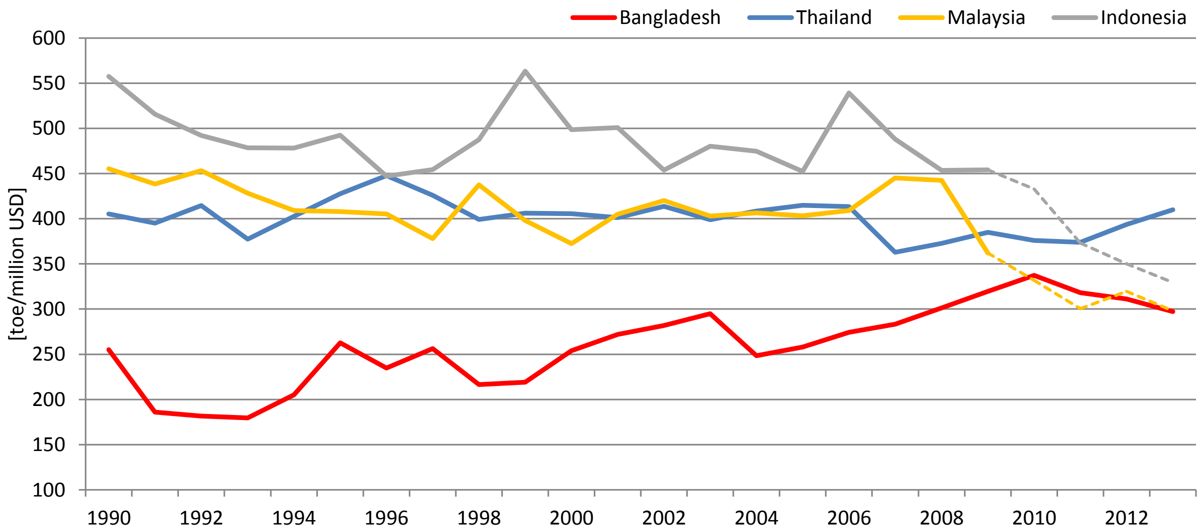


Source: Prepared by the Study Team using World Bank database and IEA statistics

Note) Declining trend of energy consumption in Malaysia and Indonesia from 2010 is considered a statistical error

Figure 7-25 Industrial Sector's Energy Consumption per Sectorial Value Added

One of the possible reasons why the ratio of industrial sector's energy consumption to sectorial GDP is creeping up (GDP elasticity higher than 1) in Bangladesh is that the economic development (=industrialization) of this country is still at an early stage and that a shift from labor-intensive industries to energy-consuming industries is in process.

Referring to the historical trend of some ASEAN countries as benchmark, this study assumes that the gradually increasing trend of industrial sector's GDP intensity will continue to increase up to 400 toe/million USD, as shown in Figure 7-26. By multiplying the prospects of this ratio by the projection of sectorial value added (GDP), this study expects that the energy consumption of the industrial sector will reach about 54,500 ktoe in 2041, about nine times increase from 2013, as shown in Figure 7-27. The main drive of the rapid increase of the sectorial energy consumption is the rapid growth of the economy itself, but is also accelerated by the expected increase of the energy intensity.

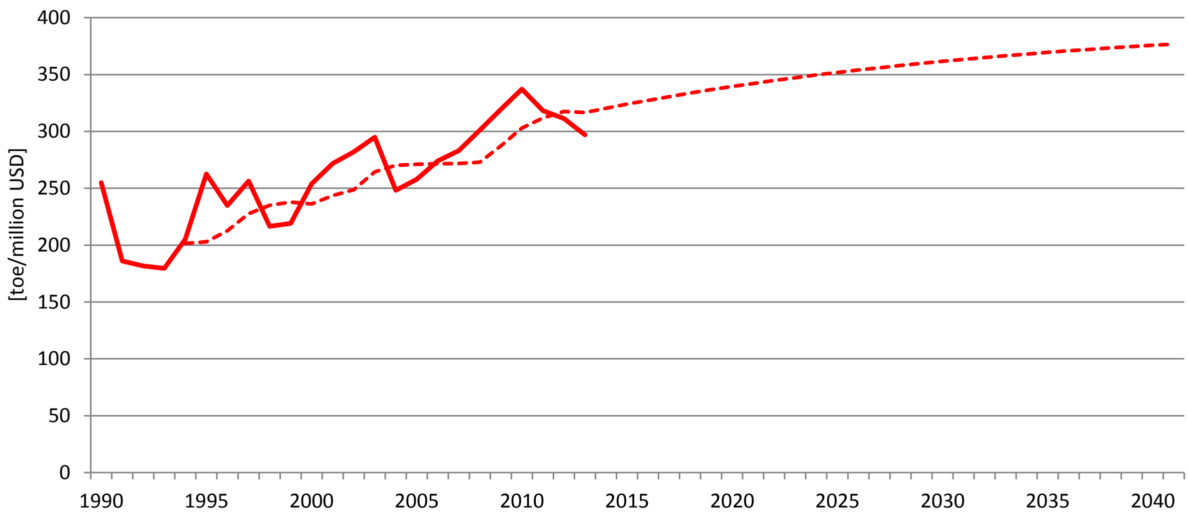


Figure 7-26 Energy Consumption per Sectorial Value Added (Projection)

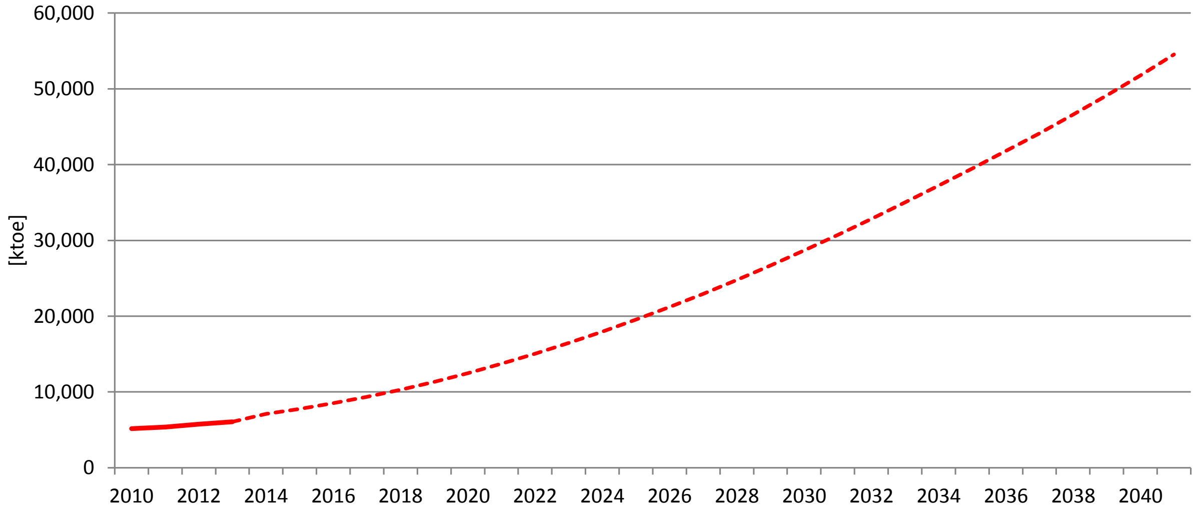


Figure 7-27 Sectorial Energy Consumption (Projection)

