constituents of condensates.
Natural Gas Liquids to Gas Ratio		Natural gas liquids to gas ratio in an oil or gas field, calculated using measured natural gas liquids and gas volumes at stated conditions.
Net-Back	2007 - 3.2.1	Linkage of input resource to the market price of the refined products.
Net Profits Interest	2001 - 9.4.4	An interest that receives a portion of the net proceeds from a well, typically after all costs have been paid.
Net Working Interest	2001 - 9.6.1	A company's working interest reduced by royalties or share of production owing to others under applicable lease and fiscal terms. (Also called Net Revenue Interest.)
Non-Hydrocarbon Gas	2007 - 3.2.4 2001 - 3.3	Natural occurring associated gases such as nitrogen, carbon dioxide, hydrogen sulfide, and helium. If non-hydrocarbon gases are present, the reported volumes should reflect the condition of the gas at the point of sale. Correspondingly, the accounts will reflect the value of the gas product at the point of sale.
Non-Associated Gas		Non-Associated Gas is a natural gas found in a natural reservoir that does not contain crude oil.
Normal Production Practices		Production practices that involve flow of fluids through wells to surface facilities that involve only physical separation of fluids and, if necessary, solids. Wells can be stimulated, using techniques including, but not limited to, hydraulic fracturing, acidization, various other chemical treatments, and thermal methods, and they can be artificially lifted (e.g., with pumps or gas lift). Transportation methods can include mixing with diluents to enable flow, as well as conventional methods of compression or pumping. Practices that involve chemical reforming of molecules of the produced fluids are considered manufacturing processes.
Oil Sands		Sand deposits highly saturated with natural bitumen. Also called "Tar Sands." Note that in deposits such as the western Canada "oil sands," significant quantities of natural bitumen may be hosted in a range of lithologies including siltstones and carbonates.
Oil Shales	2007 - 2.4	Shale, siltstone and marl deposits highly saturated with kerogen. Whether extracted by mining or in situ processes, the material must be extensively processed to yield a marketable product (synthetic crude oil).
Offset Well Location		Potential drill location adjacent to an existing well. The offset distance may be governed by well spacing regulations. In the absence of well spacing regulations, technical analysis of drainage areas may be used to define the spacing. For Proved volumes to be assigned to an offset well location there must be conclusive, unambiguous technical data which supports the reasonable certainty of production of hydrocarbon volumes and sufficient legal acreage to economically justify the development without going below the shallower of the fluid contact or the lowest known hydrocarbon.

On Production	2007 - 2.1.3.1 and Table 1	The development project is currently producing and selling petroleum to market. A project status/maturity sub-class that reflects the actions required to move a project toward commercial production.
Operator		The company or individual responsible for managing an exploration, development, or production operation.
Overlift/Underlift	2007 - 3.2.7 2001 - 3.9	Production overlift or underlift can occur in annual records because of the necessity for companies to lift their entitlement in parcel sizes to suit the available shipping schedules as agreed among the parties. At any given financial year-end, a company may be in overlift or underlift. Based on the production matching the company's accounts, production should be reported in accord with and equal to the liftings actually made by the company during the year, and not on the production entitlement for the year.
Penetration	2007 - 1.2	The intersection of a wellbore with a reservoir.
Petroleum	2007 - 1.0	Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbon compounds, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content could be greater than 50%.
Petroleum Initially-in-Place	2007 - 1.1	Petroleum Initially-in-Place is the total quantity of petroleum that is estimated to exist originally in naturally occurring reservoirs. Crude Oil-in-place, Natural Gas-in-place and Natural Bitumen-in-place are defined in the same manner (see Resources). (Also referred as Total Resource Base or Hydrocarbon Endowment.)
Pilot Project	2007 - 2.3.4, 2.4	A small-scale test or trial operation that is used to assess the suitability of a method for commercial application.
Play	2007 - 2.1.3.1 and Table 1	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects. A project maturity sub-class that reflects the actions required to move a project toward commercial production.
Pool		An individual and separate accumulation of petroleum in a reservoir.
Possible Reserves	2007 - 2.2.2 and Table 3	An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.
Primary Recovery		Primary recovery is the extraction of petroleum from reservoirs utilizing only the natural energy available in the reservoirs to move fluids through the reservoir rock to other points of recovery.
Probability	2007 - 2.2.1	The extent to which an event is likely to occur, measured by the ratio of the favorable cases to the whole number of cases possible. SPE convention is to quote cumulative probability of exceeding or equaling a quantity where P90 is the small estimate and P10 is the large estimate. (See also Uncertainty.)

Probabilistic Estimate	2007 - 3.5	The method of estimation of Resources is called probabilistic when the known geoscience, engineering, and economic data are used to generate a continuous range of estimates and their associated probabilities.
Probable Reserves	2007 - 2.2.2 and Table 3	An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.
Production	2007 - 1.1	Production is the cumulative quantity of petroleum that has been actually recovered over a defined time period. While all recoverable resource estimates and production are reported in terms of the sales product specifications, raw production quantities (sales and non-sales, including non-hydrocarbons) are also measured to support engineering analyses requiring reservoir voidage calculations.
Production-Sharing Contract	2007 - 3.3.2 2001 - 9.6.2	In a production-sharing contract between a contractor and a host government, the contractor typically bears all risk and costs for exploration, development, and production. In return, if exploration is successful, the contractor is given the opportunity to recover the incurred investment from production, subject to specific limits and terms. Ownership is retained by the host government; however, the contractor normally receives title to the prescribed share of the volumes as they are produced.
Profit Split	2001 - 9.6.2	Under a typical production-sharing agreement, the contractor is responsible for the field development and all exploration and development expenses. In return, the contractor is entitled to a share of the remaining profit oil or gas. The contractor receives payment in oil or gas production and is exposed to both technical and market risks.
Project	2007 - 1.2 2001 - 2.3	Represents the link between the petroleum accumulation and the decision-making process, including budget allocation. A project may, for example, constitute the development of a single reservoir or field, or an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership. In general, an individual project will represent a specific maturity level at which a decision is made on whether or not to proceed (i.e., spend money), and there should be an associated range of estimated recoverable resources for that project. (See also Development Plan.)
Property	2007 - 1.2 2001 - 9.4	A volume of the Earth’s crust wherein a corporate entity or individual has contractual rights to extract, process, and market a defined portion of specified in-place minerals (including petroleum). Defined in general as an area but may have depth and/or stratigraphic constraints. May also be termed a lease, concession, or license.
Prorationing		The allocation of production among reservoirs and wells or allocation of pipeline capacity among shippers, etc.
Prospect	2007 - 2.1.3.1 and Table 1	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target. A project maturity sub-class that reflects the actions required to move a project toward commercial production.

Prospective Resources	2007 - 1.1 and Table 1	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.
Proved Economic	2007 - 3.1.1	In many cases, external regulatory reporting and/or financing requires that, even if only the Proved Reserves estimate for the project is actually recovered, the project will still meet minimum economic criteria; the project is then termed as "Proved Economic."
Proved Reserves	2007 - 2.2.2 and Table 3	An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty Proved Reserves are those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. Often referred to as 1P, also as "Proven."
Purchase Contracts	2001 - 9.6.8	A contract to purchase oil and gas provides the right to purchase a specified volume of production at an agreed price for a defined term.
Pure-Service Contract	2001 - 9.7.5	A pure-service contract is an agreement between a contractor and a host government that typically covers a defined technical service to be provided or completed during a specific period of time. The service company investment is typically limited to the value of equipment, tools, and expenses for personnel used to perform the service. In most cases, the service contractor's reimbursement is fixed by the terms of the contract with little exposure to either project performance or market factors.
Range of Uncertainty	2007 - 2.2 2001 - 2.5	The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. (See Resource Uncertainty Categories.)
Raw Natural Gas	2007 - 3.2.1	Raw Natural Gas is natural gas as it is produced from the reservoir. It includes water vapor and varying amounts of the heavier hydrocarbons that may liquefy in lease facilities or gas plants and may also contain sulfur compounds such as hydrogen sulfide and other non-hydrocarbon gases such as carbon dioxide, nitrogen, or helium, but which, nevertheless, is exploitable for its hydrocarbon content. Raw Natural Gas is often not suitable for direct utilization by most types of consumers.
Reasonable Certainty	2007 - 2.2.2	If deterministic methods for estimating recoverable resource quantities are used, then reasonable certainty is intended to express a high degree of confidence that the estimated quantities will be recovered.
Reasonable Expectation	2007 - 2.1.2	Indicates a high degree of confidence (low risk of failure) that the project will proceed with commercial development or the referenced event will occur.
Reasonable Forecast	2007 - 3.1.2	Indicates a high degree of confidence in predictions of future events and commercial conditions. The basis of such forecasts includes, but is not limited to, analysis of historical records and published global economic models.
Recoverable Resources	2007 - 1.2	Those quantities of hydrocarbons that are estimated to be producible from discovered or undiscovered accumulations.

Recovery Efficiency	2007 - 2.2	A numeric expression of that portion of in-place quantities of petroleum estimated to be recoverable by specific processes or projects, most often represented as a percentage.
Reference Point	2007 - 3.2.1	A defined location within a petroleum extraction and processing operation where quantities of produced product are measured under defined conditions prior to custody transfer (or consumption). Also called Point of Sale or Custody Transfer Point.
Reserves	2007 - 1.1	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: They must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied.
Reservoir	2001 - 2.3	A subsurface rock formation containing an individual and separate natural accumulation of moveable petroleum that is confined by impermeable rocks/formations and is characterized by a single-pressure system.
Resources	2007 - 1.1	The term "resources" as used herein is intended to encompass all quantities of petroleum (recoverable and unrecoverable) naturally occurring on or within the Earth's crust, discovered and undiscovered, plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional" (see Total Petroleum Initially-in-Place). (In basin potential studies, it may be referred to as Total Resource Base or Hydrocarbon Endowment.)
Resources Categories	2007 - 2.2 and Table 3	Subdivisions of estimates of resources to be recovered by a project(s) to indicate the associated degrees of uncertainty. Categories reflect uncertainties in the total petroleum remaining within the accumulation (in-place resources), that portion of the in-place petroleum that can be recovered by applying a defined development project or projects, and variations in the conditions that may impact commercial development (e.g., market availability, contractual changes)
Resources Classes	2007 - 1.1, 2.1 and Table 1	Subdivisions of Resources that indicate the relative maturity of the development projects being applied to yield the recoverable quantity estimates. Project maturity may be indicated qualitatively by allocation to classes and sub-classes and/or quantitatively by associating a project's estimated chance of reaching producing status.
Revenue-Sharing Contract	2001 - 9.6.3	Revenue-sharing contracts are very similar to the production-sharing contracts described earlier, with the exception of contractor payment. With these contracts, the contractor usually receives a defined share of revenue rather than a share of the production.
Reversionary Interest		The right of future possession of an interest in a property when a specified condition has been met.
Risk	2001 - 2.5	The probability of loss or failure. As "risk" is generally associated with the negative outcome, the term "chance" is preferred for general usage to describe the probability of a discrete event occurring.

Risk and Reward	2001 - 9.4	Risk and reward associated with oil and gas production activities stems primarily from the variation in revenues due to technical and economic risks. Technical risk affects a company's ability to physically extract and recover hydrocarbons and is usually dependent on a number of technical parameters. Economic risk is a function of the success of a project and is critically dependent on cost, price, and political or other economic factors.
Risked-Service Contract	2007 - 3.3.2 2001 - 9.7.4	These agreements are very similar to the production-sharing agreements with the exception of contractor payment, but risk is borne by the contractor. With a risked-service contract, the contractor usually receives a defined share of revenue rather than a share of the production.
Royalty	2007 - 3.3.1 2001 - 3.8	Royalty refers to payments that are due to the host government or mineral owner (lessor) in return for depletion of the reservoirs and the producer (lessee/contractor) for having access to the petroleum resources. Many agreements allow for the producer to lift the royalty volumes, sell them on behalf of the royalty owner, and pay the proceeds to the owner. Some agreements provide for the royalty to be taken only in kind by the royalty owner.
Sales	2007 - 3.2	The quantity of petroleum product delivered at the custody transfer (reference point) with specifications and measurement conditions as defined in the sales contract and/or by regulatory authorities. All recoverable resources are estimated in terms of the product sales quantity measurements.
Shut-in Reserves	2007 - 2.1.3.2 and Table 2	Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate, but which have not started producing; (2) wells which were shut-in for market conditions or pipeline connections; or (3) wells not capable of production for mechanical reasons.
Solution Gas		Solution Gas is a natural gas which is dissolved in crude oil in the reservoir at the prevailing reservoir conditions of pressure and temperature. It is a subset of Associated Gas.
Sour Natural Gas	2001 - 3.4	Sour Natural Gas is a natural gas that contains sulfur, sulfur compounds, and/or carbon dioxide in quantities that may require removal for sales or effective use.
Stochastic	2001 - 5	Adjective defining a process involving or containing a random variable or variables or involving chance or probability such as a stochastic stimulation.
Sub-Commercial	2007 - 2.1.2	A project is Sub-Commercial if the degree of commitment is such that the accumulation is not expected to be developed and placed on production within a reasonable time frame. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. Discovered sub-commercial projects are classified as Contingent Resources.
Sub-Marginal Contingent Resources	2007 - 2.1.3.3	Known (discovered) accumulations for which evaluation of development project(s) indicated they would not meet economic criteria, even considering reasonably expected improvements in conditions.
Sweet Natural Gas	2001 - 3.3	Sweet Natural Gas is a natural gas that contains no sulfur or sulfur compounds at all, or in such small quantities that no processing is necessary for their removal in order that the gas may be sold.

Synthetic Crude Oil (SCO)	2001 - A12, A13	A mixture of hydrocarbons derived by upgrading (i.e., chemically altering) natural bitumen from oil sands, kerogen from oil shales, or processing of other substances such as natural gas or coal. SCO may contain sulfur or other non-hydrocarbon compounds and has many similarities to crude oil.
Taxes	2001 - 9.4.2	Obligatory contributions to the public funds, levied on persons, property, or income by governmental authority.
Technical Uncertainty	2007 - 2.2	Indication of the varying degrees of uncertainty in estimates of recoverable quantities influenced by range of potential in-place hydrocarbon resources within the reservoir and the range of the recovery efficiency of the recovery project being applied.
Total Petroleum Initially-in-Place	2007 - 1.1	Total Petroleum Initially-in-Place is generally accepted to be all those estimated quantities of petroleum contained in the subsurface, as well as those quantities already produced. This was defined previously by the WPC as "Petroleum-in-place" and has been termed "Resource Base" by others. Also termed "Original-in-Place" or "Hydrocarbon Endowment."
Uncertainty	2007 - 2.2 2001 - 2.5	The range of possible outcomes in a series of estimates. For recoverable resource assessments, the range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities for an individual accumulation or a project. (See also Probability.)
Unconventional Resources	2007 - 2.4,	Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and that are not significantly affected by hydrodynamic influences (also called "continuous-type deposits"). Examples include coalbed methane (CBM), basin-centered gas, shale gas, gas hydrate, natural bitumen (tar sands), and oil shale deposits. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, massive fracturing programs for shale gas, steam and/or solvents to mobilize bitumen for in-situ recovery, and, in some cases, mining activities). Moreover, the extracted petroleum may require significant processing prior to sale (e.g., bitumen upgraders). (Also termed "Non-Conventional" Resources and "Continuous Deposits.")
Undeveloped Reserves	2001 - 2.1.3.1 and Table 2	Undeveloped Reserves are quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.
Unitization		Process whereby owners group adjoining properties and divide reserves, production, costs, and other factors according to their respective entitlement to petroleum quantities to be recovered from the shared reservoir(s).
Unproved Reserves	2001 - 5.1.1	Unproved Reserves are based on geoscience and/or engineering data similar to that used in estimates of Proved Reserves, but technical or other uncertainties preclude such reserves being classified as Proved. Unproved Reserves may be further categorized as Probable Reserves and Possible Reserves.
Unrecoverable Resources	2007 - 1.1	That portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which are estimated, as of a given date, not to be recoverable. A portion of these quantities may become recoverable in the future as commercial circumstances change, technological developments occur, or additional data are acquired.

Upgrader	2007 - 2.4	A general term applied to processing plants that convert extra-heavy crude oil and natural bitumen into lighter crude and less viscous synthetic crude oil (SCO). While the detailed process varies, the underlying concept is to remove carbon through coking or to increase hydrogen by hydrogenation processes using catalysts.
Well Abandonment		The permanent plugging of a dry hole, an injection well, an exploration well, or a well that no longer produces petroleum or is no longer capable of producing petroleum profitably. Several steps are involved in the abandonment of a well: permission for abandonment and procedural requirements are secured from official agencies; the casing is removed and salvaged if possible; and one or more cement plugs and/or mud are placed in the borehole to prevent migration of fluids between the different formations penetrated by the borehole. In some cases, wells may be temporarily abandoned where operations are suspended for extended periods pending future conversions to other applications such as reservoir monitoring, enhanced recovery, etc.
Wet Gas	2001 - 3.2 2007 - 3.2.3	Wet (Rich) Gas is natural gas from which no liquids have been removed prior to the reference point. The wet gas is accounted for in resource assessments, and there is no separate accounting for contained liquids. It should be recognized that this is a resource assessment definition and not a phase behavior definition.
Working Gas Volume		With respect to underground natural gas storage, Working Gas Volume (WGV) is the volume of gas in storage above the designed level of cushion gas which can be withdrawn/injected with the installed subsurface and surface facilities (wells, flowlines, etc.) subject to legal and technical limitations (pressures, velocities, etc.). Depending on local site conditions (injection/withdrawal rates, utilization hours, etc.), the working gas volume may be cycled more than once a year.
Working Interest	2001 - 9	A company's equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.

APPENDIX B

Identified Prospects and Leads

PROSPECT AND LEAD INVENTORY - BANGLADESH										
Sl. No.	Prospect/Lead	Prospect (P) Lead (L)	Source	Area (Km^2)	Depth (meters)	Relief/Amp (meter)	Province/Play	Trap Type	Block No	Comment
1	2-1 (Oligo-Eo-Cre)	L	Bangladesh Study Group (BSG)	49	2000	120	Bogra Shelf	Eocene-Paleocene Fault Block	2	Three different plays (Oligoncene, Eocence & Cretaceous) at different levels
2	2-2	L	BSG	24	4550	90	Bogra Shelf	Eocene Sylhet LS Platform Mound	2	
3	2-3	L	BSG	16	5500	183	Bogra Shelf	Eocene Sylhet LS Platform Mound	2	
4	Kuchma	L	Gus. National Consultants (GNC)	6	3000	30	Bogra Shelf	Fault Closure	2	Drilled one well during late 50s. Well location was close to the spill point. Oil show was there. Demands further exploration.
5	Bogra	L	GGAG Map on E. Limstone	12	2200	30	Bogra Shelf	Fault Closure	2	Drilled one well during late 50s. Well location was close to the spill point. Oil show was there. Demands further exploration.
6	Sherpur East	L	GNC	45	2800	35	Bogra Shelf	Fault Closure	2	
7	3-1	L	BSG	40	4500	91	Bogra Shelf	Eocene Sylhet LS Platform Mound	3	
8	3-2	L	BSG	60	4550	61	Bogra Shelf	Eocene Sylhet LS Platform Mound	3	
9	3-3	L	BSG	28	3200	91	Bogra Shelf	Eocene Sylhet LS Platform Mound	3	
10	3-4	L	BSG	8	2900	91	Bogra Shelf	Eocene Sylhet LS Platform Mound	3	
11	3-5	L	BSG	61	1450	35	Madhupur High	Anticline - Low Relief	3	
12	3-6	L	BSG	61	2100	61	Madhupur High	Anticline - Low Relief	3	
13	3-7	L	BSG	32	5500	183	Bogra Shelf/Hinge	Eocene Sylhet LS Platform Margin Reef	3	
14	3-8	L	BSG	16	5500	183	Bogra Shelf/Hinge	Eocene Sylhet LS Platform Margin Reef	3	
15	3-9	L	BSG	16	5500	183	Bogra Shelf/Hinge	Eocene Sylhet LS Platform Margin Reef	3	
16	3-10	L	BSG	4.0	4000	35.0	Bogra Shelf/Hinge	Buried Hill	3	
17	3-11	L	BSG	8	4000	85	Bogra Shelf/Hinge	Buried Hill	3	
18	3-12	L	BSG	5	4000	35	Bogra Shelf/Hinge	Buried Hill	3	
19	3-13	L	BSG	4.0	4000	30.0	Bogra Shelf/Hinge	Buried Hill	3	
20	3-14	L	BSG	4.0	4000	35	Bogra Shelf/Hinge	Buried Hill	3	
21	4-1	L	BSG	50	4700	90	Bogra Shelf	Eocene Sylhet LS Platform Mound	4	
22	4-2	L	BSG	40	4700	90	Bogra Shelf	Eocene Sylhet LS Platform Mound	4	
23	4-3	L	BSG	65	4700	90	Bogra Shelf	Eocene Sylhet LS Platform Mound	4	
24	4-4	L	BSG	2.0	3400.0	30.0	Bogra Shelf	Buried Hill	4	
25	4-5	L	BSG	4.0	3900.0	30.0	Bogra Shelf	Buried Hill	4	
26	4-6	L	BSG	5.1	3900.0	37.0	Bogra Shelf	Buried Hill	4	
27	4-7	L	BSG	6.1	3450.0	37.0	Bogra Shelf	Buried Hill	4	
28	4-8	L	BSG	5.1	3450.0	30.0	Bogra Shelf	Buried Hill	4	
29	4-9	L	BSG	1.0	3650.0	30.0	Bogra Shelf	Buried Hill	4	
30	4-10	L	BSG	6.1	4100.0	30.0	Bogra Shelf/Hinge	Buried Hill	4	
31	4-11	L	BSG	4.0	3750.0	30.0	Bogra Shelf	Buried Hill	4	
32	4-12	L	BSG	4.0	4000.0	60.0	Bogra Shelf	Buried Hill	4	
33	4-13	L	BSG	6.1	4100.0	37.0	Bogra Shelf	Buried Hill	4	
34	4-14	L	BSG	5.1	4350	30.0	Bogra Shelf/Hinge	Buried Hill	4	
35	4-15	L	BSG	1.0	4350	30.0	Bogra Shelf	Buried Hill	4	
36	4-16	L	BSG	5.1	4150	85.0	Bogra Shelf	Buried Hill	4	
37	4-17	L	BSG	4.0	4100.0	37.0	Bogra Shelf/Hinge	Buried Hill	4	

PROSPECT AND LEAD INVENTORY - BANGLADESH

Sl. No.	Prospect/Lead	Prospect (P) Lead (L)	Source	Area (Km^2)	Depth (meters)	Relief/Amp (meter)	Province/Play	Trap Type	Block No	Comment
38	4-18	L	BSG	5.1	4100.0	30.0	Bogra Shelf	Buried Hill	4	
39	4-19	L	BSG	6.1	3900.0	30.0	Bogra Shelf/Hinge	Buried Hill	4	
40	4-20	L	BSG	30.0	3900.0	122.0	Bogra Shelf/Hinge	Wedgeout/Truncation	4	
41	4-21	L	BSG	16.2	5550.0	183	Bogra Shelf/Hinge	Eocene Sylhet LS Platform Margin Reef	4	
42	4-22	L	BSG	16.2	5550.0	183	Bogra Shelf/Hinge	Eocene Sylhet LS Platform Margin Reef	4	
43	4-23	L	BSG	16.2	5550.0	183	Bogra Shelf/Hinge	Eocene Sylhet LS Platform Margin Reef	4	
44	5-1	L	BSG	60.7	1050	60	Western Delta	Anticline - Low Relief	5	There were three leads identified by Petrobangla, namely Chalna, Bagerhat and Sarankhola. Later Cairn Energy conducted some seismic lines over those and the leads could not be confirmed. However, they could not confirm the leads suggested by BSG.
45	5-2	L	BSG	48.6	1650	60	Western Delta	Anticline - Low Relief	5	
46	5-3	L	BSG	20.2	3500	60	Western Delta	Anticline - Low Relief	5	
47	6-1 (L. & M. Mio.)	L	BSG	121.4	3800	66	Eastern Foldbelt - East	Anticline - Low Relief	6	BAPEX conducted seismic survey over 6-1 and 6-2 and failed to confirm the leads.
48	6-2 (L. & M. Mio.)	L	BSG	28.3	3200	132	Eastern Foldbelt - East	Anticline - Low Relief	6	
49	6-3	L	BSG	60.7	2150	66	Western Delta	Anticline - Low Relief	6	
50	6-4 (L. & M. Mio.)	L	BSG	20.2	3200	66	Western Delta	Anticline - Low Relief	6	
51	6-5 (L. & M. Mio.)	L	BSG	60.7	3800	33	Western Delta	Anticline - Low Relief	6	
52	6-6	L	BSG	50.6	1700	66				
53	6-7 (L. & M. Mio.)	L	BSG	59.9	3700	66	Western Delta	Anticline - Low Relief	6	
54	7-1	L	BSG	20.2	4050	66	Western Delta	Anticline - Low Relief	7	Seismic survey by Chevron could not confirm the lead
55	7-2	L	BSG	20.2	3200	66	Western Delta	Anticline - Low Relief	7	Seismic survey by Chevron could not confirm the lead
56	Char Kajal	P	Chevron	53	4000	100	Western Delta	Anticline - Low Relief	7	Chevron initially conducted semidetail seismic survey and later detailed seismic in Block 7 and confirmed the 4-way closure Char Kajal. (Ref: Report on Seismic Data & Interpretation, Chevron Bangladesh, Jan 2008.)
57	Chandramohan	L	Chevron	16kmx?	4500	70	Western Delta	Anticline - Low Relief	7	Detailed survey just completed yet to get result. (Ref: UBL-191).
58	Amtoli	L	Chevron	10kmx?	4500	50	Western Delta	Anticline - Low Relief	7	Detailed survey just completed yet to get result. (Ref: UBL-542)
59	8-1 (L, M, E. Mio-Oligo)	L	BSG	76.9	1150	132	Bogra Shelf	listric normal fault "rollover" anticline	8	Four plays (La. Mio, M. Mio, E. Mio & Oligocene) at different levels have recommended.
60	8-2 (E. Mio. & Oligo)	L	BSG	22.3	1750	66	Bogra Shelf	listric normal fault "rollover" anticline	8	Same as Anglo-Scandinavian Lead A
61	8-3	L	BSG	40.5	900	33	Bogra Shelf	listric normal fault "rollover" anticline	8	Same as Anglo-Scandinavian Lead D
62	8-4	L	BSG	18.6	950	33	Bogra Shelf	listric normal fault "rollover" anticline	8	
63	8-5A (L, M, E. Mio-Oligo)	L	BSG	12.1	1900	66	Bogra Shelf	listric normal fault "rollover" anticline	8	Four plays (La. Mio, M. Mio, E. Mio & Oligocene) at different levels have recommended.
64	8-5B (L, M, E. Mio-Oligo)	L	BSG	16.2	2150	66	Bogra Shelf	listric normal fault "rollover" anticline	8	Four plays (La. Mio, M. Mio, E. Mio & Oligocene)) at different levels have recommended.
65	8-5C (L, M, E. Mio-Oligo)	L	BSG	18.6	2600	66	Bogra Shelf	listric normal fault "rollover" anticline	8	Four plays (La. Mio, M. Mio, E. Mio & Oligocene) at different levels have recommended.
66	8-6 (L, M, E. Miocene)	L	BSG	12.1	1550	46	Bogra Shelf	listric normal fault "rollover" anticline	8	Three plays (La. Mio, M. Mio & E. Miocene) at different levels have recommended.
67	8-7	L	BSG	14.2	5500	356	Bogra Shelf	Eocene Sylhet LS Platform Margin Reef	8	
68	8-8	L	BSG	32.4	5500	180	Bogra Shelf	Eocene Sylhet LS Platform Margin Reef	8	
69	8-9	L	BSG	6.1	5500	180	Bogra Shelf	Eocene Sylhet LS Platform Margin Reef	8	
70	8-10	L	BSG	1.6	5200	90	Bogra Shelf	Eocene Sylhet LS Platform Margin Reef	8	
71	8-11	L	BSG	6.1	5050	274	Bogra Shelf	Eocene Sylhet LS Platform Margin Reef	8	

PROSPECT AND LEAD INVENTORY - BANGLADESH										
Sl. No.	**Prospect/Lead**	**Prospect (P) Lead (L)**	**Source**	**Area (Km^2)**	**Depth (meters)**	**Relief/Amp (meter)**	**Province/Play**	**Trap Type**	**Block No**	**Comment**
72	8-12	L	BSG	12.1	4100	132	Bogra Shelf	Eocene Sylhet LS Platform Mound	8	
73	8-13	L	BSG	28.3	4000	180	Bogra Shelf	Eocene Sylhet LS Platform Mound	8	
74	8-14 (Eoc. & Cret)	L	BSG	4.5	2500	90	Bogra Shelf	Eocene-Paleocene	8	
75	8-15 (L. & M. Mio.)	L	BSG	14.2	1000	66	Bogra Shelf	Anticline	8	Same as Anglo-Scandinavian Lead G
76	Lead A	L	Anglo-Scandinavian	10	3200	73	Bogra Shelf	listric normal fault "rollover" anticline	8	Lead developed by Anglo Scandinavian Petrol. Co. in 1988 study. Same as Bangladesh Study Group (BSG) Lead 8-2
77	Lead B	L	Anglo-Scandinavian	6	3960	61	Bogra Shelf	listric normal fault "rollover" anticline	8	Lead developed by Anglo Scandinavian Petrol. Co. in 1988 study. Same as 8-14 of BSG
78	Lead D	L	Anglo-Scandinavian	12	4420	82	Bogra Shelf	listric normal fault "rollover" anticline	8	Lead developed by Anglo Scandinavian Petrol. Co. in 1988 study. Same as BSG Lead 8-3
79	Lead E	L	Anglo-Scandinavian	12	3352	73	Bogra Shelf	listric normal fault "rollover" anticline	8	Lead developed by Anglo Scandinavian Petrol. Co. in 1988 study. Same as 8-1 of BSG
80	Lead F	L	Anglo-Scandinavian	9.7	1600	75	Bogra Shelf	Buried Hill	8	Lead developed by Anglo Scandinavian Petrol. Co. in 1988 study
81	Lead G	L	Anglo-Scandinavian	27	3660	274	Bogra Shelf	listric normal fault "rollover" anticline	8	Lead developed by Anglo Scandinavian Petrol. Co. in 1988 study. Same as BSG Lead 8-15
82	Lead H	L	Anglo-Scandinavian	80	4876	213	Bogra Shelf	listric normal fault "rollover" anticline + Wedgeout/Truncation	8	Lead developed by Anglo Scandinavian Petrol. Co. in 1988 study. Same as BSG lead 8-6
83	9-1 (Meghna)	Discovery	BSG		3069		Eastern Foldbelt	Anticline	9	Drilled in 1990. Gas discovery. Producing field, Meghna Gas Field (BK-9)
84	9-2 (L. & M. Mio.)/ Daudkandi	L	BSG	72.8			Eastern Foldbelt - Southern Surma Basin	Anticline	9	Seismic survey done by Petrobangla and the lead could not be confirmed. Undrilled structure SW of Bakhrabad
85	9-3 (Bangora)	Discovery	Tullow /Petrobangla		3635		Eastern Foldbelt	Anticline	9	Drilled in 2004 by Tullow. Gas discovery. Producing field, Bangora.
86	Belabo L.Mio/E.Oligo	Discovery	Petrobangla	80	3660-4800	120	Modhupur Tripura High	anticline	9	Drilled two wells by Petrobangla. Max depth 3450m. Producing field. Presently known as Narsingdi gas field. Attractive deeper prospect exists. a number of negative, (dimspot) seismic amplitude anomalies exist between 2.6 and 3.1 secs (3660-4800m), which is of interest.
87	Kashimpur	P	Petrobangla	19	2700-3200	30 ?	Eastern Fold Belt	Anticline	9	Drilled one well by Tullow. Gas show. Demand further exploration
88	Kamta	P	Pet./Bapex	16	3614	30	Modhupur Tripura High	L.A. Anticline	9	Drilled one well by Pet. Gas discovered. Suspended field. For further exploration BAPEX acquired new seismic data this year, 2010.
89	Srikail	P	BAPEX	20	3600	30	Eastern Fold Belt	Combination	9	Drilled by BAPEX. Gas show confirms TD at channel sands. Further seismic was done and drilling program is underway.
90	Srikail, North (?)	L	Tullow	?	4000 (?)	?	Eastern Fold Belt	LA Anticline	9	Lead identified by Tullow/BAPEX. Further review of available by the team is needed.
91	Chandpur (?)	L	Petrobangla	?	3600	?	Eastern Fold Belt	LA Anticline	9	Seismic survey by Tullow could not confirm the lead, however prospect still exists. Furhter survey needed to confirm the northern closure.
92	10-1 (Shahbajpur)	Discovery	BAPEX	84	3631	280	Southern Delta	Anticline	10	Drilled by BAPEX in 1995. Gas discovery. Producing field.
93	10-2 (Char Jabbar)	P	Cairn	75	3600	40	Southern Delta	LA Anticline	10	4 Way closure in MS-3, depth <1000m; Strat trap in MS-1 and MS-2. Under review by Cairn.
94	Sundalpur	P	BAPEX	20	3600	30	Eastern Fold Belt	Anticline	10	Prospect confirmed by seismic by BAPEX.
95	Kapasia Prospect (I)	P	Anglo-Scandinavian	363	3800	25	Eastern Foldbelt - Western Surma Basin	Anticline - Low Relief	11	Lead developed by Anglo Scandinavian Petrol. Co. in 1988 study. Prospect named as Kapasia confirmed by seismic by BAPEX.
96	Netrakona Prospect	P	BAPEX	120	5200	180	Surma Basin	Anticline	11	Seismic done by BAPEX delineated the 4-way closed structure.
97	Bajitpur	L	BAPEX	40	5200	60	Surma Basin		11	Ref: seismic line R-12.
98	Madon	L	BAPEX	20	5200	45	Surma Basin		11	Ref: seismic line MN-1.
99	Nandail	L	BAPEX	80	4000	100	Surma Basin		11	Seismic survey by BAPEX indicated the lead.
100	Nikli	L	BAPEX	50	4000	60	Surma Basin		11	Seismic survey by BAPEX indicated the lead.
101	Bhairab (11-2,3)	L	BAPEX/BSG	40	4000	60	Surma Basin		11	Seismic survey by BAPEX indicated the lead.

PROSPECT AND LEAD INVENTORY - BANGLADESH										
Sl. No.	**Prospect/Lead**	**Prospect (P) Lead (L)**	**Source**	**Area (Km^2)**	**Depth (meters)**	**Relief/Amp (meter)**	**Province/Play**	**Trap Type**	**Block No**	**Comment**
102	Haluaghat (11-1/ Lead-C)	L	BAPEX/BSG/AS						11	Lead based on listric fault delineated by BSG and Anglo Scandinavian studies. Detail seismic carried out by BAPEX could establish the lead.
103	12-1	L	BSG	40	4587	60	Surma Basin		12	Lead delineated by BSG. Could not be established by seismic done by Oxy.
104	12-2	L	BSG	30	4724	60	Surma Basin		12	Lead by BSG. Could not be established by Seismic.
105	12-3 (Balarampur/ Byronpur)	P	BSG	24	4815	60	Surma Basin		12	Seismic survey confirmed the structure as Balarampr.
106	12-4 (Bibiyana)	Discovery	BSG/Chevron	45	3800	650	Surma Basin	Anticline	12	Came out to be the second largest gas field of Bangladesh, Bibiyana.
107	12-5	L	BSG	20	4053	60	Surma Basin		12	Lead by BSG. Could not be established by Seismic
108	12-6	L	BSG	8	2682	60	Surma Basin		12	Lead by BSG. Could not be established by Seismic
109	12-7	L	BSG	10	2987	60	Surma Basin		12	Lead by BSG. Could not be established by Seismic
110	12-8	L	BSG	8	3140	60	Surma Basin		12	Lead by BSG. Could not be established by Seismic
111	12-9	L	BSG	12	4970	60	Surma Basin		12	Lead by BSG. Could not be established by Seismic
112	12-10	L	BSG	40	4900	121	Surma Basin	Fault Closrure	12	Possible fault closure closing against Dauki Fault.
113	12-11	L	BSG	30	4050	30	Surma Basin		12	Lead by BSG. Could not be established by Seismic
114	Chhatak East	P	Niko/BAPEX	154	4000	450	Eastern Foldbelt	Anticline	12	PK-SU-12, 20 and Niko 3-D seismic.
115	Darbesh	L	Oxy	20	2500	250	Eastern Foldbelt	Fault Closure	13	Possible fault closure closing against NE-SW fault in Sylhet structure.
116	Dupitila (?)	L	GGAG	16	2500	300	Eastern Foldbelt	Anticline	13	An anticline towards the NE of Sylhet gas field. Need detail seismic.
117	Fenchuganj-East ?	L	GNC	15	4500	400	Eastern Foldbelt	Fault Closrure	14	Prospect delineated by Shell/Carin. POS 49.7%. Evaluated resource GIIP 380 and mean 263.
118	Patharia North Pitch	L	GNC	36	3500	500	Eastern Foldbelt	Fault Closrure	14	Data source: PK-ZG-5, ZG-3, ZG-4, SU-3
119	Patharia West	L	GNC	9	3000	60	Eastern Foldbelt	Fault Closrure	14	
120	Harargaj	L	GNC	152	3500	300+	Eastern Foldbelt	Fault Closrure	14	Plio-Miocene exposed. Larger part of the structure is in India.
121	Harargaj North	L	GNC	36	3500	500	Eastern Foldbelt	Fault Closrure		PK-PAT-2, 3, 4
122	Batchia North Pitch	L	GNC	100	3500	300	Eastern Foldbelt	Fault Closrure	14	Plio-Miocene exposed. Larger part of the structure is in India.
123	Semutang East Flank	P	Shell	8	2600	100	Eastern Foldbelt	Faulted Anticline	15	4 wells were drilled by OGDC during the late 60s, discovered gas in one of the wells. Shell drilled well#5 in 1988 and discovered gas. They also presented the idea that the structure is compartmentalized by faults and thus proposed more wells in different compartments. 19% POS for 63 Bcf risked and 12 Bcf unrisked.
124	Semutang East Strat	P	Shell	2.5	2560	60	Eastern Foldbelt	Faulted Anticline + Stratigraphic	15	15% POS for mean 110 Bcf (unrisked) and 22 Bcf (risked) recoverable resources in MS1.7 sand
125	Semutang West Flank	P	Shell	3.4	2600	300	Eastern Foldbelt	Faulted Anticline	15	18% POS for mean 75 Bcf (unrisked) and 14 Bcf (risked resources in MS1.5 sand
126	Semutang South	P	Shell	5	2500	200	Eastern Foldbelt	Faulted Anticline	15	21% POS for mean 65 Bcf (unrisked) and 14 Bcf (risked resources in MS1.5 sand
127	Halda	P	Shell	20	4519	130	Eastern Foldbelt	Anticline	15	Cairn drilled one well there. Gas shows. Still have potential in the MS2.4 sand. 50% POS for mean 48 Bcf (unrisked) and 24 Bcf (risked) resources. MS 1 sands also should be reviewed.
129	Sandwip-1	P	Shell	65	3969	104	Eastern Foldbelt	Anticline	15	Sandwip East was drilled in 2000 (gas show). A huge structure. Further exploration should be continued.
130	Sandwip West	P	Shell	95	3650	100	Eastern Foldbelt	Anticline	15	Main target in M1.70.5 sand, may also include M1.60 sands; 34.4% POS for mean 683 Bcf (unrisked) and 284 Bcf (risked) recoverable resources.
131	Sandwip South	P	Shell	20	3450	120	Eastern Foldbelt	Anticline	15	looks good on seismic, 4-way closure, 39.4% POS for mean 285 Bcf (unrisked) and 112 Bcf (risked) recoverable resources.
132	Sitakund	P	Shell	162	3100	250	Eastern Foldbelt	Faulted Anticline	15	(About 50 Oil and gas seepage on surface) Sitakund #1-4 were drilled 1910-14. Sitakund #5 was drilled to 4005 m along axial crest of feature based on seismic by Petrobangla during 1983-88. Gas shows. However, the structure is still an attractive venue for exploration. Clear as to future potential. The structure has only had one deep well drilled on it. Early wells were all shallow (< 1000m) but had oil shows. 27.8% POS for mean 570 Bcf (unrisked) and 159 Bcf (risked) resources in MS1.70.5 sand.

PROSPECT AND LEAD INVENTORY - BANGLADESH										
Sl. No.	**Prospect/Lead**	**Prospect (P) Lead (L)**	**Source**	**Area (Km^2)**	**Depth (meters)**	**Relief/Amp (meter)**	**Province/Play**	**Trap Type**	**Block No**	**Comment**
133	Jaldi	P	Shell/Cairn	78	2800	700	Eastern Foldbelt-SE	Anticline	16	Three wells were drilled during 1964-70 (gas show). Subsequent seismic by Shell confirmed the structure to be still very prospective. No volumes given. Possible channel-seal strat traps in MS2 on flanks, fault-seal traps on flanks in MS1; 24% POS for mean 594 Bcf (unrisked) and 142 BCF (risked) recoverable resources. There are other fault compartments also having 35.8% POS for mean 122.4 (unrisked) and 44 Bcf (risked) resources in MS1.70.5 sand (Shell).
134	Sangu South	P	Shell	28	4000		Eastern Foldbelt	Anticline + Stratigraphic	16	Three wells were drilled during 1999-2007. Still considered a prospect. Cairn is doing 3D seismic there. 2nd and 3rd wells on prospect drilled by Cairn in 2001 & 2007. Gas shows, P&A.
135	Sangu East	P	Shell	13	3800	250	Eastern Foldbelt	Anticline + Stratigraphic	16	
136	Hatia	P	Shell	114	3440	242	Eastern Foldbelt	Anticline	16	Drilled by Cairn (gas show). 4-way closure. Looks good on seismic. Shell gives it a 60.4-60.9% POS for mean 2.474 Tcf (unrisked) and 1.503 (risked) recoverable resources in MS1 sands
137	Magnama	P	Shell				Eastern Foldbelt		16	(Not in the Shell Summary Sheet). One well drilled by Cairn (gas show). Cairn is now doing 3D seismic there. Considered to be highly prospective.
138	Kutubdia	Discovery	Union	163	3450	198	Eastern Foldbelt	Anticline	16	Kutubdia-1 was drilled during 1976-77. Gas discovered but not produced so far. still looks prospective but small. Well disc. Untested gas in 2.8 sand. Shell gives it 51% POS for mean 21 Bcf (unrisked) and 11 Bcf (risked) recoverable resources in 2.8 sand. Possible upside in untested pod of similar size to north in 2.9.6 sand but no resource given.
139	Manpura	P	Shell	23	4100	80	Eastern Foldbelt	Anticline	16	Not drilled. 4-way closure, looks valid on seismic. Shell gives it 30% POS for mean 414 BCF (unrisked) and 124 Bcf (risked) recoverable resources in MS1 sands
140	Maiskhali	P	Shell	23	4100	200	Eastern Foldbelt	Anticline	16	Not drilled. 4-way closure, highly faulted, prosp. In MS1.70 sand; Looks good on seismic. Shell gives it a 40% POS for mean 500 Bcf (unrisked) and 200 Bcf (risked) recoverable resources.
141	Matabari Deep MS1	P	Shell	50	4700	110	Eastern Foldbelt	Anticline + Stratigraphic	16	Not drilled. Strong reflector, potential deep target relying on stratigraphic trapping. Crest is not coincident with that of shallow 2.96.
142	Matabari Shallow MS2	P	Shell	185 (Min.) - 970 (P60)	1430 (4700)	110	Eastern Foldbelt	Anticline + Stratigraphic	16	Not drilled. Strong reflector, Sst with competent top seal, combined structural strat trap. Crest is not coincident with that of deeper 1.5.
143	Sonadia	P	Shell	14	4470	55	Hatiya Trough	Anticline	16	Drilled to 4028 m by Cairn. Still considered to be a prospect.
144	Reju	P	Okland/ Rexwood/ Tullow	130	4450	80	Hatiya Trough	Combination	17	Combined structural and stratigraphic closure 100 ms relief. Four way closure. Drilled one well. Non-commercial gas. Required further exploration.
145	Kuakata	P	"	375	3450	80		Faulted Anticline	17	
146	Ukhia	P	"	80	4200	80	Eastern Fold belt	4-Way dip closure	17	
147	Adinath	P	"	125	3400	130		Faulted Anticline	17	
148	D (Ohlataung)	P	"	90	3000	300+	Eastern Fold belt	3-Way dip closure	17	Surface anticline, stip structure. Further G&G studies are required to upgrade the lead into prospect.
149	E (Inani)	P	"	50	3500	150+	Eastern Fold belt	3-Way dip closure	17	Surface anticline, stip structure. Southern limit of the structure is bound by a wrench fault. Further G&G studies are required to upgrade the lead into prospect.
150	I (Dakhinila)	P	"	160	3000	300+	Eastern fold belt	3-Way dip closure	17	Surface anticline, stip structure. Further G&G studies are required to upgrade the lead into prospect.
151	F	L	"	30	*	*	Eastern fold belt	3-Way dip closure	17	Cox's Bazar 1 well is located in this closure. It is believed that there is potential prospect below the TD of CB-1 well.
152	J	L	"	75	*	70	Eastern fold belt	4-Way dip closure	17	There appears to be a strong stratigraphic element to this lead in the deeper chennelized section.
153	Q	L	"	*	*	*	Eastern fold belt	4-Way dip closure	17	4 way dip closure in the south western part of Block 17, 95 km south west of Cox's Bazar. Further G&G is required to establish the lead into prospect.