7.4 Transport Sector

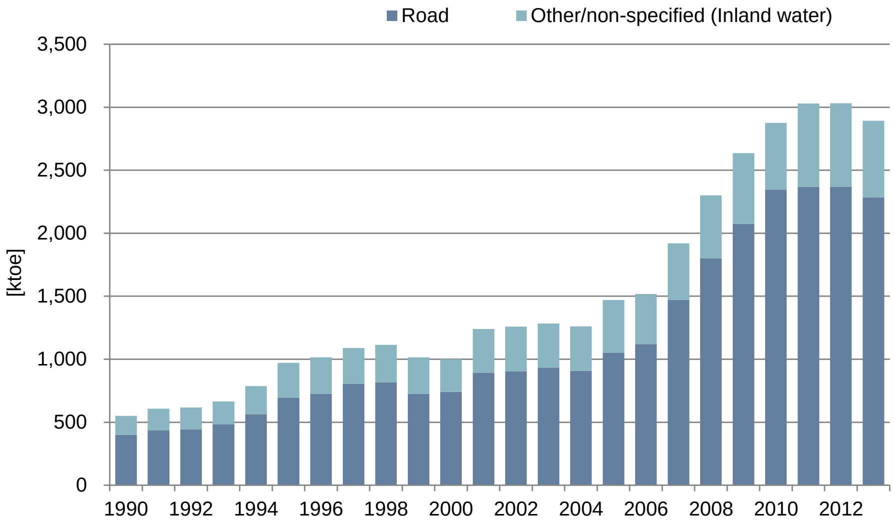
7.4.1 Current Status of Energy Demand

(1) Structure of Transport Sector in Bangladesh

The historical trend of energy consumption of transportation sector is shown in Figure 7-28. It grew more than five times in 23 years, from 544 ktoe in 1990 to 2,893 ktoe in 2013, and especially saw a high growth in late-2000s. Though the growth appears to stop in 2010s, this is considered merely a statistical error considering the recent progress of motorization of the country, and the trend of rapid growth is supposed to continue.

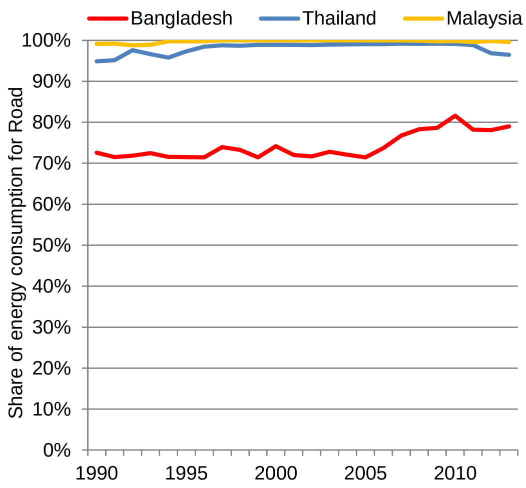
Looking at the breakdown of energy consumption by the type of transport, road transport accounts for about 80% of the total sectorial energy consumption, and the share has been creeping up as seen in Figure 7-29.

The reason why the share of road transport is relatively small compared to other countries (such as Thailand and Malaysia where its share is higher than 90%) is that Bangladesh has the large inland waterway networks and water transport has a relatively large share in total transport, though the share in sectorial energy consumption has been slightly decreasing, reflecting the progress of motorization. Development of river bridges is expected to accelerate the trend that water transport gives way to road transport.



Source: IEA Energy Balances

Figure 7-28 Historical Trend of Transport Sector's Energy Consumption in Bangladesh

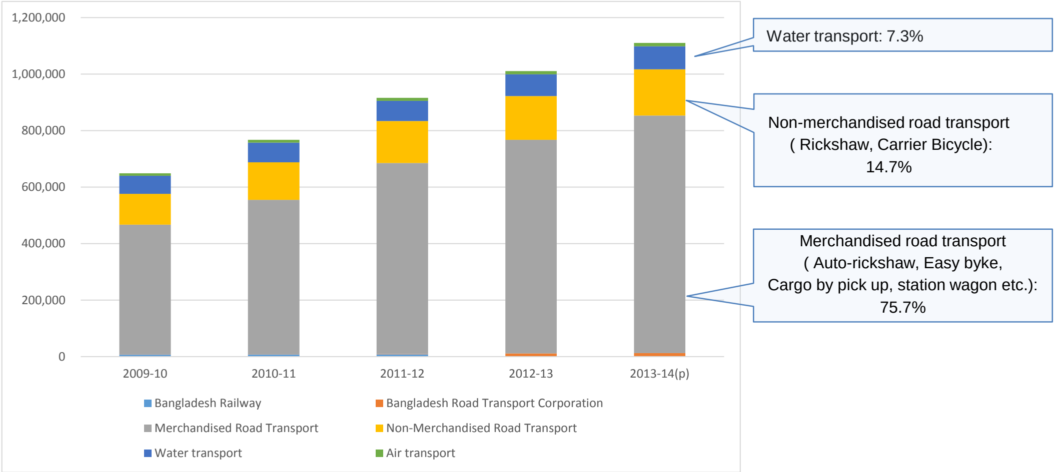


Source: IEA Energy Balances

Figure 7-29 Share of Road Transport in Sectorial Energy Consumption

Figure 7-30 shows the trend of modal share in transport sector in terms of economic value. More than 90% of value added in transportation sector is from road transport whereas the remaining parts are water transport and air transport, and railway.

Road transport can be broken down into non-merchandised road transport, such as rickshaw and carrier bicycle, merchandised road transport, such as automobiles. The merchandised road transport can be further broken down into passenger transport and cargo transport. At the moment, auto-rickshaw/tempo, easy bike and cargo (by pickup, station wagon etc.) mainly contributes to the value added of merchandised road transport in Bangladesh.



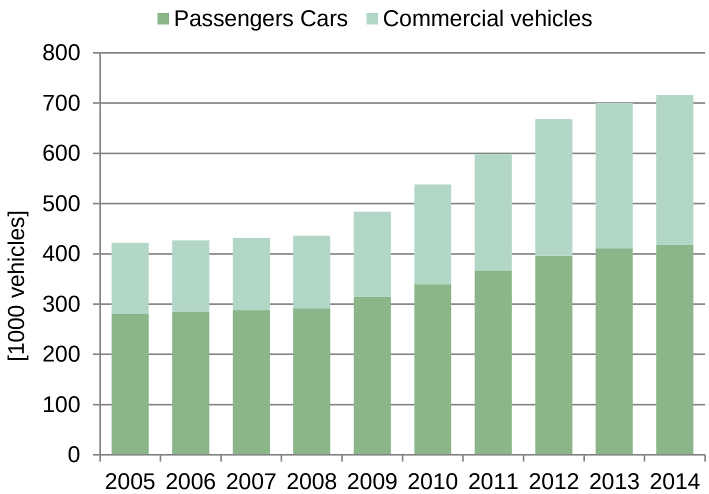
(Unit: million BDT at current price)

Source: Prepared by the Study Team using Bangladesh National Accounts Statistics (BBS)

Figure 7-30 Value Added of Transport Sector with Modal Breakdown

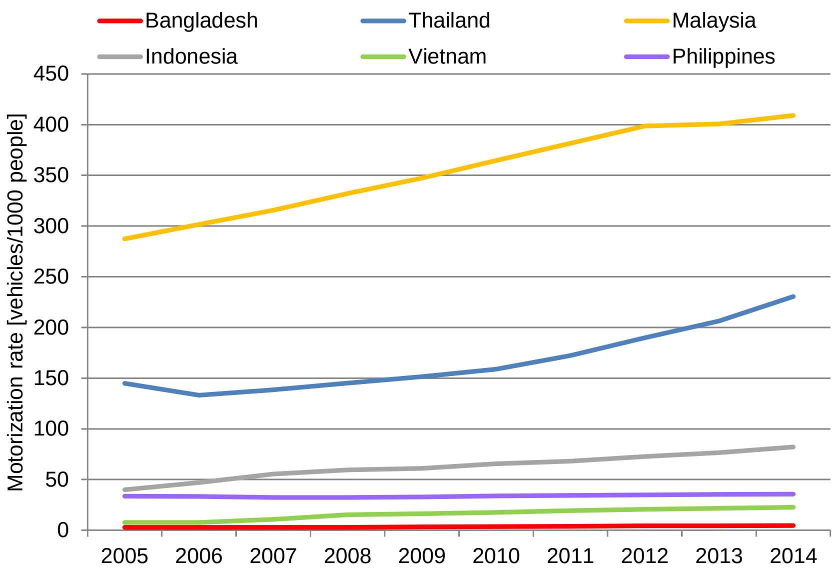
(2) General Trend of Motorization

According to International Organization of Motor Vehicle Manufacturers (OICA), the number of vehicles owned in Bangladesh has increased from 422,000 in 2005 to 716,000 in 2014, 1.7 times (6.1% p.a.) in 9 years (see Figure 7-31). However, the current level of motorization in Bangladesh, which can be expressed as the number of vehicles per 1,000 people, is still very low compared to that in ASEAN countries (see Figure 7-32).



Source: Prepared by the Study Team using World Bank database and OICA statistics

Figure 7-31 Number of Vehicles Owned in Bangladesh

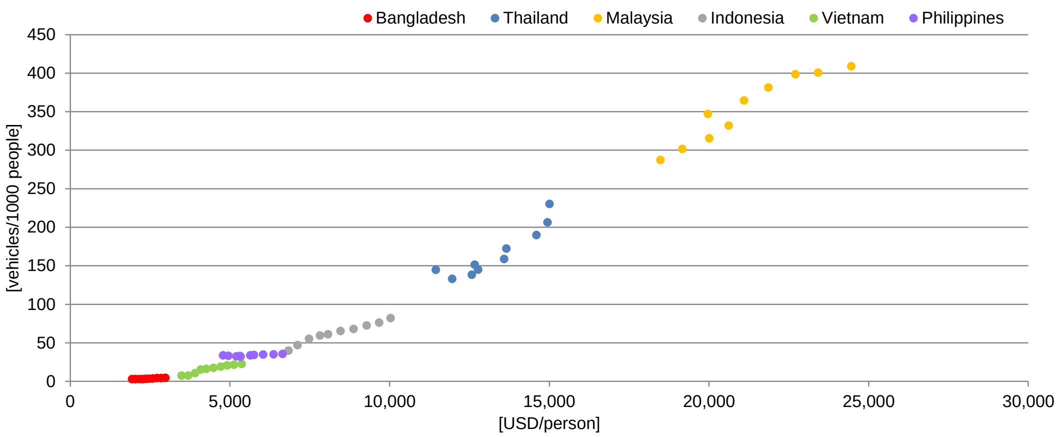


Source: Prepared by the Study Team using World Bank database and OICA statistics

Figure 7-32 Motorization Rate of Bangladesh and ASEAN Countries

The extent of car ownership can be explained by the status of economic development of each country. As seen in Figure 7-33, there's a strong correlation between GDP per capita (PPP basis) and motorization rate in ASEAN countries (Thailand, Malaysia, Indonesia, Vietnam and the Philippines). The correlation takes an S-shaped curve, i.e. the slope becomes steep when the country's GDP per capita exceeds 5,000 USD, and after taking an almost linear correlation, the slope becomes moderate when the GDP per capita reaches 20,000 USD.

As Bangladesh economy has not reached the level to trigger massive motorization, the motorization rate (vehicles per 1000 people) is still very low. But when the economic development comes to a certain level, motorization rate increases rapidly. This study expects that this rapid motorization will start around mid-2020s when GDP capita reaches 5,000 USD (see Table 6-11).



Source: Prepared by the Study Team using World Bank database and OICA statistics

Figure 7-33 Historical Trend of GDP per Capita (PPP) and Motorization Rate

The status of car ownership varies significantly among regions. Table 7-6 is the number of registered motor vehicles in each year in Bangladesh, according to the Road Transport Authority. The total number of car registration at the end of 2010 was about 1.5 million and it grew to 2.5 million as of 29th February 2016, about 1.6 times increase.

Currently the increase of motor cycles is the most conspicuous. Motor cycles not only account for more than half of total number of registration, but also it saw a rapid increase that was almost doubled during that period.

Private passenger cars accounts for the second largest share in total car registration and the number increased from about 220 thousands in 2010 to 292 thousands in February 2016. An important point to be noted about private passenger car is that the regional distribution of car registration. Out of 292 thousands in total Bangladesh, 227 thousands are registered in Dhaka. That is, most of the private passenger cars exit in Dhaka area whereas the number is still scarce in other areas.

Table 7-6 Number of Registered Motor Vehicles in Bangladesh

<Bangladesh> <Dhaka>

Sl. No	Type of Vehicles	Upto-2010	2011	2012	2013	2014	2015	29-Feb-16	Grand Total	Grand Total
1	Ambulance	2793	219	181	243	338	480	78	**4332**	**2487**
2	Auto Rickshaw	126763	20423	23545	15697	19897	20000	1999	**228324**	**8435**
3	Auto Tempo	14266	175	626	395	500	1095	136	**17193**	**1664**
4	Bus	27778	1761	1439	1107	1488	2391	577	**36541**	**24565**
5	Cargo Van	3522	489	282	687	608	399	64	**6051**	**5727**
6	Covered Van	5658	2354	1421	2271	2869	2354	416	**17343**	**13742**
7	Delivery Van	17063	1004	774	894	1176	1719	281	**22911**	**16725**
8	Human Hauler	6520	1152	715	385	225	1142	501	**10640**	**4371**
9	Jeep(Hard/Soft)	32286	2134	1569	1314	1870	3601	777	**43551**	**28926**
10	Microbus	66379	4051	3044	2537	4313	5224	1062	**86610**	**63959**
11	Minibus	25644	276	249	148	256	323	73	**26969**	**10068**
12	Motor Cycle	759257	114616	101588	85808	90685	240358	41467	**1433779**	**390062**
13	Pick Up (Double/Single Cabin)	32240	10460	7625	6553	9554	10257	1512	**78201**	**54116**
14	Private Passenger Car	219830	12950	9224	10472	14699	21062	3910	**292147**	**226645**
15	Special Purpose Vehicle	6371	396	226	227	172	296	78	**7766**	**1078**
16	Tanker	2706	317	195	226	362	324	64	**4194**	**1536**
17	Taxicab	44380	75	172	51	374	88	4	**45144**	**36466**
18	Tractor	20600	5200	3494	1885	1522	1699	423	**34823**	**22066**
19	Truck	82871	7327	4335	5129	8136	6330	958	**115086**	**48258**
20	Others	1317	7	1	1080	1595	2073	572	**6645**	**3498**
	TOTAL	**1498244**	**185386**	**160705**	**137109**	**160639**	**321215**	**54952**	**2518250**	**964394**

Source: Bangladesh Road Transport Authority (http://www.brta.gov.bd/statistics.html)

In comparison to that, auto rickshaws exist mostly outside of Dhaka area. Out of the 228 thousands registration countrywide, only 8,435 are registered in Dhaka. This implies that in Dhaka area, where the economic level is relatively high, ownership of private passenger cars has already outstripped the usage of auto rickshaws, whereas in other areas auto rickshaws are still dominant in passenger transport. To support this, the number of taxicab, which is also expected to substitute auto rickshaws with the development of economic standard, is 45 thousands and about 80% out of this are registered in Dhaka area.