PROSPECT AND LEAD INVENTORY - BANGLADESH										
Sl. No.	**Prospect/Lead**	**Prospect (P) Lead (L)**	**Source**	**Area (Km^2)**	**Depth (meters)**	**Relief/Amp (meter)**	**Province/Play**	**Trap Type**	**Block No**	**Comment**
154	R	L	"	*	*	*	Eastern fold belt		17	5 way dip closure in the south western part of Block 17, 95 km south west of Cox's Bazar. Further G&G is required to establish the lead into prospect.
155	Cox's Bazar	P			3350		Eastern fold belt		17	
156	Teknaf	P	"	40	3500	100	Eastern fold belt	Faulted Anticline	18	Total-Tullow carried out 3-D seismic and confirmed the structure.
157	Coral Dip	P	"	125	4100	???	Eastern fold belt	Faulted Anticline	18	Tightly folded, complex, faulted anticline.
158	K	L	"	36	4200	???	Eastern fold belt	4-Way dip closure	18	The closure may be cut obliquely by a minor fault and is associated with a possible gas chimney seen on the seismic. BODC-1 was drilled south and slightly downdip of the culmination; it proved the presence of numerous 20-30m sandstone reservoirs below 1900m. Several shows were recorded below 4000m. Well was perforated, in an inappropriate interval, at casing shoe location and thus the well did not flow. Recent petrophysical studies suggests that this sand and another at 4100m are gas bearing. In that case the trap would be about 36 Sq. Km.
159	St. Martin Island O	P	"	65	4000	???	Eastern fold belt	4-Way dip closure	18	This lead covers the area of St. Martin's Island in the south eastern corner of Block 18. There is oil show on the island itself and oil show is also reported from across the border in Myanmar. Further G&G is required to establish the lead into prospect.
160	BODC-1	P			3800				18	
161	BODC-2	P			3700				18	
162	BODC-3	P			3800				18	
163	BINA-1	P			3950				18	
164	BINA-2	P			3950				18	
165	ARCO A1	P							19	
166	Lead 19-A	L	Maersk Olie OG	200-320, 280 (P50)	3200	500	Western Delta -Offshore	Buried Hill	19	Undrilled "erosional trap" leads identified by Maersk Olie OG in 1997 for Bid Round. Traps are "buried hill"- type traps formed by submarine canyon erosional processes.
167	Lead 19-B	L	Maersk Olie OG	60-110, 90 (P50)	3900	500	Western Delta -Offshore	Buried Hill	19	Same as above
168	Lead 20-A	L	Maersk Olie OG	250-400, 350 (P50)	2200	400	Western Delta -Offshore	Buried Hill	20	Same as above
169	Lead 20-B	L	Maersk Olie OG	150-300, 250 (P50)	2000	500	Western Delta -Offshore	Buried Hill	20	Same as above
170	Lead 20-C	L	Maersk Olie OG	250-400, 350 (P50)	3200	500	Western Delta -Offshore	Buried Hill	20	Same as above
171	Bandarban	L	OGDC/UMC/PB	249	3000+	400+	Eastern Fold belt	Faulted Anticline	22	Further G&G required.
172	Barkal	L	OGDC/UMC/PB	104	3000+	400+	Eastern Fold belt	Faulted Anticline	22	Further G&G required.
173	Belachari	L	OGDC/UMC/PB	140	3000+	300+	Eastern Fold belt	Faulted Anticline	22	Further G&G required.
174	Bhuachari	L	OGDC/UMC/PB	41	3000+	400+	Eastern Fold belt	Faulted Anticline	22	Further G&G required.
175	Changohtang	L	OGDC/UMC/PB	67	3000+	400+	Eastern Fold belt	Faulted Anticline	22	Further G&G required.
176	Gilachari	L	OGDC/UMC/PB	62	3000+	400+	Eastern Fold belt	Faulted Anticline	22	Further G&G required.
177	Gobamura	L	OGDC/UMC/PB	124	3000+	400+	Eastern Fold belt	Faulted Anticline	22	Further G&G required.
178	Kasalang	L	OGDC/UMC/PB	124	3000+	400+	Eastern fold belt	Faulted Anticline	22	Further G&G required.
179	Matamuhuri	L	OGDC/UMC/PB	453	3000+	400+	Eastern Fold belt	Faulted Anticline	22	Further G&G required.
180	Shishak	L	OGDC/UMC/PB	47	3000+	400+	Eastern Fold belt	Faulted Anticline	22	Further G&G required.
181	Uttan Chhatra	L	OGDC/UMC/PB	227	3000+	400+	Eastern Fold belt	Faulted Anticline	22	Further G&G required.
182	Sitapahar	L	OGDC/UMC/PB		3000+	400+	Eastern Fold belt		22	Shell drilled two shallow wells to 211m and 1560m. Further G&G is required.

* Okland report does not provide detail geometry of the sturctures in blocks 17 and 18. Geometry of the exposed structures may be estimated from photomosaics later by experts.

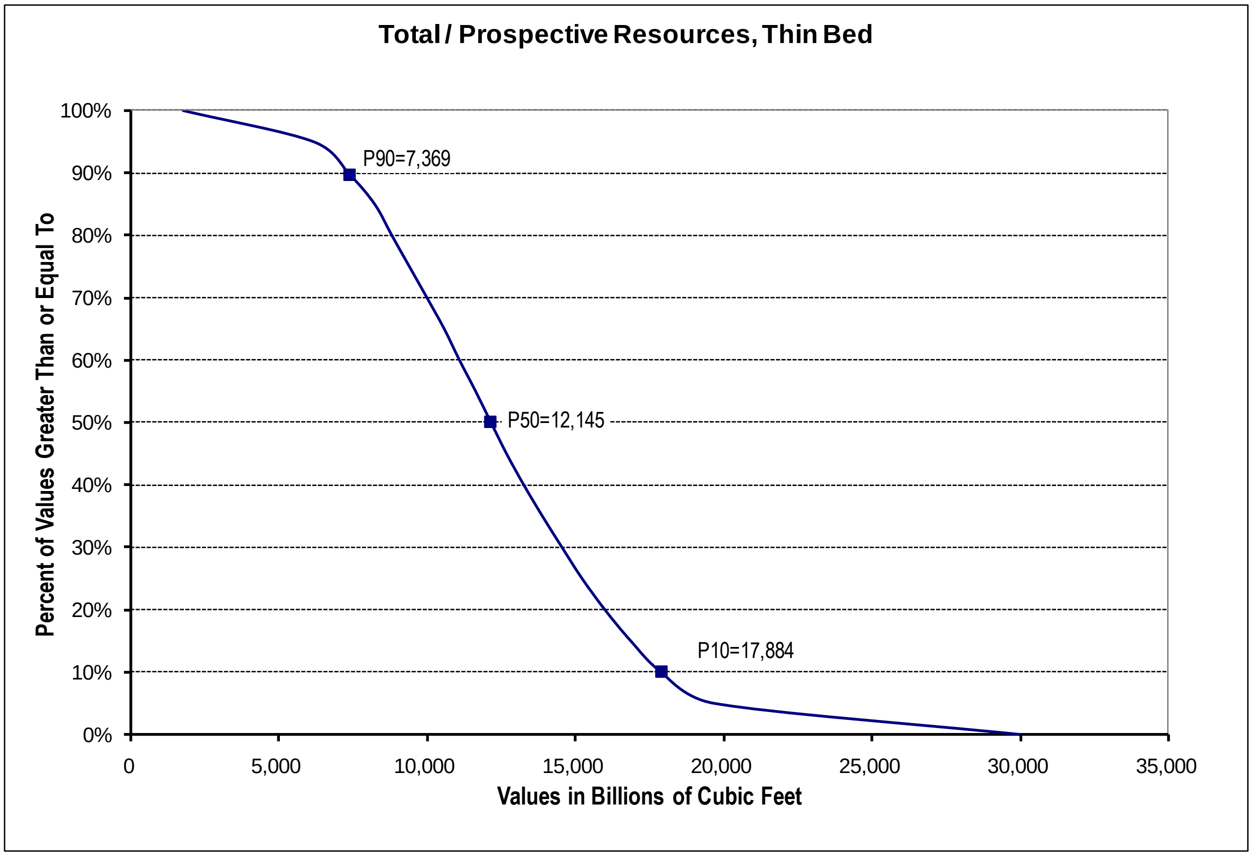
APPENDIX C

MORE DETAILS ON

RESOURCE ESTIMATES

THIN BEDS

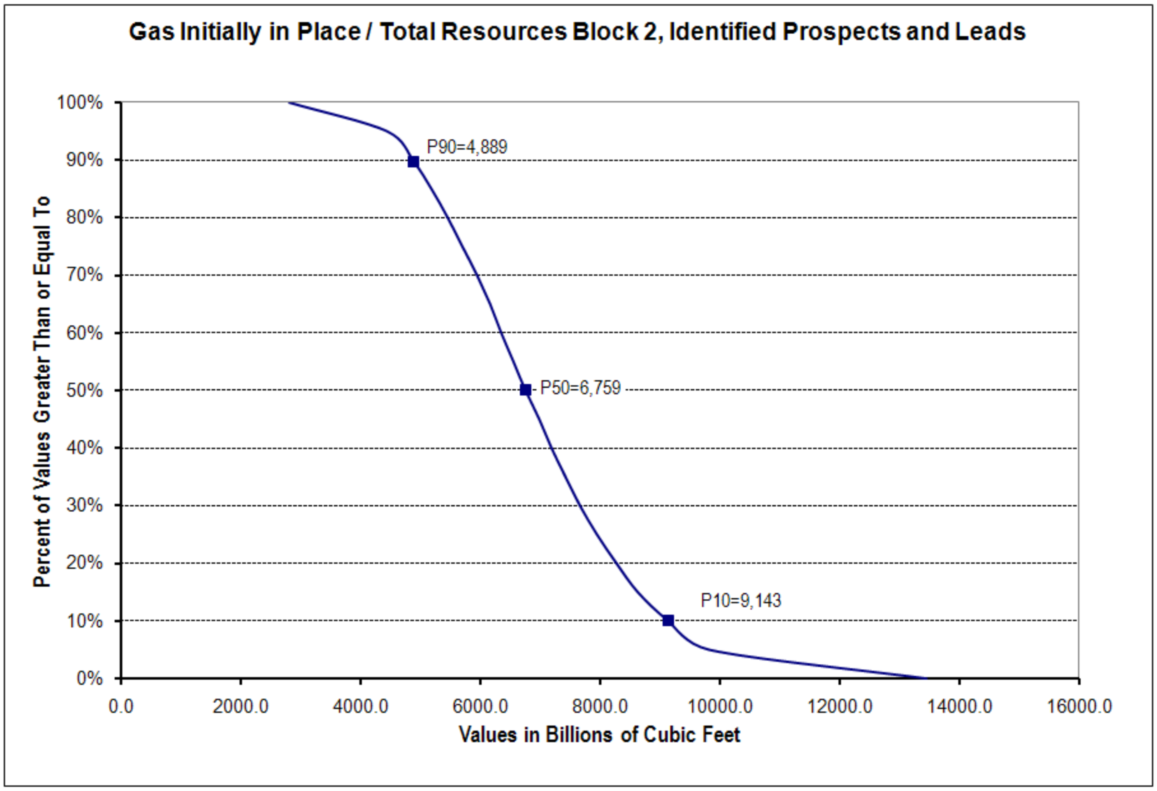
Field	Mean Prospective Gas Resources, BCF
Bakhrabad	697
Bangora	321
Beani	72
Fenchuganj	150
Habiganj	1,478
Jalalabad	691
Kailash	1,389
Moulavi	482
Narshingdi	115
Rashidpur	1,676
Salda	142
Sangu	364
Shahbazpur	139
Sylhet	199
Titas	3,950
Chattak	257
Feni	65
Kamta	21
Meghna	32
Begumganj	26
Kutubdia	24
Semutang	169
Total	**12,459**

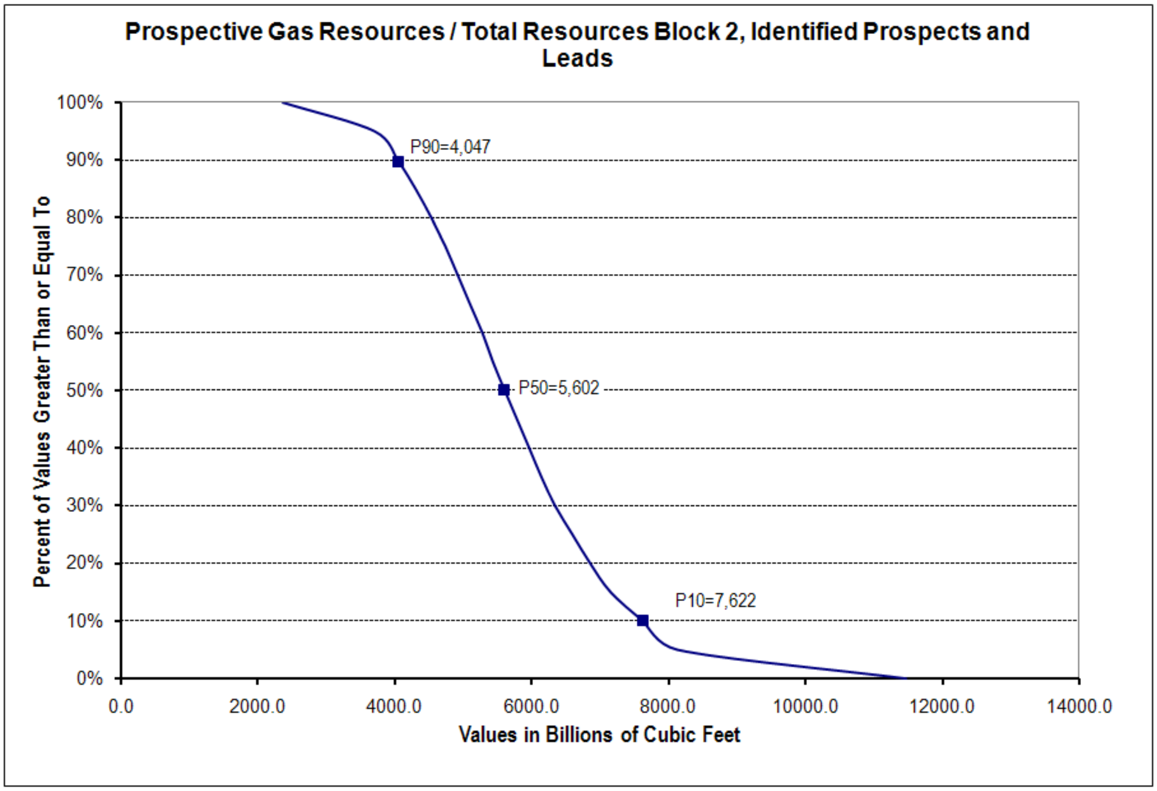

Total / Prospective Resources, Thin Bed
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=7,369
P50=12,145
P10=17,884
0
5,000
10,000
15,000
20,000
25,000
30,000
35,000
Values in Billions of Cubic Feet

IDENTIFIED PROSPECTS AND LEADS

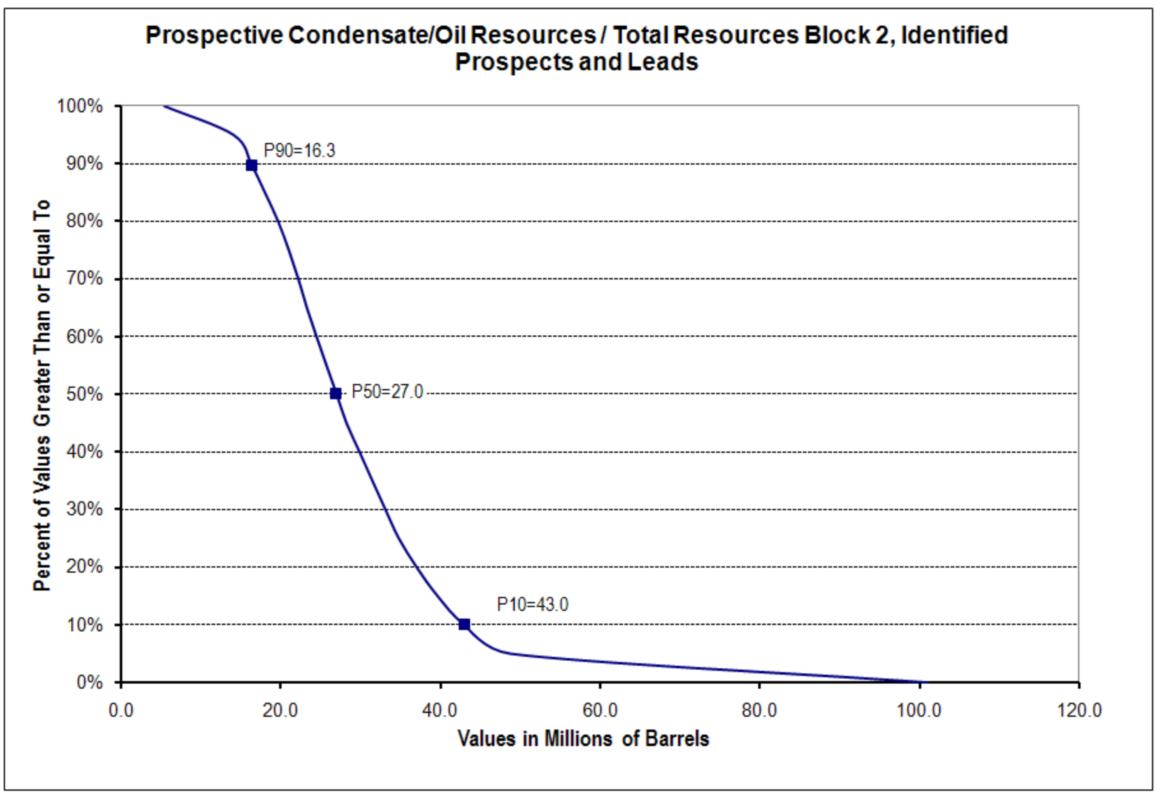
Block 2

Prospect / Lead	Mean Prospective Gas Resources, BCF
2-1 (Oligo-Eo-Cre)	1,549
2-2	2,127
2-3	1,467
Sherpur East	579
Total	5,722





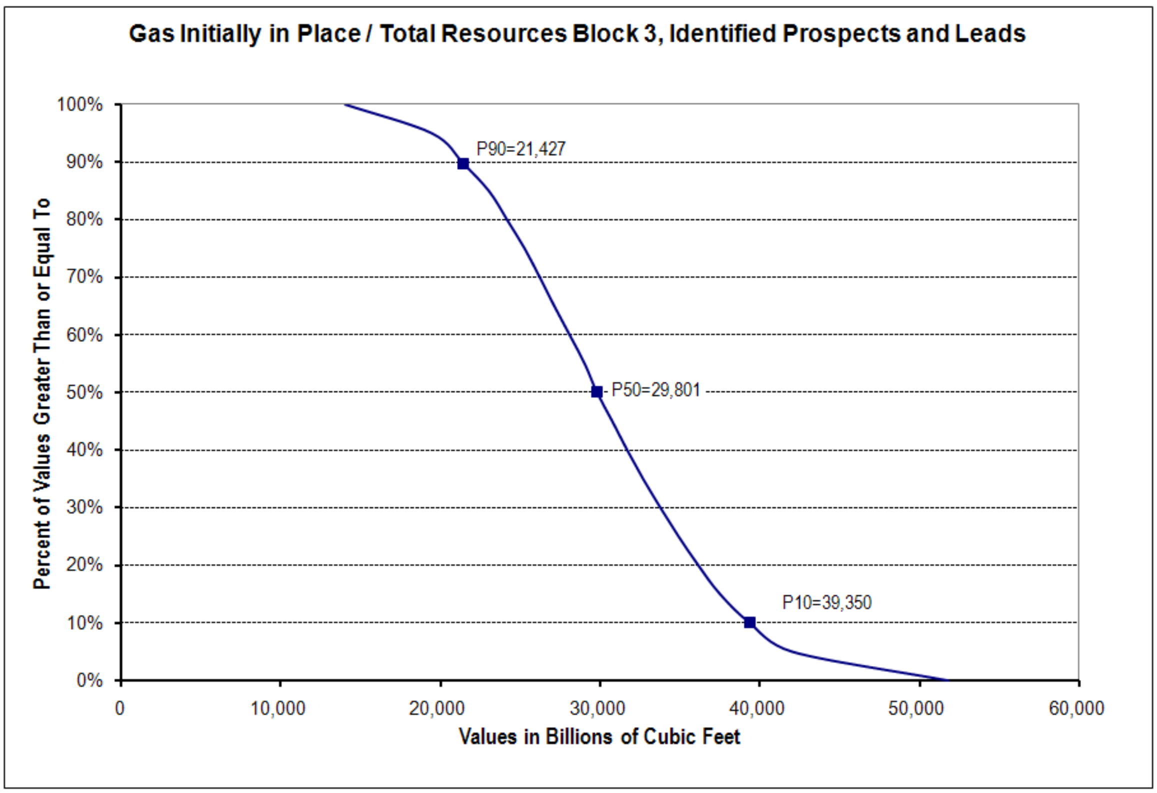
Prospective Gas Resources / Total Resources Block 2, Identified Prospects and Leads
P90=4,047
P50=5,602
P10=7,622
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
0.0
2000.0
4000.0
6000.0
8000.0
10000.0
12000.0
14000.0
Values in Billions of Cubic Feet

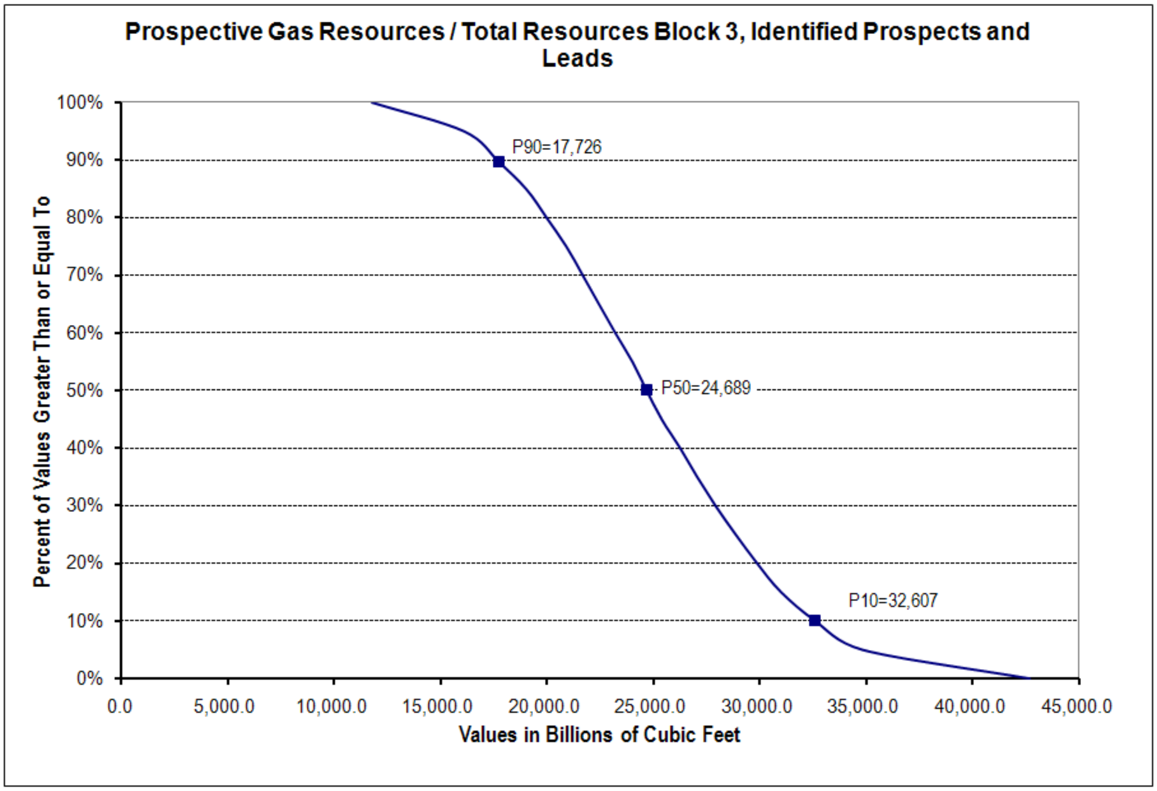


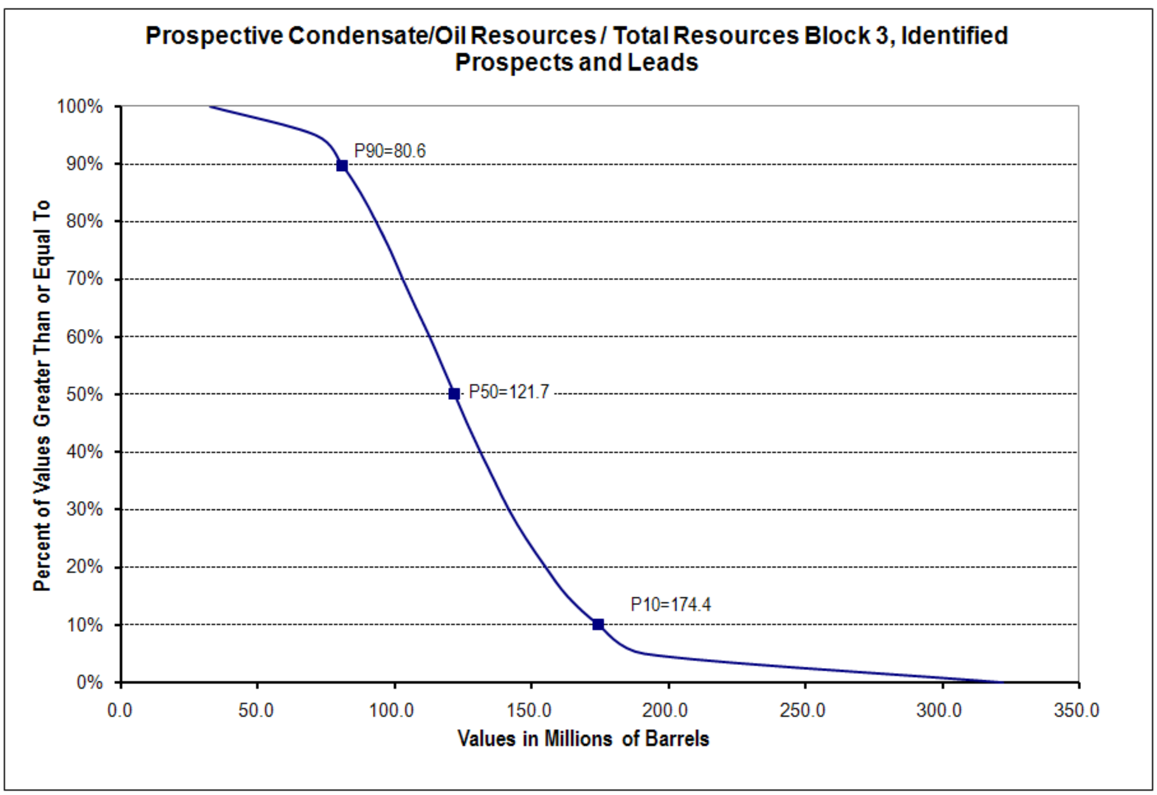
Prospective Condensate/Oil Resources / Total Resources Block 2, Identified Prospects and Leads
P90=16.3
P50=27.0
P10=43.0
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
0.0
20.0
40.0
60.0
80.0
100.0
120.0
Values in Millions of Barrels

Block 3

Prospect / Lead	Mean Prospective Gas Resources, BCF
3-1	3,536
3-2	5,276
3-3	2,234
3-4	658
3-5	2,477
3-6	3,173
3-7	3,048
3-8	1,463
3-9	1,464
3-10	264
3-11	530
3-12	333
3-13	265
3-14	265
Total	24,988

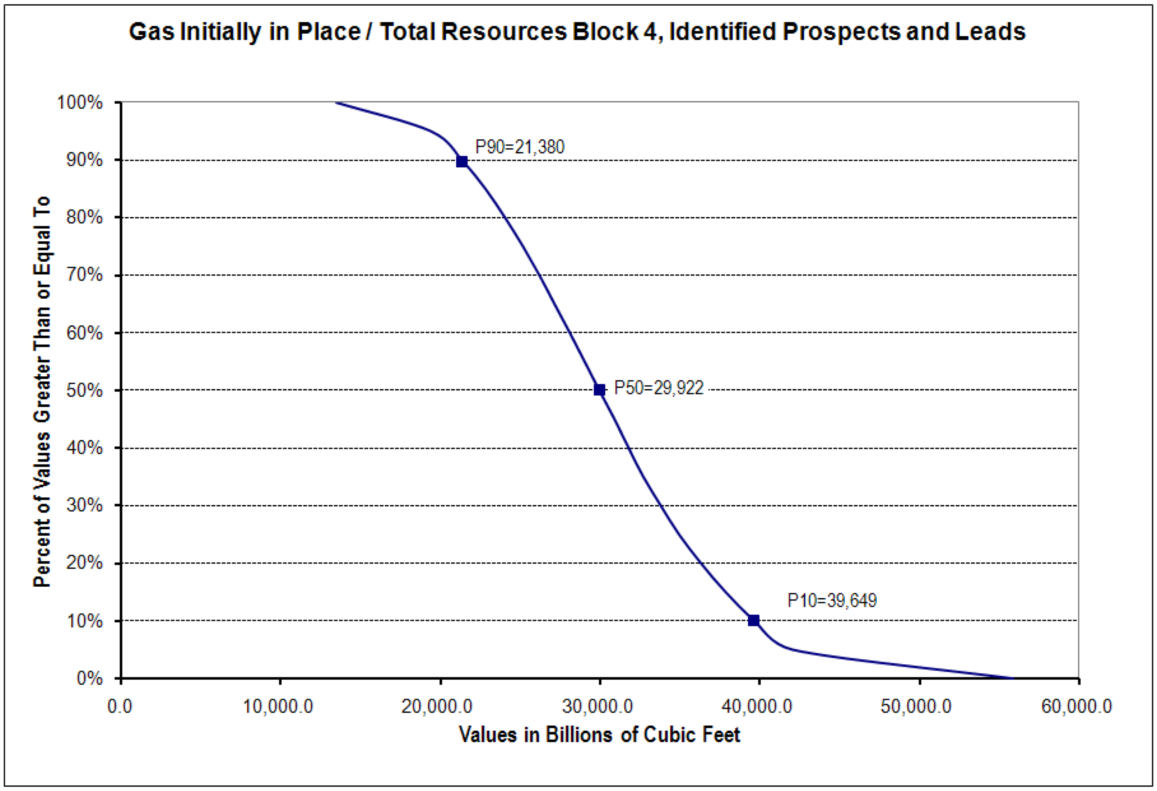


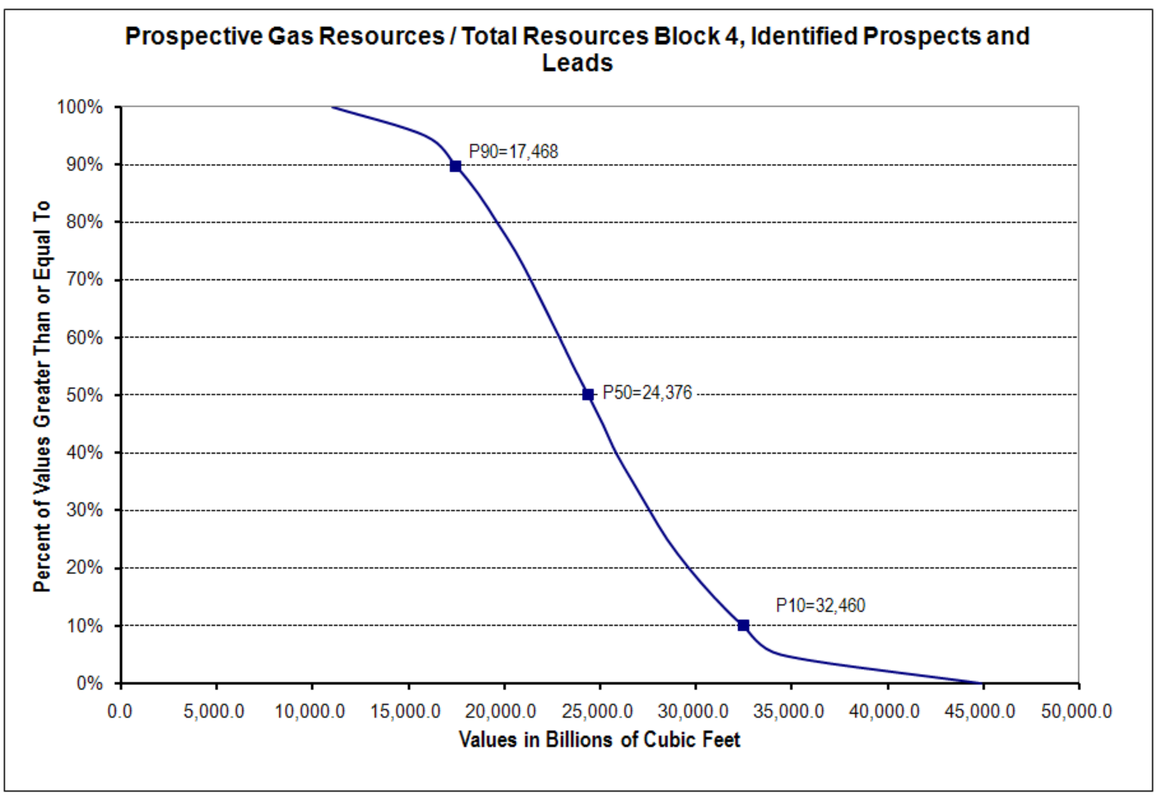

Prospective Gas Resources / Total Resources Block 3, Identified Prospects and Leads
P90=17,726
P50=24,689
P10=32,607
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0.0
5,000.0
10,000.0
15,000.0
20,000.0
25,000.0
30,000.0
35,000.0
40,000.0
45,000.0
Values in Billions of Cubic Feet

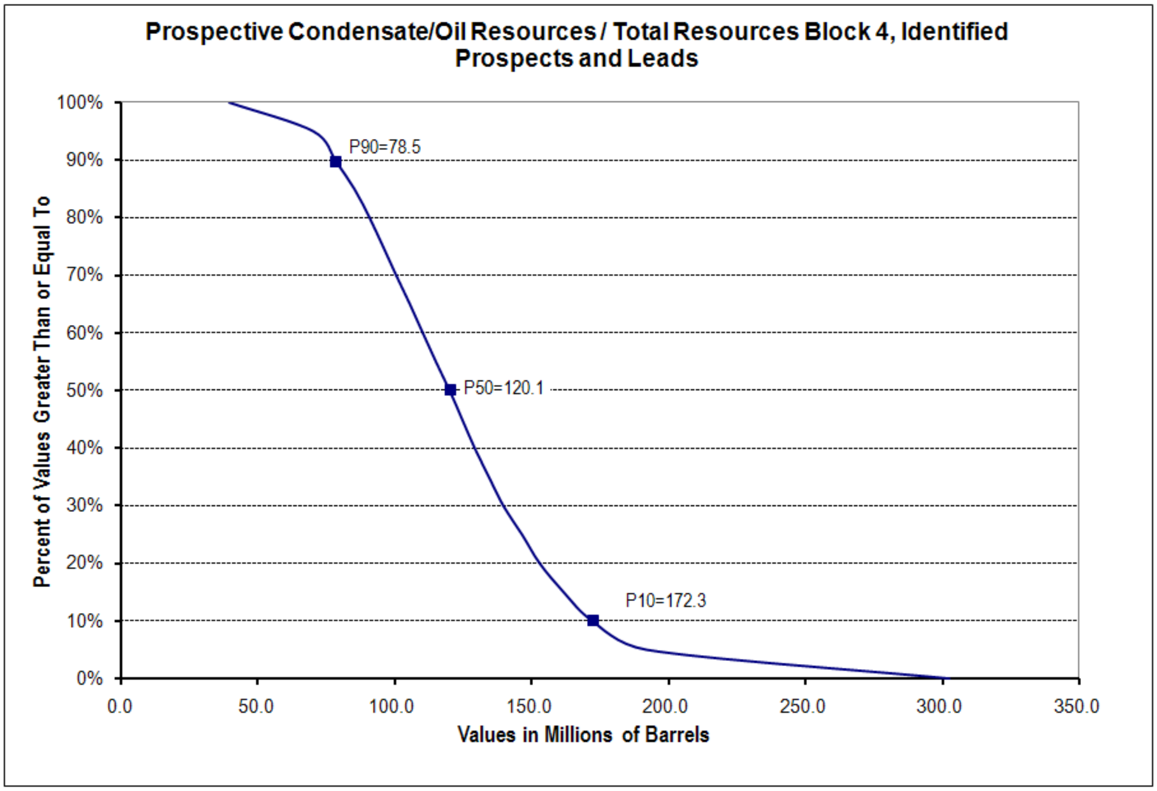

Prospective Condensate/Oil Resources / Total Resources Block 3, Identified Prospects and Leads
P90=80.6
P50=121.7
P10=174.4
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0.0
50.0
100.0
150.0
200.0
250.0
300.0
350.0
Values in Millions of Barrels

Block 4

Prospect / Lead	Mean Prospective Gas Resources, BCF
4-1	4,462
4-2	3,570
4-3	5,597
4-4	127
4-5	263
4-6	348
4-7	409
4-8	335
4-9	78
4-11	260
4-12	265
4-13	428
4-15	82
4-16	351
4-18	352
4-10	400
4-14	357
4-17	266
4-19	396
4-20	1,919
4-21	1,470
4-22	1,470
4-23	1,469
Total	24,676


Gas Initially in Place / Total Resources Block 4, Identified Prospects and Leads
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
P90=21,380
P50=29,922
P10=39,649
0.0
10,000.0
20,000.0
30,000.0
40,000.0
50,000.0
60,000.0
Values in Billions of Cubic Feet

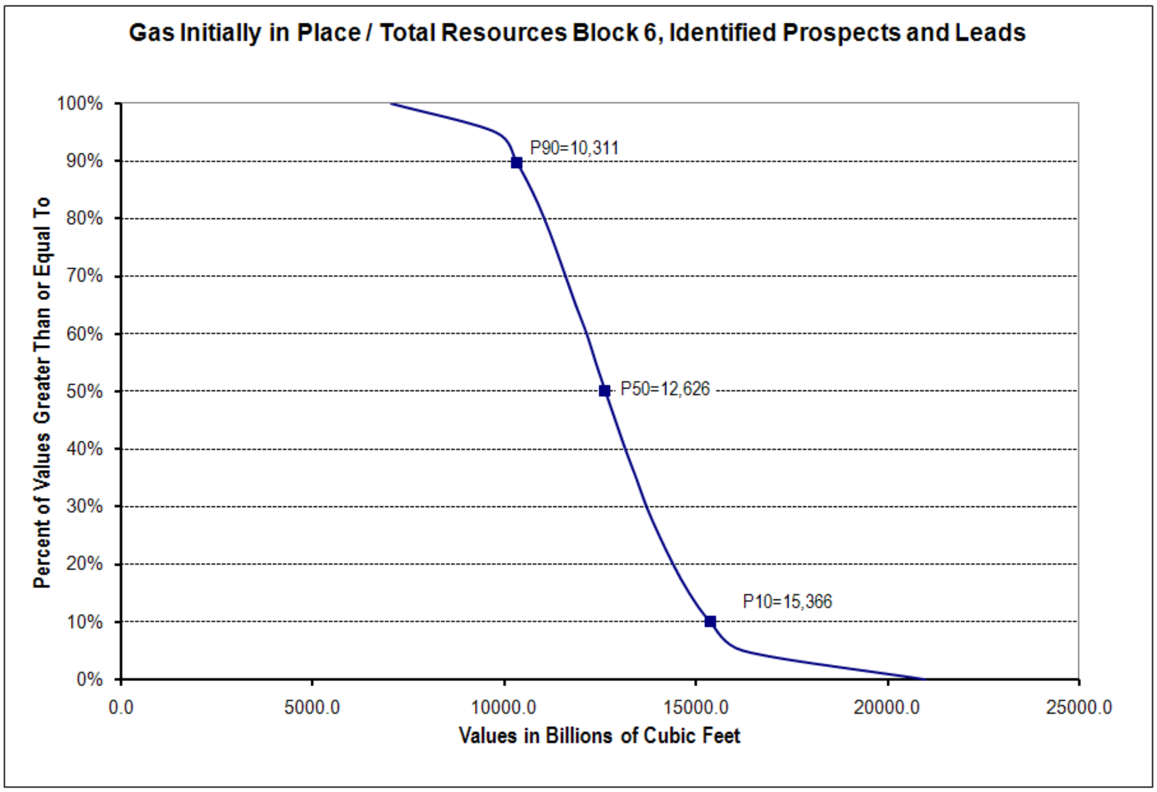

Prospective Gas Resources / Total Resources Block 4, Identified Prospects and Leads
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
P90=17,468
P50=24,376
P10=32,460
0.0
5,000.0
10,000.0
15,000.0
20,000.0
25,000.0
30,000.0
35,000.0
40,000.0
45,000.0
50,000.0
Values in Billions of Cubic Feet

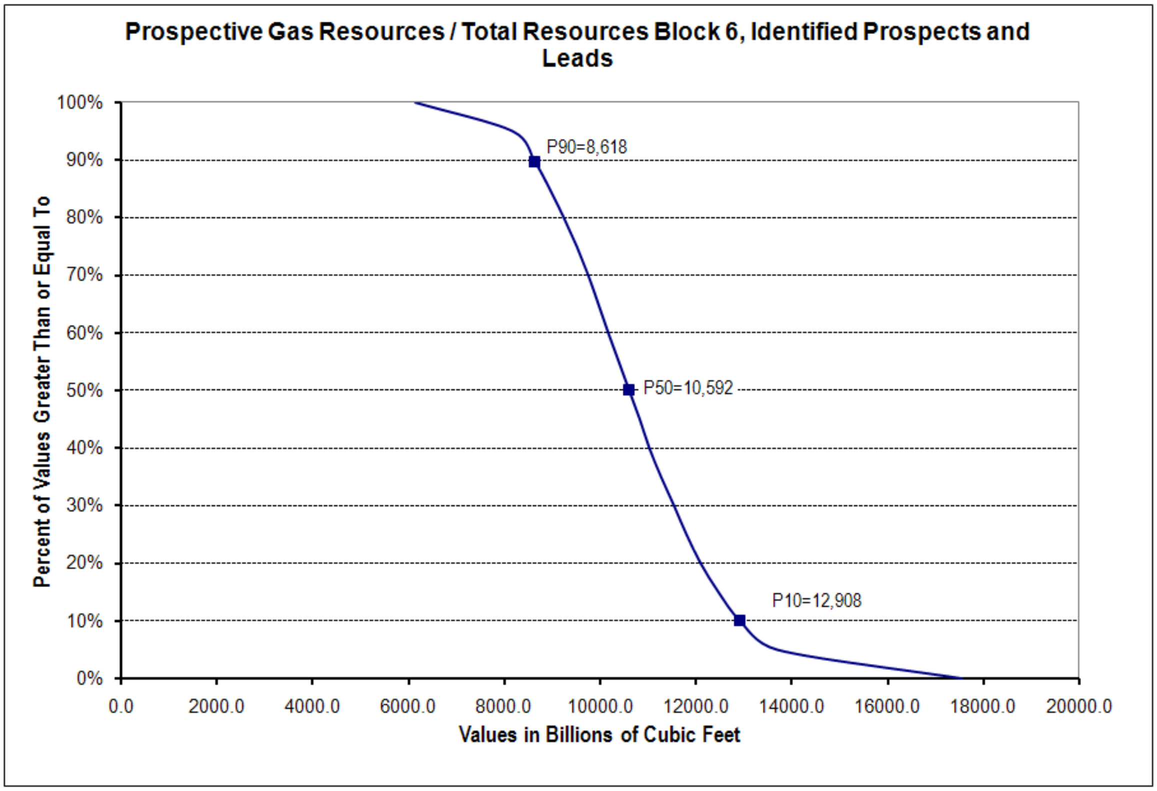


Prospective Condensate/Oil Resources / Total Resources Block 4, Identified Prospects and Leads
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=78.5
P50=120.1
P10=172.3
0.0
50.0
100.0
150.0
200.0
250.0
300.0
350.0
Values in Millions of Barrels

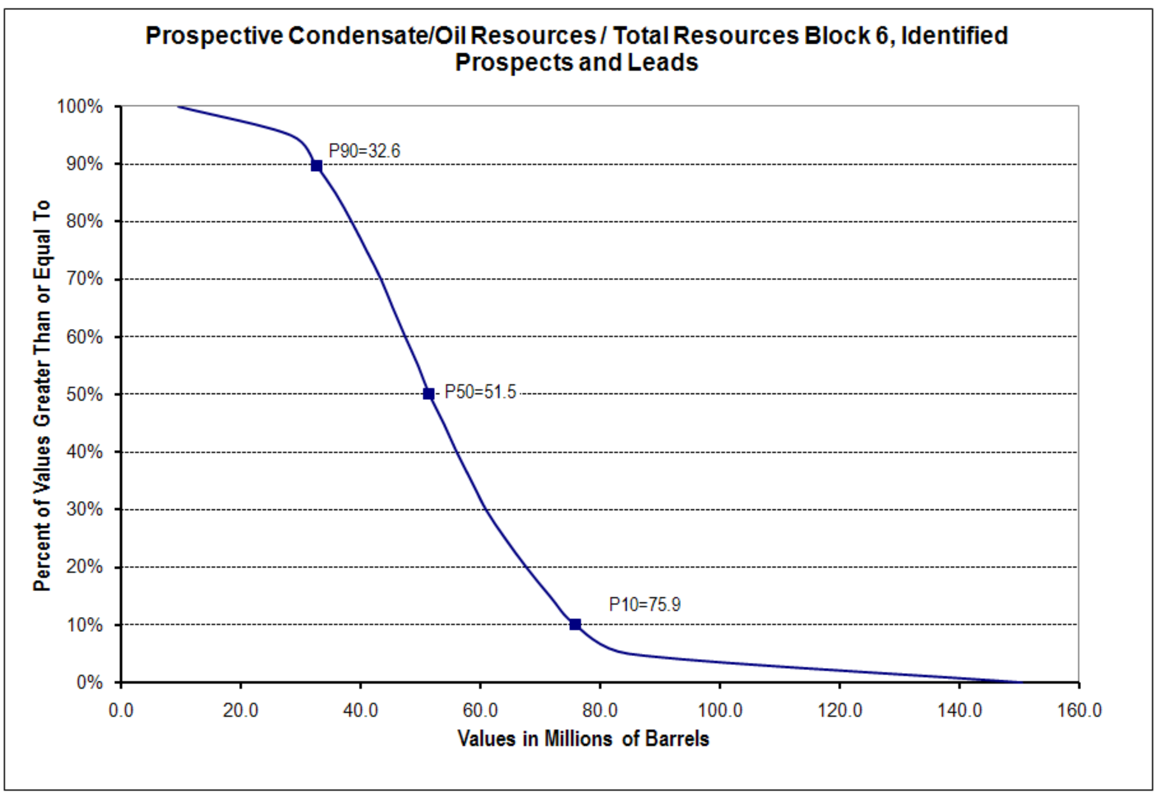
Block 6

Prospect / Lead	Mean Prospective Gas Resources, BCF
6-3	2,715
6-4 (L. & M. Mio.)	1,113
6-5 (L. & M. Mio)	3,516
6-7 (L. & M. Mio)	3,355
Total	10,699





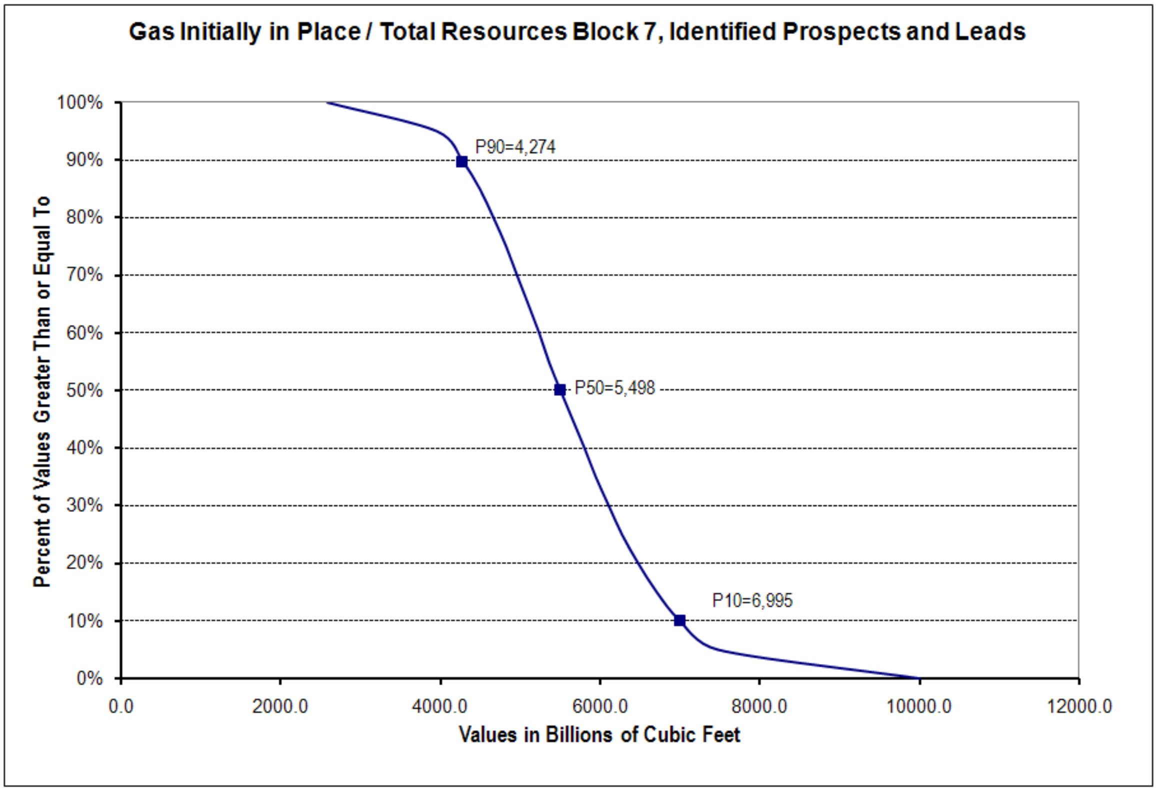
Prospective Gas Resources / Total Resources Block 6, Identified Prospects and Leads
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
P90=8,618
P50=10,592
P10=12,908
0.0
2000.0
4000.0
6000.0
8000.0
10000.0
12000.0
14000.0
16000.0
18000.0
20000.0
Values in Billions of Cubic Feet

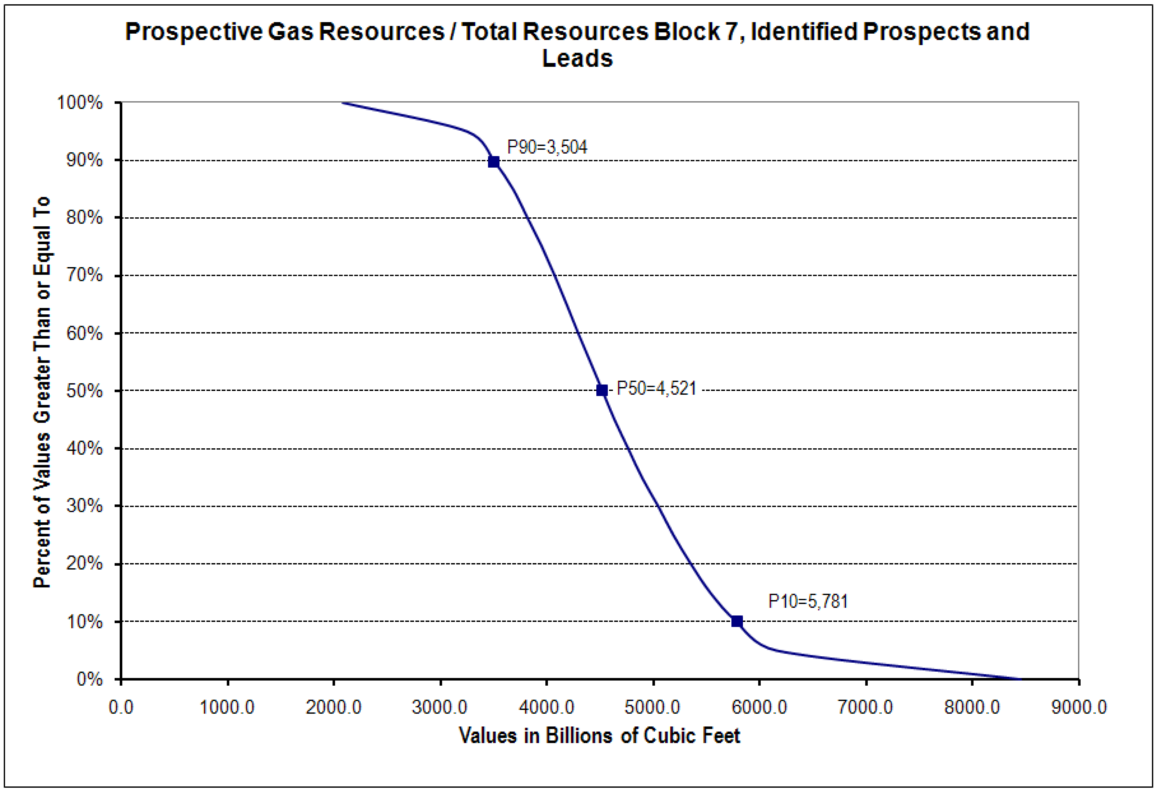


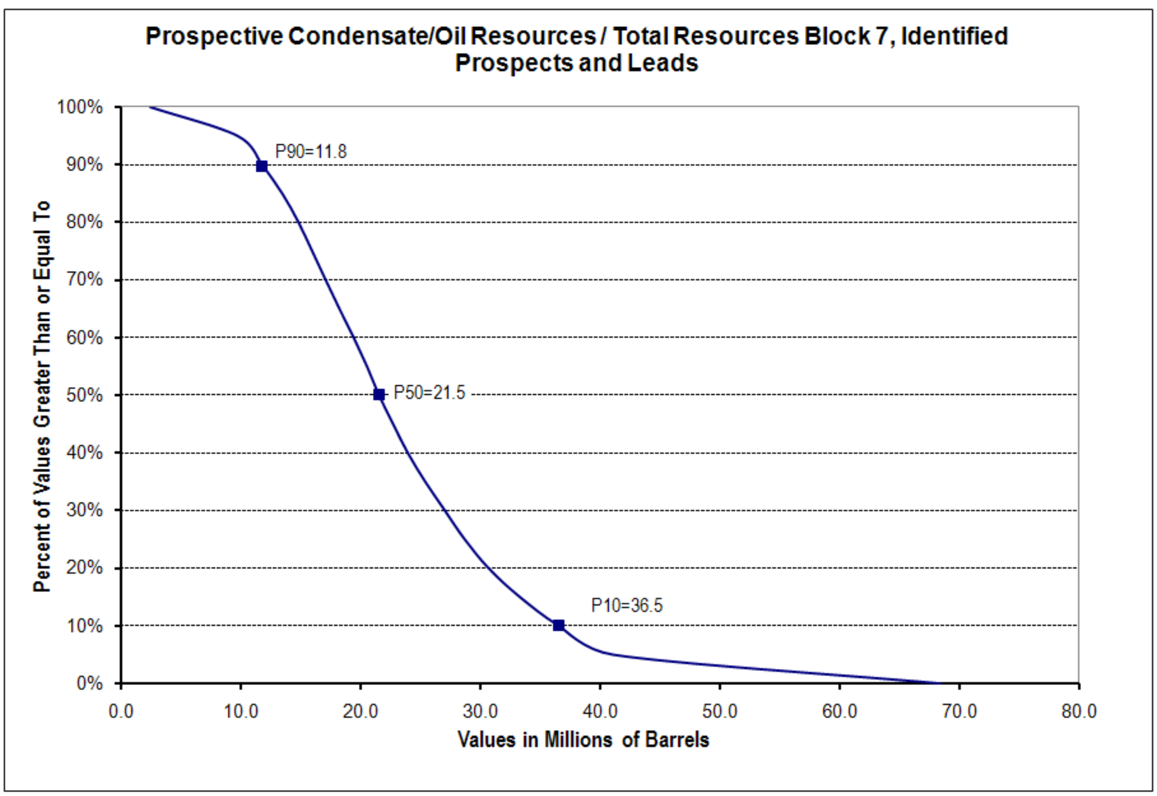
Prospective Condensate/Oil Resources / Total Resources Block 6, Identified Prospects and Leads
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
P90=32.6
P50=51.5
P10=75.9
0.0
20.0
40.0
60.0
80.0
100.0
120.0
140.0
160.0
Values in Millions of Barrels

Block 7

Prospect / Lead	Mean Prospective Gas Resources, BCF
Char Kajal	3,050
Chandra mohan	953
Amtoli	596
Total	4,599

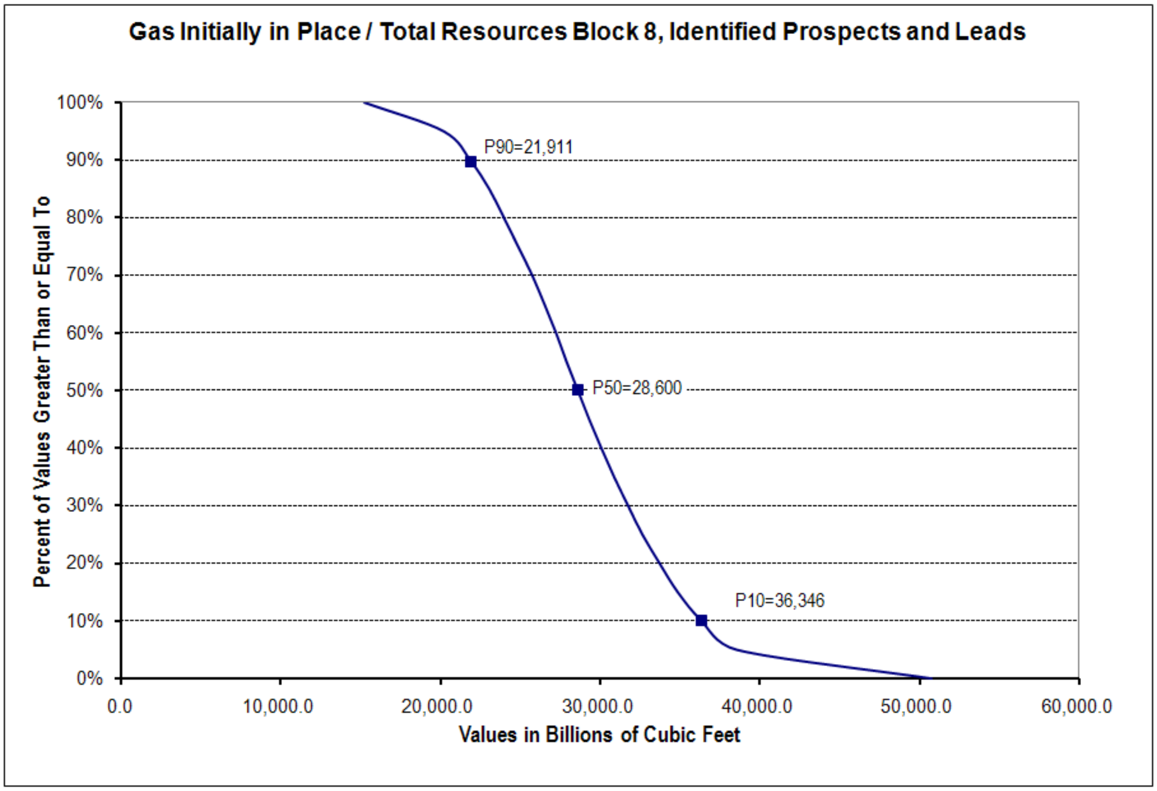


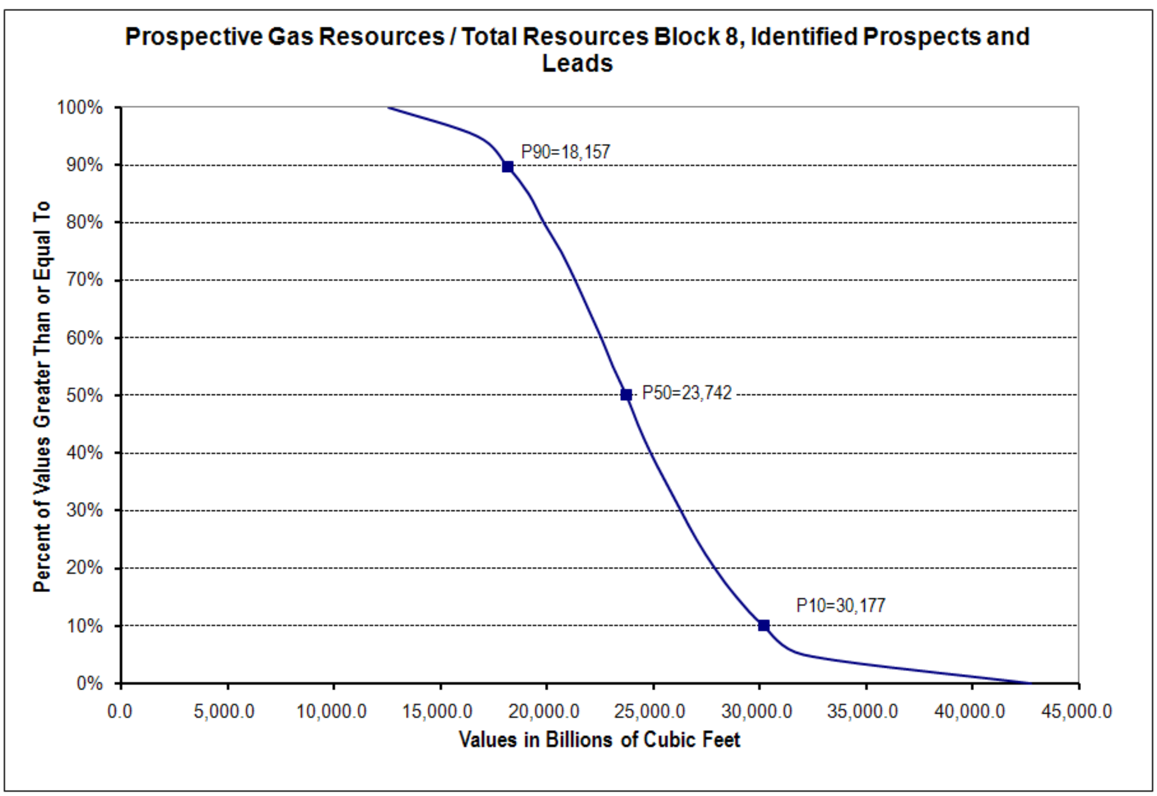

Prospective Gas Resources / Total Resources Block 7, Identified Prospects and Leads
P90=3,504
P50=4,521
P10=5,781
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0.0
1000.0
2000.0
3000.0
4000.0
5000.0
6000.0
7000.0
8000.0
9000.0
Values in Billions of Cubic Feet

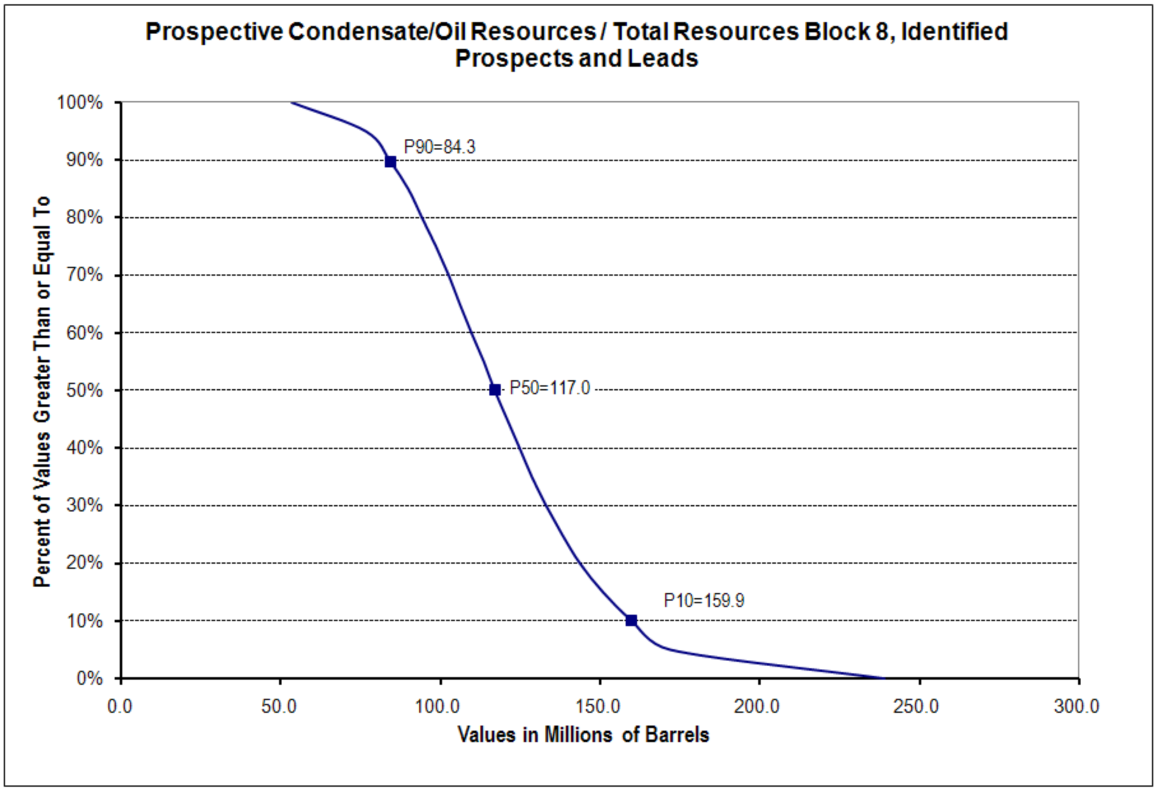

Prospective Condensate/Oil Resources / Total Resources Block 7, Identified Prospects and Leads
P90=11.8
P50=21.5
P10=36.5
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0.0
10.0
20.0
30.0
40.0
50.0
60.0
70.0
80.0
Values in Millions of Barrels

Block 8

Prospect / Lead	Mean Prospective Gas Resources, BCF
8-1 (L, M, E. Mio-Oligo)	1,831
8-2 (E. Mio & Oligo)	755
8-3	824
8-4	401
8-5A (L, M, E. Mio-Oligo)	436
8-5B (L, M, E. Mio-Oligo)	613
8-5C (L, M, E. Mio-Oligo)	802
8-6 (L, M, E. Miocene)	369
8-7	1,501
8-8	3,426
8-9	734
8-10	313
8-11	680
8-12	1,211
8-13	2,824
8-14 (Eoc. & Cret)	443
8-15 (L. & M. Mio)	249
Lead A	412
Lead B	266
Lead D	516
Lead E	481
Lead F	250
Lead G	1,130
Lead H	3,510
Total	23,977


Gas Initially in Place / Total Resources Block 8, Identified Prospects and Leads
P90=21,911
P50=28,600
P10=36,346
Percent of Values Greater Than or Equal To
Values in Billions of Cubic Feet
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0.0
10,000.0
20,000.0
30,000.0
40,000.0
50,000.0
60,000.0

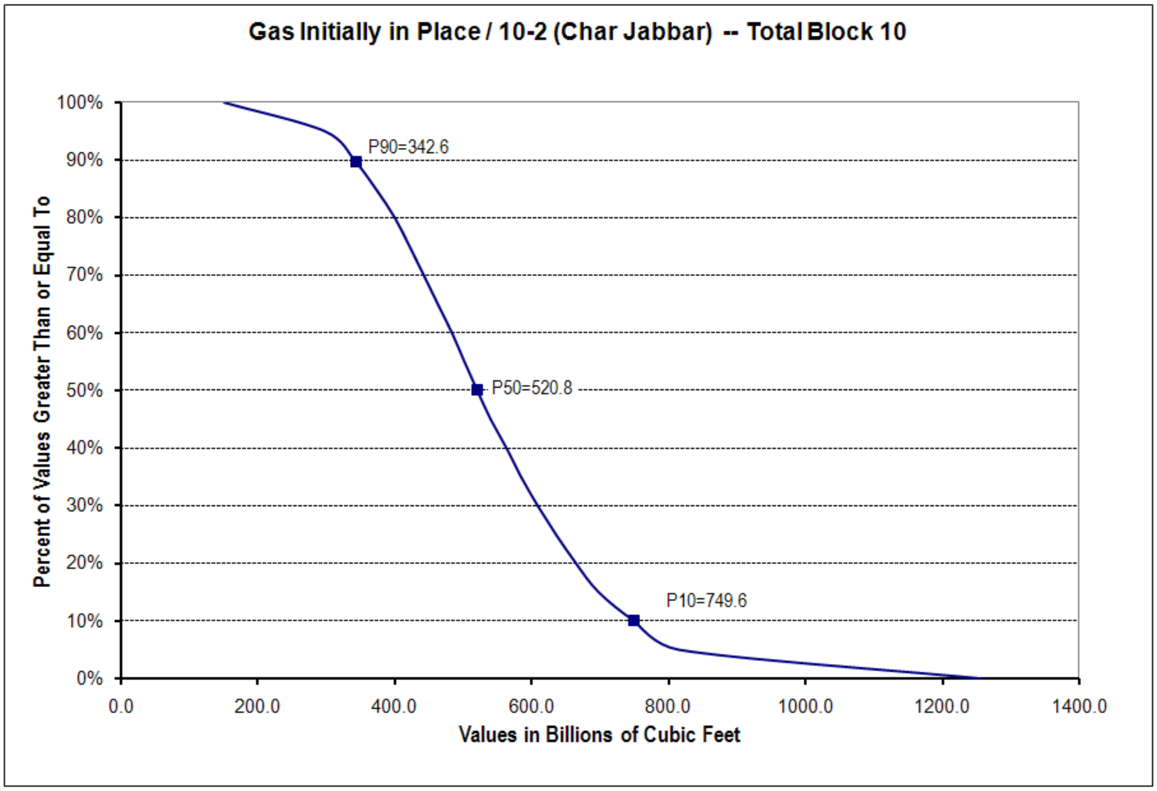

Prospective Gas Resources / Total Resources Block 8, Identified Prospects and Leads
P90=18,157
P50=23,742
P10=30,177
Percent of Values Greater Than or Equal To
Values in Billions of Cubic Feet
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0.0
5,000.0
10,000.0
15,000.0
20,000.0
25,000.0
30,000.0
35,000.0
40,000.0
45,000.0

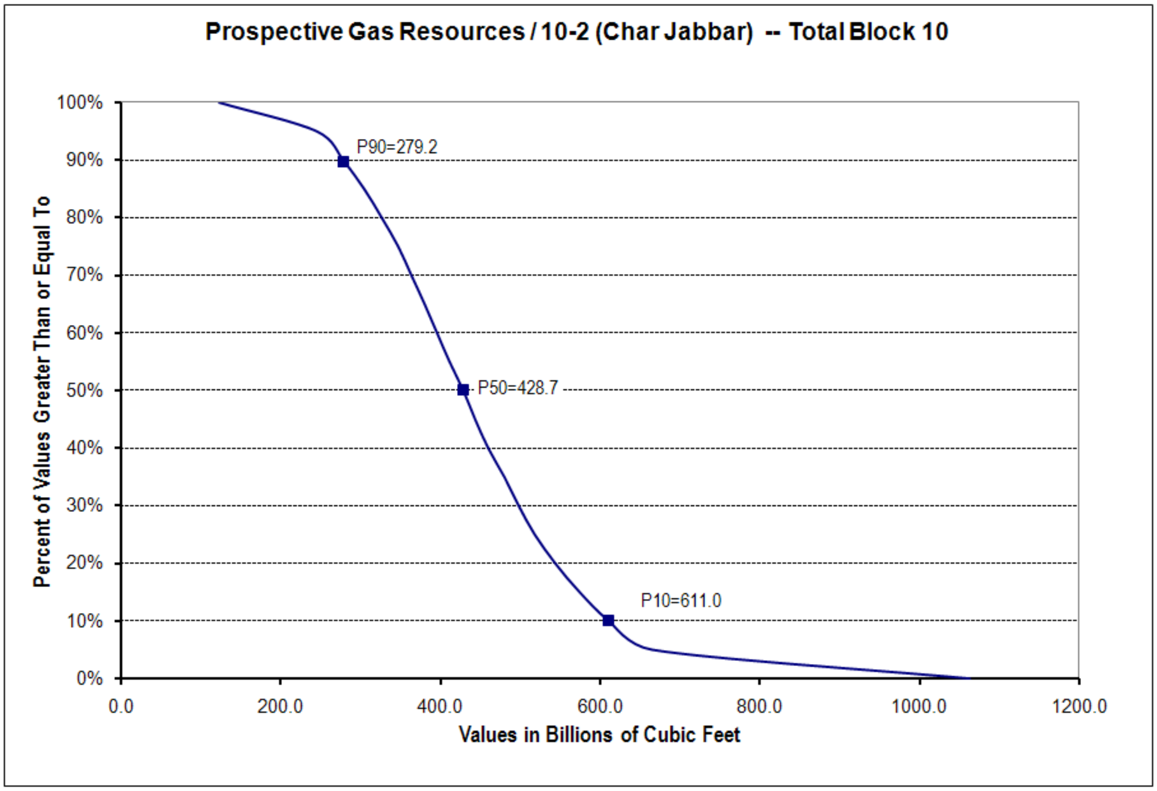


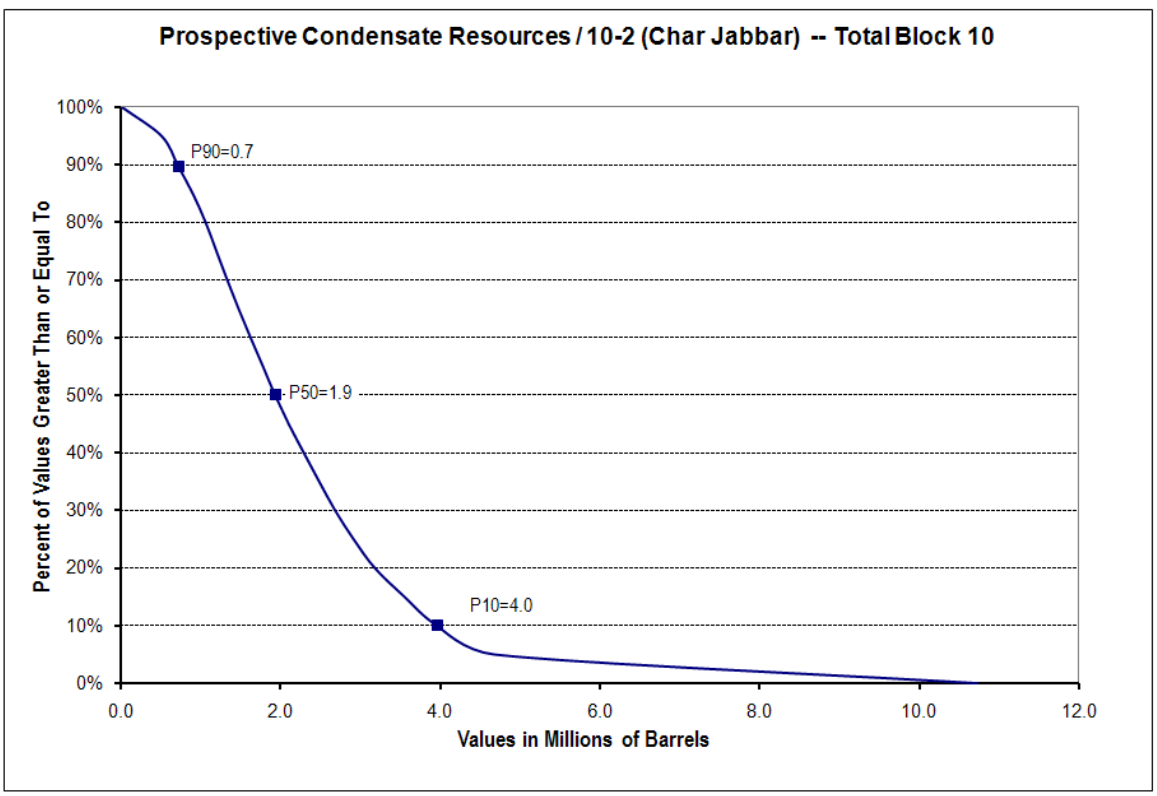
Prospective Condensate/Oil Resources / Total Resources Block 8, Identified Prospects and Leads
P90=84.3
P50=117.0
P10=159.9
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0.0
50.0
100.0
150.0
200.0
250.0
300.0
Percent of Values Greater Than or Equal To
Values in Millions of Barrels

Block 10

Prospect / Lead	Mean Prospective Gas Resources, BCF
10-2 (Char Jabbar)	439
Total	439

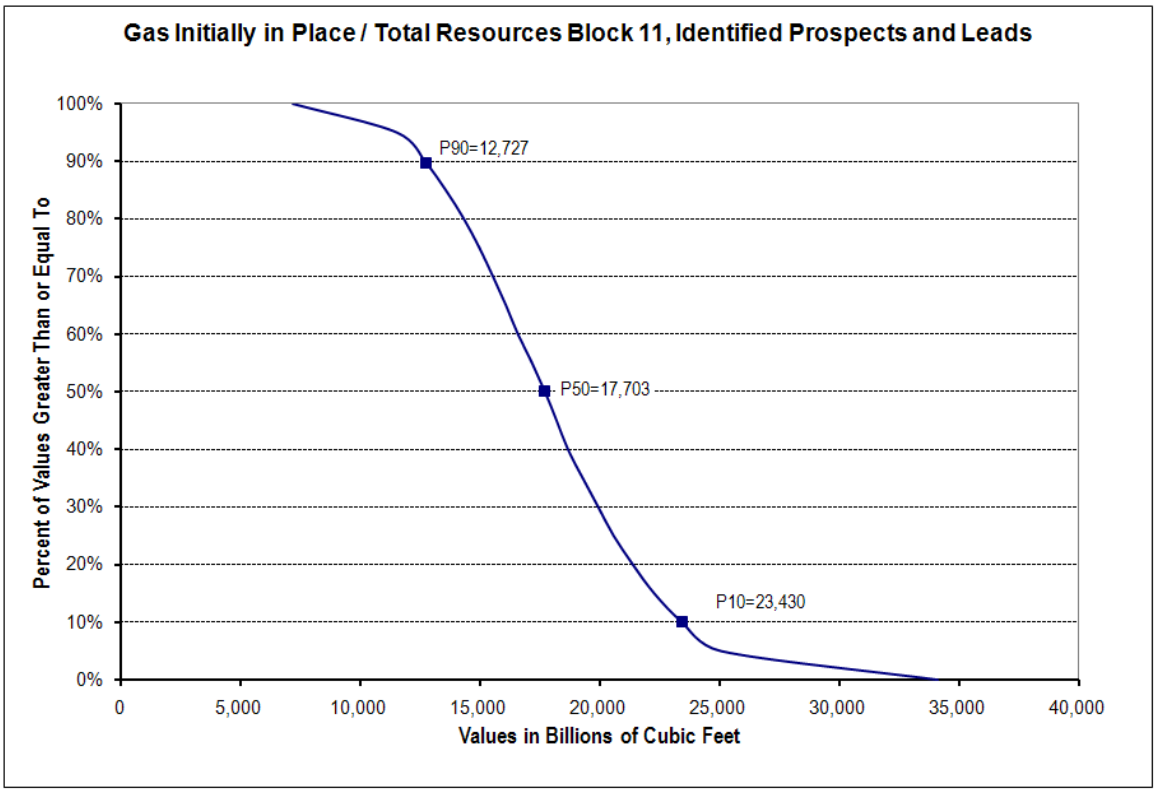


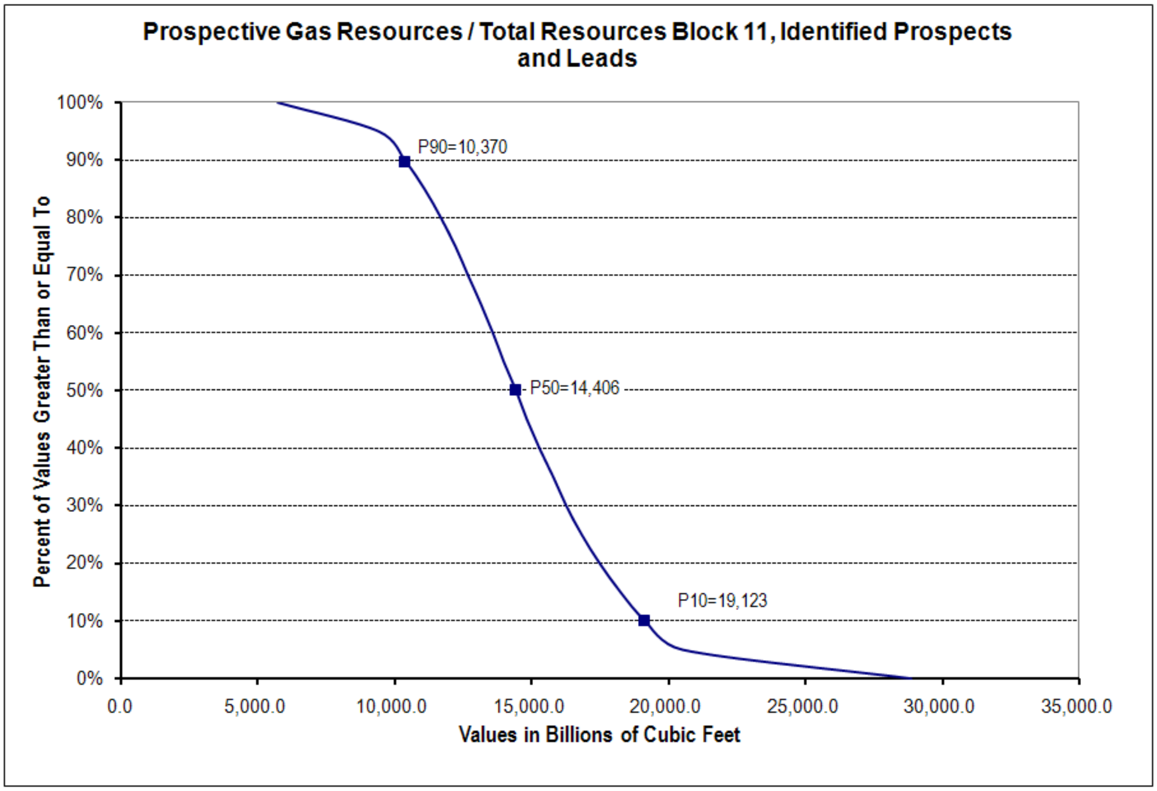

Prospective Gas Resources / 10-2 (Char Jabbar) -- Total Block 10
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=279.2
P50=428.7
P10=611.0
0.0
200.0
400.0
600.0
800.0
1000.0
1200.0
Values in Billions of Cubic Feet


Prospective Condensate Resources / 10-2 (Char Jabbar) -- Total Block 10
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=0.7
P50=1.9
P10=4.0
0.0
2.0
4.0
6.0
8.0
10.0
12.0
Values in Millions of Barrels

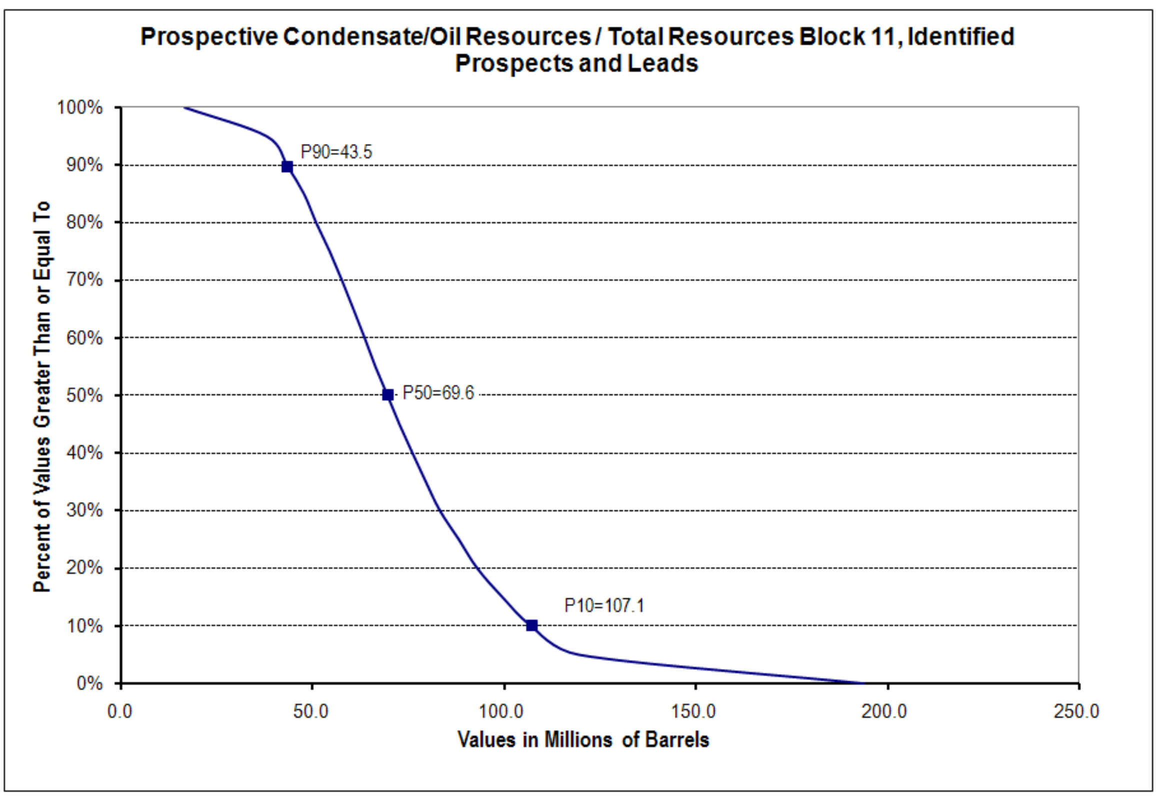
Block 11

Prospect / Lead	Mean Prospective Gas Resources, BCF
Netrakona	5,074
Bajitpur	1,759
Madon	918
Nandail	3,256
Nikli	2,006
Bhairab (11-2,3)	1,585
Haluaghat (11-1, Lead C)	11
Total	14,609





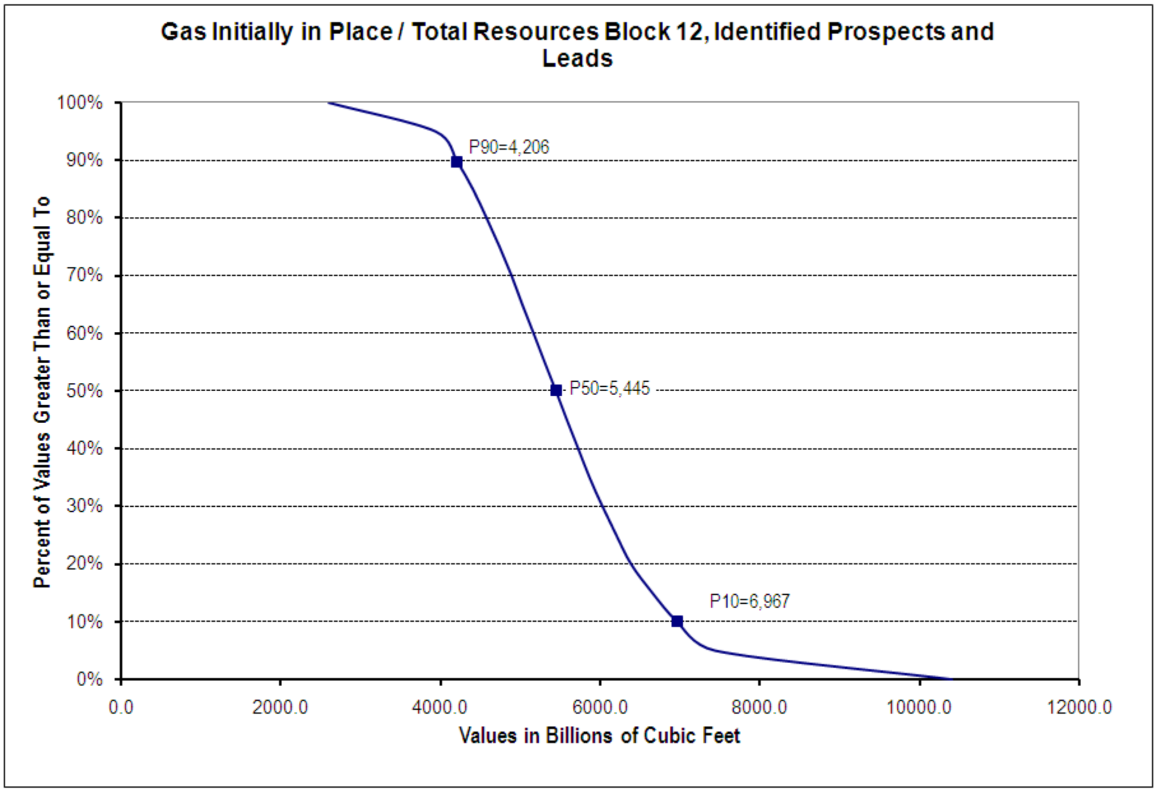
Prospective Gas Resources / Total Resources Block 11, Identified Prospects and Leads
P90=10,370
P50=14,406
P10=19,123
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0.0
5,000.0
10,000.0
15,000.0
20,000.0
25,000.0
30,000.0
35,000.0
Percent of Values Greater Than or Equal To
Values in Billions of Cubic Feet

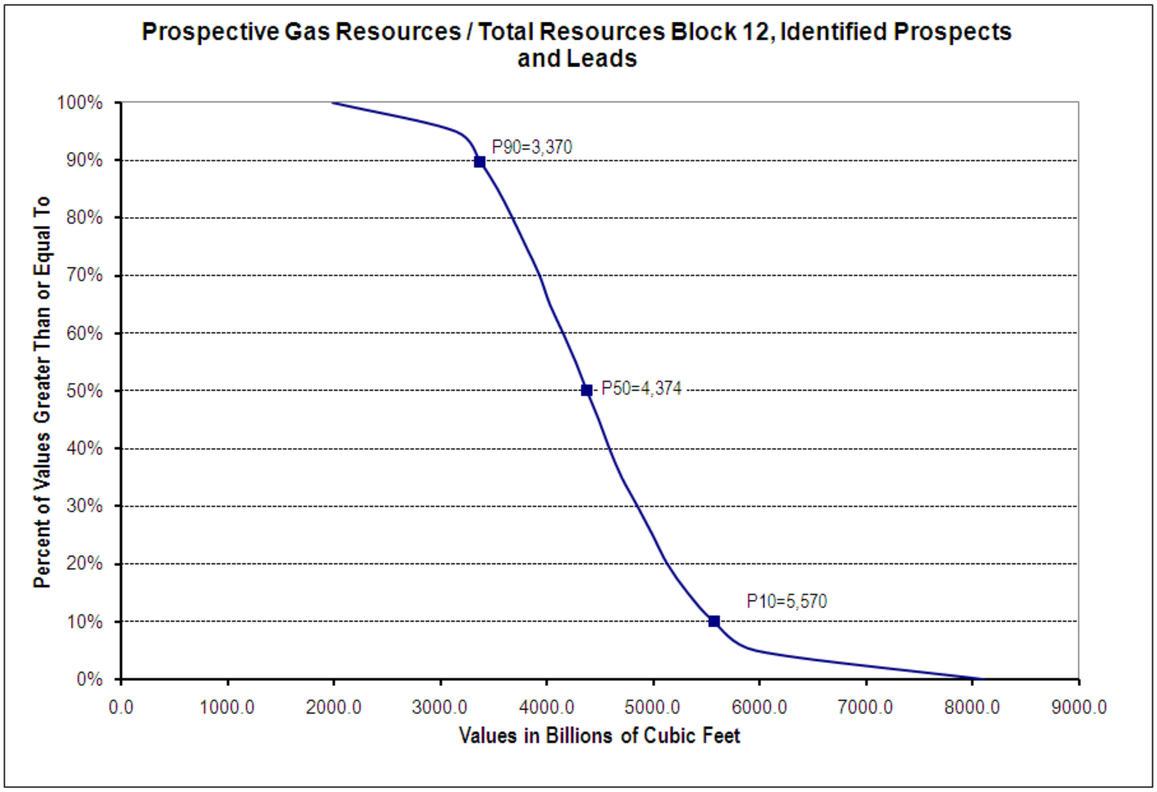


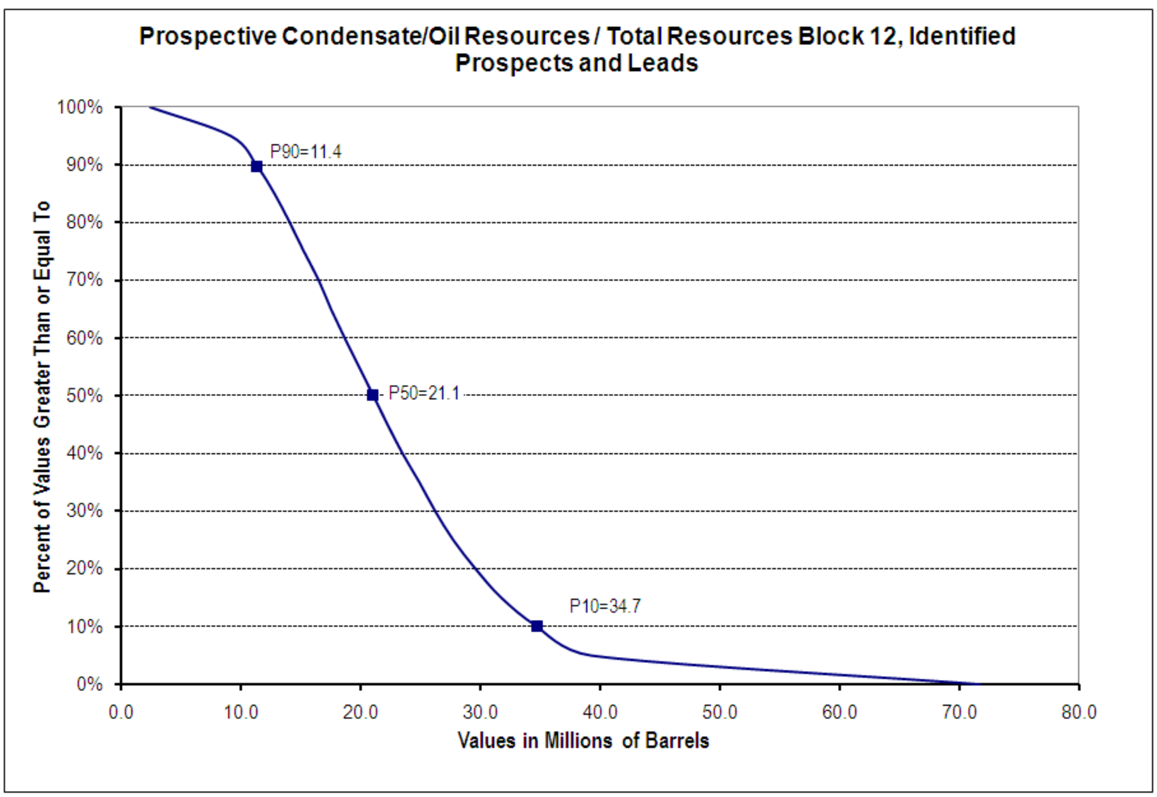
Prospective Condensate/Oil Resources / Total Resources Block 11, Identified Prospects and Leads
P90=43.5
P50=69.6
P10=107.1
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0.0
50.0
100.0
150.0
200.0
250.0
Percent of Values Greater Than or Equal To
Values in Millions of Barrels

Block 12

Prospect / Lead	Mean Prospective Gas Resources, BCF
12-3 (BalarampurByronpur)	2,184
12-10	2,251
Total	4,435