This study therefore projects that the registration of auto rickshaws may still continue to increase outside of Dhaka area for years to come, but will be gradually replaced by passenger cars like in Dhaka area. It means that there is a huge potential for private car ownership to increase rapidly especially in rural area. In addition, considering the continuous migration of residents from rural areas to urban areas, the car ownership in Dhaka area is considered to increase further. The traffic congestion in Dhaka is still a serious problem but this can be worsened unless appropriate policy measures for mitigating this are not in place.

7.4.2 Key Factors That Affect Future Prospects of Energy Demand

(1) Long-term Policy on Transport Sector

In Bangladesh, some long-term policies on the transport sector were developed, as described below. However, it seems that these past literatures did not care much about the energy usage of the sector, much less to energy efficiency.

In addition, there obviously is not any regular statistics or information on the energy use in transport sector. Developing database on energy use of this sector is needed for grasping the status correctly and for making policy direction for rationalizing energy use and improving energy efficiency.

1) Road Master Plan (2009)

Road Master Plan was developed in response to the direction provided by the National Land Transport Policy and was intended to be the guideline for the investment in the road infrastructure over the next twenty years.

In this Master Plan, a comprehensive investment program was set to:

- Protect the value of RHD's (Road and Highways Department's) road and bridge assets;
- Improve the connectivity of the road network;
- Enhance and develop the strategic road network to meet economic and traffic growth target;
- Improve the Zila Road network to enhance connectivity to the country's growth centers;
- Improve road safety and reduce road accidents;
- Provide environmental and social protection; and
- Outline the institutional improvements required for RHD to deliver the above.

2) The National Integrated Multimodal Transport Policy (2013)

The National Integrated Multimodal Transport Policy, 2013 was prepared in order to redress the imbalance by an overemphasis on road subsector on development started taking place from the beginning of 1990. This policy is to address all modes of transport in an integrated way so that future investment can take account of the best mode in each case to meet overall government objectives including environment issues and safety.

The primary objective of the Multimodal Integrated Transport Policy is to emphasize the roles of rail, inland water transport, aviation alongside road transport in order to ensure the development of the overall transport network. The objectives of the Integrated Multimodal Transport Policy are to:

- Reduce cost of transport goods, so as to make goods and services within Bangladesh less costly;
- Aid export competitiveness, through lower transport costs;
- Improve safety;
- Reduce accident rate;
- Take advantages of Bangladesh's geographical position to trade in transport services and induce efficiency in transport sector;
- Reduce the worst environmental effects of transport;
- Ensure that transport meets social needs in terms of cost accessibility to all sectors of society;
- Improve integration of the overall transport network and foster measures to make interchange between modes easier;
- Reduce the need for travel by better land use planning;
- Use transport as means to assist poverty reduction;
- Improve fuel and energy security; and
- Increase alternative options for passenger and freight transport.

(2) Thailand's Case as a Good Practice for Reference

1) Comparison of Transport Sector Data

This study considers that the case of Thailand to deal with the issues pertaining to the transport sector can be a good reference for Bangladesh. Table 7-7 compares the data regarding the transport sector in Bangladesh and Thailand. In Thailand the number of motor vehicle with 4 or more wheels per 1000 people is 198 units, around 50 times of that in Bangladesh.

Table 7-7 Comparison of Transportation Related Data between Bangladesh and Thailand

		unit	Bangladesh	Thailand	year
motor vehicle	number of motor vehicle (4wheel or more)	1000unit	570	13,213	2012
	number of motor vehicle per 1000people	unit	4	198	
	number of motor cycle	1000unit	1,161	19,169	
road	road length of main roads	km	20,735	51,855	Thailand:2006, Bangladesh:2003
	main road density in terms of population	km/1000people	1.5	3.7	
rail	rail lines	km	2,835	5,327	2012
	passenger	million people*km	7,305	7,504	
	cargo	million ton*km	710	2,455	
air	passenger; international line	million people*km	565	8,204	2011
	passenger; domestic line	million people*km	4,630	59,159	
	passenger; total	million people*km	5,195	67,363	
waterway	Container port traffic	TEU: 20 feet equivalent units	1,571,461	7,702,476	2013

Source: Prepared by the Study Team using the data of Japan Statistics Office and WB

2) Measures for Mitigating Traffic Congestion

Bangkok, the capital of Thailand, is infamous for its traffic jams like Dhaka. According to the World Bank, the average vehicle speed during rush hours is 17.2 km/h in the morning and 24.2 km/h in the evening. Table 7-8 shows the main measures taken and considered in Thailand to mitigate traffic congestion. By introducing measures for mitigating traffic jam the following effects are expected.

- increase of the average vehicle speed;
- reduction of lost time for transportation;
- reduction of fuel consumption and fuel cost;
- reduction of CO2 emission;
- reduction of exhausted toxic gas;
- reduction of stress of drivers;
- reduction of traffic accidents;

Table 7-8 Measures Taken in Bangkok for Mitigating Traffic Congestion

Categories	Main Measures
Mordal Shift	construction of urban railways (METRO etc.)
	introduction of Bus Rapid Transit
	introduction of Park & Ride System
Road Development	widening of a road
	develop ring road
	construction of flyover
Regulation	road pricing
	time dispersion(staggered commuting, flex time etc.)
Provision of Road Information by ICT	Smart Traffic Sign
	Traffic Signal Control

Source: JICA Study Team

3) Introducing Eco Car Program

Thailand started the 'Eco-car program' in 2007 that offered preferential tax treatment to car manufacturers producing Eco-car. There were various requirements such as a fuel consumption of 20 km or more per liter, compliance with the European exhaust gas regulations "EURO 4", etc. Various benefits like 8 years exemption from corporation tax were provided to the approved manufacturers of "eco-cars". Also, for purchasers (consumers), a goods tax rate of 17% was introduced as a preferential tax treatment (please see table below).

The second stage of 'eco-car program' started in 2014 which requested a fuel consumption of 20 km or more per liter, compliance with the European exhaust gas regulations "EURO 5", etc. The conditions were that production must commence before year end 2019, and the production from the fourth year and beyond must be 100,000 vehicles or more p.a. (please see table below).

For the first Eco car program five Japanese manufacturers, i.e. Nissan, Honda, Mitsubishi, Suzuki and Toyota were approved. And for the second Eco car program, besides the aforementioned five manufacturers, five other manufacturers from America and Europe were newly approved.