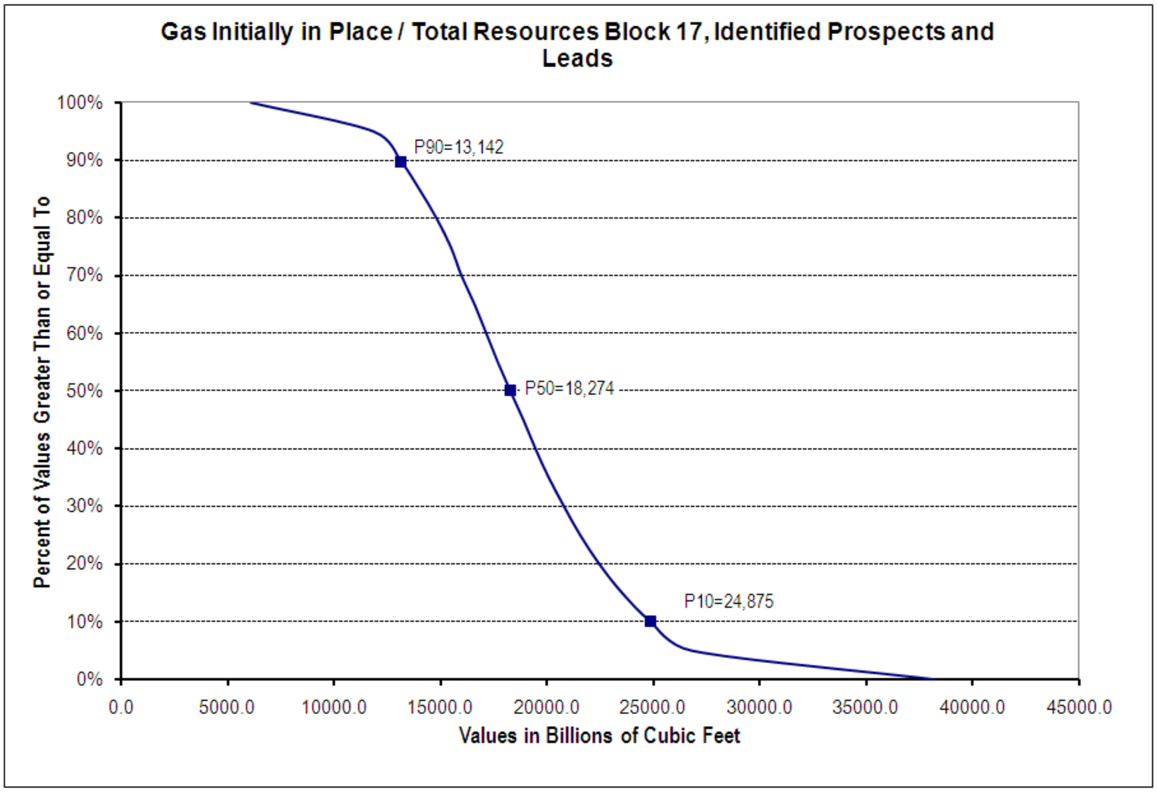


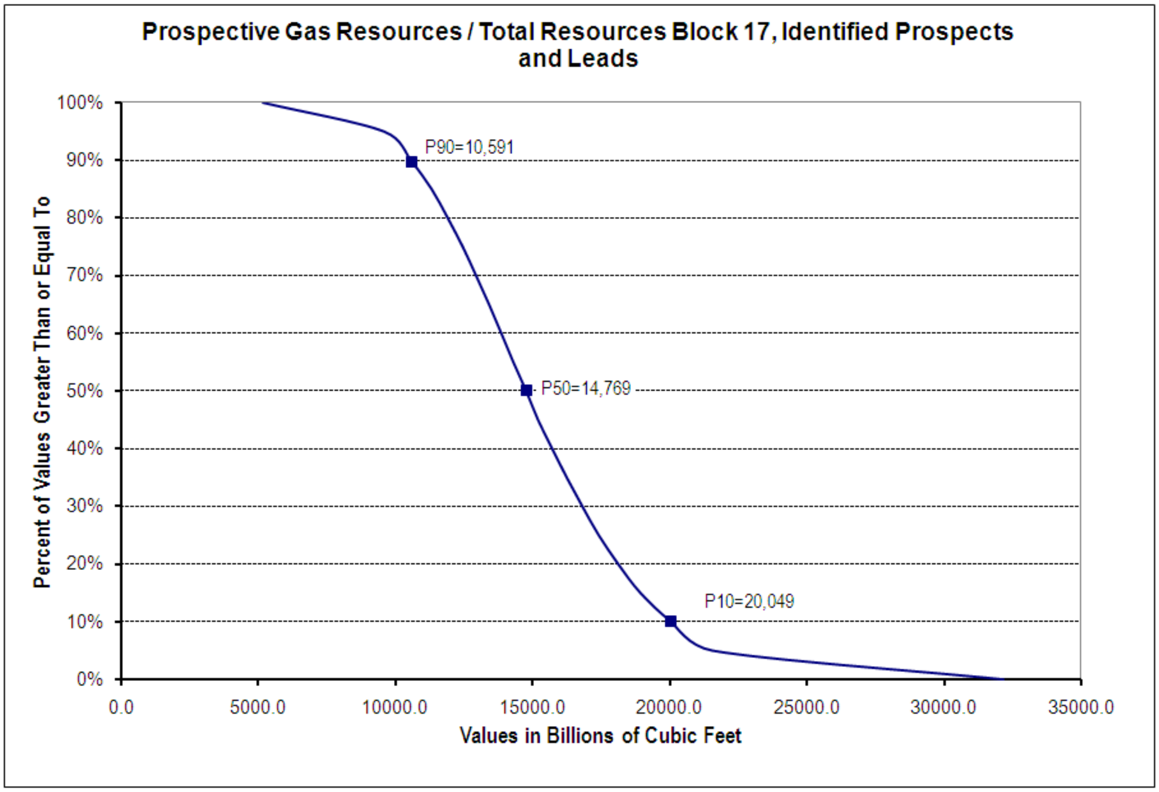

Prospective Gas Resources / Total Resources Block 12, Identified Prospects and Leads
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=3,370
P50=4,374
P10=5,570
0.0
1000.0
2000.0
3000.0
4000.0
5000.0
6000.0
7000.0
8000.0
9000.0
Values in Billions of Cubic Feet


Prospective Condensate/Oil Resources / Total Resources Block 12, Identified Prospects and Leads
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=11.4
P50=21.1
P10=34.7
0.0
10.0
20.0
30.0
40.0
50.0
60.0
70.0
80.0
Values in Millions of Barrels

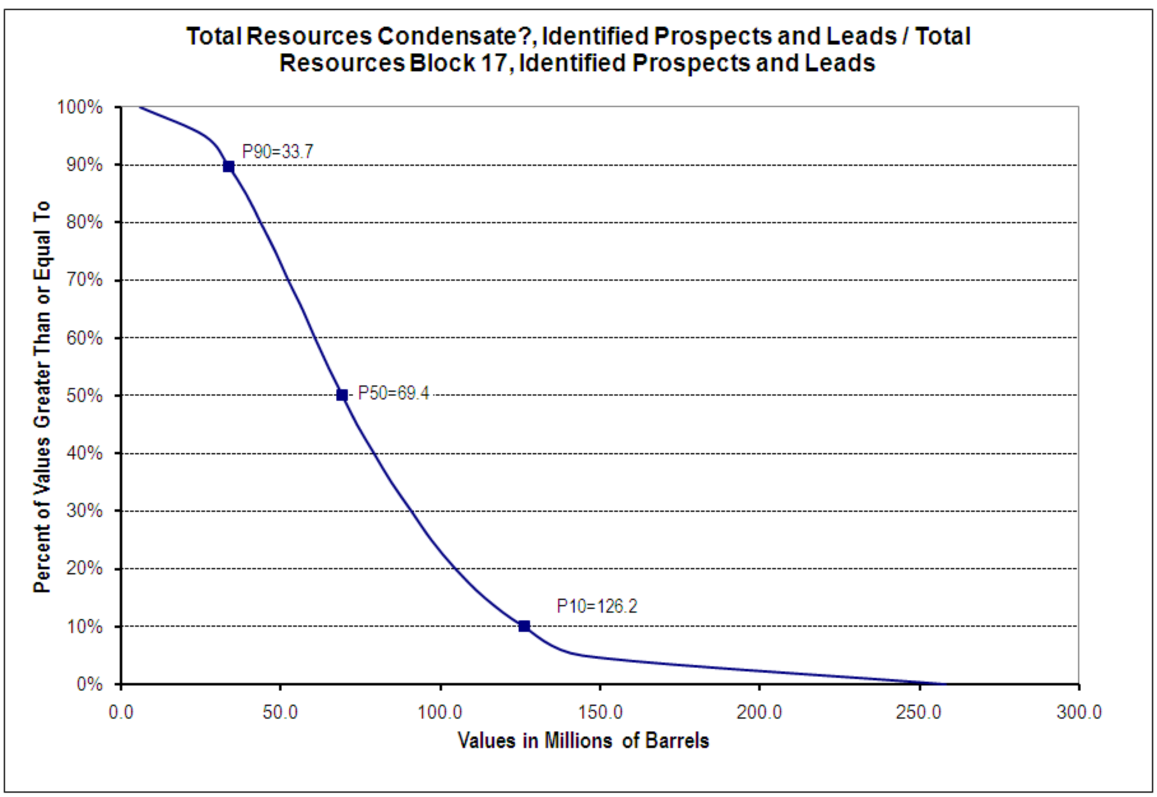
Block 17

Prospect / Lead	Mean Prospective Gas Resources, BCF
Kuakata	11,305
Adinath	3,782
Total	15,087





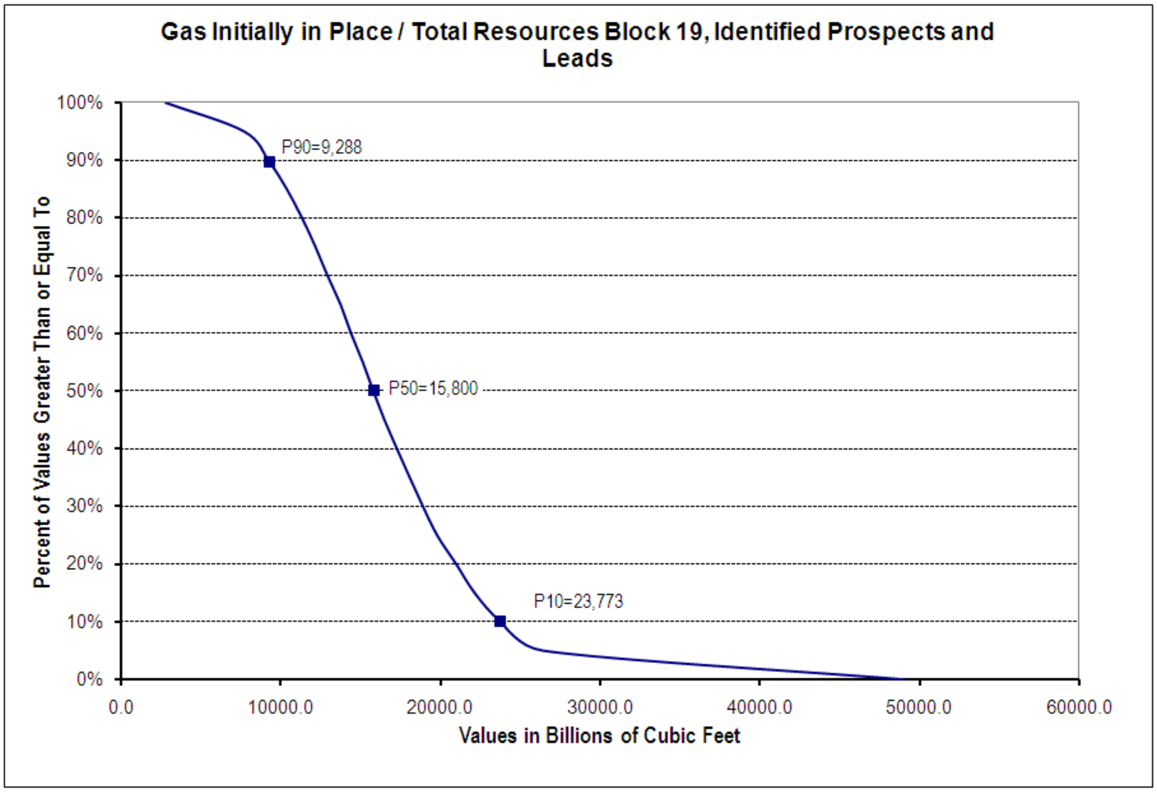
Prospective Gas Resources / Total Resources Block 17, Identified Prospects and Leads
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
P90=10,591
P50=14,769
P10=20,049
0.0
5000.0
10000.0
15000.0
20000.0
25000.0
30000.0
35000.0
Values in Billions of Cubic Feet

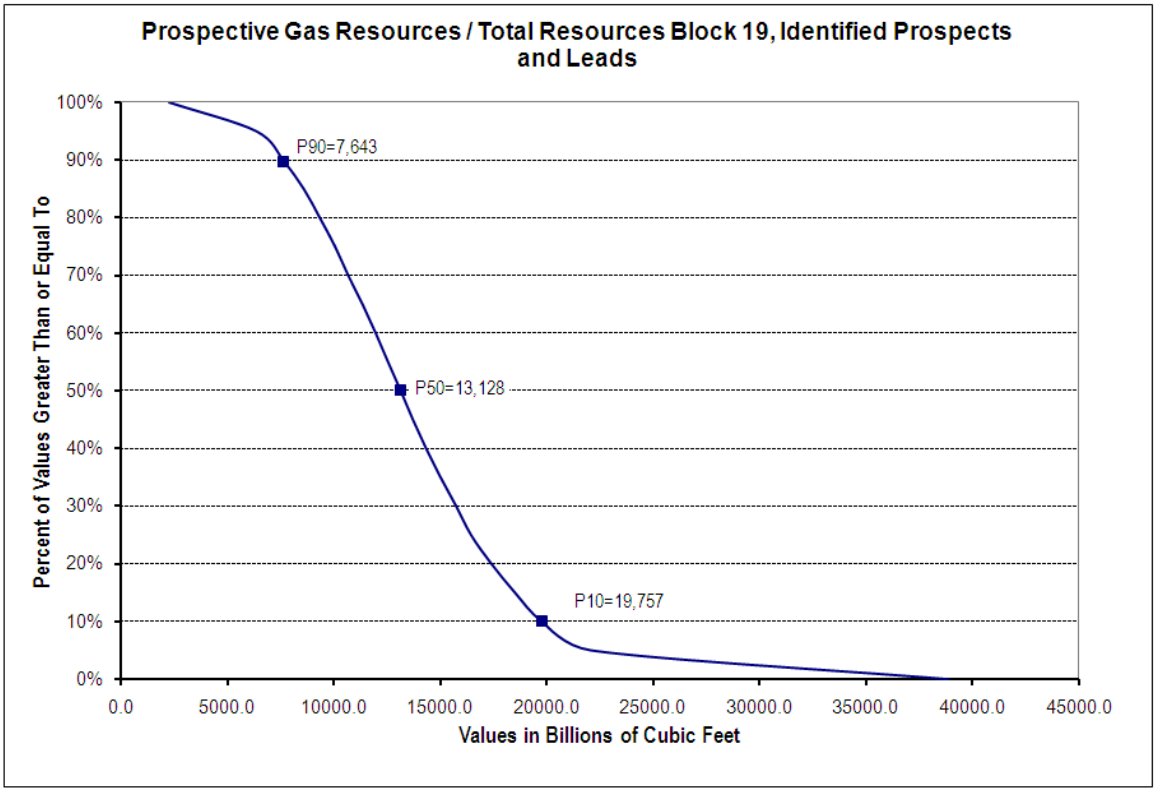


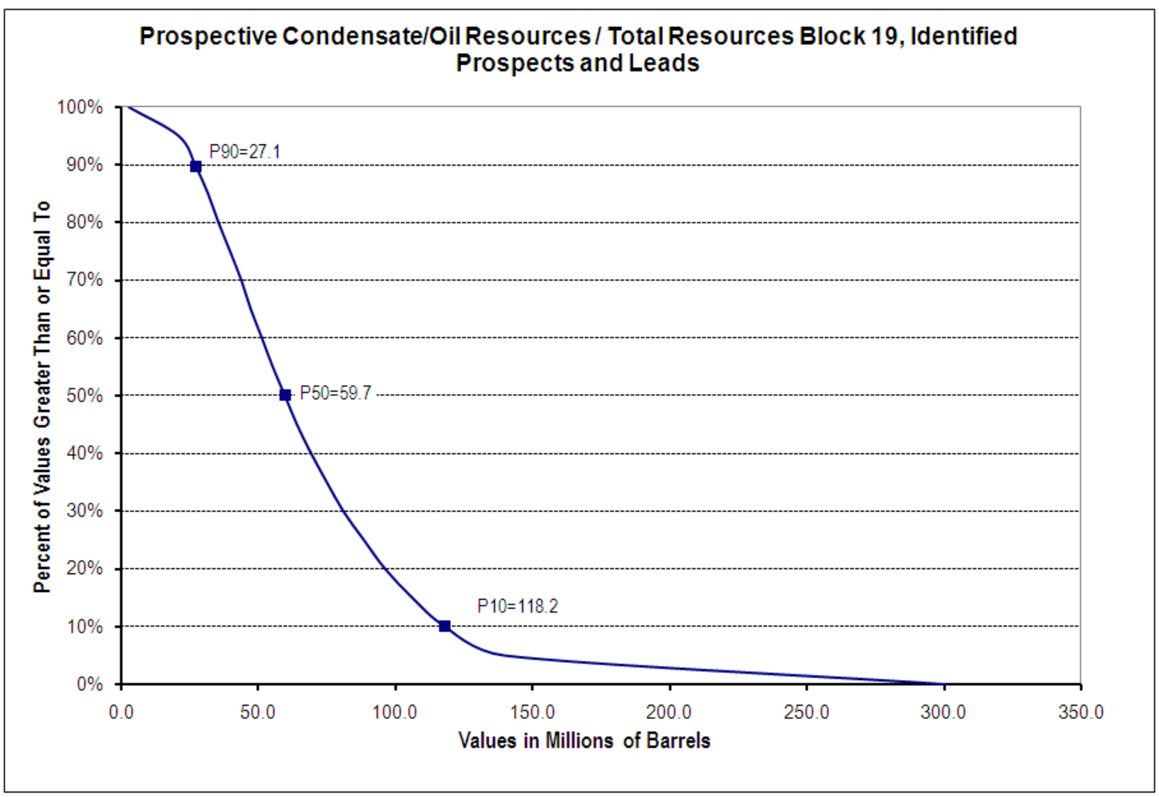
Total Resources Condensate?, Identified Prospects and Leads / Total Resources Block 17, Identified Prospects and Leads
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
P90=33.7
P50=69.4
P10=126.2
0.0
50.0
100.0
150.0
200.0
250.0
300.0
Values in Millions of Barrels

Block 19

Prospect / Lead	Mean Prospective Gas Resources, BCF
Lead 19-A	9,639
Lead 19-B	3,867
Total	13,506

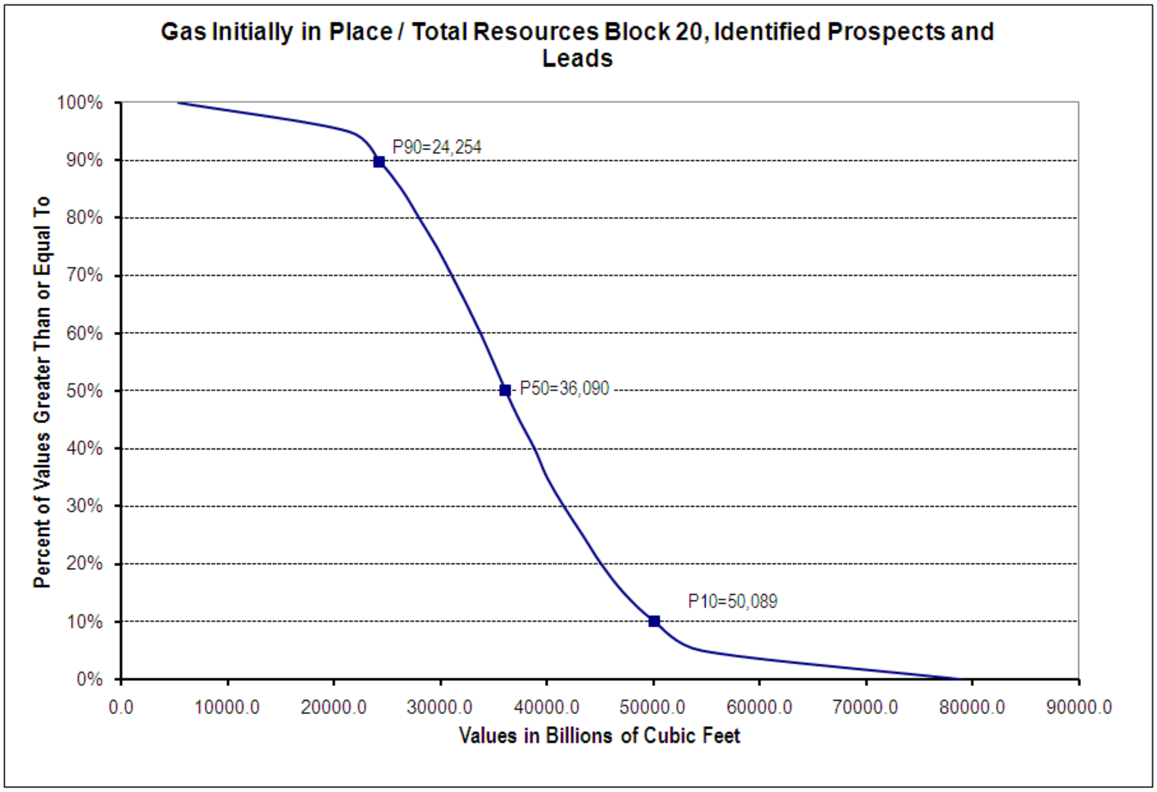


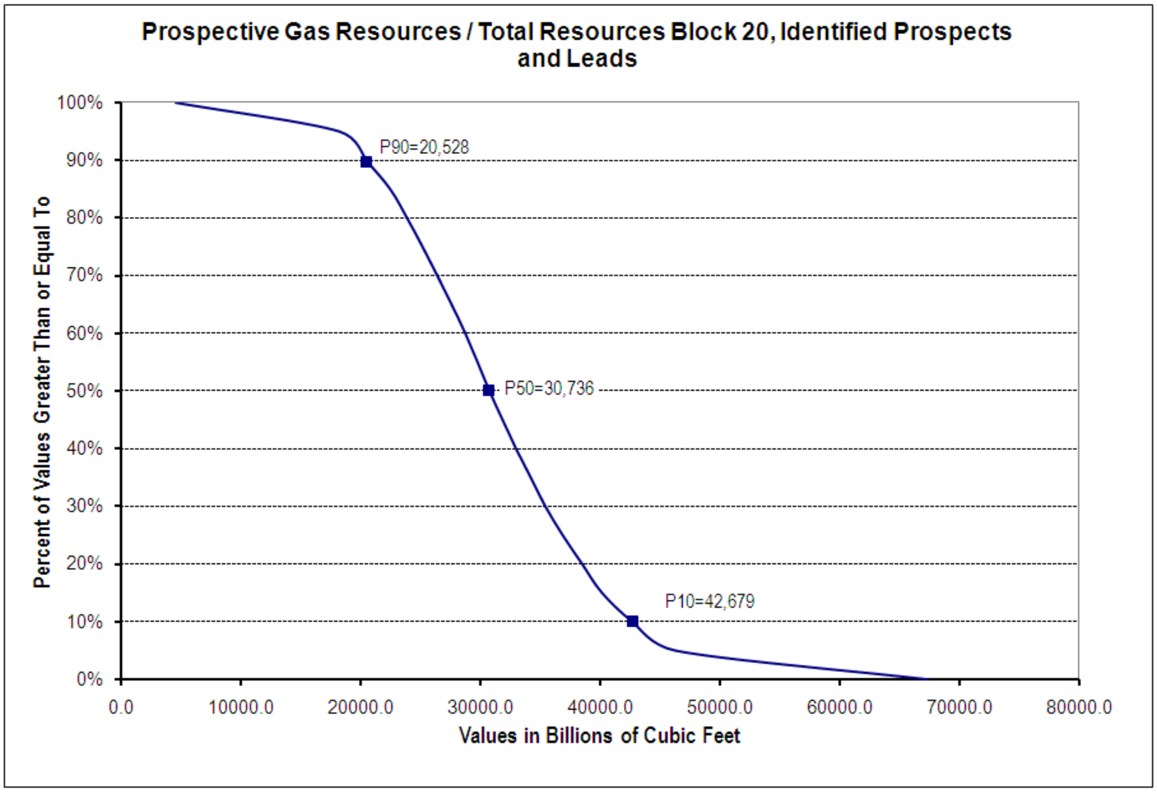

Prospective Gas Resources / Total Resources Block 19, Identified Prospects and Leads
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
P90=7,643
P50=13,128
P10=19,757
0.0
5000.0
10000.0
15000.0
20000.0
25000.0
30000.0
35000.0
40000.0
45000.0
Values in Billions of Cubic Feet


Prospective Condensate/Oil Resources / Total Resources Block 19, Identified Prospects and Leads
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
P90=27.1
P50=59.7
P10=118.2
0.0
50.0
100.0
150.0
200.0
250.0
300.0
350.0
Values in Millions of Barrels

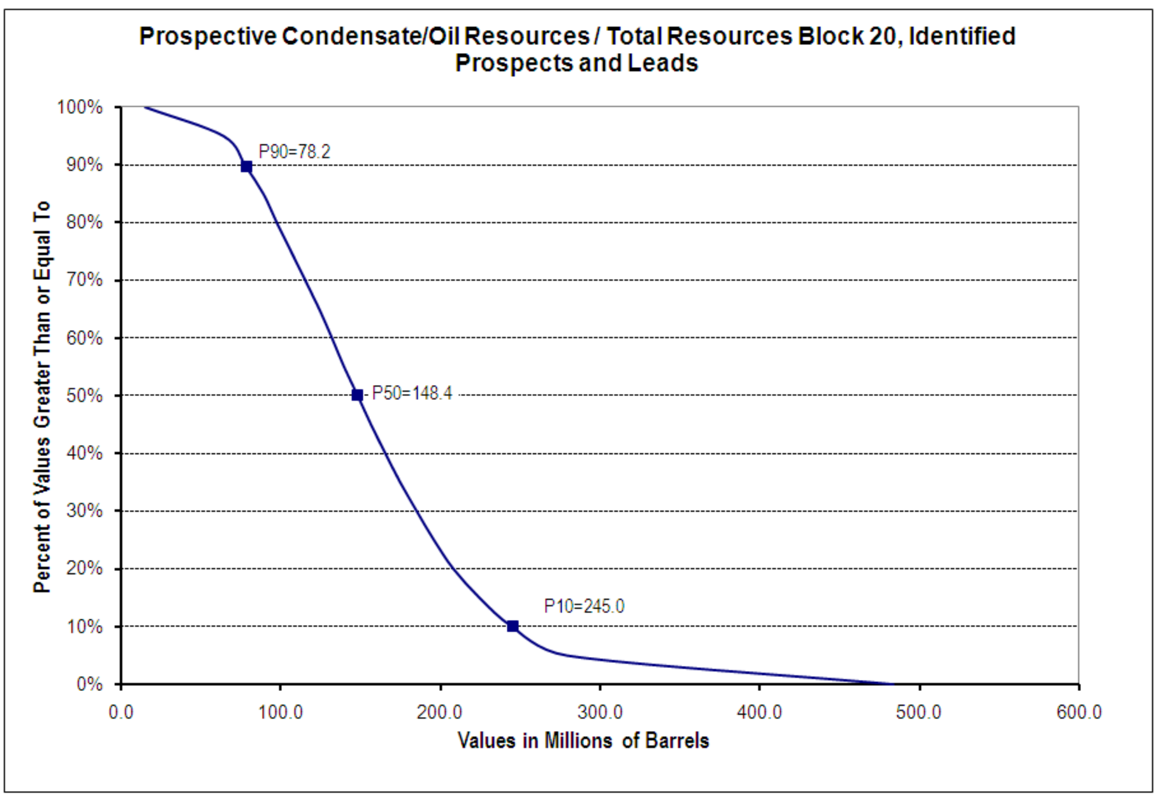
Block 20

Prospect / Lead	Mean Prospective Gas Resources, BCF
Lead 20-A	11,068
Lead 20-B	7,292
Lead 20-C	12,975
Total	31,335





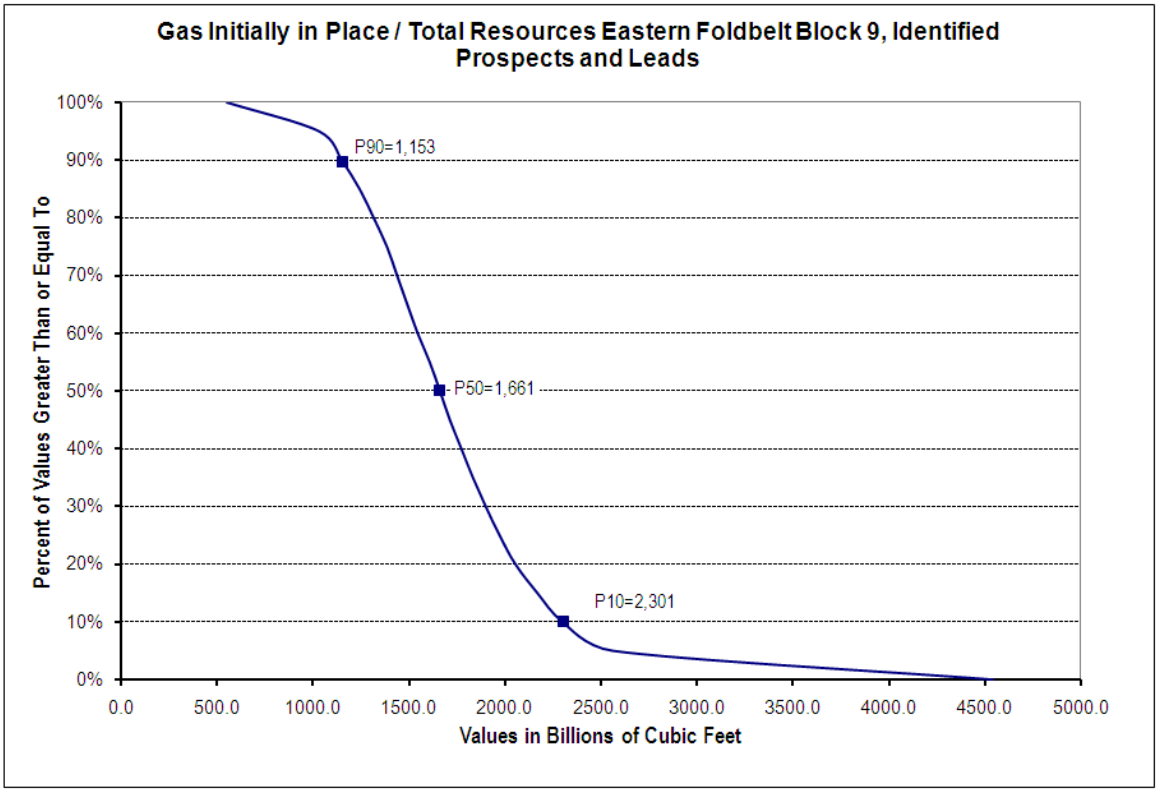
Prospective Gas Resources / Total Resources Block 20, Identified Prospects and Leads
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
P90=20,528
P50=30,736
P10=42,679
0.0
10000.0
20000.0
30000.0
40000.0
50000.0
60000.0
70000.0
80000.0
Values in Billions of Cubic Feet

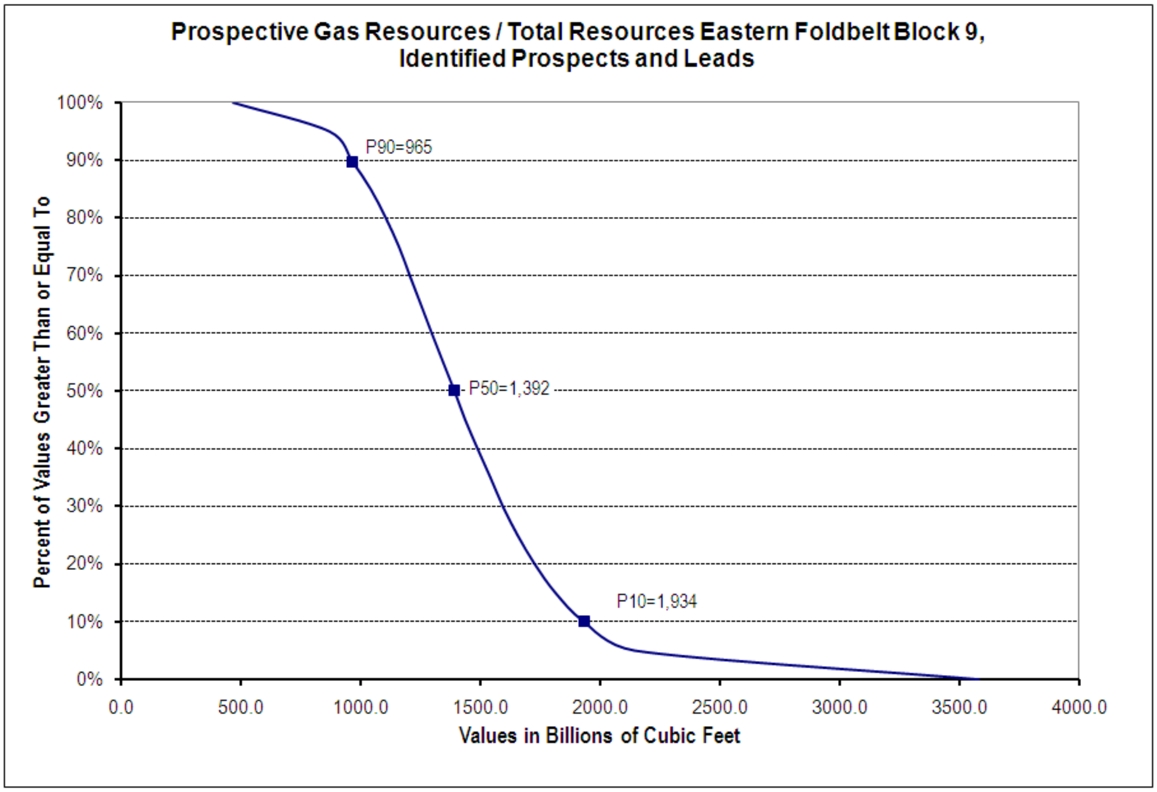


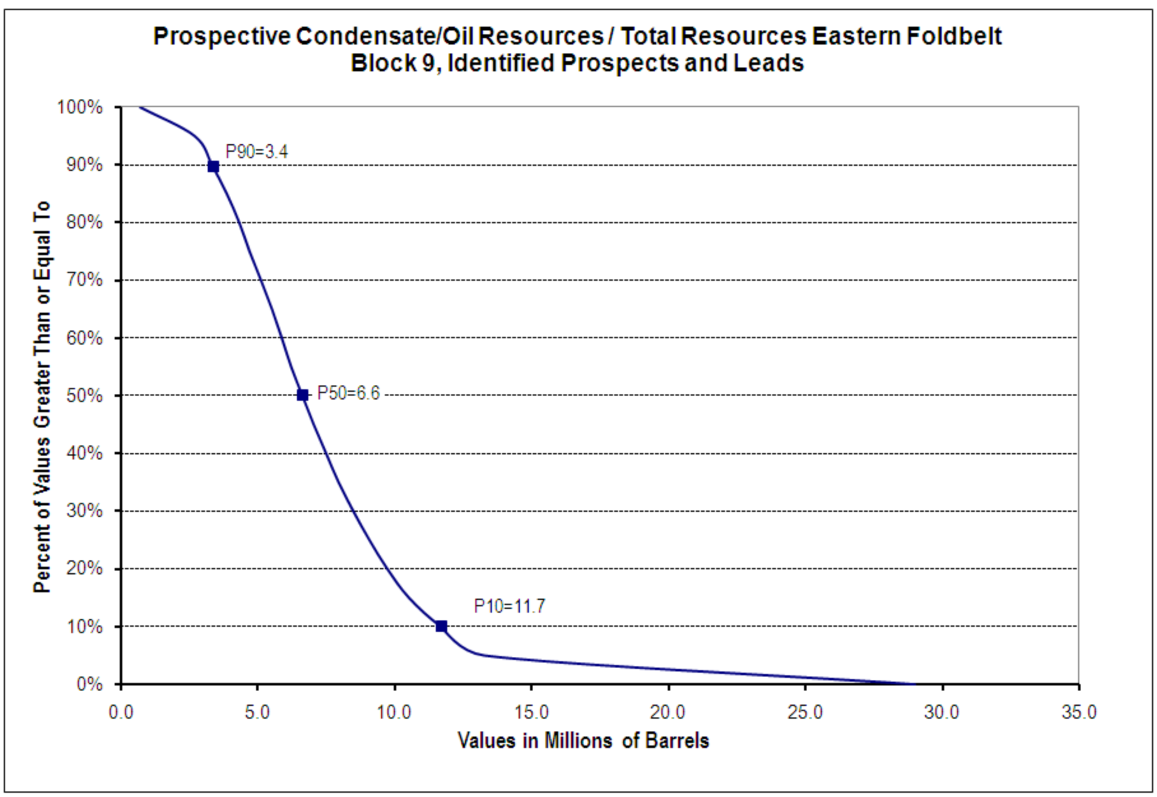
Prospective Condensate/Oil Resources / Total Resources Block 20, Identified Prospects and Leads
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
P90=78.2
P50=148.4
P10=245.0
0.0
100.0
200.0
300.0
400.0
500.0
600.0
Values in Millions of Barrels

Eastern Foldbelt Block 9

Prospect / Lead	Mean Prospective Gas Resources, BCF
Srikail North	309
Chandpur	254
9-2	868
Total	1,432

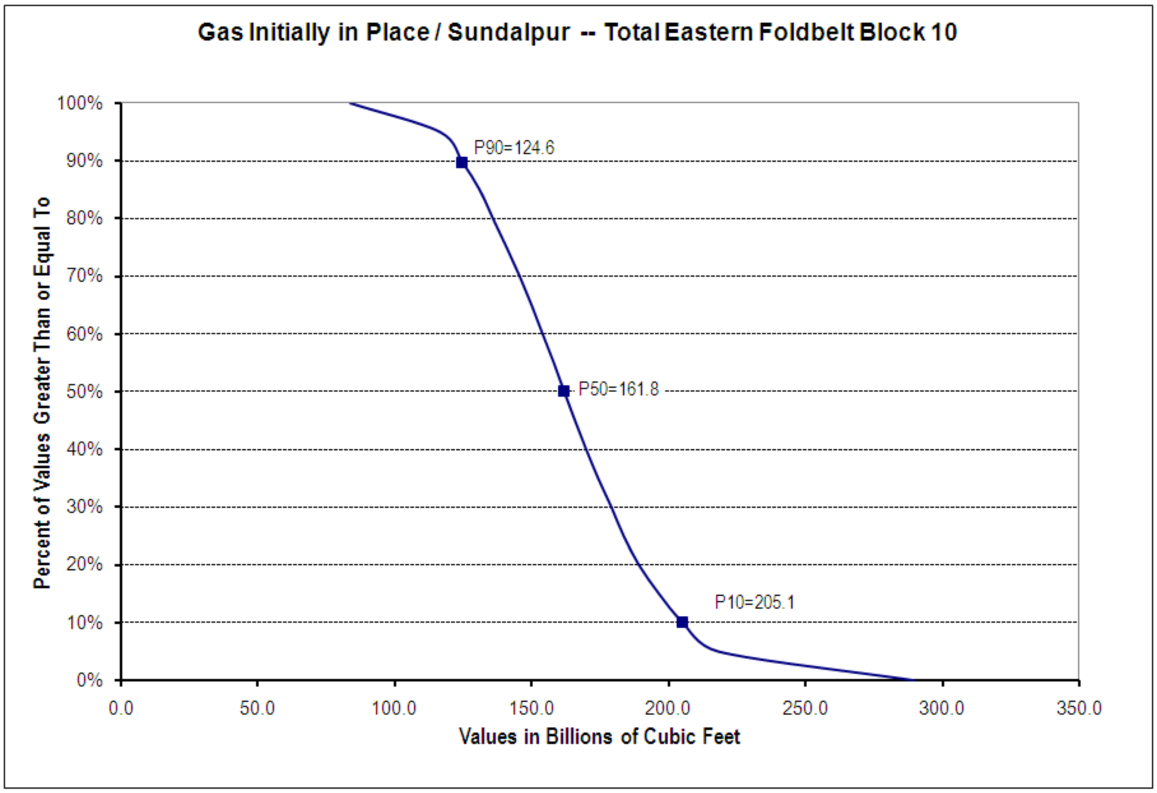


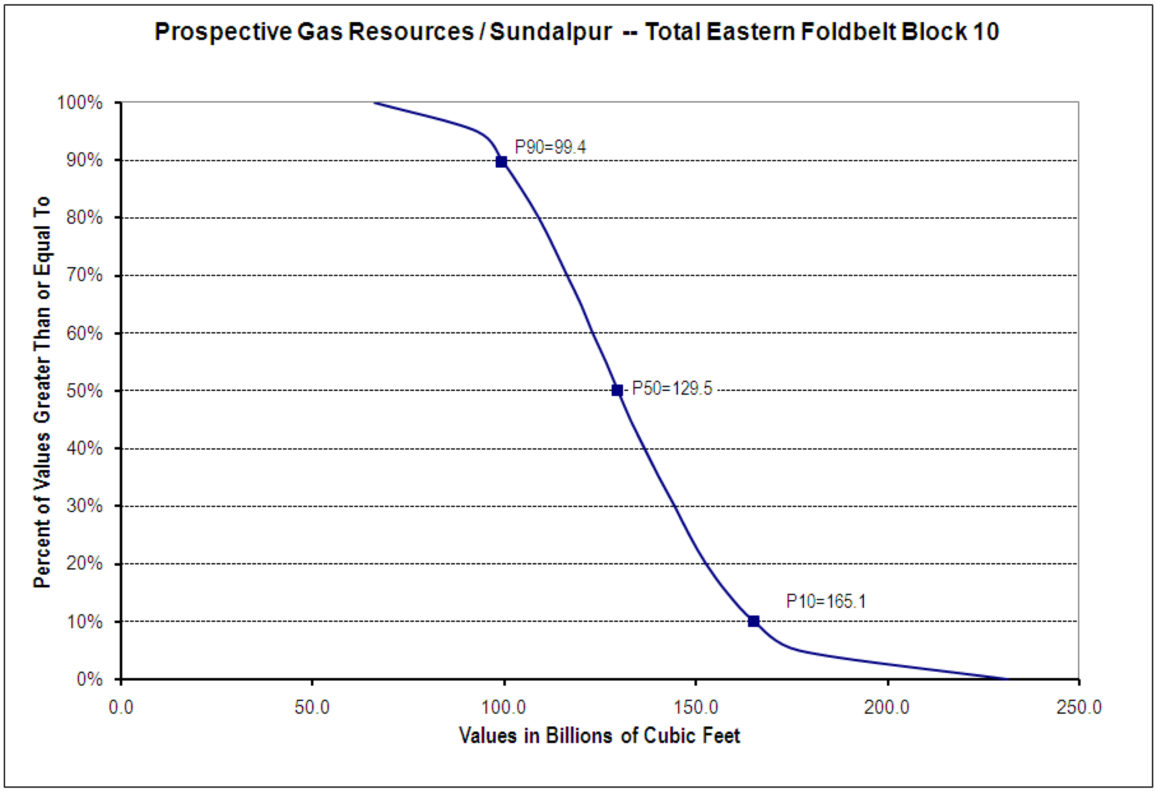

Prospective Gas Resources / Total Resources Eastern Foldbelt Block 9, Identified Prospects and Leads
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=965
P50=1,392
P10=1,934
0.0
500.0
1000.0
1500.0
2000.0
2500.0
3000.0
3500.0
4000.0
Values in Billions of Cubic Feet

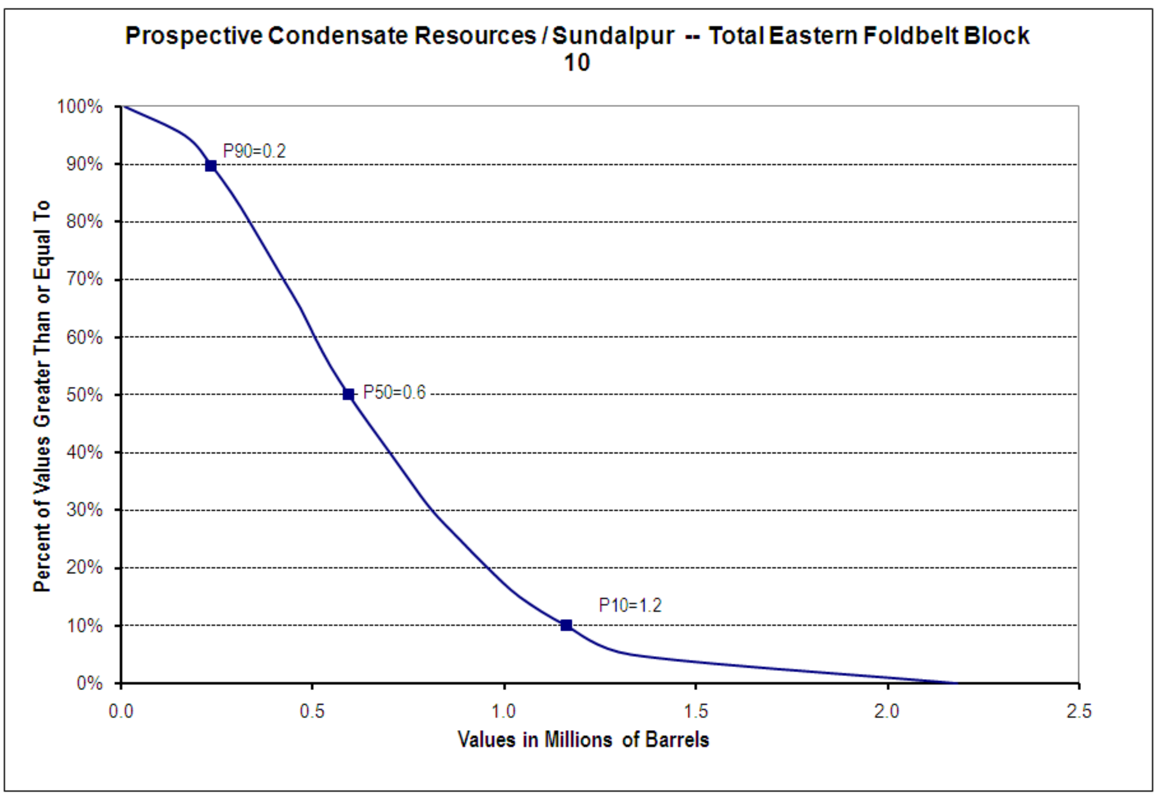

Prospective Condensate/Oil Resources / Total Resources Eastern Foldbelt Block 9, Identified Prospects and Leads
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=3.4
P50=6.6
P10=11.7
0.0
5.0
10.0
15.0
20.0
25.0
30.0
35.0
Values in Millions of Barrels

Eastern Foldbelt Block 10

Prospect / Lead	Mean Prospective Gas Resources, BCF
Sundalpur	131
Total	131

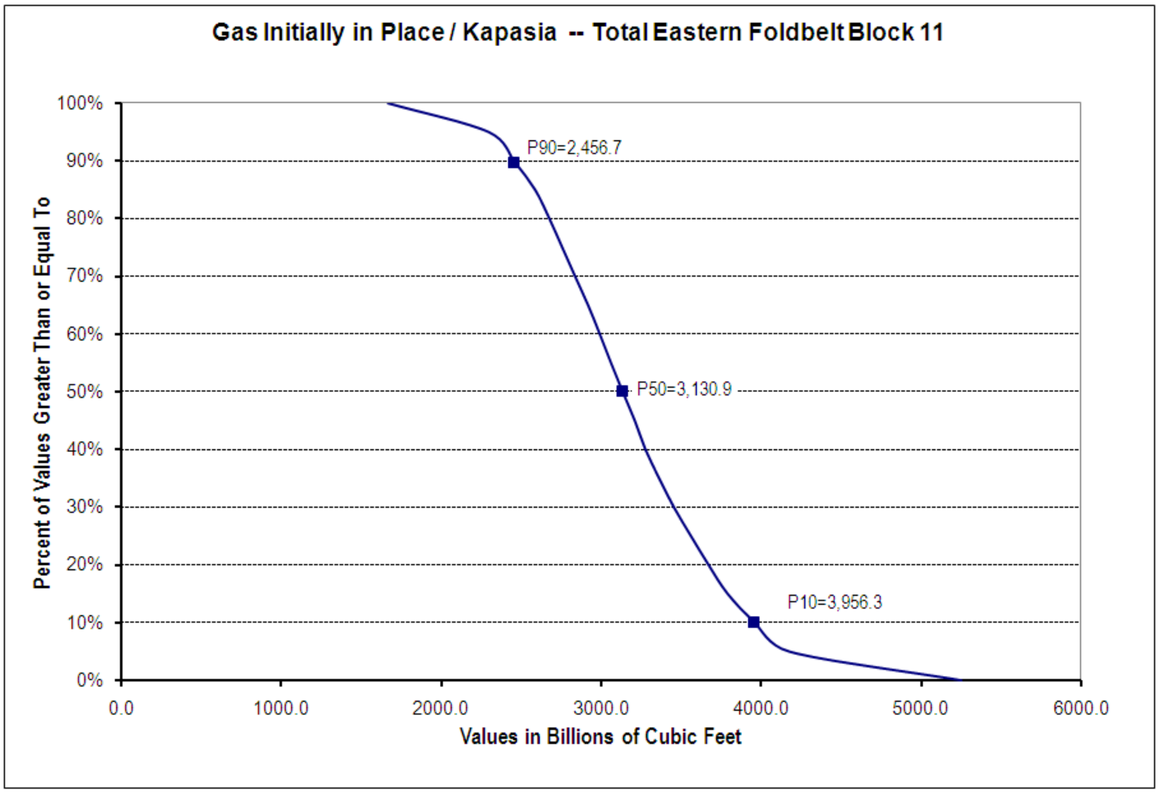


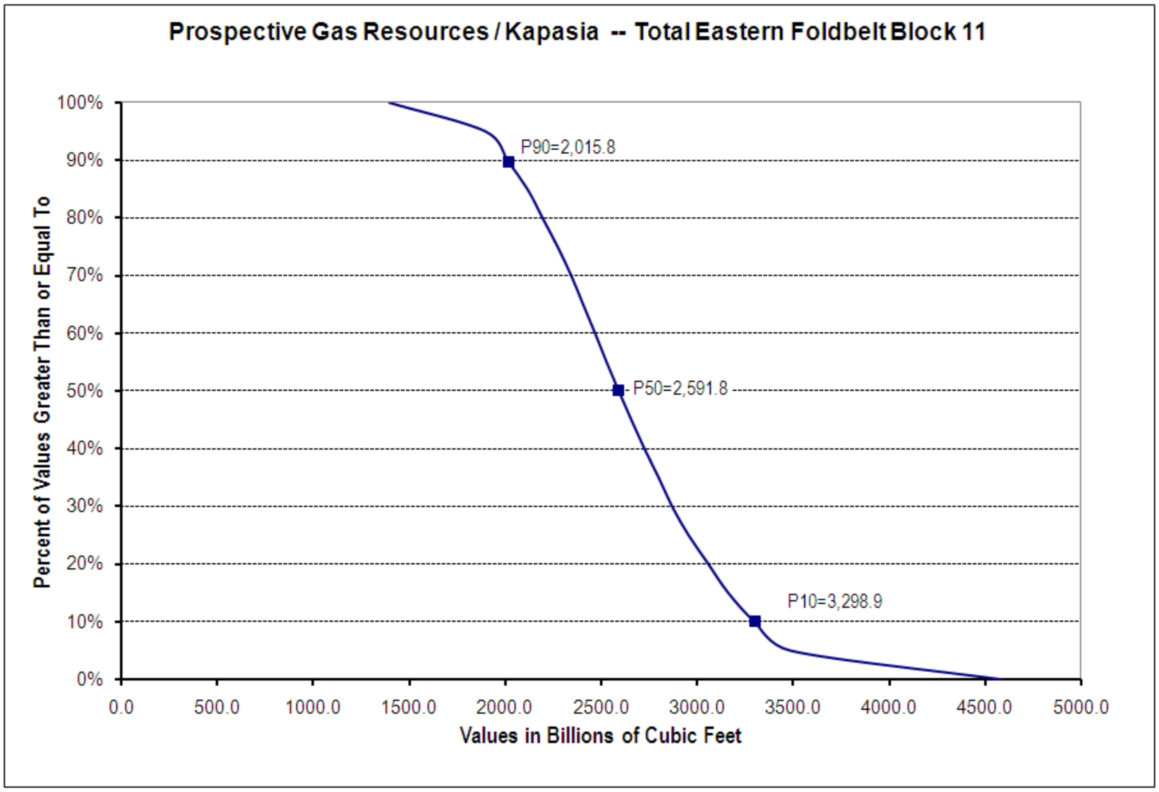

Prospective Gas Resources / Sundalpur -- Total Eastern Foldbelt Block 10
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=99.4
P50=129.5
P10=165.1
0.0
50.0
100.0
150.0
200.0
250.0
Values in Billions of Cubic Feet

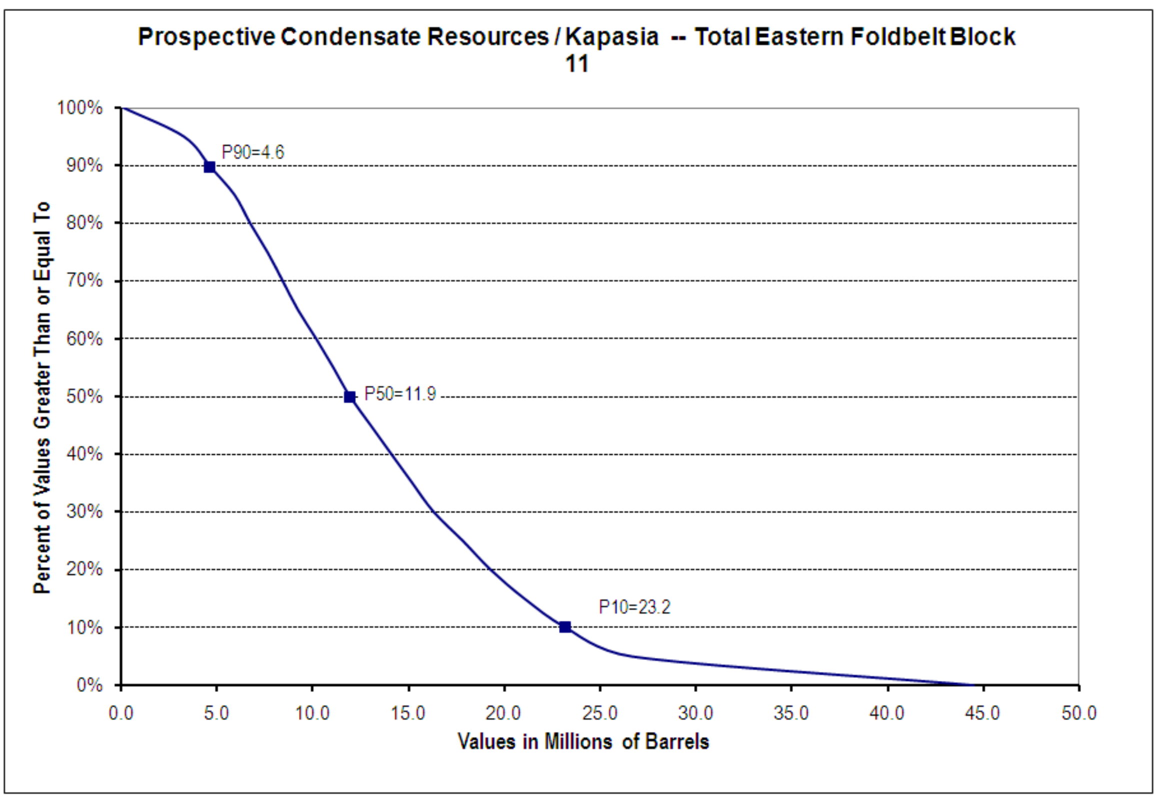

Prospective Condensate Resources / Sundalpur -- Total Eastern Foldbelt Block 10
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=0.2
P50=0.6
P10=1.2
0.0
0.5
1.0
1.5
2.0
2.5
Values in Millions of Barrels

Eastern Foldbelt Block 11

Prospect / Lead	Mean Prospective Gas Resources, BCF
Kapasia	2,632
Total	2,632

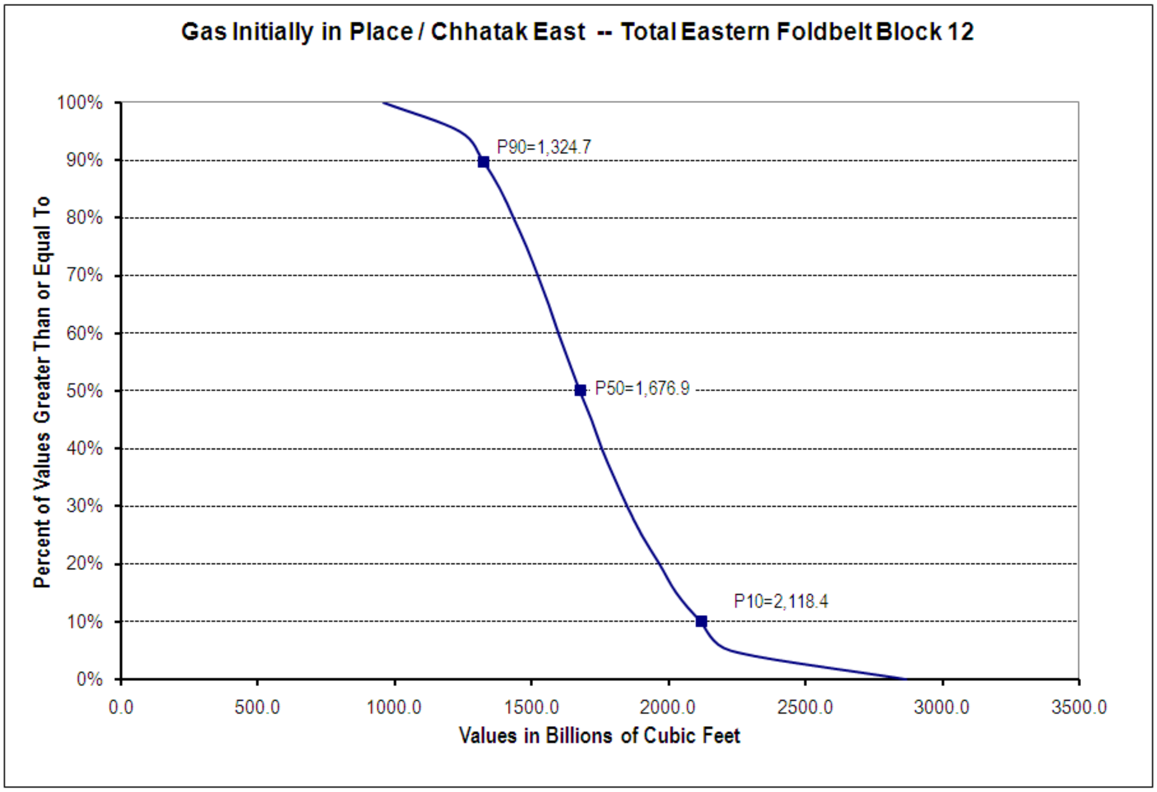


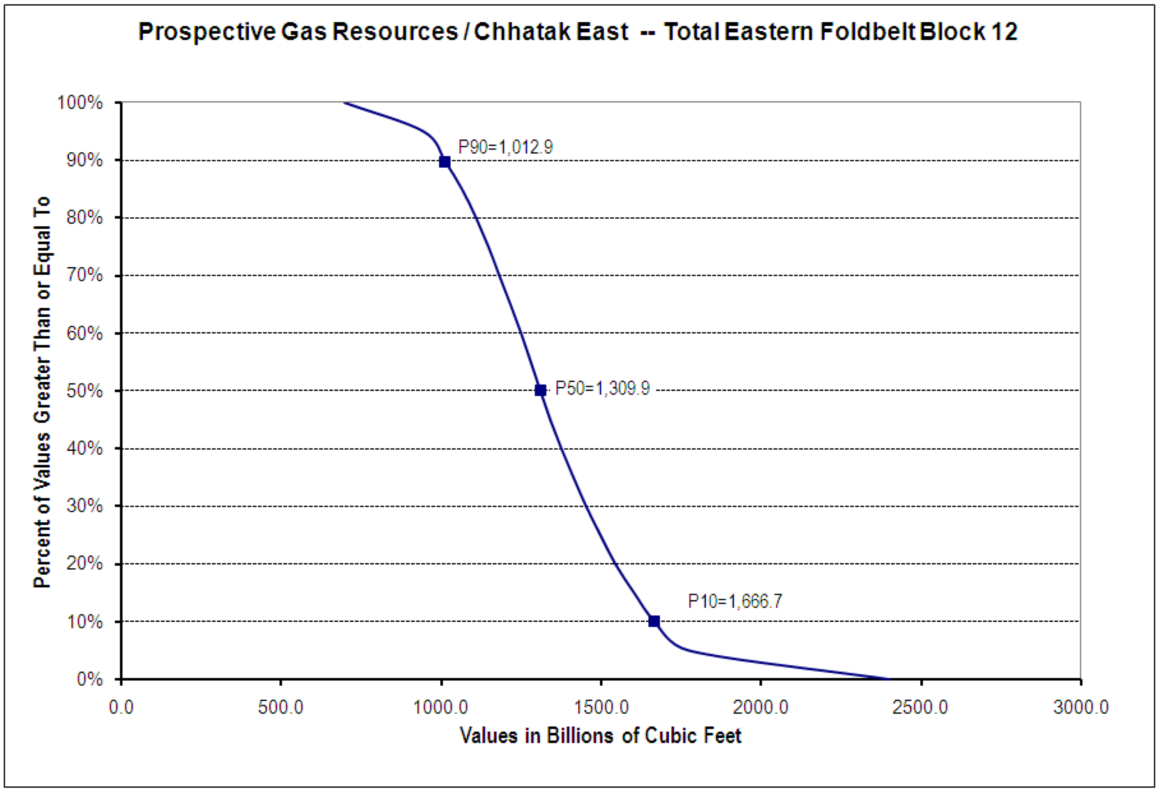

Prospective Gas Resources / Kapasia -- Total Eastern Foldbelt Block 11
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=2,015.8
P50=2,591.8
P10=3,298.9
0.0
500.0
1000.0
1500.0
2000.0
2500.0
3000.0
3500.0
4000.0
4500.0
5000.0
Values in Billions of Cubic Feet


Prospective Condensate Resources / Kapasia -- Total Eastern Foldbelt Block 11
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=4.6
P50=11.9
P10=23.2
0.0
5.0
10.0
15.0
20.0
25.0
30.0
35.0
40.0
45.0
50.0
Values in Millions of Barrels

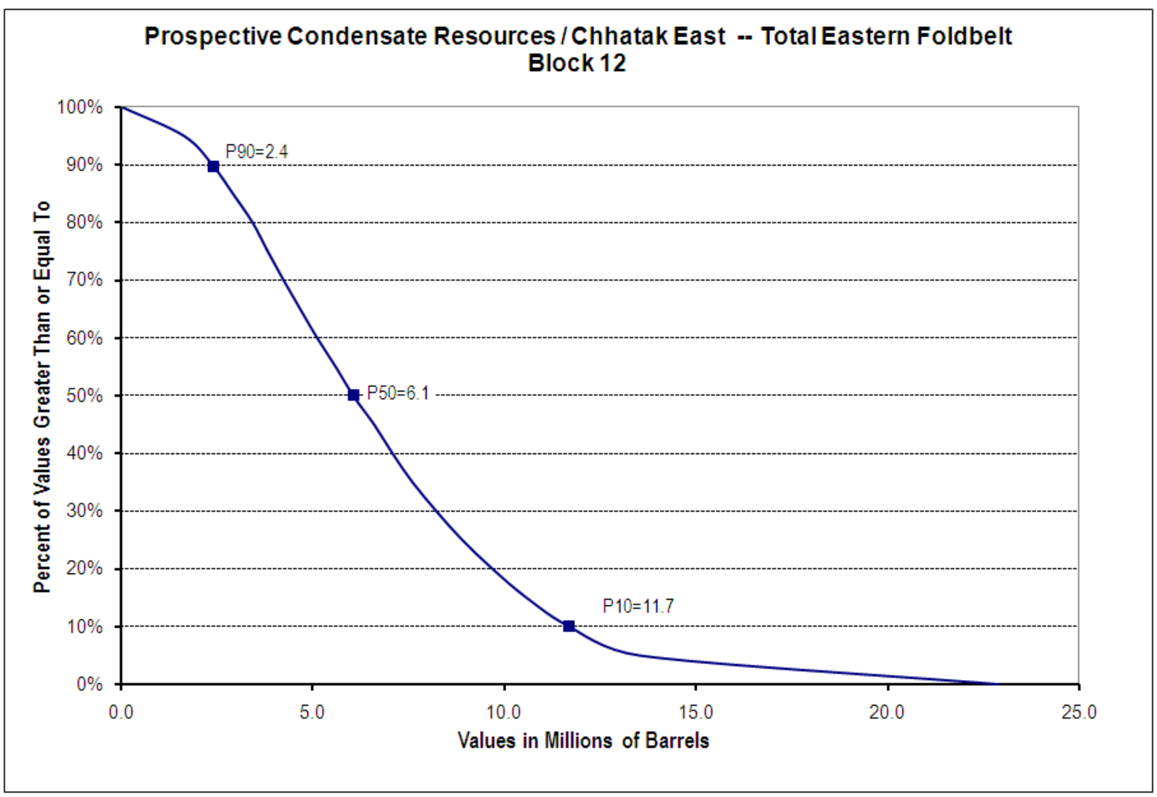
Eastern Foldbelt Block 12

Prospect / Lead	Mean Prospective Gas Resources, BCF
Chhatak East	1,330
Total	1,330





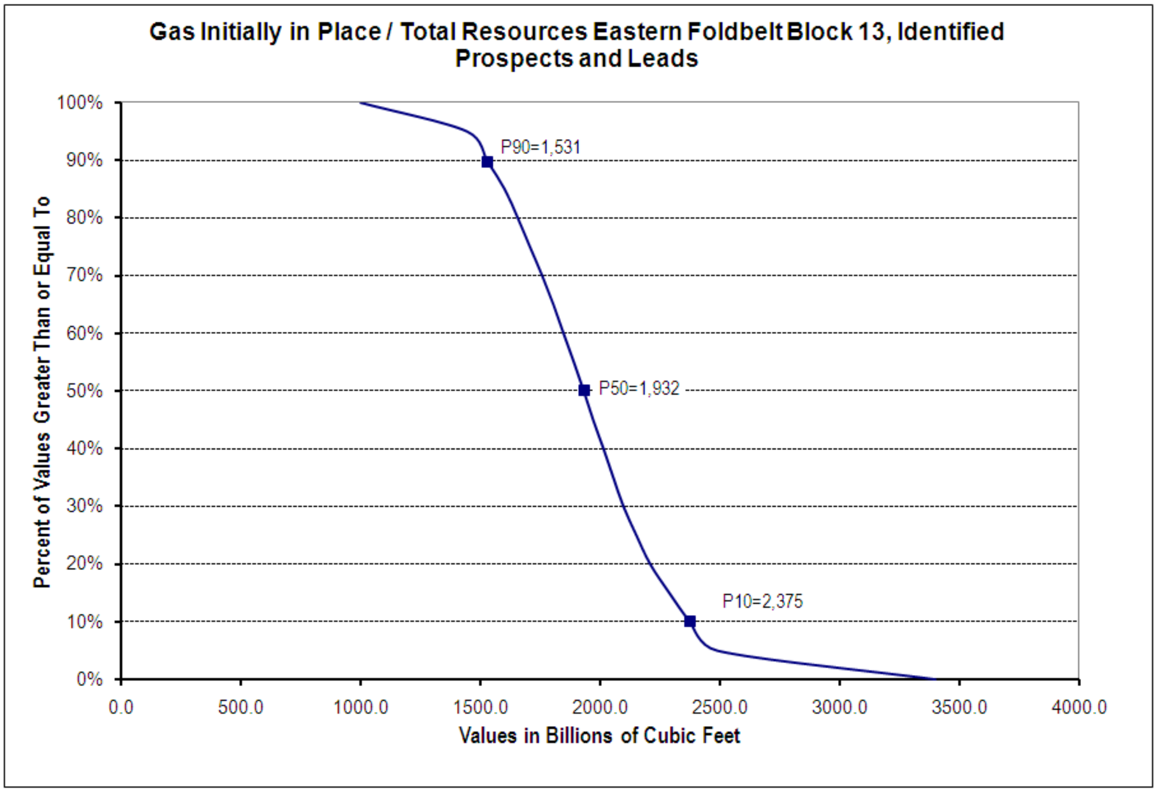
Prospective Gas Resources / Chhatak East -- Total Eastern Foldbelt Block 12
P90=1,012.9
P50=1,309.9
P10=1,666.7
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0.0
500.0
1000.0
1500.0
2000.0
2500.0
3000.0
Values in Billions of Cubic Feet

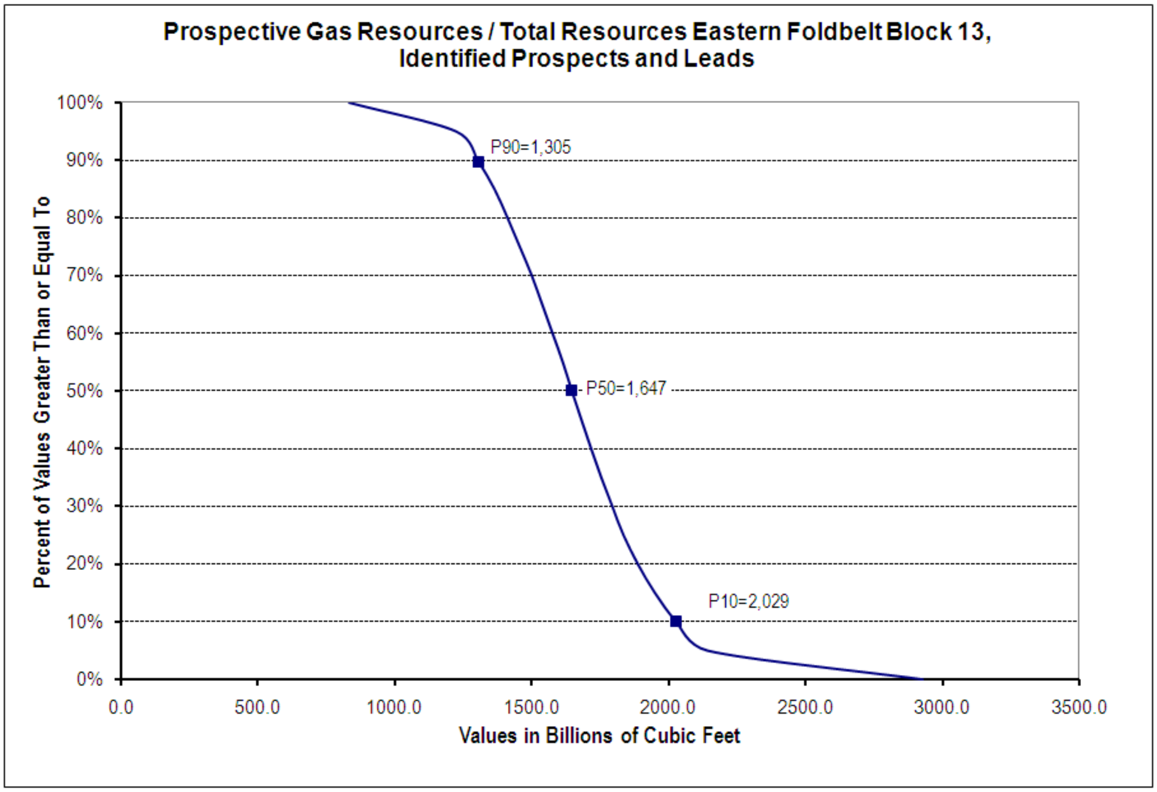


Prospective Condensate Resources / Chhatak East -- Total Eastern Foldbelt Block 12
P90=2.4
P50=6.1
P10=11.7
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0.0
5.0
10.0
15.0
20.0
25.0
Values in Millions of Barrels

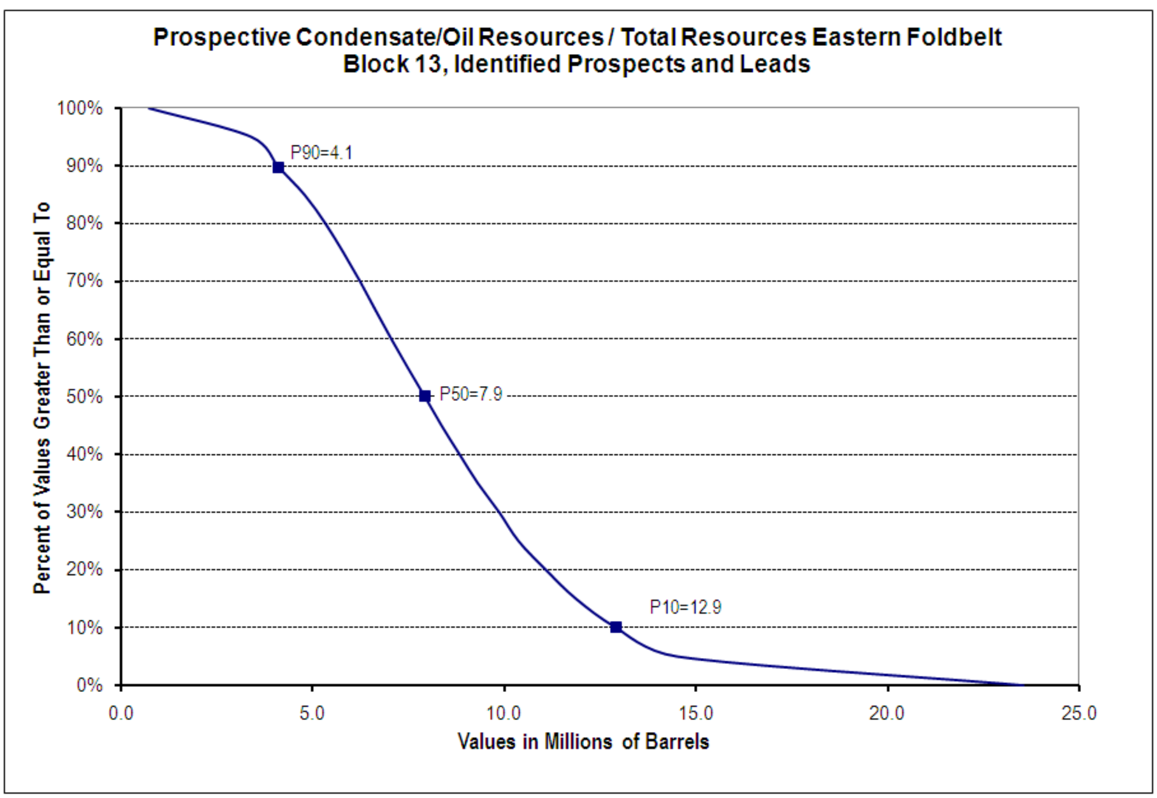
Eastern Foldbelt Block 13

Prospect / Lead	Mean Prospective Gas Resources, BCF
Darbesh	913
Dupitila	746
Total	1,659





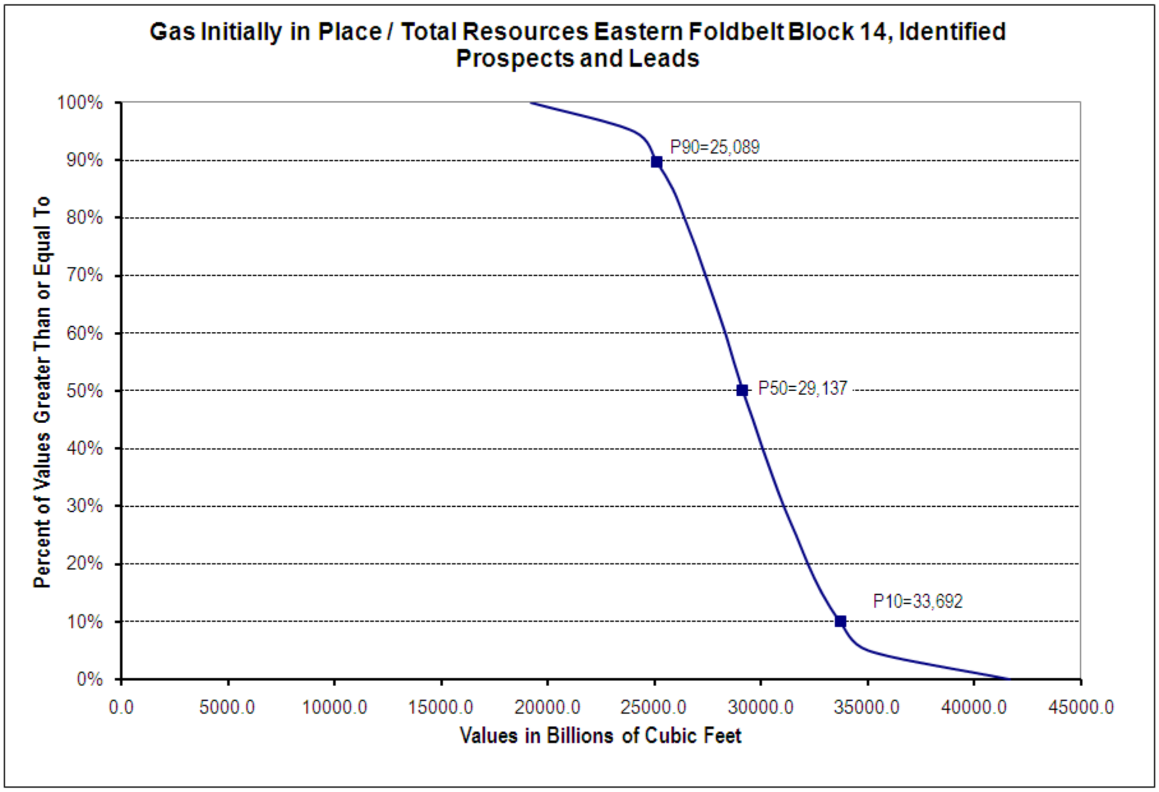
Prospective Gas Resources / Total Resources Eastern Foldbelt Block 13, Identified Prospects and Leads
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
P90=1,305
P50=1,647
P10=2,029
0.0
500.0
1000.0
1500.0
2000.0
2500.0
3000.0
3500.0
Values in Billions of Cubic Feet

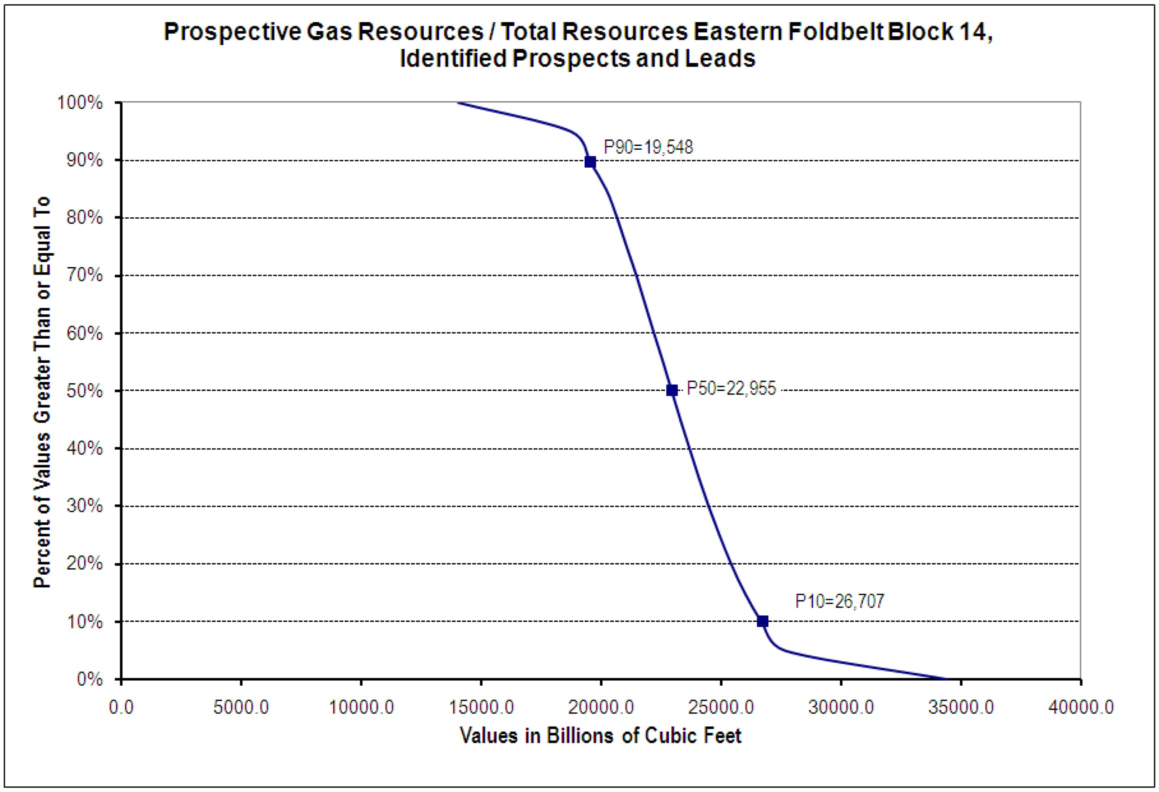


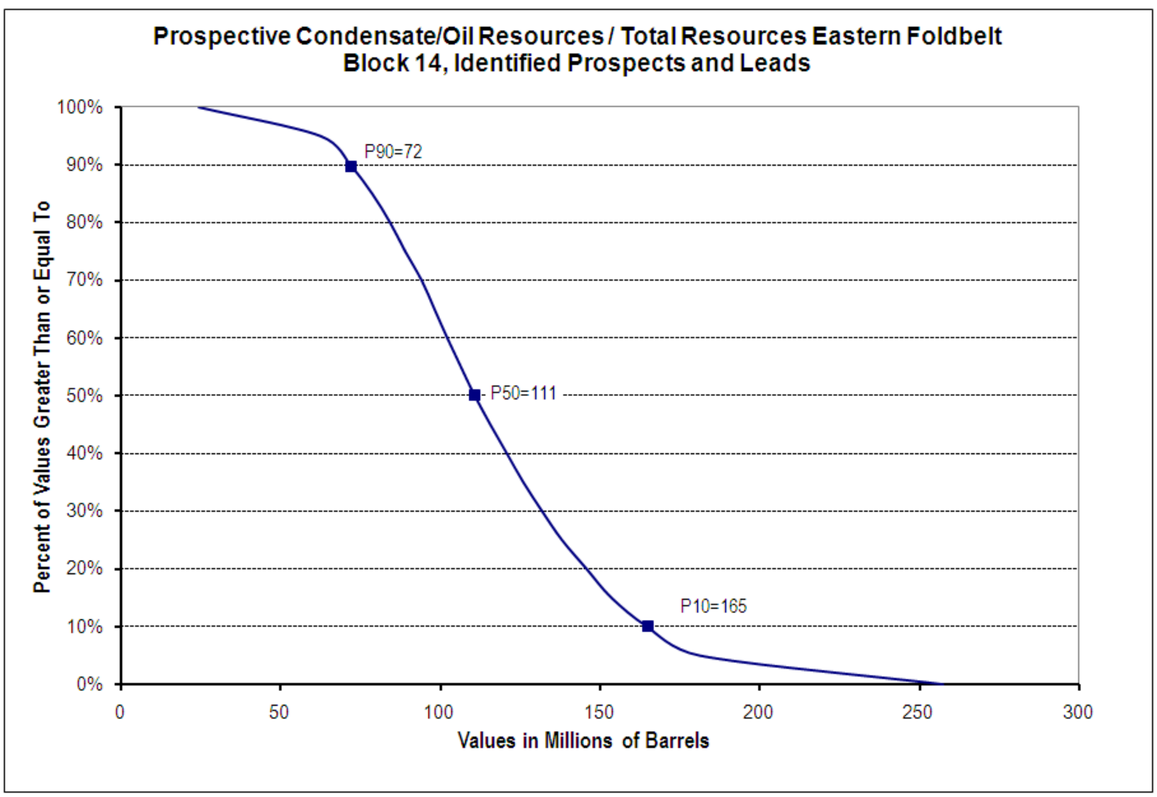
Prospective Condensate/Oil Resources / Total Resources Eastern Foldbelt Block 13, Identified Prospects and Leads
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Percent of Values Greater Than or Equal To
P90=4.1
P50=7.9
P10=12.9
0.0
5.0
10.0
15.0
20.0
25.0
Values in Millions of Barrels

Eastern Foldbelt Block 14

Prospect / Lead	Mean Prospective Gas Resources, BCF
Fenchunganj East	1,048
Patharia North Pitch	2,390
Patharia West	452
Harargaj	10,122
Harargaj North	2,420
Batchia North Pitch	6,641
Total	23,072

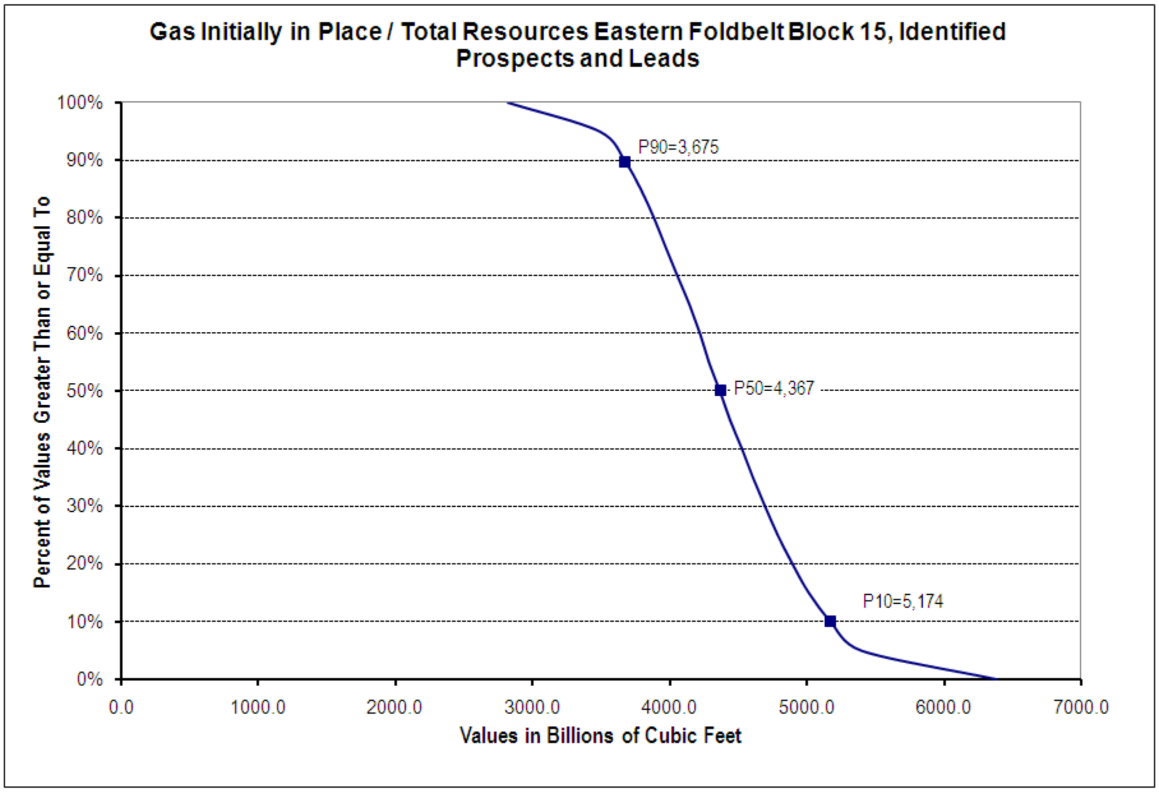


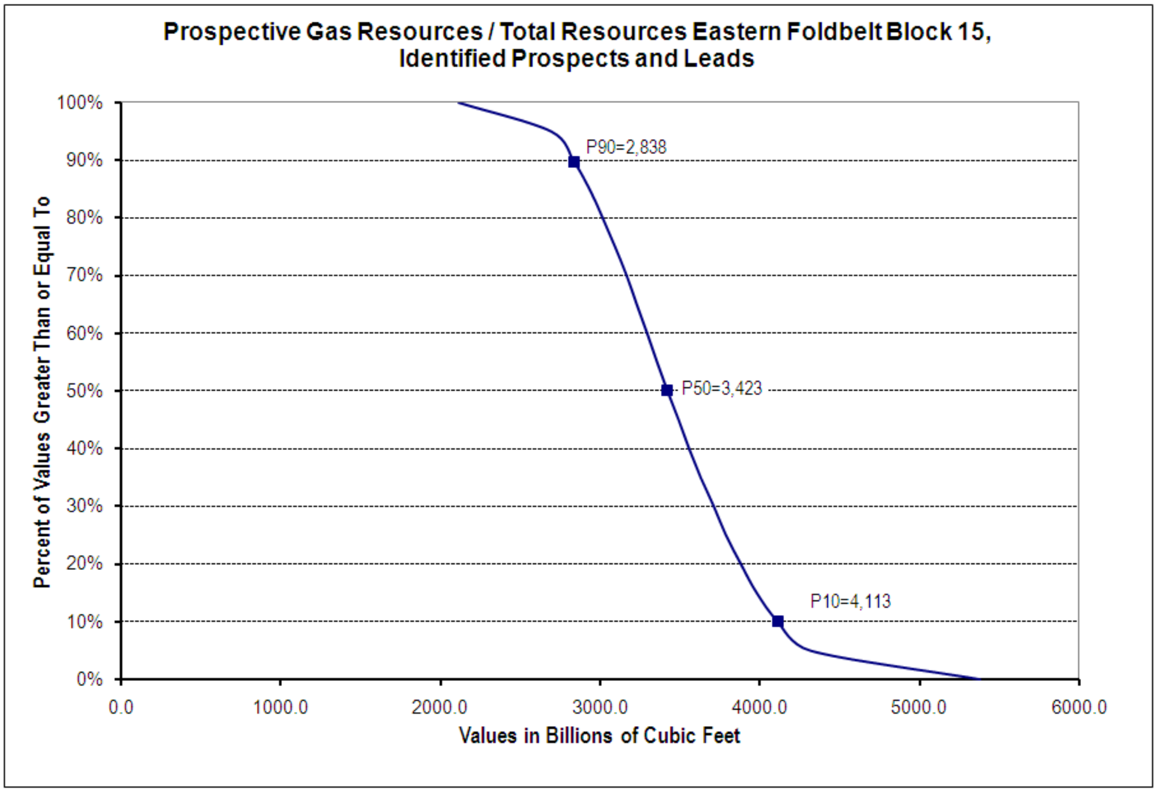

Prospective Gas Resources / Total Resources Eastern Foldbelt Block 14, Identified Prospects and Leads
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=19,548
P50=22,955
P10=26,707
0.0
5000.0
10000.0
15000.0
20000.0
25000.0
30000.0
35000.0
40000.0
Values in Billions of Cubic Feet


Prospective Condensate/Oil Resources / Total Resources Eastern Foldbelt Block 14, Identified Prospects and Leads
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=72
P50=111
P10=165
0
50
100
150
200
250
300
Values in Millions of Barrels

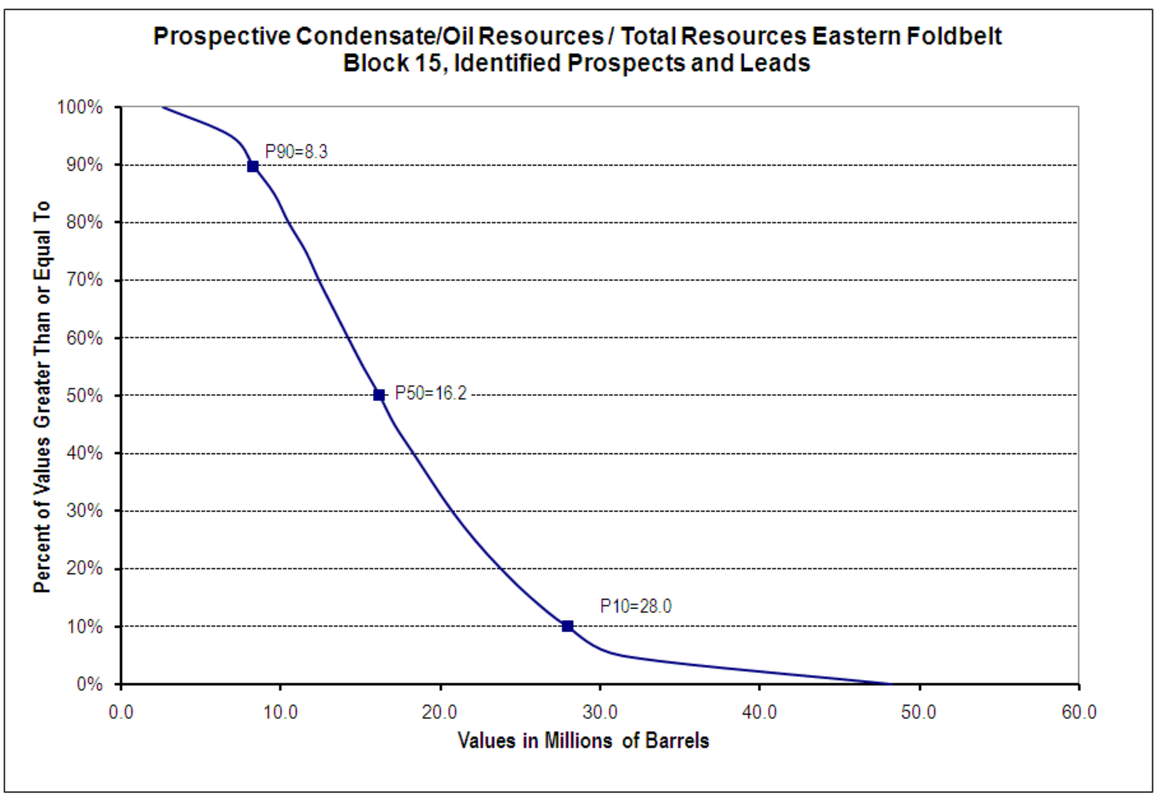
Eastern Foldbelt Block 15

Prospect / Lead	Mean Prospective Gas Resources, BCF
Semutang East Strat	53
Semutang West Flank	68
Semutang South	91
Sandwip West	2,705
Sandwip South	539
Total	3,455