Table 7-9 Outline of Eco car Project Conducted in Thailand

	eco car program	2nd eco car program
start year	2007	2013
main requirement	1300cc or less(gasolin car) 1400cc or less(diesel car) fuel consumption 20km/l or more clear the standard of EURO4 CO2 emission 120g/km or less	1300cc or less(gasolin car) 1500cc or less(diesel car) fuel consumption 23.3km/l or more clear the standard of EURO5 CO2 emission 100g/km or less start production by 2019
main benefit to manufacture	income tax free for maximum 8 years import tax free for production machine	income tax free for 6 years etc. import tax free for production machine
benefit to consumer	consumption tax 17% (30% for passengers car for 2000cc or more)	consumption tax 14%

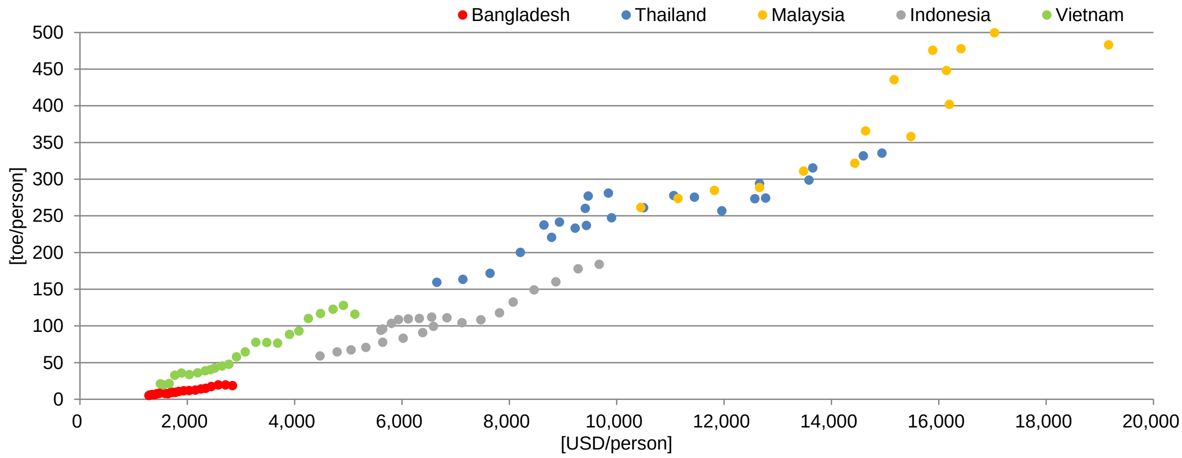
Source: JICA Study Team

7.4.3 Projection of Energy Consumption

As discussed in 7.4.1 , the car ownership starts increasing acceleratedly when the country's GDP per capita (PPP) reaches around 5,000 USD. Because the increased car ownership directly affects the energy consumption, the transport sector's energy consumption is expected to see a rapid growth from mid-2020.

Figure 7-34 shows the relation between GDP per capita (PPP basis) and transport sector energy consumption per capita in Bangladesh and ASEAN countries (Thailand, Malaysia, Indonesia, Vietnam and the Philippines). Like the case of motorization rate (see Figure 7-33), the overall trend of these countries is tracing an S-shaped curve, though it is not as clear as the motorization rate. That is:

- Energy consumption increases acceleratedly when the economic development comes to a certain level and the car ownership (motorization) increases rapidly, and
- The growth rate of energy consumption becomes moderate when the economic development reaches a certain level of maturity and the transport with private vehicles is taken over by the advanced public transport system especially in the urban area.

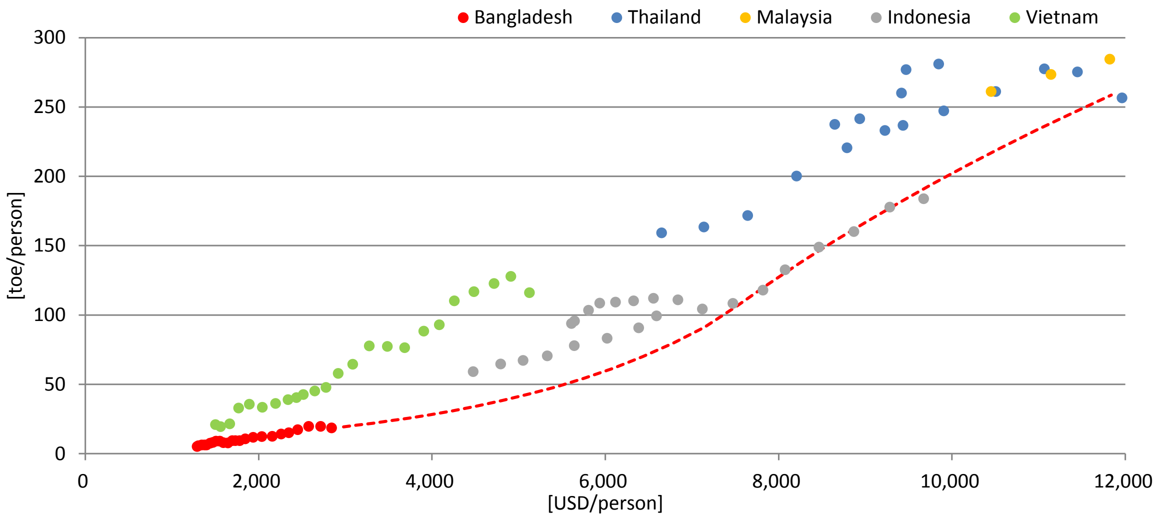


Source: Prepared by the Study Team using World Bank database and IEA energy balances

Figure 7-34 Historical Trend of GDP per Capita (PPP) and Transport Sector's Energy Consumption per Capita in Bangladesh and ASEAN Countries

According to this figure, especially the historical trend of Indonesia and Thailand that the transport sector's energy consumption per capital starts growing steeply when GDP capita reached around 5,000-6,000 USD and the growth becomes moderate when it exceeds 8,000 USD, this study considers that the car ownership increases rapidly during that period.

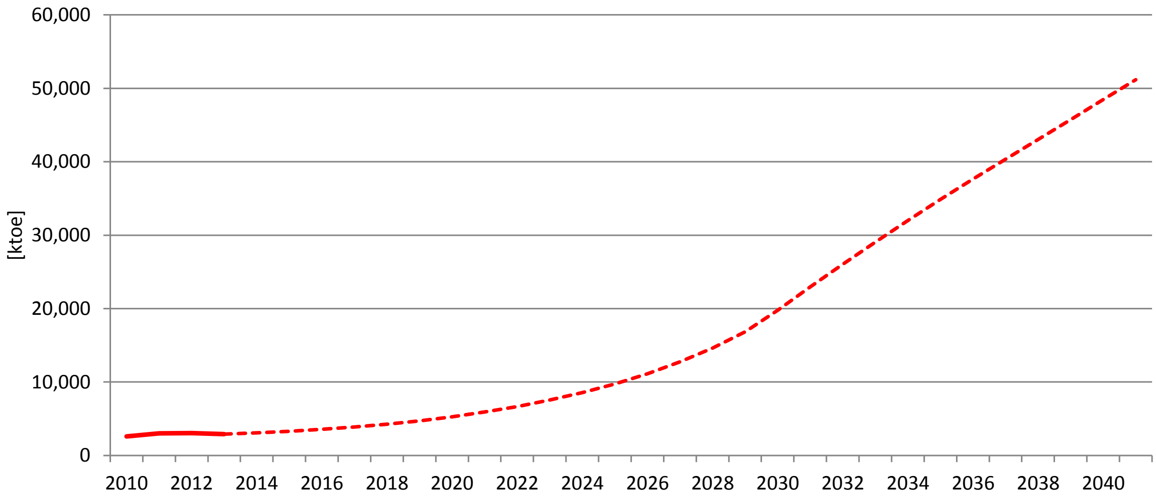
Assuming that Bangladesh will also follow this track, transport sector's energy consumption per population will increase rapidly from mid-2020s to early 2030s in accordance with the accelerated car ownership, as shown in Figure 7-35.