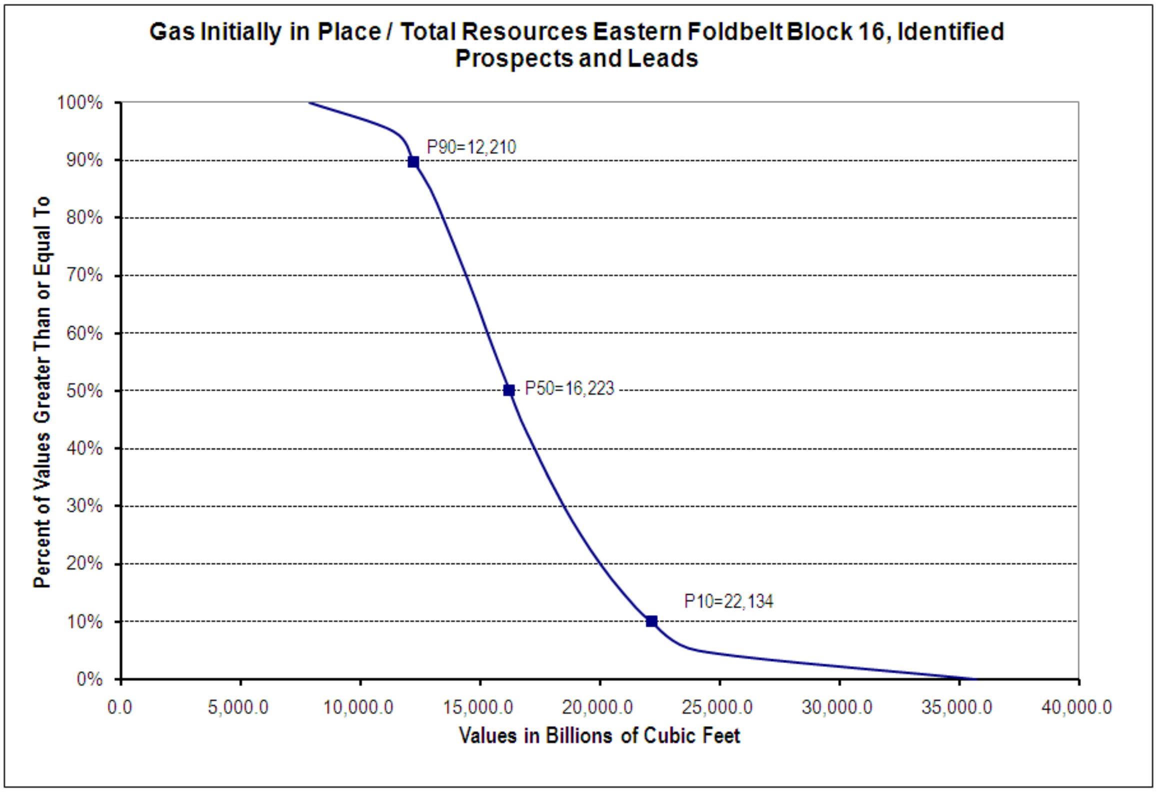
Prospective Gas Resources / Total Resources Eastern Foldbelt Block 15, Identified Prospects and Leads
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=2,838
P50=3,423
P10=4,113
0.0
1000.0
2000.0
3000.0
4000.0
5000.0
6000.0
Values in Billions of Cubic Feet

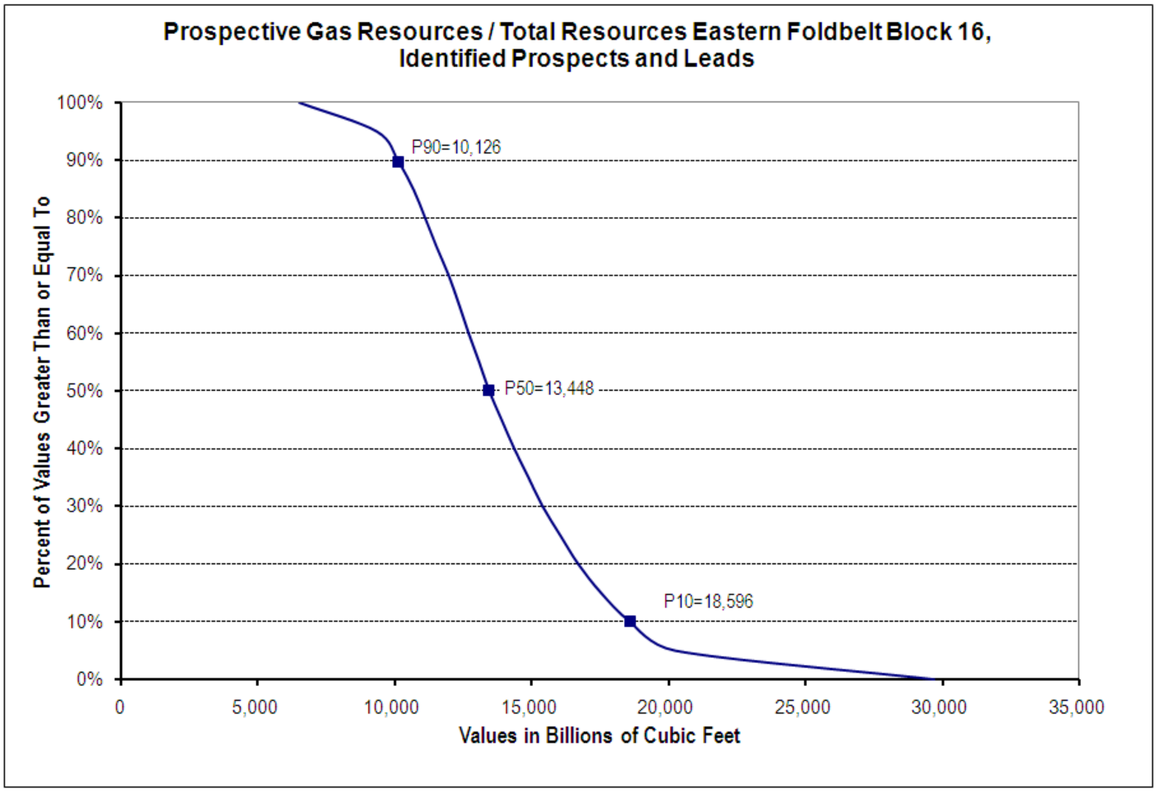


Prospective Condensate/Oil Resources / Total Resources Eastern Foldbelt Block 15, Identified Prospects and Leads
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=8.3
P50=16.2
P10=28.0
0.0
10.0
20.0
30.0
40.0
50.0
60.0
Values in Millions of Barrels

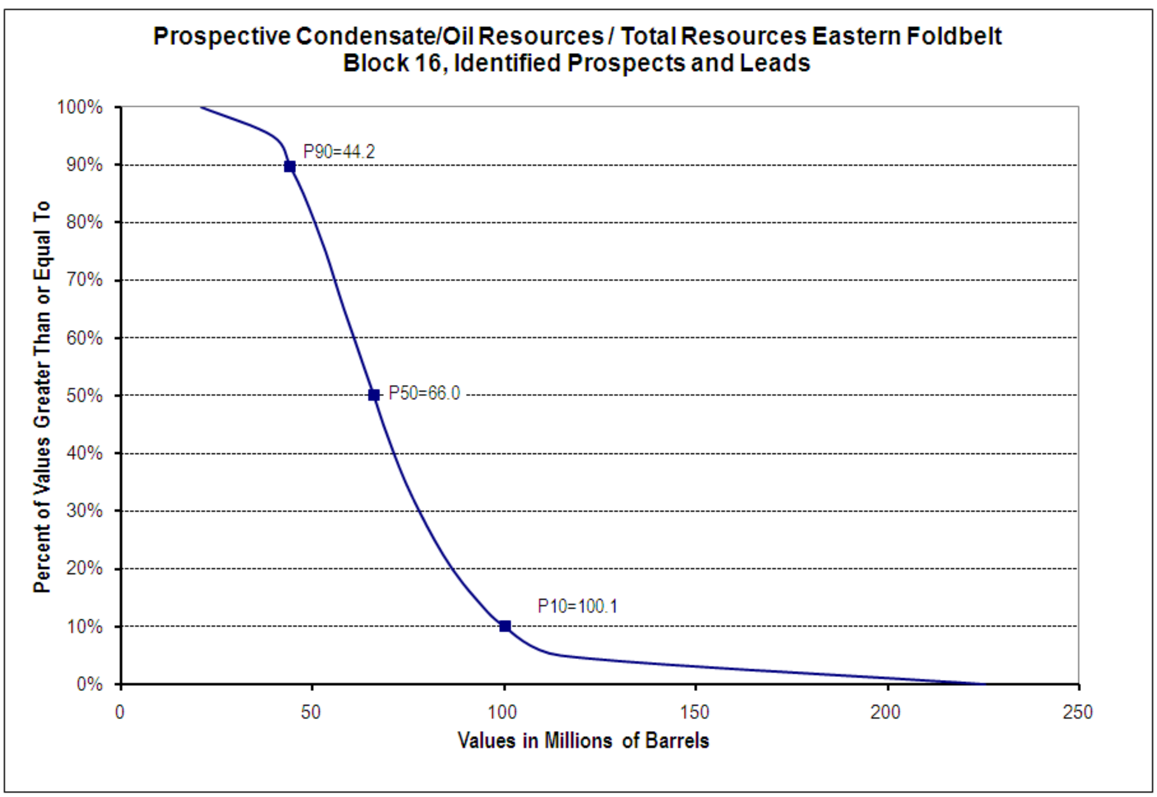
Eastern Foldbelt Block 16

Prospect / Lead	Mean Prospective Gas Resources, BCF
Sangu East	181
Manpura	408
Maiskhali	962
Matabari Deep MS1	875
Matabari Shallow MS2	4,548
Sangu South	477
Hatia	1,788
Magnama	1,229
Kutubdia	2,276
Jaldi	1,006
Sonadia	263
Total	14,013





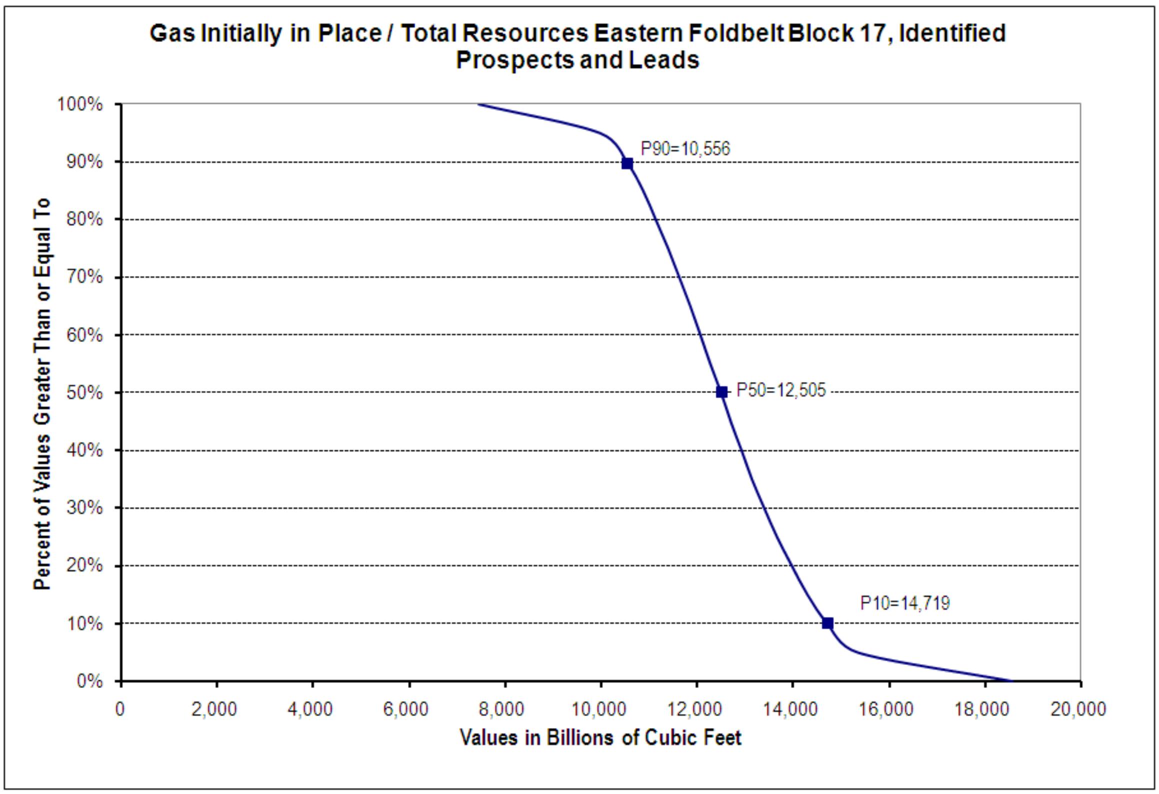
Prospective Gas Resources / Total Resources Eastern Foldbelt Block 16, Identified Prospects and Leads
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=10,126
P50=13,448
P10=18,596
0
5,000
10,000
15,000
20,000
25,000
30,000
35,000
Values in Billions of Cubic Feet

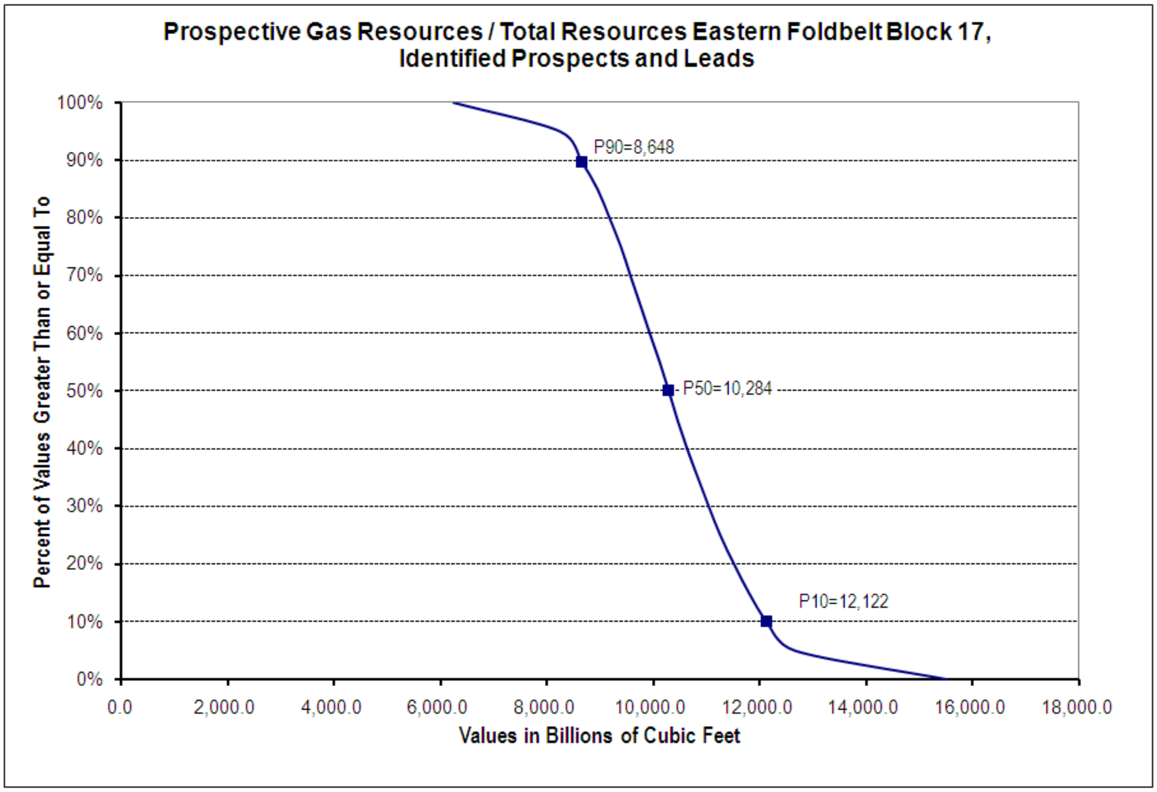


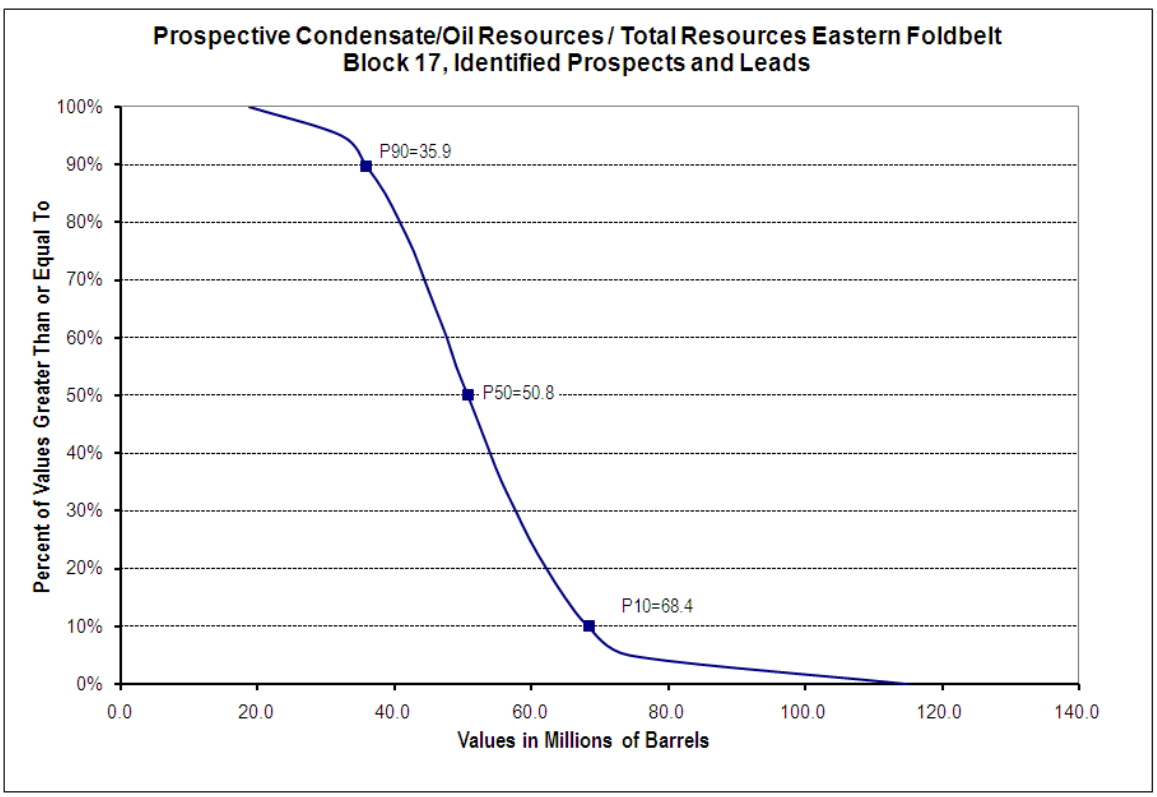
Prospective Condensate/Oil Resources / Total Resources Eastern Foldbelt Block 16, Identified Prospects and Leads
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=44.2
P50=66.0
P10=100.1
0
50
100
150
200
250
Values in Millions of Barrels

Eastern Foldbelt Block 17

Prospect / Lead	Mean Prospective Gas Resources, BCF
Ukhia	1,618
D (Ohlataung)	1,380
E (Inani)	974
I (Dakhinila)	2,479
J	1,282
Q	1,303
R	1,303
Total	10,339

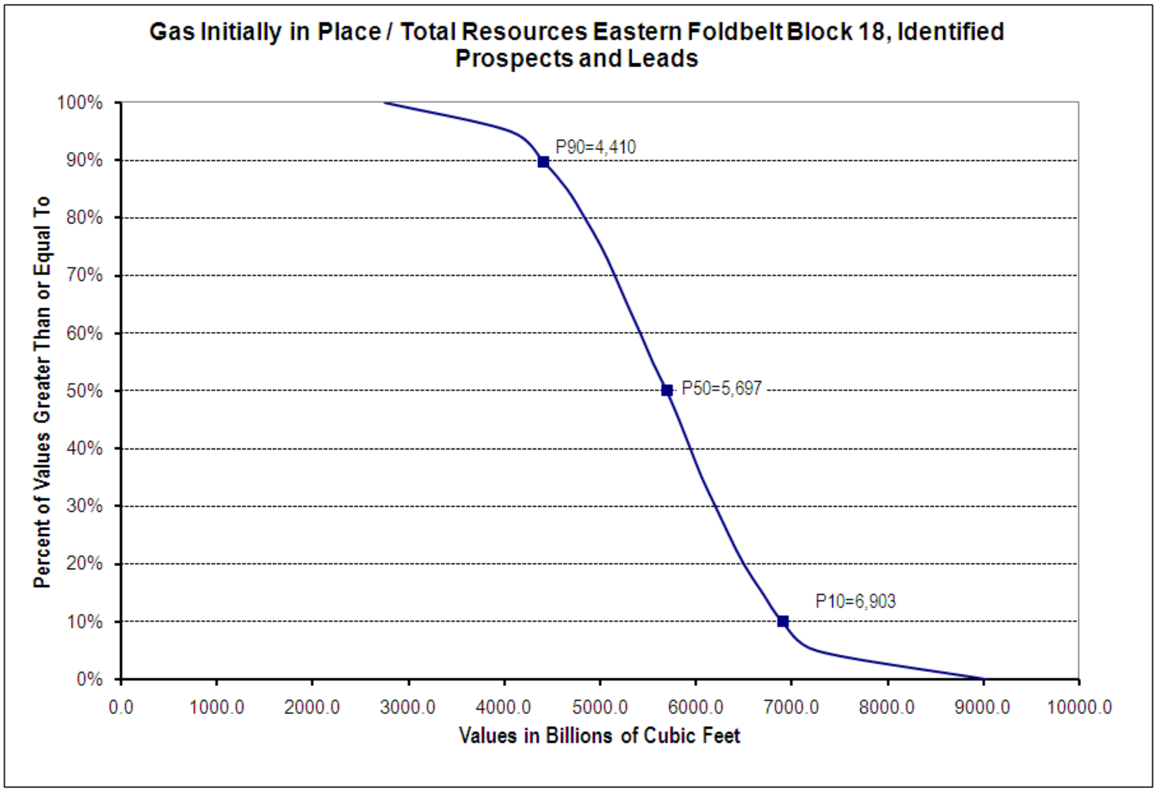


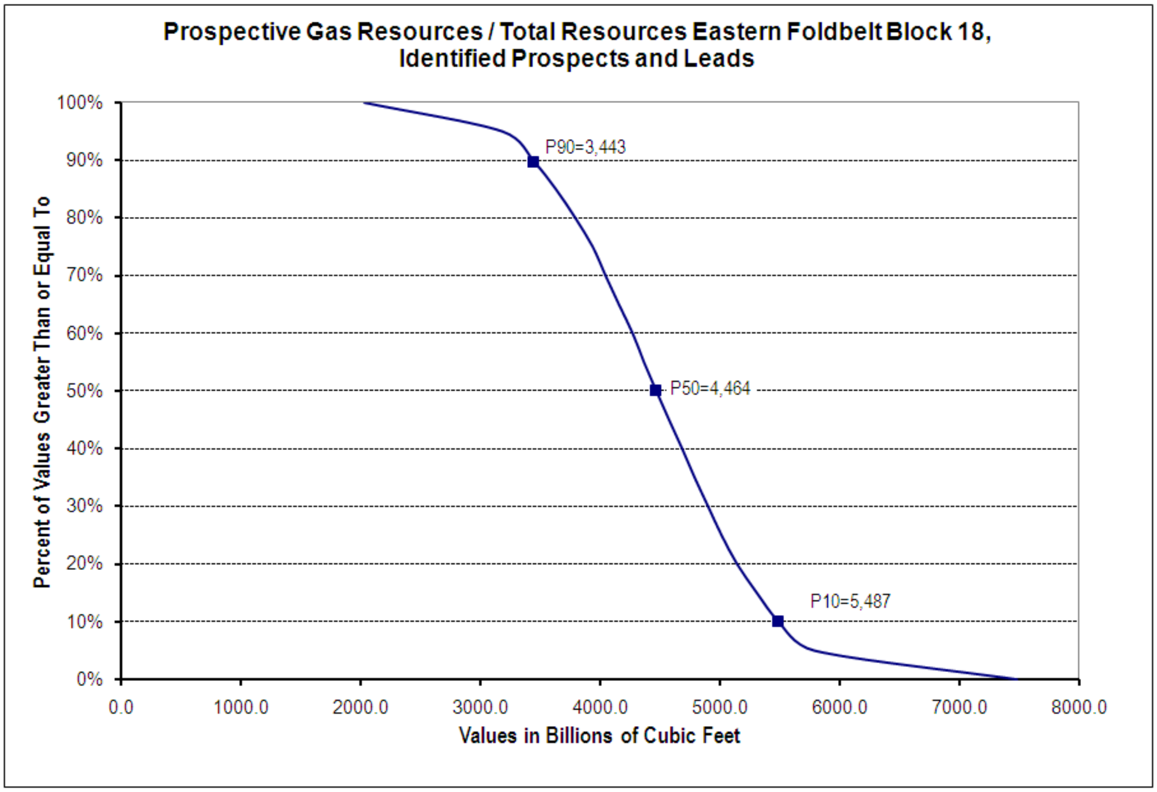

Prospective Gas Resources / Total Resources Eastern Foldbelt Block 17, Identified Prospects and Leads
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=8,648
P50=10,284
P10=12,122
0.0
2,000.0
4,000.0
6,000.0
8,000.0
10,000.0
12,000.0
14,000.0
16,000.0
18,000.0
Values in Billions of Cubic Feet

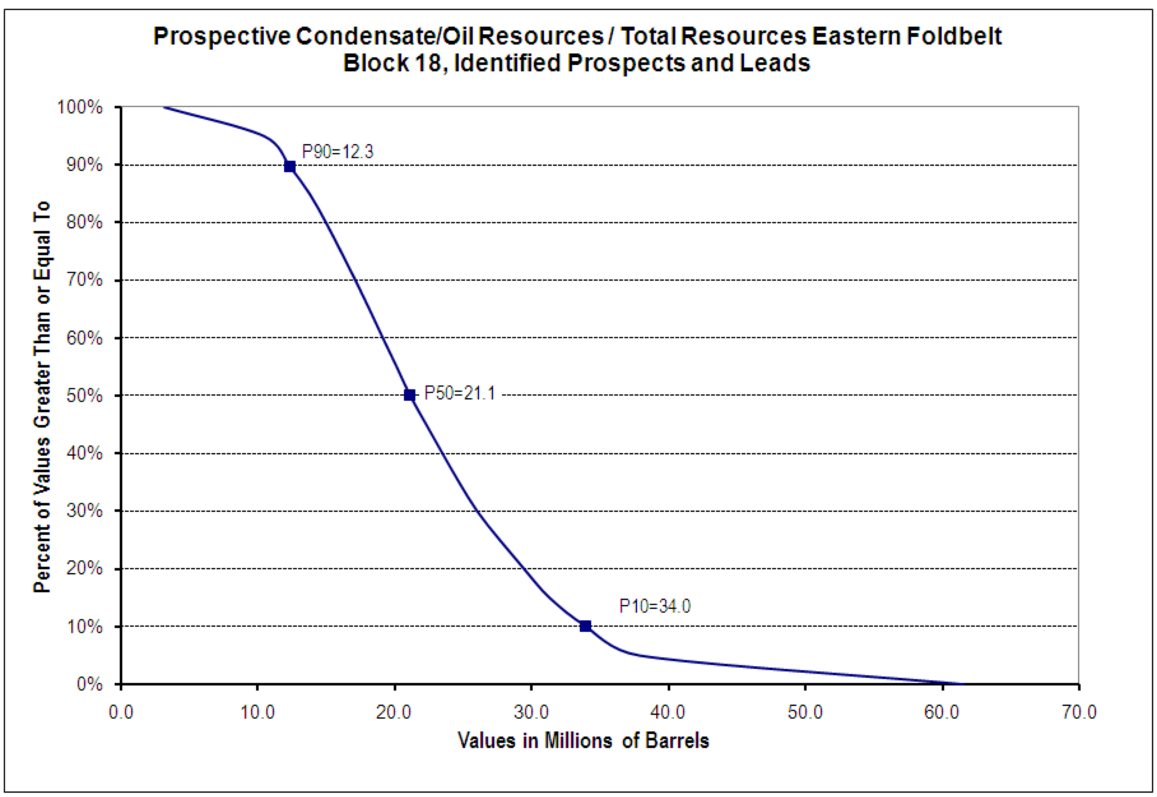

Prospective Condensate/Oil Resources / Total Resources Eastern Foldbelt Block 17, Identified Prospects and Leads
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=35.9
P50=50.8
P10=68.4
0.0
20.0
40.0
60.0
80.0
100.0
120.0
140.0
Values in Millions of Barrels

Eastern Foldbelt Block 18

Prospect / Lead	Mean Prospective Gas Resources, BCF
Teknaf	625
Coral Dip	2,548
St Martin Island O	1,300
Total	4,473

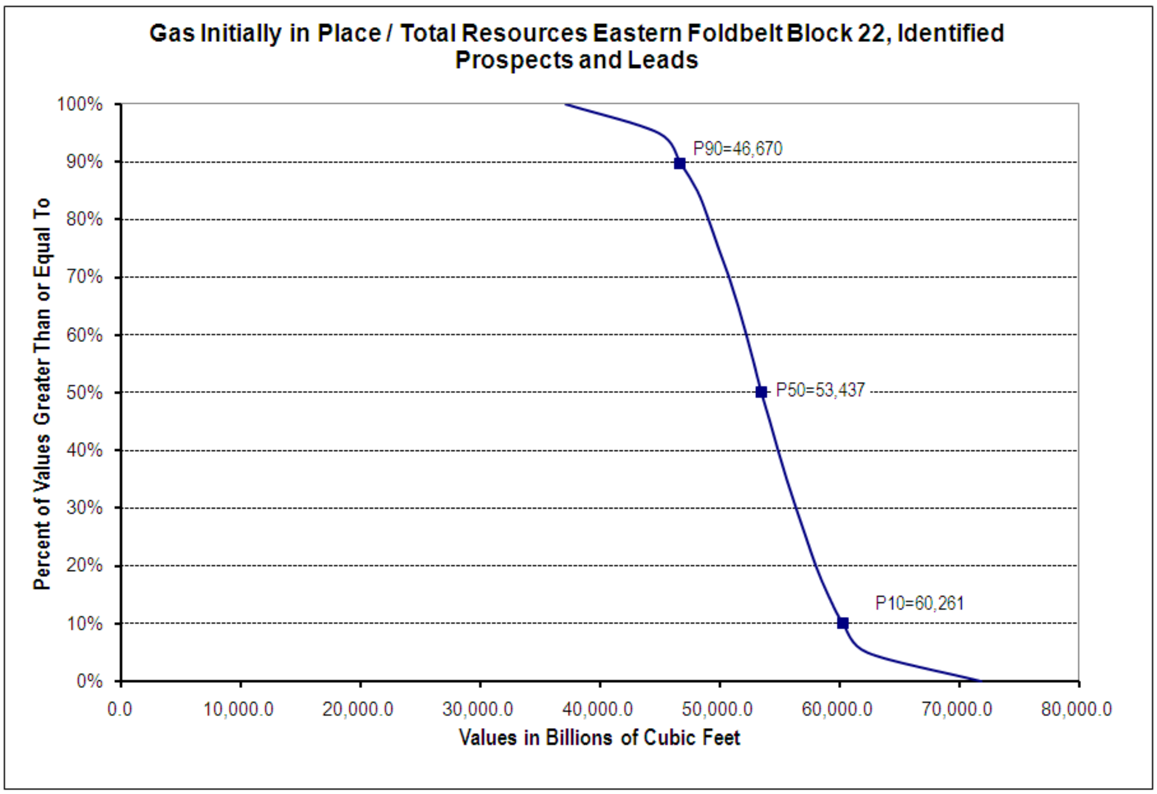


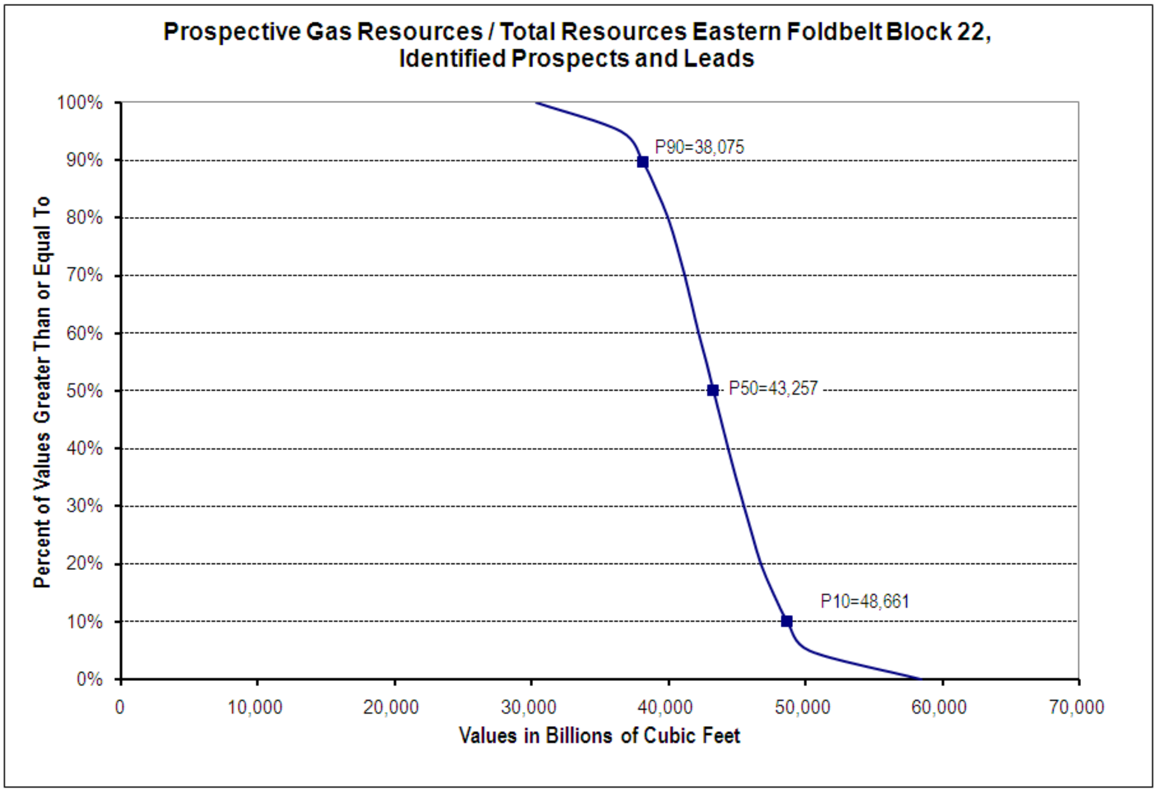

Prospective Gas Resources / Total Resources Eastern Foldbelt Block 18, Identified Prospects and Leads
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=3,443
P50=4,464
P10=5,487
0.0
1000.0
2000.0
3000.0
4000.0
5000.0
6000.0
7000.0
8000.0
Values in Billions of Cubic Feet

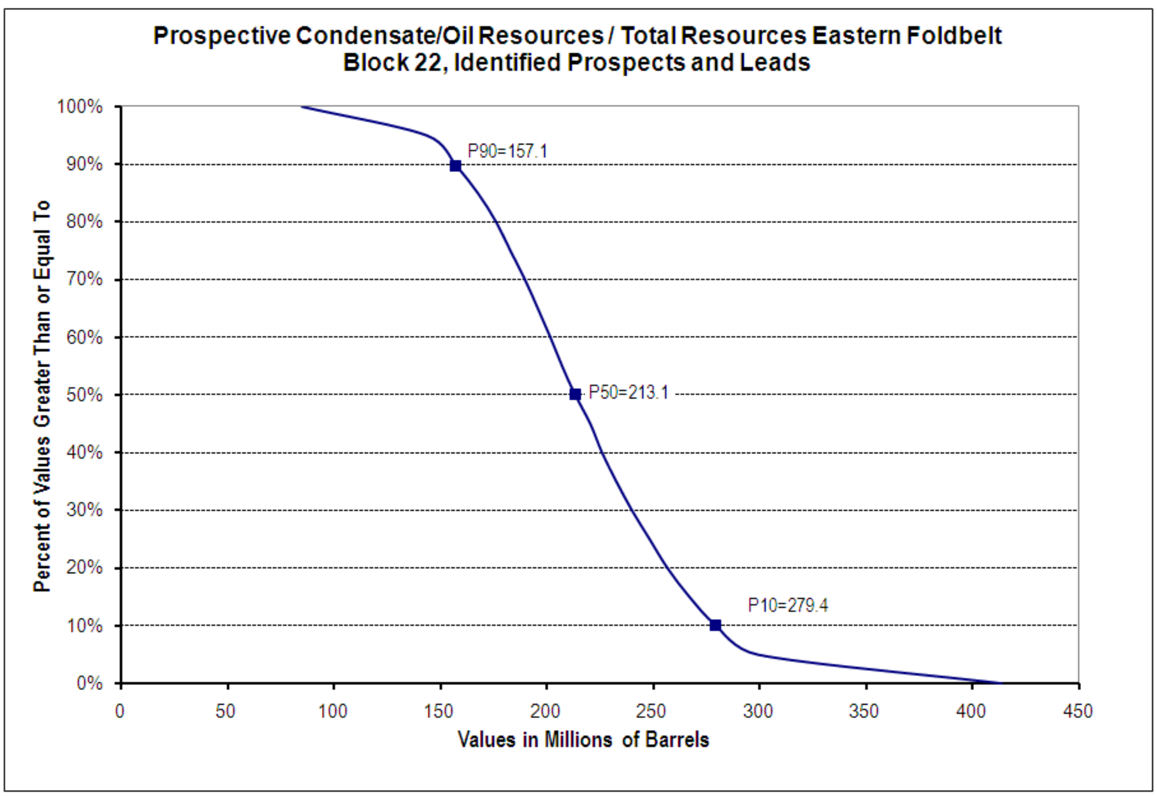

Prospective Condensate/Oil Resources / Total Resources Eastern Foldbelt Block 18, Identified Prospects and Leads
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=12.3
P50=21.1
P10=34.0
0.0
10.0
20.0
30.0
40.0
50.0
60.0
70.0
Values in Millions of Barrels

Eastern Foldbelt Block 22

Prospect / Lead	Mean Prospective Gas Resources, BCF
Bandarban	7,183
Barkal	2,694
Belachari	3,915
Bhuachari	1,020
Changohtang	1,768
Gilachari	1,600
Gobamura	3,212
Kasalang	3,212
Matamuhuri	11,735
Shishak	1,208
Uttan Chhatra	5,787
Total	43,333

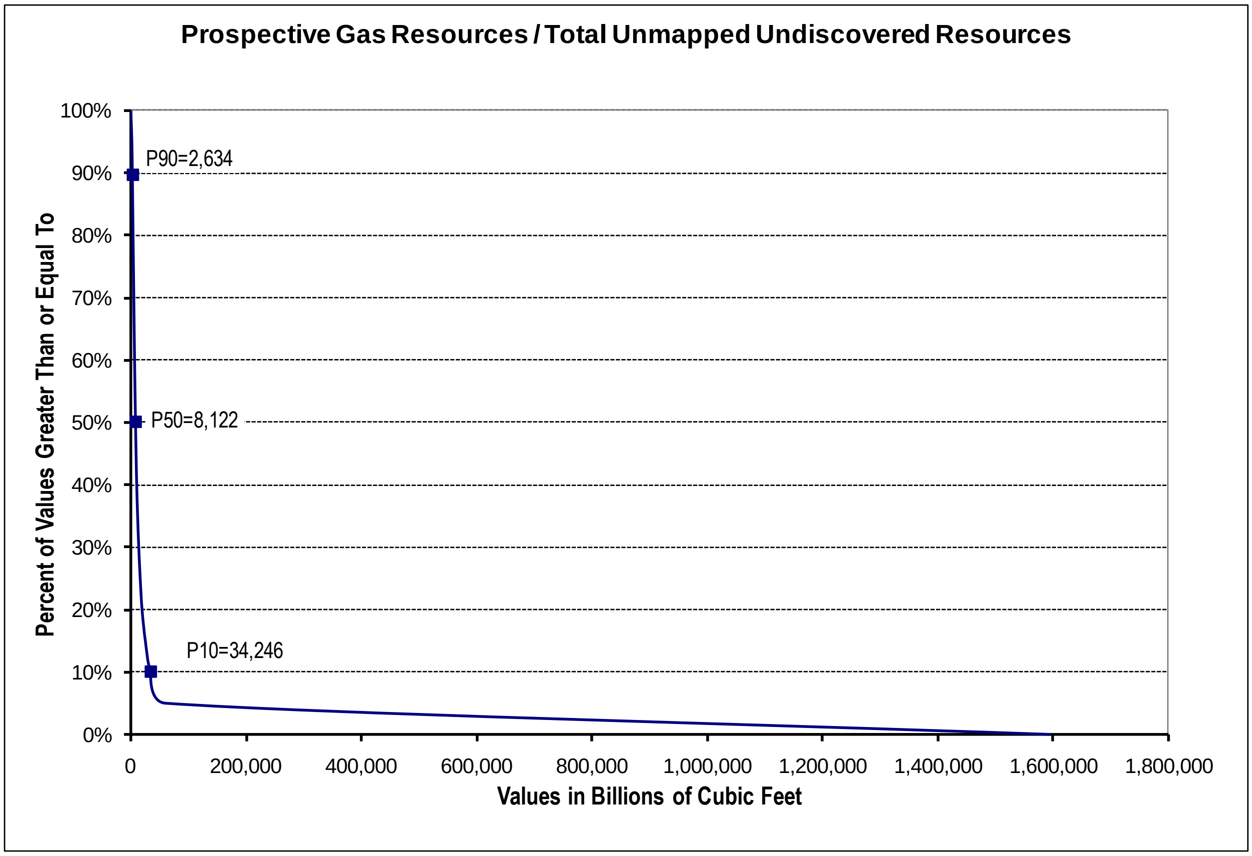


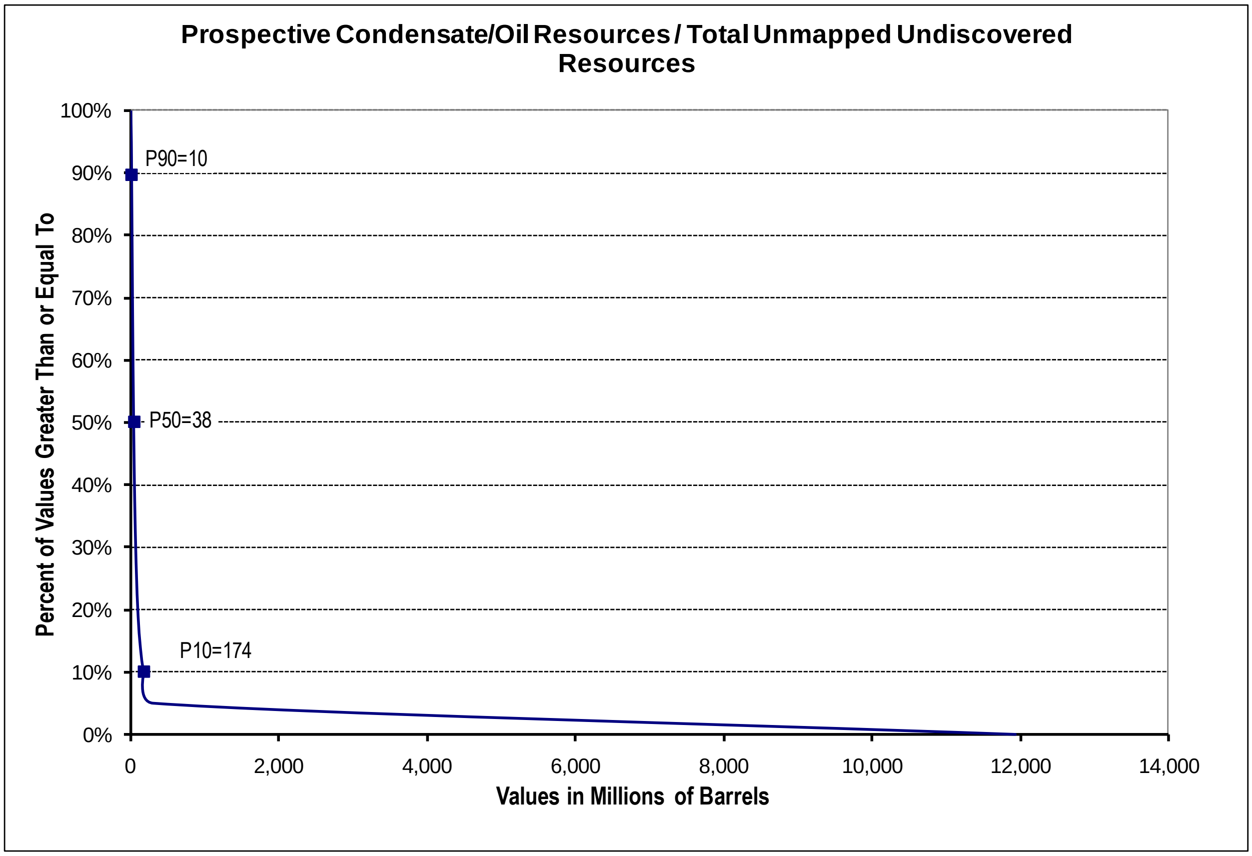

Prospective Gas Resources / Total Resources Eastern Foldbelt Block 22, Identified Prospects and Leads
P90=38,075
P50=43,257
P10=48,661
Percent of Values Greater Than or Equal To
Values in Billions of Cubic Feet
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
10,000
20,000
30,000
40,000
50,000
60,000
70,000


Prospective Condensate/Oil Resources / Total Resources Eastern Foldbelt Block 22, Identified Prospects and Leads
P90=157.1
P50=213.1
P10=279.4
Percent of Values Greater Than or Equal To
Values in Millions of Barrels
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
50
100
150
200
250
300
350
400
450

UNMAPPED UNDISCOVERED RESOURCES

Assessment Area	Mean Prospective Gas Resources, BCF	Mean Prospective Oil Resources, MMBO
Surma Basin	3,979	19.3
Eastern Foldbelt	12	0.1
Faulted Anticlines	1,423	7.0
Folded Anticlines	12,438	65.5
Western Slope	57	0.3
Western Platform	0	0.0
Total	**17,909**	**92**