Source: Prepared by the Study Team

Figure 7-35 Sectorial Energy Consumption per Capita (Projection)

Multiplying the projection of energy consumption per capita by the projected population (see Figure 6-21), the transport sector's energy consumption in Bangladesh is expected to reach around 51,000 ktoe in 2041, about 18 time of the current level (2,893 ktoe in 2013), as shown in Figure 7-36. Rapid increase of energy consumption can be seen from mid-2020s, though the government's plan of public transport (e.g. MRT in Dhaka area) is taken into account.



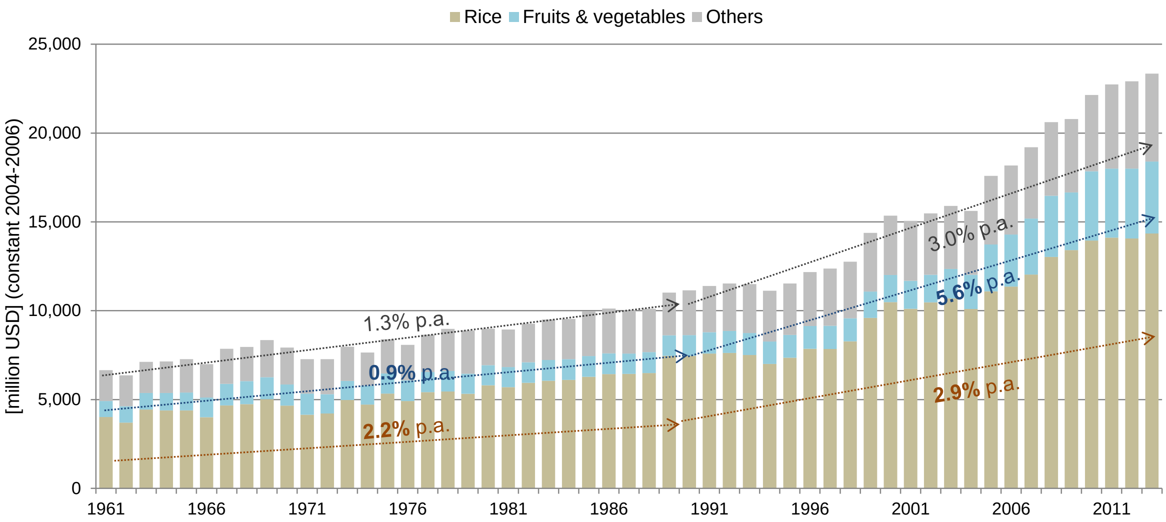
Source: Prepared by the Study Team

Figure 7-36 Sectorial Energy Consumption (Projection)

7.5 Agricultural Sector

7.5.1 Current Status of Energy Demand and Key Factors That Affect Future Prospects

Figure 7-37 shows the historical trend of agricultural production in Bangladesh according to the United Nation's Food and Agriculture Organization (FAO). In Bangladesh, rice has been the major agricultural product and its share in total agricultural production has been constantly around 60% or more since 1960s.
For thirty years from 1961 to 1990, the total agricultural production increased by 1.7 times, i.e. 1.8% p.a. During that period, rice grew by 1.9 times (2.2% p.a.), fruits and vegetables by 1.3 times (0.9% p.a.) and others by 1.4% (1.3%), which indicates that rice was main driver for the growth of the country's agricultural production.
For twenty-three years from 1991 to 2013, the total agricultural production increased by 2.1 times (3.3% p.a.). The fact that the average growth rate was higher than that in previous period despite the migration from agriculture to industry driven by industrialization is considered due to the improved productivity. During this period, rice grew by 1.9 times (2.9% p.a.), whereas fruits and vegetables by 3.5 times (5.6%) and others by 2.0 times (3.0% p.a.). This indicates that the growth of fruits and vegetables replaced rice as the main driver for the production growth.
As a general trend, agricultural sector changes its structure by shifting from primitive self-sufficiency centering on grain production (rice, wheat etc.) to diversification with more value-added products, such as fruits, vegetables and dairy products. This reflects the people's preference for variety of foods with the improvement of economic standard and the shift to value added products for export driven by the improved productivity.

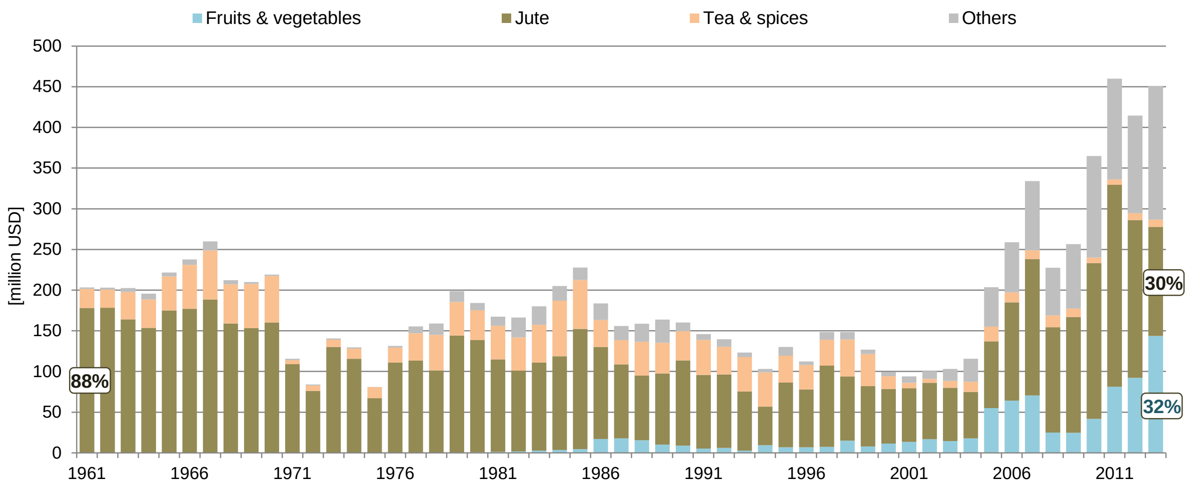


Source: FAO Statistics

Figure 7-37 Historical Trend of Agricultural Production in Bangladesh

Figure 7-38 shows the historical trend of agricultural products export. Until recently jute has been the main export product of Bangladesh and it accounted for 88% of total agricultural products export. In 1970, though the share of jute in total agricultural products export was still high, the export amount itself started declining, and later, along with the growth of other products, its share also started declining, down to about 30% in 2013. Export of tea leaves, which used to be the second largest agricultural product after jute, also started declining from 1990s and its export in 2013 was less than 10% of that in 1961.

In the meanwhile, the export of fruits and vegetables started expanding from mid-2000s, after a dip in late-2000 which is considered due to the Global Financial Crisis, it again started growing rapidly. In 2013, they accounted for 32% of total agricultural products export. The export value of fruits and vegetables has increased by 16 times in 23 years (12.8% p.a.) from 9 million USD in 1990 to 144 million USD in 2013.