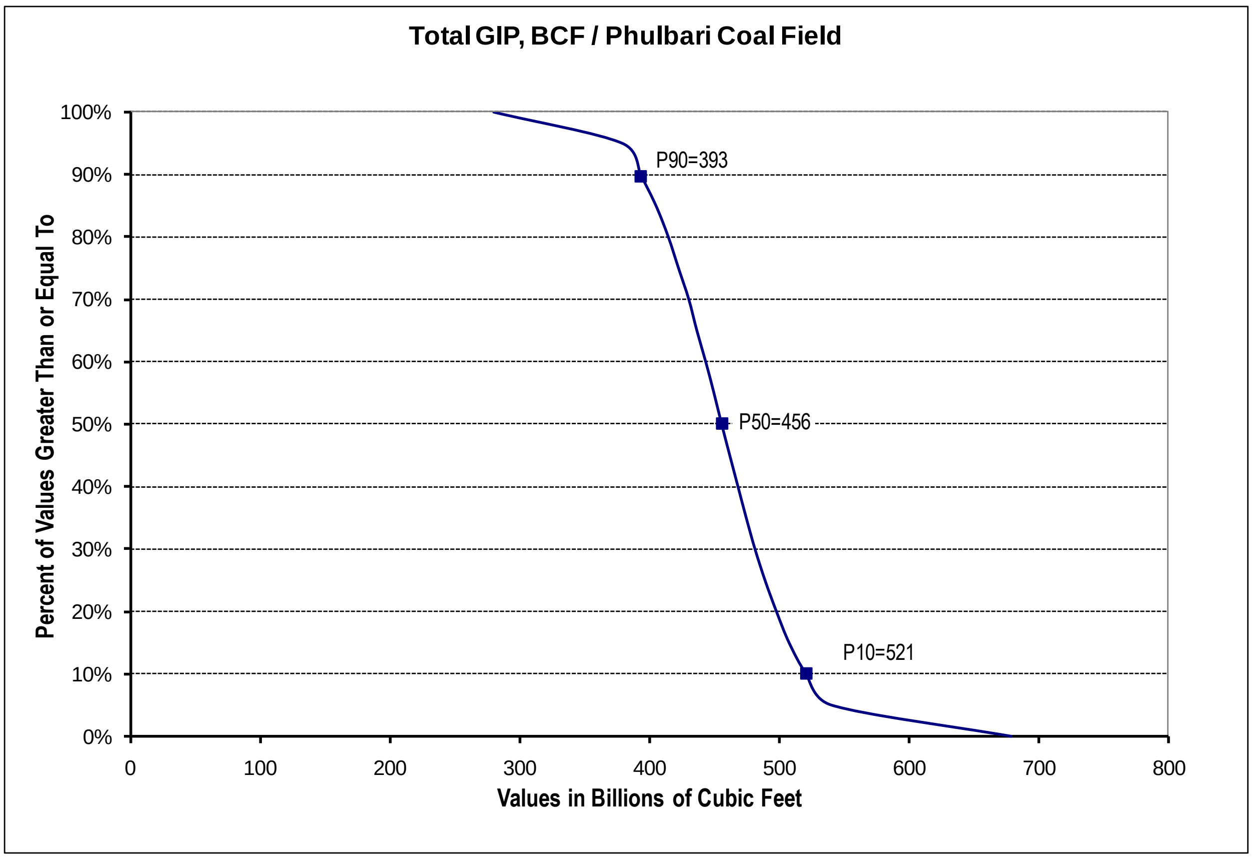


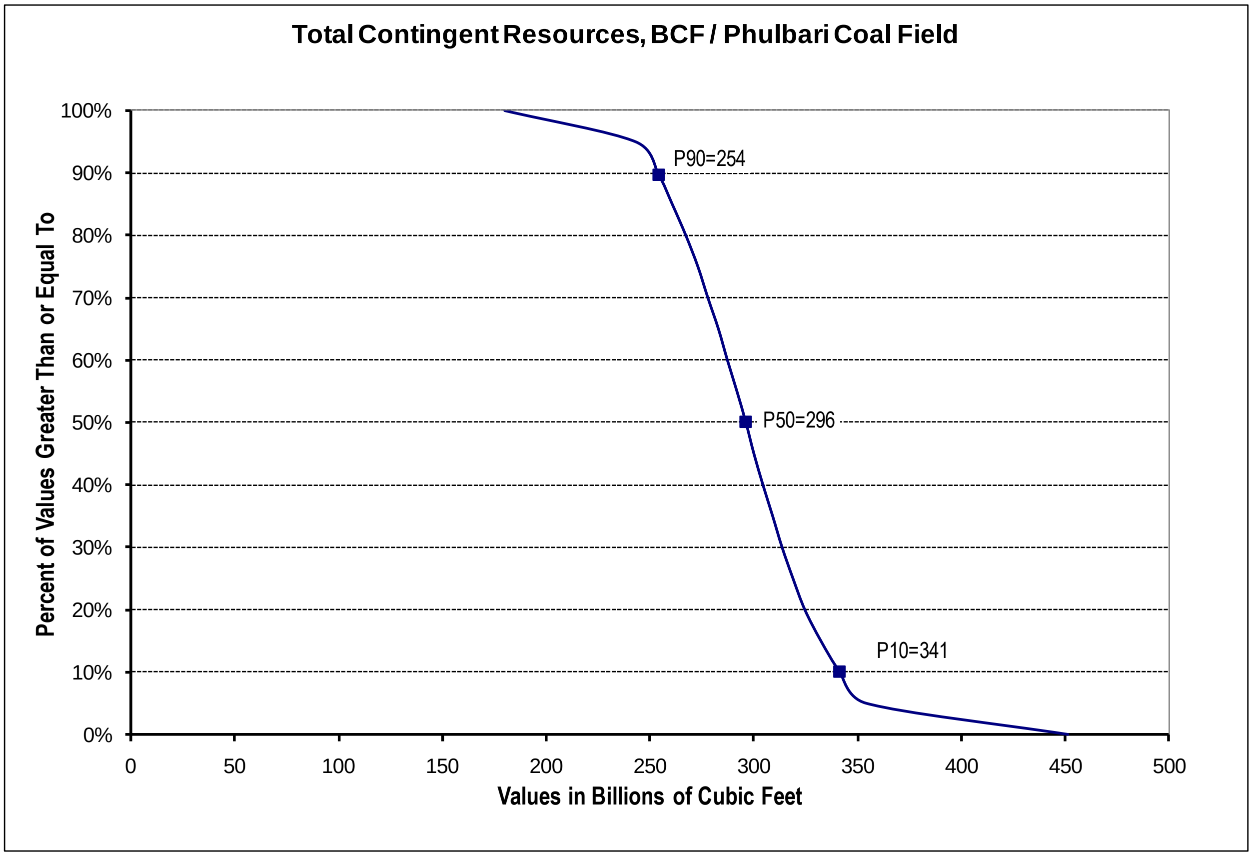
Prospective Condensate/Oil Resources / Total Unmapped Undiscovered Resources
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=10
P50=38
P10=174
0
2,000
4,000
6,000
8,000
10,000
12,000
14,000
Values in Millions of Barrels

COALBED METHANE

Phulbari Coal Field

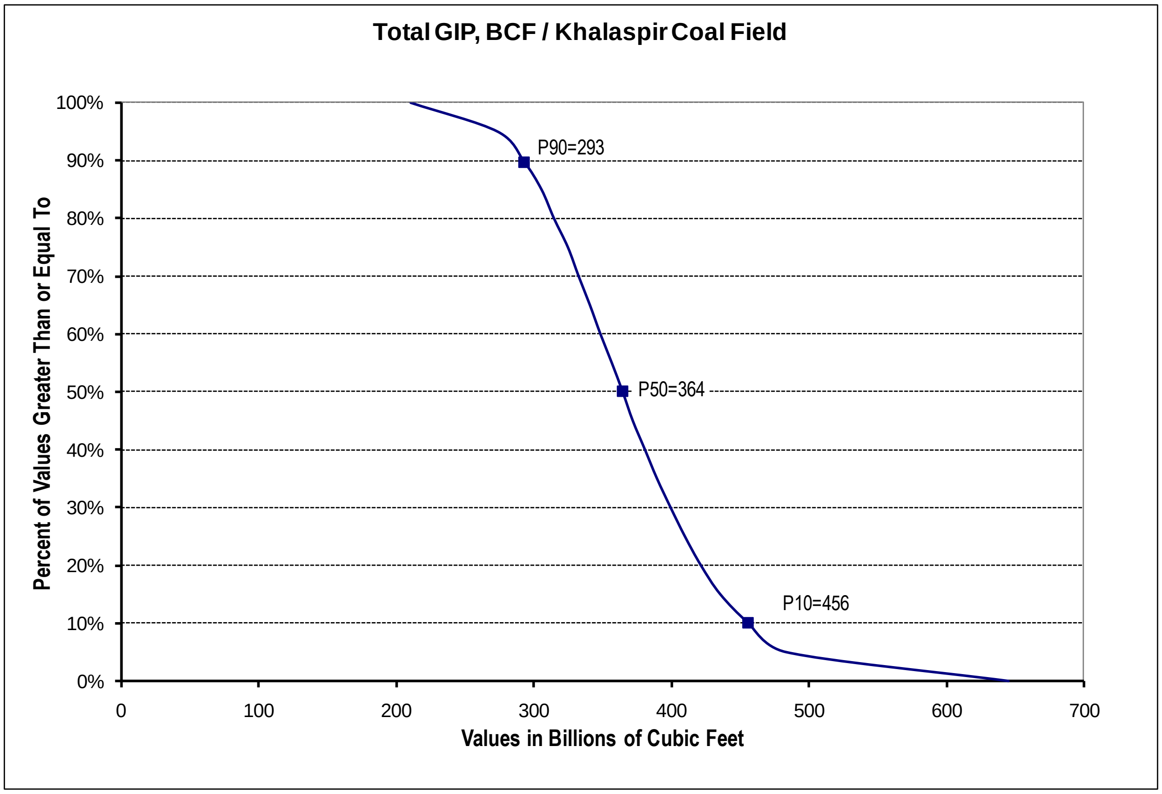
Coal Seam	Mean Contingent Gas Resources, BCF
Seam I	19
Seam II	60
Seam III	41
Seam IV	33
Seam V	27
Seam VI	26
Seam VII	26
Seam VIII	63
Total	**297**

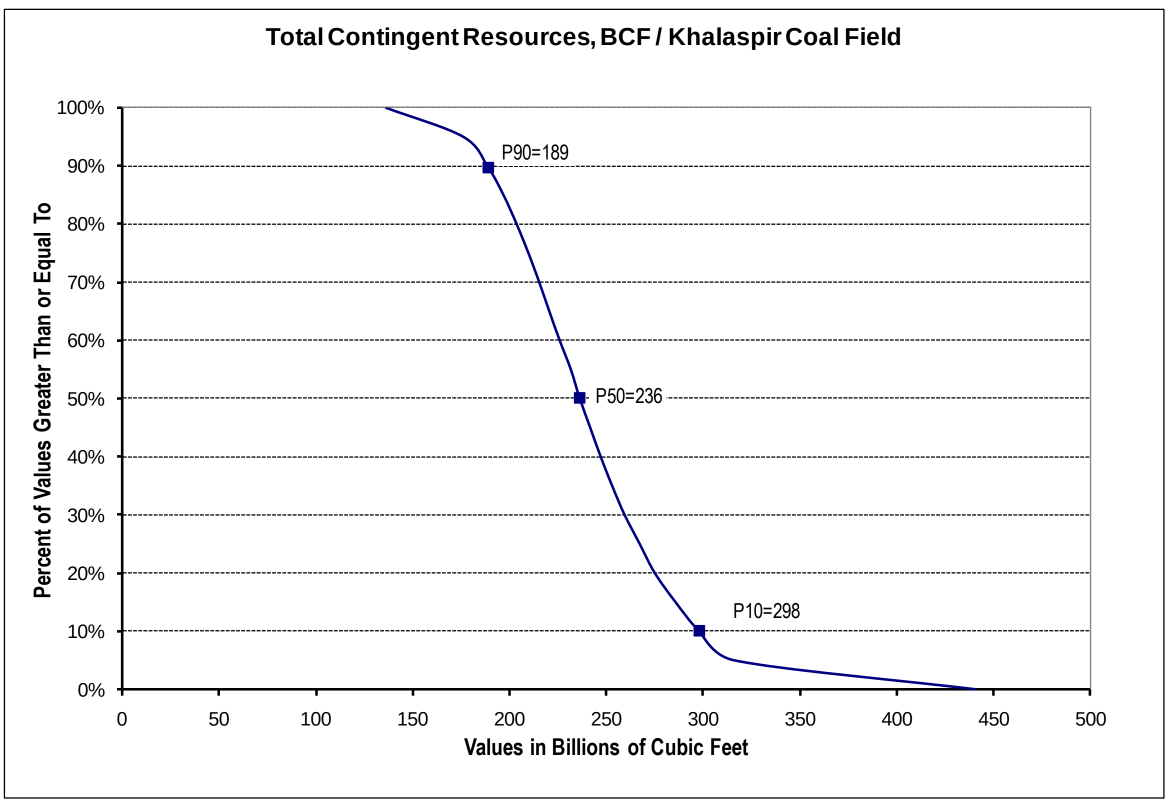




Khalaspir Coal Field

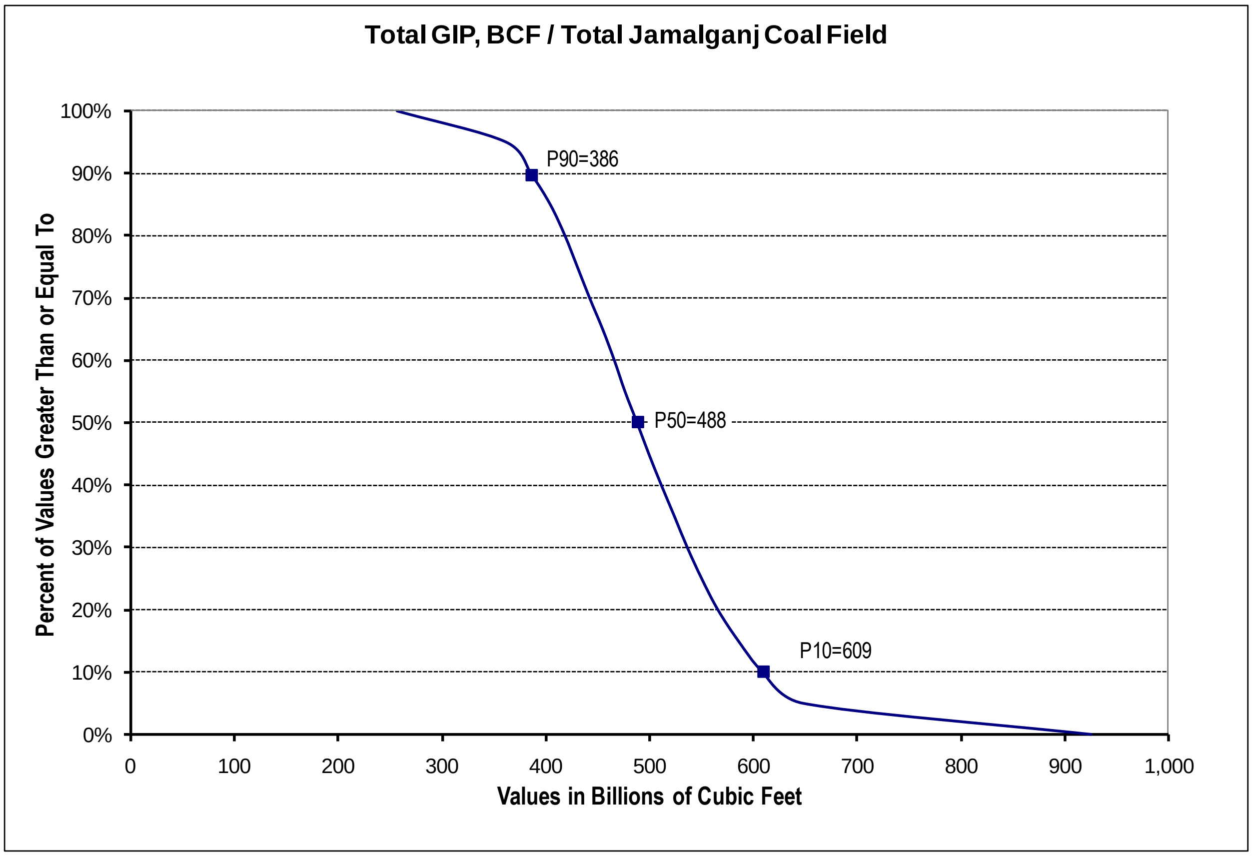
Coal Seam	Mean Contingent Gas Resources, BCF
Zone I	100
Zone II	53
Zone III	7
Zone IV	34
Zone V	13
Zone VI	17
Zone VII	10
Zone VIII	7
Total	**240**

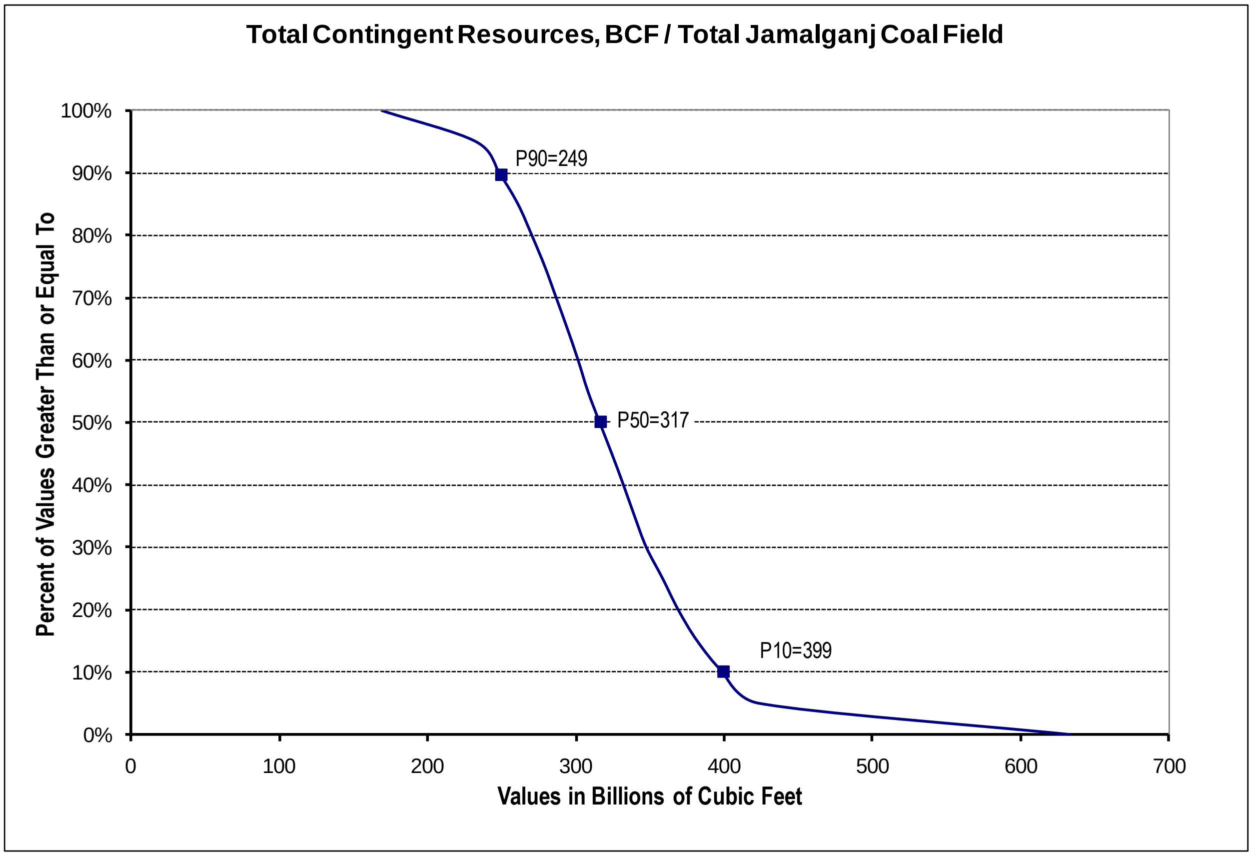

Total GIP, BCF / Khalaspir Coal Field
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=293
P50=364
P10=456
0
100
200
300
400
500
600
700
Values in Billions of Cubic Feet


Total Contingent Resources, BCF / Khalaspir Coal Field
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=189
P50=236
P10=298
0
50
100
150
200
250
300
350
400
450
500
Values in Billions of Cubic Feet

Jamalganj Coal Field

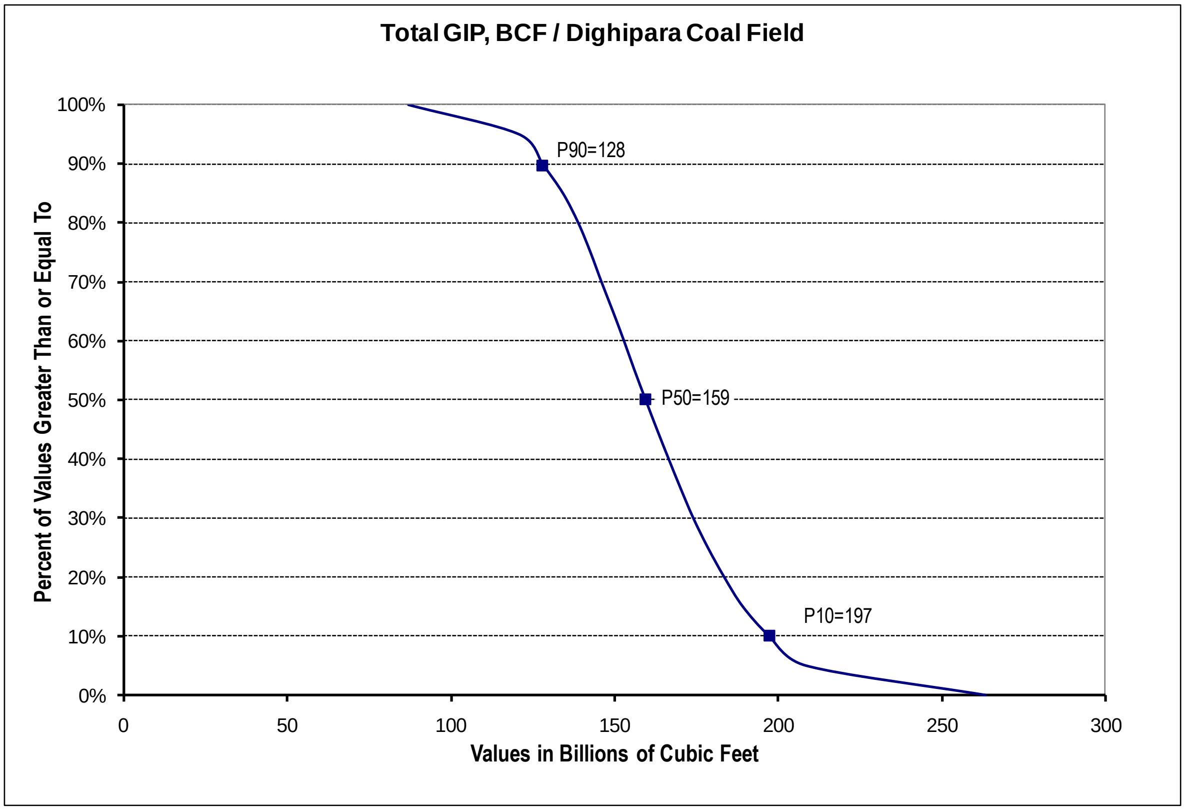
Coal Seam	Mean Contingent Gas Resources, BCF
Seam I	28
Seam II	27
Seam III	97
Seam IV	54
Seam V	47
Seam VI	27
Seam VII	41
Total	**321**

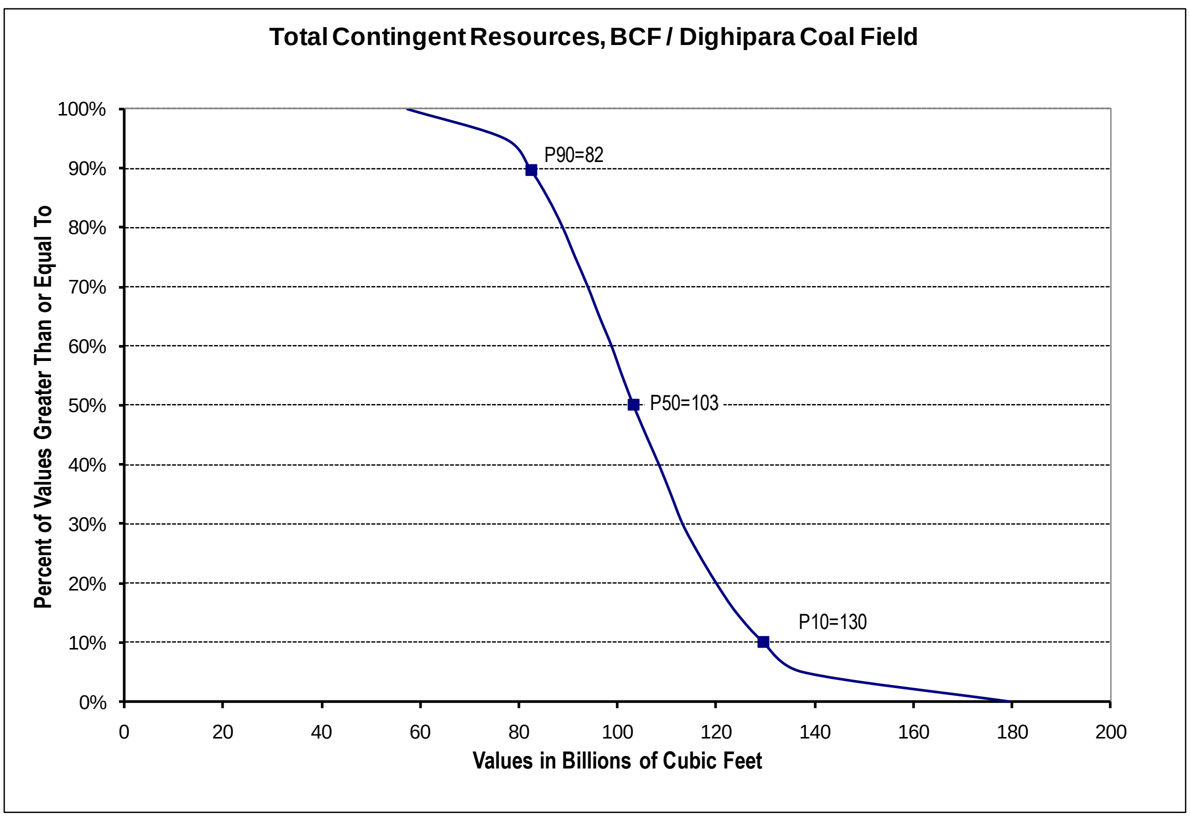




Dighipara Coal Field

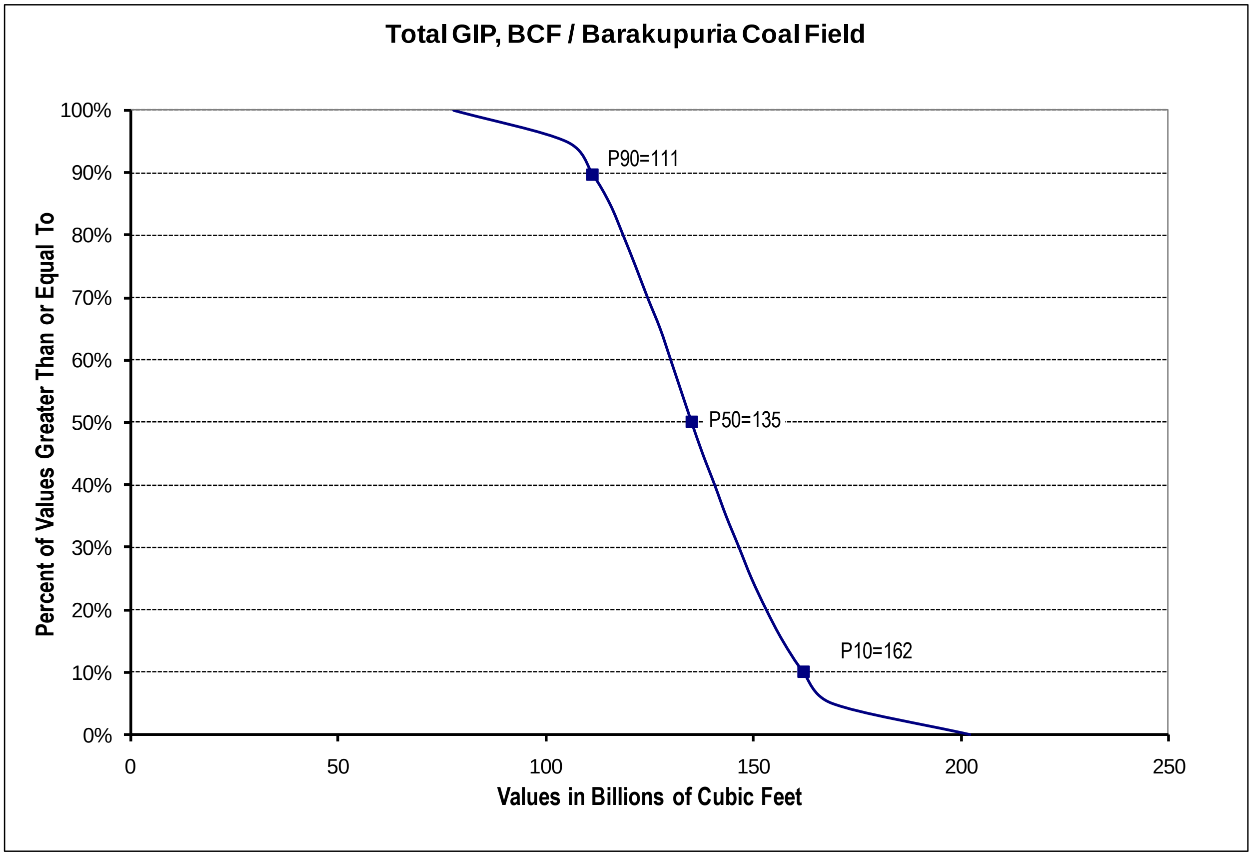
Coal Seam	Mean Contingent Gas Resources, BCF
Seam I	29
Seam II	58
Seam III	12
Seam IV	3
Seam V	2
Total	**105**

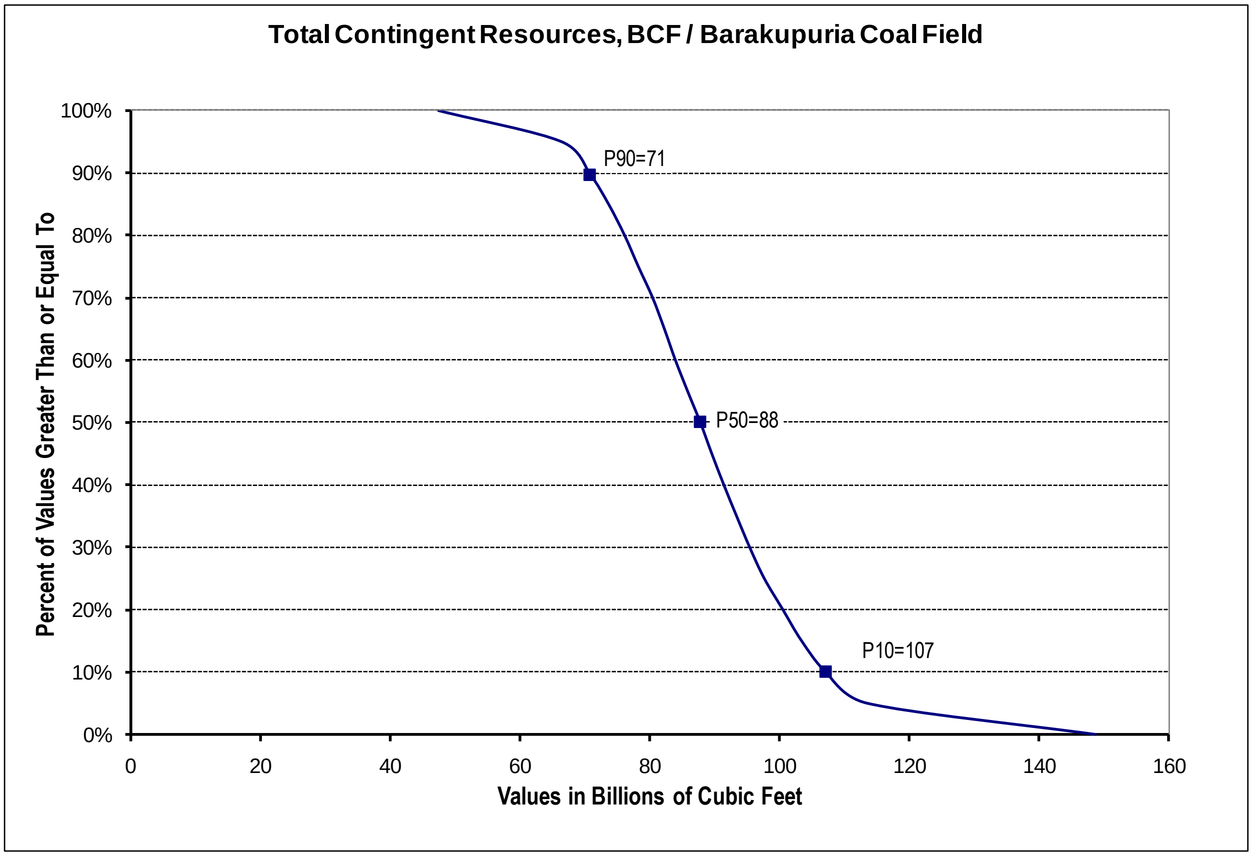

Total GIP, BCF / Dighipara Coal Field
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
50
100
150
200
250
300
Values in Billions of Cubic Feet
P90=128
P50=159
P10=197


Total Contingent Resources, BCF / Dighipara Coal Field
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
20
40
60
80
100
120
140
160
180
200
Values in Billions of Cubic Feet
P90=82
P50=103
P10=130

Barakupuria Coal Field

Coal Seam	Mean Contingent Gas Resources, BCF
Seam II	4
Seam III	1
Seam IV	9
Seam V	8
Seam VI	66
Total	**88**

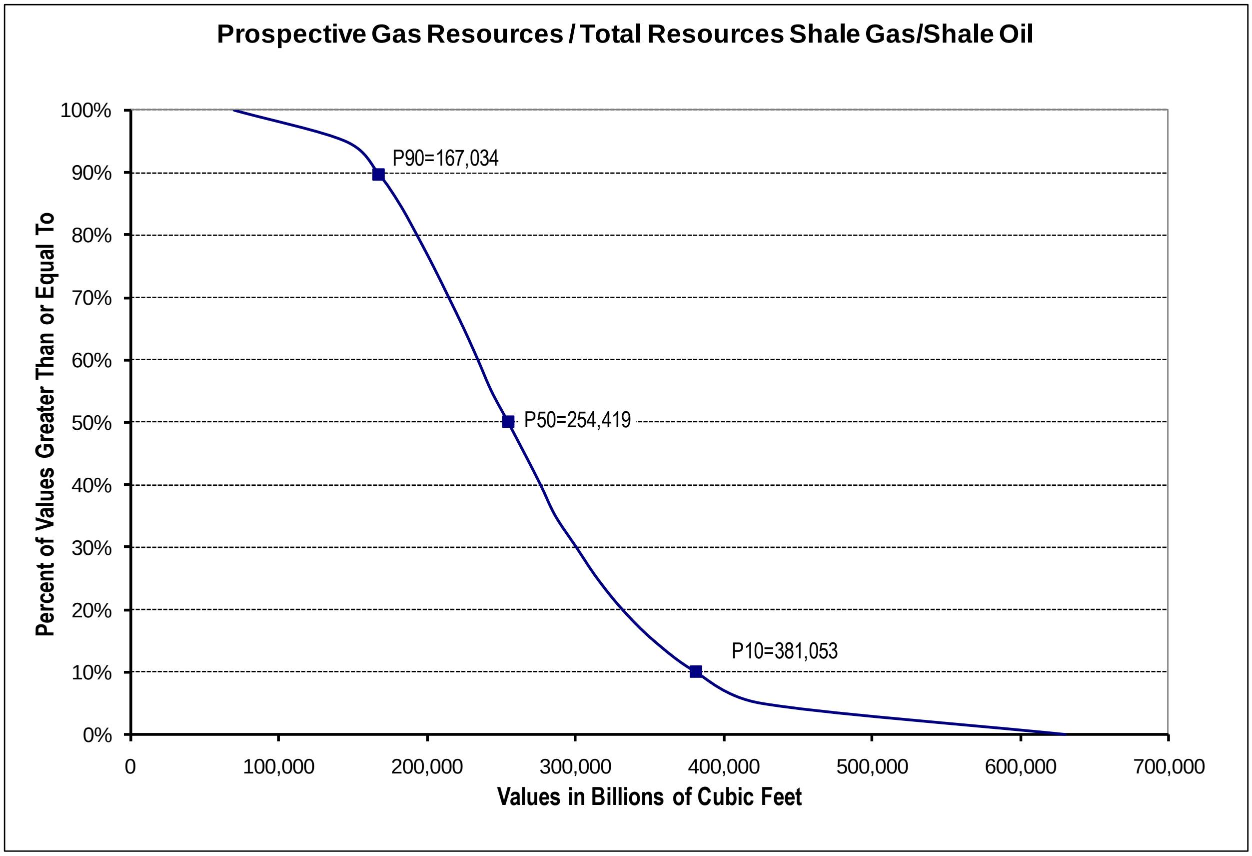


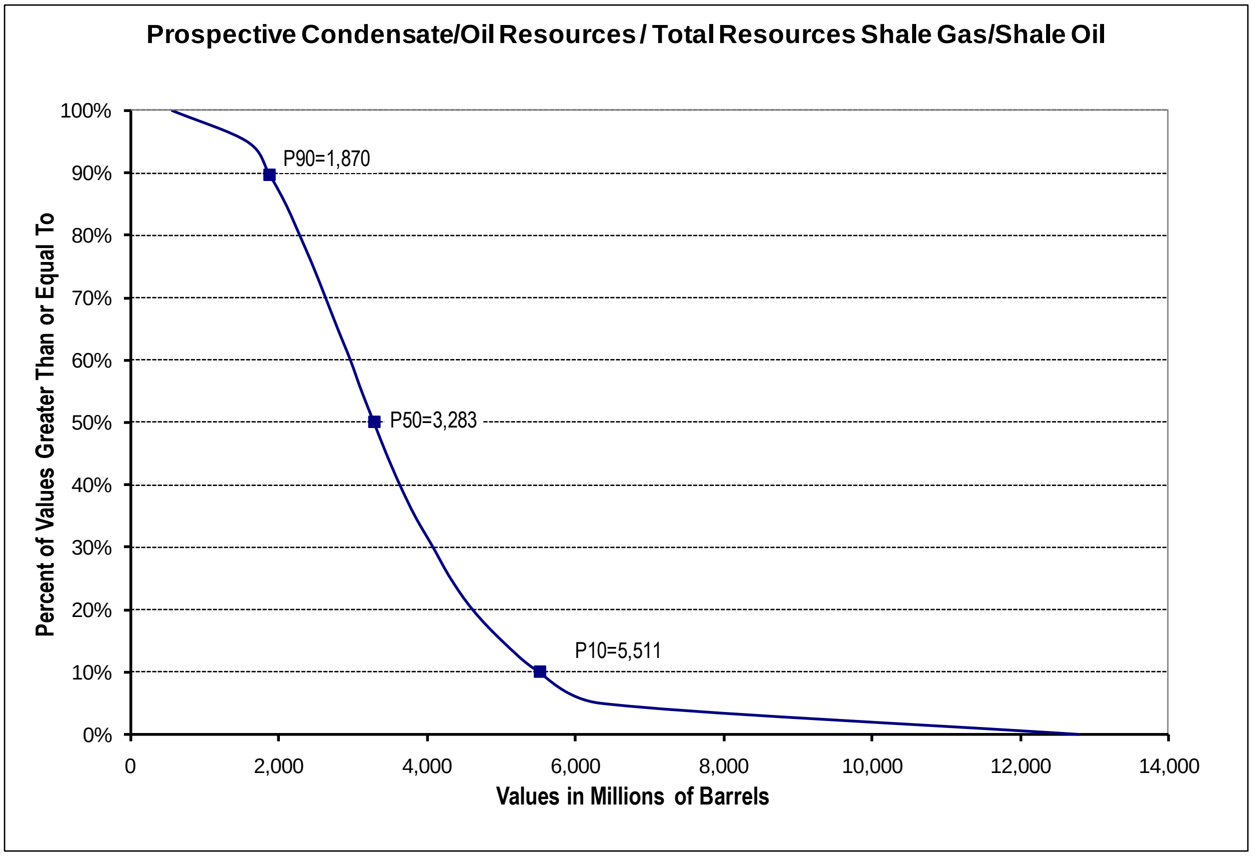


Total Contingent Resources, BCF / Barakupuria Coal Field
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
20
40
60
80
100
120
140
160
Values in Billions of Cubic Feet
P90=71
P50=88
P10=107

IDENTIFIED PROSPECTS AND LEADS

Shale Gas Area	Mean Prospective Gas Resources, BCF	Mean Prospective Oil Resources, MMBO
Bogra Slope Oil	1,176	2,210
Bogra Slope Gas	39,534	197
Surma Basin	23,332	117
Hatia Trough	109,277	543
Eastern Fold Belt	91,780	459
Total	**265,100**	**3,526**




Prospective Condensate/Oil Resources / Total Resources Shale Gas/Shale Oil
Percent of Values Greater Than or Equal To
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
P90=1,870
P50=3,283
P10=5,511
0
2,000
4,000
6,000
8,000
10,000
12,000
14,000
Values in Millions of Barrels

APPENDIX D

PROBABILISTIC INPUT PARAMETERS

MAPPED PROSPECTS AND LEADS

Petroleum System:	Block 2			
Prospect/Lead:	2-1 (Oligo-Eo-Cre)			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	5,578	6,562	7,546
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	21	24
Water Sat.	%	30	38	45
Drainage area	Acres	9,884	12,108	13,591
Net Pay	feet	66	131	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	98.4	147.6	196.9

Petroleum System:	Block 2			
Prospect/Lead:	2-2			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	13,944	14,929	15,913
Abandonment Pressure	Psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	5	10	15
Water Sat.	%	30	38	45
Drainage area	Acres	4,448	5,931	7,413
Net Pay	feet	328	623	705
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	590.6	705.4	2,788.9

Petroleum System:	Block 2			
Prospect/Lead:	2-3			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	17,061	18,046	19,030
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	5	10	15
Water Sat.	%	30	38	45
Drainage area	Acres	2,965	3,954	4,942
Net Pay	feet	328	623	705
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	590.6	705.4	2,788.9

Petroleum System:	Block 2			
Prospect/Lead:	Sherpur East			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	8,203	9,187	10,171
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	23	27
Water Sat.	%	30	38	45
Drainage area	Acres	9,390	11,120	12,355
Net Pay	feet	20	39	66
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	32.8	49.2	65.6

Petroleum System:	Block 3			
Prospect/Lead:	3-1			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	13,780	14,765	15,749
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	5	10	15
Water Sat.	%	30	38	45
Drainage area	Acres	7,413	9,884	12,355
Net Pay	feet	328	623	705
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	590.6	705.4	2,788.9

Petroleum System:	Block 3			
Prospect/Lead:	3-2			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	13,944	14,929	15,913
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	5	10	15
Water Sat.	%	30	38	45
Drainage area	Acres	12,849	14,826	16,556
Net Pay	feet	328	623	705
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	590.6	705.4	2,788.9

Petroleum System:	Block 3			
Prospect/Lead:	3-3			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	9,187	10,499	11,812
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	5	10	15
Water Sat.	%	30	38	45
Drainage area	Acres	4,942	6,919	8,649
Net Pay	feet	328	623	705
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	590.6	705.4	2,788.9

Petroleum System:	Block 3			
Prospect/Lead:	3-4			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	8,203	9,515	10,827
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	5	10	15
Water Sat.	%	30	38	45
Drainage area	Acres	1,483	1,977	2,718
Net Pay	feet	328	623	705
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	590.6	705.4	2,788.9

Petroleum System:	Block 3			
Prospect/Lead:	3-5			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	4,101	4,757	5,414
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	13,591	15,073	16,803
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 3			
Prospect/Lead:	3-6			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	5,578	6,890	8,203
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	13,591	15,073	16,803
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 3			
Prospect/Lead:	3-7			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	17,061	18,046	19,030
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	5	10	15
Water Sat.	%	30	38	45
Drainage area	Acres	6,672	7,907	9,884
Net Pay	feet	328	623	705
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	590.6	705.4	2,788.9

Petroleum System:	Block 3			
Prospect/Lead:	3-8			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	17,061	18,046	19,030
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	5	10	15
Water Sat.	%	30	38	45
Drainage area	Acres	2,965	3,954	4,942
Net Pay	feet	328	623	705
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	590.6	705.4	2,788.9

Petroleum System:	Block 3			
Prospect/Lead:	3-9			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	17,061	18,046	19,030
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	5	10	15
Water Sat.	%	30	38	45
Drainage area	Acres	2,965	3,954	4,942
Net Pay	feet	328	623	705
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	590.6	705.4	2,788.9

Petroleum System:	Block 3			
Prospect/Lead:	3-10			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	12,140	13,124	14,108
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	494	988	1,483
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 3			
Prospect/Lead:	3-11			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	12,140	13,124	14,108
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	1,483	1,977	2,471
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 3			
Prospect/Lead:	3-12			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	12,140	13,124	14,108
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	494	1,236	1,977
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 3			
Prospect/Lead:	3-13			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	12,140	13,124	14,108
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	494	988	1,483
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 3			
Prospect/Lead:	3-14			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	12,140	13,124	14,108
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	494	988	1,483
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 4			
Prospect/Lead:	4-1			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	14,436	15,421	16,405
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	5	10	15
Water Sat.	%	30	38	45
Drainage area	Acres	9,884	12,355	14,826
Net Pay	feet	328	623	705
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	590.6	705.4	2,788.9

Petroleum System:	Block 4			
Prospect/Lead:	4-2			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	14,436	15,421	16,405
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	5	10	15
Water Sat.	%	30	38	45
Drainage area	Acres	7,907	9,884	11,861
Net Pay	feet	328	623	705
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	590.6	705.4	2,788.9

Petroleum System:	Block 4			
Prospect/Lead:	4-3			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	14,436	15,421	16,405
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	5	10	15
Water Sat.	%	30	38	45
Drainage area	Acres	12,355	16,062	18,533
Net Pay	feet	328	623	705
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	590.6	705.4	2,788.9

Petroleum System:	Block 4			
Prospect/Lead:	4-4			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	9,843	11,155	12,468
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	247	494	741
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 4			
Prospect/Lead:	4-5			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	11,484	12,796	14,108
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	494	988	1,483
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 4			
Prospect/Lead:	4-6			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	11,484	12,796	14,108
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	494	1,260	1,977
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 4			
Prospect/Lead:	4-7			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	10,171	11,319	12,140
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	741	1,507	2,471
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 4			
Prospect/Lead:	4-8			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	10,171	11,319	12,140
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	494	1,260	1,977
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 4			
Prospect/Lead:	4-9			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	10,499	11,976	13,124
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	0	247	494
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 4			
Prospect/Lead:	4-10			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	12,140	13,452	14,765
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	741	1,507	2,224
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 4			
Prospect/Lead:	4-11			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	10,827	12,304	13,452
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	494	988	1,483
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 4			
Prospect/Lead:	4-12			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	12,140	13,124	14,108
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	494	988	1,483
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 4			
Prospect/Lead:	4-13			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	12,140	13,452	14,765
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	988	1,507	2,224
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 4			
Prospect/Lead:	4-14			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	13,124	14,272	15,421
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	494	1,260	1,977
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 4			
Prospect/Lead:	4-15			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	13,124	14,272	15,421
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	0	247	494
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 4			
Prospect/Lead:	4-16			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	12,140	13,616	14,765
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	494	1,260	1,977
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 4			
Prospect/Lead:	4-17			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	12,140	13,452	14,765
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	494	988	1,483
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 4			
Prospect/Lead:	4-18			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	12,140	13,452	14,765
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	494	1,260	1,977
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 4			
Prospect/Lead:	4-19			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	11,812	12,796	13,780
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	741	1,507	2,224
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 4			
Prospect/Lead:	4-20			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	11,812	12,796	13,780
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	5,683	7,413	8,649
Net Pay	feet	82	180	262
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 4			
Prospect/Lead:	4-21			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	17,061	18,210	19,686
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	5	10	15
Water Sat.	%	30	38	45
Drainage area	Acres	2,965	4,003	4,942
Net Pay	feet	328	623	705
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	590.6	705.4	2,788.9