Source: FAO Statistics

Figure 7-38 Historical Trend of Agricultural Products Export in Bangladesh

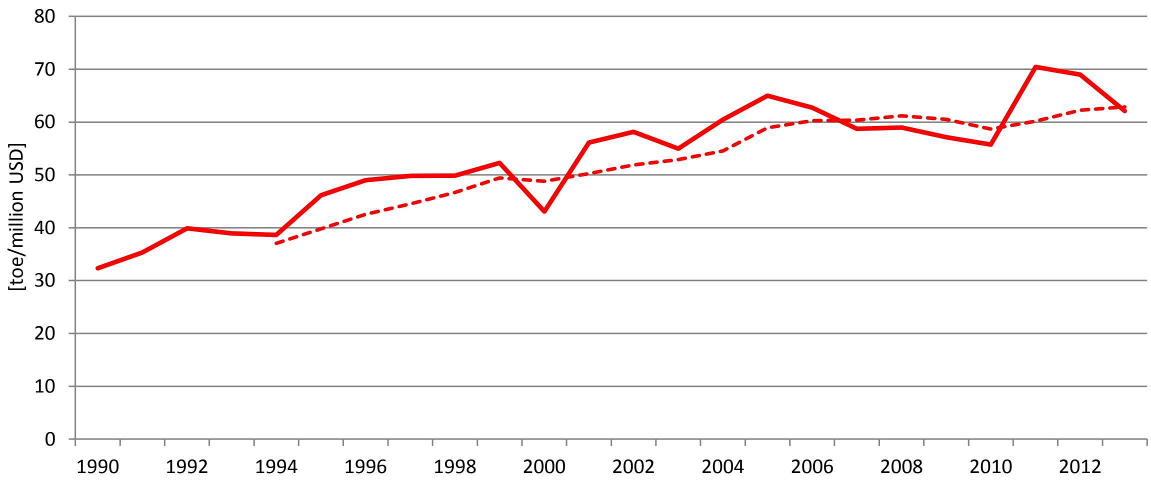
It needs to be noted that these value-added products generally require more care for preserving quality and freshness. In order to achieve this, a modernized storage system needs to be established so that these products are conserved and transported in an appropriate temperature, along with the logistic system to enable quick transport and packaging, and marketing system to support them.

In order to achieve this and to enhance the international competitiveness of export products, development of infrastructure is inevitable, especially that for electricity supply, which is also pointed out by a World Bank report[11].

7.5.2 Projection of Energy Consumption

Figure 7-39 shows the historical trend of agricultural sector's energy consumption in Bangladesh divided by the sectorial value added of agriculture (constant price), along with its five-year moving average (indicated as a dotted line). Like the analysis on the industrial sector, this is a ratio of energy consumption to sectorial valued added (= GDP) to analyze how much energy (toe) is consumed for the sector to yield of 1 million USD

Though there's an increase and decrease from year to year, a gradually increasing trend can be observed. This is considered because the agriculture is shifting to more value-added products and more energy needs to be consumed for producing a same value in the sector as discussed in the previous section. However, this creeping trend is has been moderate since mid-2000s, probably because the increasing value-added is high enough to cover the increasing energy consumption.



Source: Prepared by the Study Team using World Bank database and IEA energy balances
Note) Dotted line is the five-year moving average

Figure 7-39 Agricultural Sector's Energy Consumption per Sectorial Value Added

Figure 7-40 compares this historical trend with ASEAN countries (Thailand, Indonesia and Vietnam). The historical trend in Indonesia and Vietnam is similar to that in Bangladesh, ranging mostly between 50 and 70 toe/million USD since 2000s.

Considering that the historical trend in Thailand has been much higher than the other three countries, the reliability of statistic data needs to be doubted, at least in terms of international comparison. However, referring to the performance in Indonesia and Vietnam, this study assumes that a creeping trend of agricultural sector's energy intensity will continue until moderately it reaches to toe/million USD, as shown in Figure 7-41.

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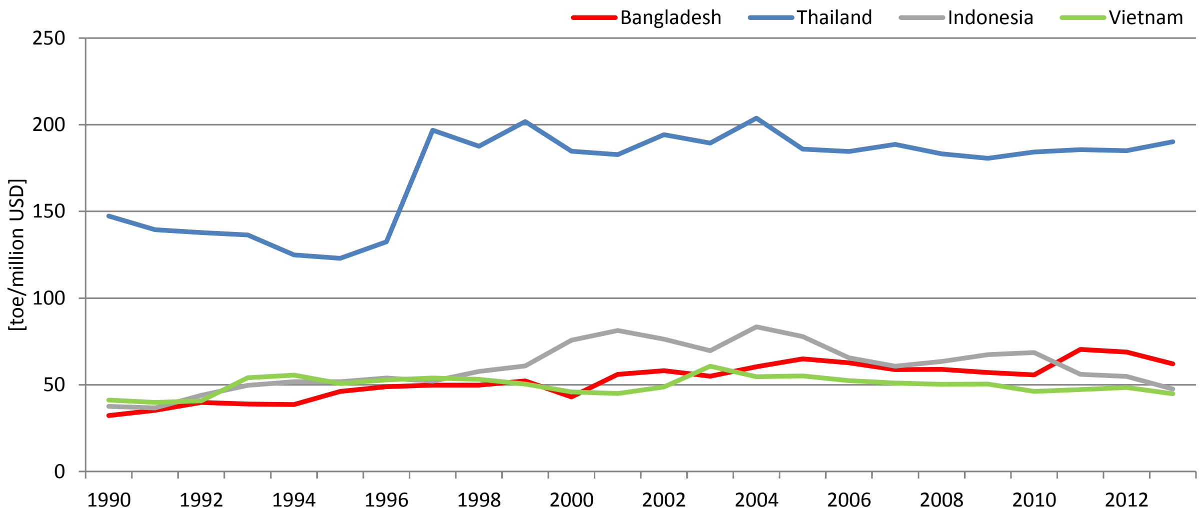
[11] World Bank "High-value Agriculture in Bangladesh: An Assessment of Agro-business Opportunities and Constraints" (2008)



Source: Prepared by the Study Team using World Bank database and IEA energy balances

Figure 7-40 Agricultural Sector's Energy Consumption per Sectorial Value Added (Comparison with ASEAN Countries)

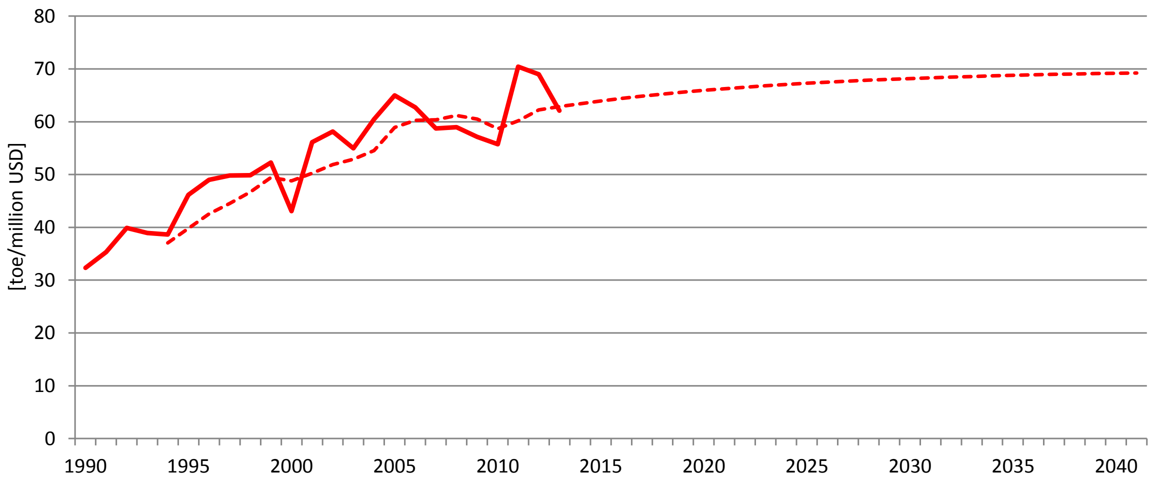


Figure 7-41 Energy Consumption per Sectorial Value Added (Projection)

Agricultural sector's energy consumption will reach around 4,200 ktoe in 2041, about four times increase from 2013, as shown in Figure 7-42.