Petroleum System:	Block 4			
Prospect/Lead:	4-22			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	17,061	18,210	19,686
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	5	10	15
Water Sat.	%	30	38	45
Drainage area	Acres	2,965	4,003	4,942
Net Pay	feet	328	623	705
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	590.6	705.4	2,788.9

Petroleum System:	Block 4			
Prospect/Lead:	4-23			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	17,061	18,210	19,686
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	5	10	15
Water Sat.	%	30	38	45
Drainage area	Acres	2,965	4,003	4,942
Net Pay	feet	328	623	705
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	590.6	705.4	2,788.9

Petroleum System:	Block 6			
Prospect/Lead:	6-3			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	5,906	7,054	8,203
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	21	25
Water Sat.	%	30	38	45
Drainage area	Acres	12,355	14,999	16,803
Net Pay	feet	98	180	246
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 6			
Prospect/Lead:	6-4 (L. & M. Mio.)			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	9,515	10,499	11,484
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	21	25
Water Sat.	%	30	38	45
Drainage area	Acres	4,201	4,992	5,931
Net Pay	feet	98	180	246
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 6			
Prospect/Lead:	6-5 (L. & M. Mio)			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	11,484	12,468	13,452
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	21	25
Water Sat.	%	30	38	45
Drainage area	Acres	13,591	14,999	16,803
Net Pay	feet	98	180	246
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 6			
Prospect/Lead:	6-7 (L. & M. Mio)			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	10,827	12,140	13,124
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	21	25
Water Sat.	%	30	38	45
Drainage area	Acres	12,355	14,802	16,803
Net Pay	feet	98	180	246
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 7			
Prospect/Lead:	Char Kajal			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	12,140	13,124	14,108
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	21	25
Water Sat.	%	30	38	45
Drainage area	Acres	11,120	13,097	14,826
Net Pay	feet	98	180	246
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 7			
Prospect/Lead:	Chandra mohan			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	13,780	14,765	15,749
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	21	25
Water Sat.	%	30	38	45
Drainage area	Acres	2,965	3,954	4,942
Net Pay	feet	98	180	246
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 7			
Prospect/Lead:	Amtoli			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	13,780	14,765	15,749
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	21	25
Water Sat.	%	30	38	45
Drainage area	Acres	1,730	2,471	3,212
Net Pay	feet	98	180	246
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	131.2	196.9	262.5

Petroleum System:	Block 8			
Prospect/Lead:	8-1 (L, M, E. Mio-Oligo)			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	2,953	3,773	4,593
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	16,062	19,002	21,004
Net Pay	feet	66	125	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	98.4	147.6	196.9

Petroleum System:	Block 8			
Prospect/Lead:	8-2 (E. Mio & Oligo)			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	4,593	5,742	6,562
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	4,448	5,510	6,672
Net Pay	feet	66	125	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	49.2	98.4	164.1

Petroleum System:	Block 8			
Prospect/Lead:	8-3			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	2,297	2,953	3,937
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	8,649	10,008	11,861
Net Pay	feet	66	125	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	49.2	98.4	164.1

Petroleum System:	Block 8			
Prospect/Lead:	8-4			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	2,297	3,117	3,937
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	3,707	4,596	6,178
Net Pay	feet	66	125	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	49.2	98.4	164.1

Petroleum System:	Block 8			
Prospect/Lead:	8-5A (L, M, E. Mio-Oligo)			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	4,922	6,234	7,874
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	2,224	2,990	3,707
Net Pay	feet	66	125	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	98.4	147.6	196.9

Petroleum System:	Block 8			
Prospect/Lead:	8-5B (L, M, E. Mio-Oligo)			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	5,578	7,054	8,203
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	2,965	4,003	4,942
Net Pay	feet	66	125	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	98.4	147.6	196.9

Petroleum System:	Block 8			
Prospect/Lead:	8-5C (L, M, E. Mio-Oligo)			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	7,218	8,531	9,843
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	3,459	4,596	5,931
Net Pay	feet	66	125	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	98.4	147.6	196.9

Petroleum System:	Block 8			
Prospect/Lead:	8-6 (L, M, E. Miocene)			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	3,609	5,086	6,234
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	25	30
Water Sat.	%	30	38	45
Drainage area	Acres	2,224	2,990	3,707
Net Pay	feet	66	125	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	98.4	147.6	196.9

Petroleum System:	Block 8			
Prospect/Lead:	8-7			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	16,405	18,046	19,686
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	5	10	15
Water Sat.	%	30	38	45
Drainage area	Acres	2,718	3,509	4,201
Net Pay	feet	328	623	984
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	590.6	705.4	2,788.9

Petroleum System:	Block 8			
Prospect/Lead:	8-8			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	16,405	18,046	19,686
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	5	10	15
Water Sat.	%	30	38	45
Drainage area	Acres	6,672	8,006	9,143
Net Pay	feet	328	623	984
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	590.6	705.4	2,788.9

Petroleum System:	Block 8			
Prospect/Lead:	8-9			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	16,405	18,046	19,686
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	5	10	15
Water Sat.	%	30	38	45
Drainage area	Acres	988	1,507	2,471
Net Pay	feet	328	623	984
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	590.6	705.4	2,788.9

Petroleum System:	Block 8			
Prospect/Lead:	8-10			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	15,749	17,061	18,702
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	5	10	15
Water Sat.	%	30	38	45
Drainage area	Acres	247	395	1,236
Net Pay	feet	328	623	984
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	590.6	705.4	2,788.9

Petroleum System:	Block 8			
Prospect/Lead:	8-11			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	14,765	16,569	18,046
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	5	10	15
Water Sat.	%	30	38	45
Drainage area	Acres	741	1,507	2,471
Net Pay	feet	328	623	984
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	590.6	705.4	2,788.9

Petroleum System:	Block 8			
Prospect/Lead:	8-12			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	11,484	13,452	14,765
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	5	10	15
Water Sat.	%	30	38	45
Drainage area	Acres	2,224	2,990	3,707
Net Pay	feet	328	623	984
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	590.6	705.4	2,788.9

Petroleum System:	Block 8			
Prospect/Lead:	8-13			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	11,484	13,124	14,765
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	5	10	15
Water Sat.	%	30	38	45
Drainage area	Acres	5,931	6,993	7,907
Net Pay	feet	328	623	984
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	590.6	705.4	2,788.9

Petroleum System:	Block 8			
Prospect/Lead:	8-14 (Eoc. & Cret)			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	7,546	8,203	8,859
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	5	10	15
Water Sat.	%	30	38	45
Drainage area	Acres	494	1,112	1,977
Net Pay	feet	328	623	984
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	590.6	705.4	2,788.9

Petroleum System:	Block 8			
Prospect/Lead:	8-15 (L. & M. Mio)			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	2,297	3,281	3,937
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	21	24
Water Sat.	%	30	38	45
Drainage area	Acres	2,471	3,509	4,448
Net Pay	feet	66	125	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	49.2	98.4	164.1

Petroleum System:	Block 8			
Prospect/Lead:	Lead A			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	8,859	10,499	12,140
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	21	24
Water Sat.	%	30	38	45
Drainage area	Acres	1,730	2,471	3,459
Net Pay	feet	66	125	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	49.2	98.4	164.1

Petroleum System:	Block 8			
Prospect/Lead:	Lead B			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	11,484	12,993	14,108
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	21	24
Water Sat.	%	30	38	45
Drainage area	Acres	494	1,483	2,471
Net Pay	feet	66	125	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	49.2	98.4	164.1

Petroleum System:	Block 8			
Prospect/Lead:	Lead D			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	13,124	14,502	15,749
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	21	24
Water Sat.	%	30	38	45
Drainage area	Acres	1,977	2,965	3,954
Net Pay	feet	66	125	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	49.2	98.4	164.1

Petroleum System:	Block 8			
Prospect/Lead:	Lead E			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	10,171	10,998	11,812
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	21	24
Water Sat.	%	30	38	45
Drainage area	Acres	1,977	2,965	3,954
Net Pay	feet	66	125	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	49.2	98.4	164.1

Petroleum System:	Block 8			
Prospect/Lead:	Lead F			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	3,937	5,250	6,562
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	21	24
Water Sat.	%	30	38	45
Drainage area	Acres	1,483	2,397	2,965
Net Pay	feet	66	125	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	49.2	98.4	164.1

Petroleum System:	Block 8			
Prospect/Lead:	Lead G			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	11,155	12,008	13,124
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	21	24
Water Sat.	%	30	38	45
Drainage area	Acres	4,942	6,672	8,649
Net Pay	feet	66	125	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	49.2	98.4	164.1

Petroleum System:	Block 8			
Prospect/Lead:	Lead H			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	15,342	15,998	16,654
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	21	24
Water Sat.	%	30	38	45
Drainage area	Acres	17,297	19,768	22,239
Net Pay	feet	66	125	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	60.0	90.0	100.0
Gross Sand	ft	49.2	98.4	164.1

Petroleum System:	Block 10			
Prospect/Lead:	10-2 (Char Jabbar) -- Total Block 10			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.800
Depth	ft	10,827	11,812	13,124
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	14	16	20
Water Sat.	%	40	42	45
Drainage area	Acres	12,355	18,533	22,239
Net Pay	feet	16	25	33
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	100.0	100.0
Gross Sand	ft	16.4	24.6	32.8

Petroleum System:	Block 11			
Prospect/Lead:	Netrakona			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	15,749	17,061	18,046
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	11	16	20
Water Sat.	%	26	32	47
Drainage area	Acres	24,711	29,653	32,124
Net Pay	feet	49	164	279
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	98.4	196.9	295.3

Petroleum System:	Block 11			
Prospect/Lead:	Bajitpur			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	15,749	17,061	18,046
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	11	16	20
Water Sat.	%	26	32	47
Drainage area	Acres	7,413	9,884	12,355
Net Pay	feet	49	164	279
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	98.4	196.9	295.3

Petroleum System:	Block 11			
Prospect/Lead:	Madon			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	15,749	17,061	18,046
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	11	16	20
Water Sat.	%	26	32	47
Drainage area	Acres	2,965	4,942	7,413
Net Pay	feet	49	164	279
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	98.4	196.9	295.3

Petroleum System:	Block 11			
Prospect/Lead:	Nandail			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	11,812	13,124	14,765
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	11	16	20
Water Sat.	%	26	32	47
Drainage area	Acres	16,062	19,768	22,239
Net Pay	feet	49	164	279
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	98.4	196.9	295.3

Petroleum System:	Block 11			
Prospect/Lead:	Nikli			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	11,812	13,124	14,765
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	11	16	20
Water Sat.	%	26	32	47
Drainage area	Acres	8,649	12,355	14,826
Net Pay	feet	49	164	279
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	98.4	196.9	295.3

Petroleum System:	Block 11			
Prospect/Lead:	Bhairab (11-2,3)			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	11,812	13,124	14,765
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	11	16	20
Water Sat.	%	26	32	47
Drainage area	Acres	6,178	9,884	12,355
Net Pay	feet	49	164	279
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	98.4	196.9	295.3

Petroleum System:	Block 11			
Prospect/Lead:	Haluaghat (11-1, Lead C)			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	11,484	13,780	16,405
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	10	13	18
Water Sat.	%	26	32	47
Drainage area	Acres	15	55	120
Net Pay	feet	49	164	279
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	98.4	196.9	295.3

Petroleum System:	Block 12			
Prospect/Lead:	12-10			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	9,187	9,843	10,499
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	16	18	20
Water Sat.	%	42	44	46
Drainage area	Acres	22,239	25,699	28,417
Net Pay	feet	69	92	125
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Block 12			
Prospect/Lead:	12-3 (BalarampurByronpur)			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.700	0.750	0.800
Depth	ft	15,093	15,798	16,733
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	10	13	18
Water Sat.	%	26	32	47
Drainage area	Acres	4,448	5,931	7,413
Net Pay	feet	197	312	492
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	246.1	328.1	492.2

Petroleum System:	Block 17			
Prospect/Lead:	Kuakata			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.457	0.750	0.800
Depth	ft	9,843	11,319	12,796
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	15	20	24
Water Sat.	%	30	38	45
Drainage area	Acres	74,132	92,664	102,549
Net Pay	feet	49	92	131
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	80.0	90.0	100.0
Gross Sand	ft	65.6	98.4	131.2

Petroleum System:	Block 17			
Prospect/Lead:	Adinath			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.457	0.750	0.800
Depth	ft	9,843	11,155	12,796
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	15	20	24
Water Sat.	%	30	38	45
Drainage area	Acres	18,533	30,888	40,772
Net Pay	feet	49	92	131
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	80.0	90.0	100.0
Gross Sand	ft	65.6	98.4	131.2

Petroleum System:	Block 19			
Prospect/Lead:	Lead 19-A			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	8,203	10,499	12,140
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	15	20	24
Water Sat.	%	30	38	45
Drainage area	Acres	49,421	69,189	79,074
Net Pay	feet	10	131	246
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	262.5	295.3	328.1
Gross Sand	ft	16.4	147.6	246.1

Petroleum System:	Block 19			
Prospect/Lead:	Lead 19-B			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.457	0.700	0.800
Depth	ft	10,827	12,796	14,765
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	15	20	24
Water Sat.	%	30	38	45
Drainage area	Acres	14,826	22,239	27,182
Net Pay	feet	10	131	246
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	262.5	295.3	328.1
Gross Sand	ft	16.4	147.6	246.1

Petroleum System:	Block 20			
Prospect/Lead:	Lead 20-A			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	6,234	7,218	8,203
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	21	24
Water Sat.	%	30	38	45
Drainage area	Acres	61,776	86,487	98,842
Net Pay	feet	10	131	246
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	80.0	90.0	100.0
Gross Sand	ft	16.4	147.6	246.1

Petroleum System:	Block 20			
Prospect/Lead:	Lead 20-B			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	5,578	6,562	7,546
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	21	24
Water Sat.	%	30	38	45
Drainage area	Acres	37,066	61,776	74,132
Net Pay	feet	10	131	246
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	80.0	90.0	100.0
Gross Sand	ft	16.4	147.6	246.1

Petroleum System:	Block 20			
Prospect/Lead:	Lead 20-C			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	9,515	10,499	11,484
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	21	24
Water Sat.	%	30	38	45
Drainage area	Acres	61,776	86,487	98,842
Net Pay	feet	10	131	246
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	80.0	90.0	100.0
Gross Sand	ft	16.4	147.6	246.1

Petroleum System:	Eastern Foldbelt Block 9			
Prospect/Lead:	Srikail North			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.457	0.750	0.850
Depth	ft	8,859	9,843	10,499
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	20	21
Water Sat.	%	32	35	40
Drainage area	Acres			
Net Pay	feet	16	43	66
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	70.0	80.0	90.0
Gross Sand	ft	23.0	49.2	82.0

Petroleum System:	Eastern Foldbelt Block 9			
Prospect/Lead:	Chandpur			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	8,859	9,843	10,499
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	20	21
Water Sat.	%	32	35	40
Drainage area	Acres			
Net Pay	feet	16	43	66
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	70.0	80.0	90.0
Gross Sand	ft	23.0	49.2	82.0

Petroleum System:	Eastern Foldbelt Block 9			
Prospect/Lead:	9-2			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	8,859	9,843	10,499
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	18	20	21
Water Sat.	%	32	35	40
Drainage area	Acres	17,297	17,989	18,533
Net Pay	feet	16	43	66
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	70.0	80.0	90.0
Gross Sand	ft	23.0	49.2	82.0

Petroleum System:	Eastern Foldbelt Block 10			
Prospect/Lead:	Sundalpur -- Total Eastern Foldbelt Block 10			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.457	0.750	0.800
Depth	ft	11,155	11,812	12,468
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	14	16	20
Water Sat.	%	40	42	45
Drainage area	Acres	4,448	4,942	5,189
Net Pay	feet	16	25	33
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	100.0	100.0
Gross Sand	ft	16.4	24.6	32.8

Petroleum System:	Eastern Foldbelt Block 11			
Prospect/Lead:	Kapasia -- Total Eastern Foldbelt Block 11			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	11,812	12,468	13,124
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	19	20	21
Water Sat.	%	25	30	33
Drainage area	Acres	86,487	89,699	93,900
Net Pay	feet	13	20	30
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	78.0	80.0	82.0
Gross Sand	ft	16.4	23.0	32.8

Petroleum System:	Eastern Foldbelt Block 12			
Prospect/Lead:	Chhatak East -- Total Eastern Foldbelt Block 12			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.700	0.750	0.800
Depth	ft	12,468	13,124	13,780
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	19	20	21
Water Sat.	%	25	30	33
Drainage area	Acres	34,595	38,054	39,537
Net Pay	feet	13	20	30
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	78.0	80.0	82.0
Gross Sand	ft	16.4	23.0	32.8

Petroleum System:	Eastern Foldbelt Block 13			
Prospect/Lead:	Darbesh			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	7,546	8,203	8,859
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	19	20	21
Water Sat.	%	15	17	23
Drainage area	Acres	3,954	4,942	5,683
Net Pay	feet	75	131	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	85.0	90.0	95.0
Gross Sand	ft	82.0	147.6	213.3

Petroleum System:	Eastern Foldbelt Block 13			
Prospect/Lead:	Dupitila			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	7,546	8,203	8,859
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	19	20	21
Water Sat.	%	15	17	23
Drainage area	Acres	3,459	3,954	4,448
Net Pay	feet	75	131	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	85.0	90.0	95.0
Gross Sand	ft	82.0	147.6	213.3

Petroleum System:	Eastern Foldbelt Block 14			
Prospect/Lead:	Fenchunganj East			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.750	0.800	0.850
Depth	ft	14,108	14,765	15,421
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	19	20	21
Water Sat.	%	15	17	23
Drainage area	Acres	3,212	3,707	4,448
Net Pay	feet	75	131	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	85.0	90.0	95.0
Gross Sand	ft	82.0	147.6	213.3

Petroleum System:	Eastern Foldbelt Block 14			
Prospect/Lead:	Patharia North Pitch			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.750	0.800	0.850
Depth	ft	10,827	11,484	12,140
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	19	20	21
Water Sat.	%	15	17	23
Drainage area	Acres	7,907	8,896	9,884
Net Pay	feet	75	131	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	85.0	90.0	95.0
Gross Sand	ft	82.0	147.6	213.3

Petroleum System:	Eastern Foldbelt Block 14			
Prospect/Lead:	Patharia West			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	9,187	9,843	10,499
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	19	20	21
Water Sat.	%	15	17	23
Drainage area	Acres	1,977	2,224	2,471
Net Pay	feet	75	131	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	85.0	90.0	95.0
Gross Sand	ft	82.0	147.6	213.3

Petroleum System:	Eastern Foldbelt Block 14			
Prospect/Lead:	Harargaj			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.750	0.800	0.850
Depth	ft	10,827	11,484	12,140
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	19	20	21
Water Sat.	%	15	17	23
Drainage area	Acres	35,830	37,560	39,537
Net Pay	feet	75	131	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	85.0	90.0	95.0
Gross Sand	ft	82.0	147.6	213.3

Petroleum System:	Eastern Foldbelt Block 14			
Prospect/Lead:	Harargaj North			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.750	0.800	0.850
Depth	ft	10,827	11,484	12,140
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	19	20	21
Water Sat.	%	15	17	23
Drainage area	Acres	8,154	8,896	9,884
Net Pay	feet	75	131	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	85.0	90.0	95.0
Gross Sand	ft	82.0	147.6	213.3

Petroleum System:	Eastern Foldbelt Block 14			
Prospect/Lead:	Batchia North Pitch			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.750	0.800	0.850
Depth	ft	10,827	11,484	12,140
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	19	20	21
Water Sat.	%	15	17	23
Drainage area	Acres	22,239	24,711	27,182
Net Pay	feet	75	131	197
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	85.0	90.0	95.0
Gross Sand	ft	82.0	147.6	213.3

Petroleum System:	Eastern Foldbelt Block 15				
Prospect/Lead:	Semutang East Strat				
			Minimum	Most Likely	Maximum
Gas Gravity			0.56	0.60	0.65
N2	%		0.00%	0.35%	0.80%
CO2	%		0.00%	0.26%	1.00%
H2S	%		0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019	
press gradient	psi/ft	0.800	0.850	0.900	
Depth	ft	7,710	8,399	9,187	
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr	
Porosity	%	10	12	15	
Water Sat.	%	42	44	46	
Drainage area	Acres	247	618	1,236	
Net Pay	feet	59	82	125	
Condensate Content	Bbl/MMCF	0	3	12	
Net/Gross Ratio	fraction	80.0	90.0	100.0	
Gross Sand	ft	75.5	98.4	131.2	

Petroleum System:	Eastern Foldbelt Block 15			
Prospect/Lead:	Semutang West Flank			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.800	0.850	0.900
Depth	ft	7,874	8,531	9,187
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	10	12	15
Water Sat.	%	42	44	46
Drainage area	Acres	494	840	1,236
Net Pay	feet	69	92	125
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 15			
Prospect/Lead:	Semutang South			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.500	0.850	0.900
Depth	ft	7,546	8,203	8,859
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	10	12	15
Water Sat.	%	42	44	46
Drainage area	Acres	741	1,236	1,730
Net Pay	feet	69	92	125
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 15			
Prospect/Lead:	Sandwip West			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.700	0.800	0.900
Depth	ft	11,319	11,976	12,632
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	16	18	20
Water Sat.	%	42	44	46
Drainage area	Acres	21,004	23,475	24,711
Net Pay	feet	69	92	125
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 15			
Prospect/Lead:	Sandwip South			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.700	0.800	0.900
Depth	ft	10,663	11,319	11,976
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	16	18	20
Water Sat.	%	42	44	46
Drainage area	Acres	4,201	4,942	5,683
Net Pay	feet	59	82	125
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	80.0	90.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 16			
Prospect/Lead:	Sangu East			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.433	0.456	0.479
Depth	ft	11,812	12,468	13,124
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	10	12	15
Water Sat.	%	30	35	45
Drainage area	Acres	2,471	3,212	3,707
Net Pay	feet	33	92	105
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 16			
Prospect/Lead:	Manpura			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.700	0.750	0.800
Depth	ft	12,796	13,452	14,108
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	10	12	15
Water Sat.	%	30	35	45
Drainage area	Acres	4,942	5,683	6,178
Net Pay	feet	33	92	105
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 16			
Prospect/Lead:	Maiskhali			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.700	0.750	0.800
Depth	ft	12,796	13,452	14,108
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	10	12	15
Water Sat.	%	30	35	45
Drainage area	Acres	4,942	5,683	6,178
Net Pay	feet	131	180	230
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	80.0	90.0	100.0
Gross Sand	ft	164.1	196.9	229.7

Petroleum System:	Eastern Foldbelt Block 16			
Prospect/Lead:	Matabari Deep MS1			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.700	0.750	0.800
Depth	ft	14,765	15,421	16,077
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	10	12	15
Water Sat.	%	30	35	45
Drainage area	Acres	9,884	12,355	13,591
Net Pay	feet	33	66	131
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	70.0	85.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 16			
Prospect/Lead:	Matabari Shallow MS2			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.406	0.427	0.449
Depth	ft	4,036	4,692	5,348
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	10	12	15
Water Sat.	%	30	35	45
Drainage area	Acres	45,714	74,132	239,692
Net Pay	feet	33	66	131
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	70.0	85.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 16			
Prospect/Lead:	Sangu South			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.457	0.750	0.800
Depth	ft	11,484	13,124	14,765
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	10	12	15
Water Sat.	%	30	35	45
Drainage area	Acres	4,942	6,919	8,649
Net Pay	feet	33	66	131
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	70.0	85.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 16			
Prospect/Lead:	Hatia			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.457	0.500	0.800
Depth	ft	9,843	11,287	12,468
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	10	12	15
Water Sat.	%	30	35	45
Drainage area	Acres	25,946	28,170	29,653
Net Pay	feet	33	66	131
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	70.0	85.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 16			
Prospect/Lead:	Magnama			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.433	0.456	0.479
Depth	ft	8,400	10,100	11,600
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	10	12	15
Water Sat.	%	30	35	45
Drainage area	Acres	6,000	24,000	38,000
Net Pay	feet	33	66	131
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	70.0	85.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 16			
Prospect/Lead:	Kutubdia			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.433	0.456	0.479
Depth	ft	9,843	11,319	12,796
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	10	12	15
Water Sat.	%	30	35	45
Drainage area	Acres	35,830	40,278	44,479
% Recovery				
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	70.0	85.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 16			
Prospect/Lead:	Jaldi			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.433	0.456	0.479
Depth	ft	7,874	9,187	10,499
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	10	12	15
Water Sat.	%	30	35	45
Drainage area	Acres	17,297	19,274	21,004
Net Pay	feet	33	66	131
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	70.0	85.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 16			
Prospect/Lead:	Sonadia			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.700	0.750	0.800
Depth	ft	13,780	14,666	15,421
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	10	12	15
Water Sat.	%	30	35	45
Drainage area	Acres	2,471	3,459	4,695
Net Pay	feet	33	66	131
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	70.0	85.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 17			
Prospect/Lead:	Ukhia			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.700	0.750	0.800
Depth	ft	13,124	13,780	14,436
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	13	15	15
Water Sat.	%	30	35	45
Drainage area	Acres	17,297	19,768	21,004
Net Pay	feet	33	92	105
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 17			
Prospect/Lead:	D (Ohlataung)			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	9,187	9,843	10,499
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	13	15	15
Water Sat.	%	30	35	45
Drainage area	Acres	19,768	22,239	23,475
Net Pay	feet	33	92	105
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 17			
Prospect/Lead:	E (Inani)			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.700	0.750	0.800
Depth	ft	10,827	11,484	12,140
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	13	15	15
Water Sat.	%	30	35	45
Drainage area	Acres	9,884	12,355	13,591
Net Pay	feet	33	92	105
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 17			
Prospect/Lead:	I (Dakhinila)			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	9,187	9,843	10,499
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	13	15	15
Water Sat.	%	30	35	45
Drainage area	Acres	35,830	39,537	42,008
Net Pay	feet	33	92	105
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 17			
Prospect/Lead:	J			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.457	0.500	0.800
Depth	ft	8,203	9,843	11,484
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	13	15	15
Water Sat.	%	30	35	45
Drainage area	Acres	16,062	18,533	19,768
Net Pay	feet	33	92	105
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 17			
Prospect/Lead:	Q			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.457	0.500	0.800
Depth	ft	8,203	9,843	11,484
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	13	15	15
Water Sat.	%	30	35	45
Drainage area	Acres	5,000	20,000	25,000
Net Pay	feet	33	92	105
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 17			
Prospect/Lead:	R			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.457	0.500	0.800
Depth	ft	8,203	9,843	11,484
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	13	15	15
Water Sat.	%	30	35	45
Drainage area	Acres	5,000	20,000	25,000
Net Pay	feet	33	92	105
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 18			
Prospect/Lead:	Teknaf			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.420	0.457	0.550
Depth	ft	10,827	11,484	12,140
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	13	15	15
Water Sat.	%	30	35	45
Drainage area	Acres	7,413	9,884	11,120
Net Pay	feet	33	92	105
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 18			
Prospect/Lead:	Coral Dip			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.700	0.750	0.800
Depth	ft	12,468	13,452	14,436
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	13	15	15
Water Sat.	%	30	35	45
Drainage area	Acres	27,182	30,888	33,359
Net Pay	feet	33	92	105
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 18			
Prospect/Lead:	St Martin Island O			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.700	0.750	0.800
Depth	ft	12,468	13,124	13,780
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	13	15	15
Water Sat.	%	30	35	45
Drainage area	Acres	12,355	16,062	18,533
Net Pay	feet	33	92	105
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 22			
Prospect/Lead:	Bandarban			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.700	0.750	0.800
Depth	ft	13,124	13,780	14,436
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	16	18	20
Water Sat.	%	42	44	46
Drainage area	Acres	56,834	61,529	65,483
Net Pay	feet	69	92	125
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 22			
Prospect/Lead:	Barkal			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.450	0.750	0.800
Depth	ft	9,187	9,843	10,499
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	16	18	20
Water Sat.	%	42	44	46
Drainage area	Acres	22,239	25,699	28,417
Net Pay	feet	69	92	125
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 22			
Prospect/Lead:	Belachari			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.700	0.750	0.800
Depth	ft	10,827	11,484	12,140
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	16	18	20
Water Sat.	%	42	44	46
Drainage area	Acres	30,888	34,595	37,066
Net Pay	feet	69	92	125
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 22			
Prospect/Lead:	Bhuachari			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.450	0.750	0.800
Depth	ft	9,187	9,843	10,499
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	16	18	20
Water Sat.	%	42	44	46
Drainage area	Acres	7,413	10,131	11,614
Net Pay	feet	69	92	125
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 22			
Prospect/Lead:	Changohtang			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.450	0.750	0.800
Depth	ft	9,187	9,843	10,499
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	16	18	20
Water Sat.	%	42	44	46
Drainage area	Acres	14,826	16,556	18,533
Net Pay	feet	69	92	125
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 22			
Prospect/Lead:	Gilachari			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.450	0.750	0.800
Depth	ft	8,203	9,843	11,484
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	16	18	20
Water Sat.	%	42	44	46
Drainage area	Acres	13,591	15,321	16,556
Net Pay	feet	69	92	125
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 22			
Prospect/Lead:	Gobamura			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.450	0.750	0.800
Depth	ft	8,203	9,843	11,484
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	16	18	20
Water Sat.	%	42	44	46
Drainage area	Acres	27,182	30,641	33,359
Net Pay	feet	69	92	125
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 22			
Prospect/Lead:	Kasalang			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.450	0.750	0.800
Depth	ft	8,203	9,843	11,484
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	16	18	20
Water Sat.	%	42	44	46
Drainage area	Acres	27,182	30,641	33,359
Net Pay	feet	69	92	125
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 22			
Prospect/Lead:	Matamuhuri			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.450	0.750	0.800
Depth	ft	8,203	9,843	11,484
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	16	18	20
Water Sat.	%	42	44	46
Drainage area	Acres	103,784	111,939	117,375
Net Pay	feet	69	92	125
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 22			
Prospect/Lead:	Shishak			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.450	0.750	0.800
Depth	ft	8,203	9,843	11,484
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	16	18	20
Water Sat.	%	42	44	46
Drainage area	Acres	9,884	11,614	12,849
Net Pay	feet	69	92	125
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

Petroleum System:	Eastern Foldbelt Block 22			
Prospect/Lead:	Uttan Chhatra			
		Minimum	Most Likely	Maximum
Gas Gravity		0.56	0.60	0.65
N2	%	0.00%	0.35%	0.80%
CO2	%	0.00%	0.26%	1.00%
H2S	%	0.00%	0.00%	0.00%
temp gradient	°F/ft	0.010	0.014	0.019
press gradient	psi/ft	0.450	0.750	0.800
Depth	ft	8,203	9,843	11,484
Abandonment Pressure	psia	0.1 x pr	0.14 x pr	0.2 x pr
Porosity	%	16	18	20
Water Sat.	%	42	44	46
Drainage area	Acres	49,421	56,093	59,305
Net Pay	feet	69	92	125
Condensate Content	Bbl/MMCF	0	3	12
Net/Gross Ratio	fraction	90.0	95.0	100.0
Gross Sand	ft	75.5	98.4	131.2

UNMAPPED

Petroleum System:	unmapped undiscovered resources			
Prospect/Lead:	Surma Basin			
		Minimum	Most Likely	Maximum
Number of Fields		7	12	80
CGR	Bbl/MMCF	0	3	12
		Mean	St. Deviation	Shift
Size of Fields	BCF	222.71	908.95	42
Number of Mapped Prospects/Leads			19	

Petroleum System:	unmapped undiscovered resources			
Prospect/Lead:	Eastern Foldbelt			
		Minimum	Most Likely	Maximum
Number of Fields		1	6	15
CGR	Bbl/MMCF	0	3	12
		Mean	St. Deviation	Shift
Size of Fields	BCF	28.75	35.8	42
Number of Mapped Prospects/Leads			11	

Petroleum System:	unmapped undiscovered resources			
Prospect/Lead:	Faulted Anticlines			
		Minimum	Most Likely	Maximum
Number of Fields		2	11	35
CGR	Bbl/MMCF	0	3	12
		Mean	St. Deviation	Shift
Size of Fields	BCF	72.02	170.67	42
Number of Mapped Prospects/Leads			4	

Petroleum System:	unmapped undiscovered resources			
Prospect/Lead:	Folded Anticlines			
		Minimum	Most Likely	Maximum
Number of Fields		12	51	160
CGR	Bbl/MMCF	0	3	12
		Mean	St. Deviation	Shift
Size of Fields	BCF	232.06	899.03	42
Number of Mapped Prospects/Leads			29	

Petroleum System:	unmapped undiscovered resources			
Prospect/Lead:	Western Slope			
		Minimum	Most Likely	Maximum
Number of Fields		1	10	55
CGR	Bbl/MMCF	0	3	12
		Mean	St. Deviation	Shift
Size of Fields	BCF	98.32	408.6	42
Number of Mapped Prospects/Leads			41	

Petroleum System:	unmapped undiscovered resources			
Prospect/Lead:	Western Platform			
		Minimum	Most Likely	Maximum
Number of Fields		1	3	12
CGR	Bbl/MMCF	0	3	12
		Mean	St. Deviation	Shift
Size of Fields	BCF	28.75	35.8	42
Number of Mapped Prospects/Leads			36	

SHALE OIL AND SHALE GAS

Petroleum System:	Shale Oil			
Prospect/Lead:	Bogra Slope Oil			
		Minimum	Most Likely	Maximum
Area	Acres	208,087	1,040,436	2,080,871
Thickness	feet	24	120	240
Expected Oil Content	Bbl/acre-ft	6	12	21
GOR	SCF/Bbl	200	400	1000

Petroleum System:	Shale Gas			
Prospect/Lead:	Bogra Slope Gas			
		Minimum	Most Likely	Maximum
Area	Acres	208,087	1,040,436	2,080,871
Thickness	feet	24	118	350
Expected Gas Content	MCF/acre-ft	145	182	218
CGR	Bbl/MMCF	0	3	12

Petroleum System:	Shale Gas			
Prospect/Lead:	Surma Basin			
		Minimum	Most Likely	Maximum
Area	Acres	190,444	952,219	1,904,438
Thickness	feet	18	100	200
Expected Gas Content	MCF/acre-ft	145	182	218
CGR	Bbl/MMCF	0	3	12

Petroleum System:	Shale Gas			
Prospect/Lead:	Hatia Trough			
		Minimum	Most Likely	Maximum
Area	Acres	829,136	4,145,681	8,291,361
Thickness	feet	18	83	240
Expected Gas Content	MCF/acre-ft	145	182	218
CGR	Bbl/MMCF	0	3	12

Petroleum System:	Shale Gas			
Prospect/Lead:	Eastern Fold Belt			
		Minimum	Most Likely	Maximum
Area	Acres	584,675	2,923,376	5,846,751
Thickness	feet	48	120	240
Expected Gas Content	MCF/acre-ft	145	182	218
CGR	Bbl/MMCF	0	3	12

CBM

Coal Field:	Barakupuria			
Layer:	Seam II			
		Min	Mode	Max
Area, acres	187			
Average Net Coal Thickness, ft	48	45.8	47.9	50.0
Shale Density, tons/acre-ft	2,276	1,789	2,276	2,763
Gas Content, SCF/ton	339	230	339	448
Recovery Factor	65%	50%	65%	80%

Coal Field:	Barakupuria			
Layer:	Seam III			
		Min	Mode	Max
Area, acres	277			
Average Net Coal Thickness, ft	12	4.3	11.2	21.7
Coal Density, tons/acre-ft	1,856	1,826	1,856	1,887
Gas Content, SCF/ton	339	230	339	448
Recovery Factor	65%	50%	65%	80%

Coal Field:	Barakupuria			
Layer:	Seam IV			
		Min	Mode	Max
Area, acres	795			
Average Net Coal Thickness, ft	23	10.24	24.39	33.43
Shale Density, tons/acre-ft	2,220	1,702	2,220	2,738
Gas Content, SCF/ton	339	230	339	448
Recovery Factor	65%	50%	65%	80%

Coal Field:	Barakupuria			
Layer:	Seam V			
		Min	Mode	Max
Area, acres	1,086			
Average Net Coal Thickness, ft	18	4.3	15.3	34.0
Coal Density, tons/acre-ft	1,912	1,789	1,912	2,035
Gas Content, SCF/ton	339	230	339	448
Recovery Factor	65%	50%	65%	80%

Coal Field:	Barakupuria			
Layer:	Seam VI			
		Min	Mode	Max
Area, acres	1,538			
Average Net Coal Thickness, ft	107	71.0	112.5	139.0
Shale Density, tons/acre-ft	1,801	1,690	1,801	1,912
Gas Content, SCF/ton	339	230	339	448
Recovery Factor	65%	50%	65%	80%

Coal Field:	Dighipara			
Layer:	Seam I			
		Min	Mode	Max
Area, acres	1,236			
Average Net Coal Thickness, ft	58	33.5	55.8	83.7
Coal Density, tons/acre-ft	1,616	1,456	1,616	1,776
Gas Content, SCF/ton	388	212	388	565
Recovery Factor	65%	50%	65%	80%

Coal Field:	Dighipara			
Layer:	Seam II			
		Min	Mode	Max
Area, acres	1,236			
Average Net Coal Thickness, ft	115	66.9	111.6	167.3
Shale Density, tons/acre-ft	1,616	1,456	1,616	1,776
Gas Content, SCF/ton	388	212	388	565
Recovery Factor	65%	50%	65%	80%

Coal Field:	Dighipara			
Layer:	Seam III			
		Min	Mode	Max
Area, acres	1,236			
Average Net Coal Thickness, ft	24	13.8	23.0	34.5
Coal Density, tons/acre-ft	1,616	1,456	1,616	1,776
Gas Content, SCF/ton	388	212	388	565
Recovery Factor	65%	50%	65%	80%

Coal Field:	Dighipara			
Layer:	Seam IV			
		Min	Mode	Max
Area, acres	1,236			
Average Net Coal Thickness, ft	7	3.94	6.56	9.84
Shale Density, tons/acre-ft	1,616	1,456	1,616	1,776
Gas Content, SCF/ton	388	212	388	565
Recovery Factor	65%	50%	65%	80%

Coal Field:	Dighipara			
Layer:	Seam V			
		Min	Mode	Max
Area, acres	1,236			
Average Net Coal Thickness, ft	5	2.7	4.5	6.7
Coal Density, tons/acre-ft	1,616	1,456	1,616	1,776
Gas Content, SCF/ton	388	212	388	565
Recovery Factor	65%	50%	65%	80%

Coal Field:	Jamalganj			
Layer:	Seam I			
		Min	Mode	Max
Area, acres	2,881			
Average Net Coal Thickness, ft	23	5.0	23.3	41.6
Coal Density, tons/acre-ft	2,159	1,542	2,159	2,775
Gas Content, SCF/ton	297	141	297	452
Recovery Factor	65%	50%	65%	80%

Coal Field:	Jamalganj			
Layer:	Seam II			
		Min	Mode	Max
Area, acres	2,881			
Average Net Coal Thickness, ft	23	8.4	18.8	40.9
Coal Density, tons/acre-ft	2,159	1,542	2,159	2,775
Gas Content, SCF/ton	297	141	297	452
Recovery Factor	65%	50%	65%	80%

Coal Field:	Jamalganj			
Layer:	Seam III			
		Min	Mode	Max
Area, acres	2,881			
Average Net Coal Thickness, ft	81	14.0	75.5	153.6
Coal Density, tons/acre-ft	2,159	1,542	2,159	2,775
Gas Content, SCF/ton	297	141	297	452
Recovery Factor	65%	50%	65%	80%

Coal Field:	Jamalganj			
Layer:	Seam IV			
		Min	Mode	Max
Area, acres	2,881			
Average Net Coal Thickness, ft	45	14.93	38.43	81.30
Coal Density, tons/acre-ft	2,159	1,542	2,159	2,775
Gas Content, SCF/ton	297	141	297	452
Recovery Factor	65%	50%	65%	80%

Coal Field:	Jamalganj			
Layer:	Seam V			
		Min	Mode	Max
Area, acres	2,881			
Average Net Coal Thickness, ft	39	7.7	41.0	68.8
Coal Density, tons/acre-ft	2,159	1,542	2,159	2,775
Gas Content, SCF/ton	297	141	297	452
Recovery Factor	65%	50%	65%	80%

Coal Field:	Jamalganj			
Layer:	Seam VI			
		Min	Mode	Max
Area, acres	2,881			
Average Net Coal Thickness, ft	22	8.4	21.8	36.1
Coal Density, tons/acre-ft	2,159	1,542	2,159	2,775
Gas Content, SCF/ton	297	141	297	452
Recovery Factor	65%	50%	65%	80%

Coal Field:	Jamalganj			
Layer:	Seam VII			
		Min	Mode	Max
Area, acres	2,881			
Average Net Coal Thickness, ft	35	10.5	41.0	52.0
Coal Density, tons/acre-ft	2,159	1,542	2,159	2,775
Gas Content, SCF/ton	297	141	297	452
Recovery Factor	65%	50%	65%	80%

Coal Field:	Khalaspir			
Layer:	Zone I			
		Min	Mode	Max
Area, acres	3,030	0.36		1.91
Average Net Coal Thickness, ft	60	19.8	55.6	106.0
Coal Density, tons/acre-ft	2,159	1,542	2,159	2,775
Gas Content, SCF/ton	388	212	388	565
Recovery Factor	65%	50%	65%	80%

Coal Field:	Khalaspir			
Layer:	Zone II			
		Min	Mode	Max
Area, acres	3,030	0.72		1.23
Average Net Coal Thickness, ft	32	23.4	32.6	40.0
Shale Density, tons/acre-ft	2,159	1,542	2,159	2,775
Gas Content, SCF/ton	388	212	388	565
Recovery Factor	65%	50%	65%	80%

Coal Field:	Khalaspir			
Layer:	Zone III			
		Min	Mode	Max
Area, acres	3,030	0.75		1.50
Average Net Coal Thickness, ft	4	3.0	4.0	6.0
Coal Density, tons/acre-ft	2,159	1,542	2,159	2,775
Gas Content, SCF/ton	388	212	388	565
Recovery Factor	65%	50%	65%	80%

Coal Field:	Khalaspir			
Layer:	Zone IV			
		Min	Mode	Max
Area, acres	3,030	0.55		1.40
Average Net Coal Thickness, ft	21	11.5	20.9	29.2
Shale Density, tons/acre-ft	2,159	1,542	2,159	2,775
Gas Content, SCF/ton	388	212	388	565
Recovery Factor	65%	50%	65%	80%

Coal Field:	Khalaspir			
Layer:	Zone V			
		Min	Mode	Max
Area, acres	3,030			
Average Net Coal Thickness, ft	8	5.0	7.5	11.3
Coal Density, tons/acre-ft	2,159	1,542	2,159	2,775
Gas Content, SCF/ton	388	212	388	565
Recovery Factor	65%	50%	65%	80%

Coal Field:	Khalaspir			
Layer:	Zone VI			
		Min	Mode	Max
Area, acres	3,030			
Average Net Coal Thickness, ft	10	3.9	8.9	18.5
Shale Density, tons/acre-ft	2,159	1,542	2,159	2,775
Gas Content, SCF/ton	388	212	388	565
Recovery Factor	65%	50%	65%	80%

Coal Field:	Khalaspir			
Layer:	Zone VII			
		Min	Mode	Max
Area, acres	3,030			
Average Net Coal Thickness, ft	6	4.2	5.4	8.0
Shale Density, tons/acre-ft	2,159	1,542	2,159	2,775
Gas Content, SCF/ton	388	212	388	565
Recovery Factor	65%	50%	65%	80%

Coal Field:	Khalaspir			
Layer:	Zone VIII			
		Min	Mode	Max
Area, acres	3,030			
Average Net Coal Thickness, ft	4	1.0	4	7
Shale Density, tons/acre-ft	2,159	1,542	2,159	2,775
Gas Content, SCF/ton	388	212	388	565
Recovery Factor	65%	50%	65%	80%

Coal Field:	Phulbari			
Layer:	Seam I			
		Min	Mode	Max
Area, acres	3,064			
Average Net Coal Thickness, ft	11	6.6	11.0	16.5
Coal Density, tons/acre-ft	2,159	1,542	2,159	2,775
Gas Content, SCF/ton	388	212	388	565
Recovery Factor	65%	50%	65%	80%

Coal Field:	Phulbari			
Layer:	Seam II			
		Min	Mode	Max
Area, acres	3,064			
Average Net Coal Thickness, ft	36	20.8	34.7	52.1
Shale Density, tons/acre-ft	2,159	1,542	2,159	2,775
Gas Content, SCF/ton	388	212	388	565
Recovery Factor	65%	50%	65%	80%

Coal Field:	Phulbari			
Layer:	Seam III			
		Min	Mode	Max
Area, acres	3,064			
Average Net Coal Thickness, ft	25	14.4	24.0	36.0
Coal Density, tons/acre-ft	2,159	1,542	2,159	2,775
Gas Content, SCF/ton	388	212	388	565
Recovery Factor	65%	50%	65%	80%

Coal Field:	Phulbari			
Layer:	Seam IV			
		Min	Mode	Max
Area, acres	3,064			
Average Net Coal Thickness, ft	20	11.48	19.13	28.69
Shale Density, tons/acre-ft	2,159	1,542	2,159	2,775
Gas Content, SCF/ton	388	212	388	565
Recovery Factor	65%	50%	65%	80%

Coal Field:	Phulbari			
Layer:	Seam V			
		Min	Mode	Max
Area, acres	3,064			
Average Net Coal Thickness, ft	16	9.5	15.8	23.8
Coal Density, tons/acre-ft	2,159	1,542	2,159	2,775
Gas Content, SCF/ton	388	212	388	565
Recovery Factor	65%	50%	65%	80%

Coal Field:	Phulbari			
Layer:	Seam VI			
		Min	Mode	Max
Area, acres	3,064			
Average Net Coal Thickness, ft	16	9.2	15.3	22.9
Shale Density, tons/acre-ft	2,159	1,542	2,159	2,775
Gas Content, SCF/ton	388	212	388	565
Recovery Factor	65%	50%	65%	80%

Coal Field:	Phulbari			
Layer:	Seam VII			
		Min	Mode	Max
Area, acres	3,064			
Average Net Coal Thickness, ft	16	9.2	15.3	23.0
Shale Density, tons/acre-ft	2,159	1,542	2,159	2,775
Gas Content, SCF/ton	388	212	388	565
Recovery Factor	65%	50%	65%	80%

Coal Field:	Phulbari			
Layer:	Seam VIII			
		Min	Mode	Max
Area, acres	3,064			
Average Net Coal Thickness, ft	38	22.0	36.7	55.1
Shale Density, tons/acre-ft	2,159	1,542	2,159	2,775
Gas Content, SCF/ton	388	212	388	565
Recovery Factor	65%	50%	65%	80%