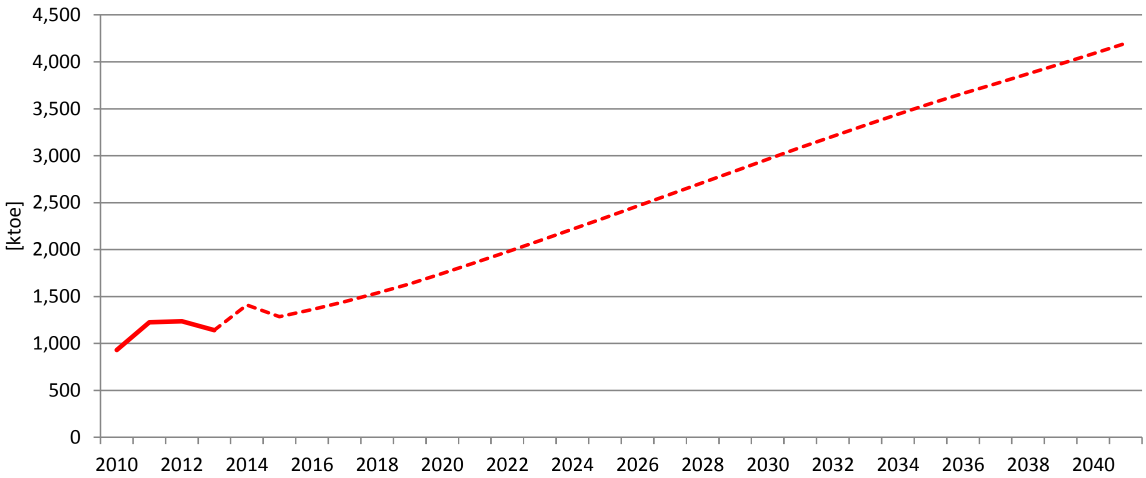


Figure 7-42 Sectorial Energy Consumption (Projection)

7.6 Total Energy Supply & Demand Balance Up to 2041

7.6.1 Projection of Total Final Energy Consumption

The projection of final energy consumption in the BAU (business as usual) scenario, which is the sum of energy consumption of each sector as explained in the previous sections of this chapter, is shown in Figure 7-43 and Table 7-10.

In this BAU scenario, industrial sector, which is expected to grow by 7.8% p.a. from 2014 to 2041, will become the largest sector of energy consumption. Transport sector, which is expected to grow by 11.0% p.a., will consume almost as much energy as the industrial sector.

In the meanwhile, residential sector, which accounted for about half of the total energy consumption, will see a relatively moderate growth and its share in the total energy consumption is expected to decline.

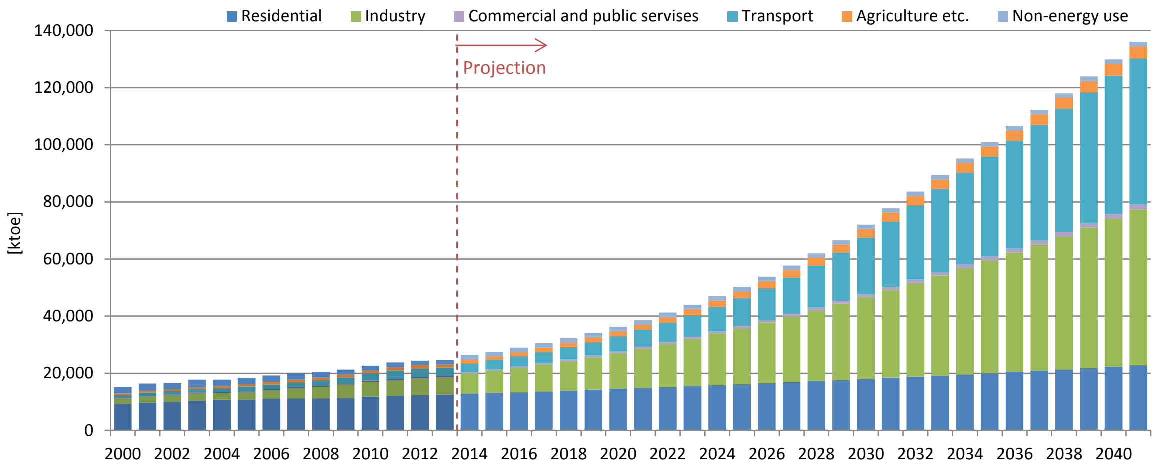


Figure 7-43 Projection of Total Final Energy Consumption – BAU Scenario

Table 7-10 Projection of Total Final Energy Consumption – BAU Scenario

Sectors	2014		2041		Average growth rate ('14-'41)
	ktoe	(share)	ktoe	(share)	
Residential	12,815	(48%)	**22,797**	**(17%)**	**2.2% p.a.**
Industrial	7,116	(27%)	**54,526**	**(40%)**	**7.8% p.a.**
Commercial & Public Service	468	(2%)	**1,776**	**(1%)**	**5.1% p.a.**
Transport	3,080	(12%)	**51,187**	**(38%)**	**11.0% p.a.**
Agriculture	1,409	(5%)	**4,197**	**(3%)**	**4.1% p.a.**
Others	47	(0%)	**47**	**(0%)**	**0.0% p.a.**
Non-energy use	1,534	(6%)	**1,534**	**(1%)**	**-**
Total	**26,469**	**(100%)**	**136,064**	**(100%)**	**6.3% p.a.**

The total final consumption (TFC) is expected to grow by 5.1 times from 2014 to 2041, i.e. 6.3% p.a. increase. The projection of GDP growth during the same period is 6.1%, hence the GDP elasticity of energy consumption during the projection period, which is the ratio of energy consumption's growth rate divided by GDP growth rate, is slightly higher than 1 (about 1.03).

Figure 7-44 is the historical trend and projection of energy intensity, which is the ratio of total final energy consumption divided by GDP (real base). When the country's GDP is continuously growing, its GDP elasticity becomes lower than 1 when the energy intensity decreases, and the GDP elasticity becomes higher than 1 when the energy intensity increases.

Since 2000s, Bangladesh has seen a declining trend of energy intensity, i.e. GDP elasticity of energy consumption has been lower than 1, and this trend is expected to continue until mid-2020s due to the moderate growth of residential sector energy consumption. Energy intensity will decrease from 3.42 toe/million BDT in 2014 to around 3 toe/million BDT (-12% down) during that period.

However, the energy intensity will start increasing afterwards, i.e. GDP elasticity becomes higher than 1. It will become 3.15 toe/million BDT in 2030 (-8% down from 2014), and then 3.56 toe/million BDT in 2041 (4% up from 2014). As a result, GDP elasticity of the entire projection period (from 2014 to 2041) will become higher than 1.

The increase of energy intensity after mid-2020s is mainly driven by industrial sector and transport sector that are expected to grow continuously higher than GDP.

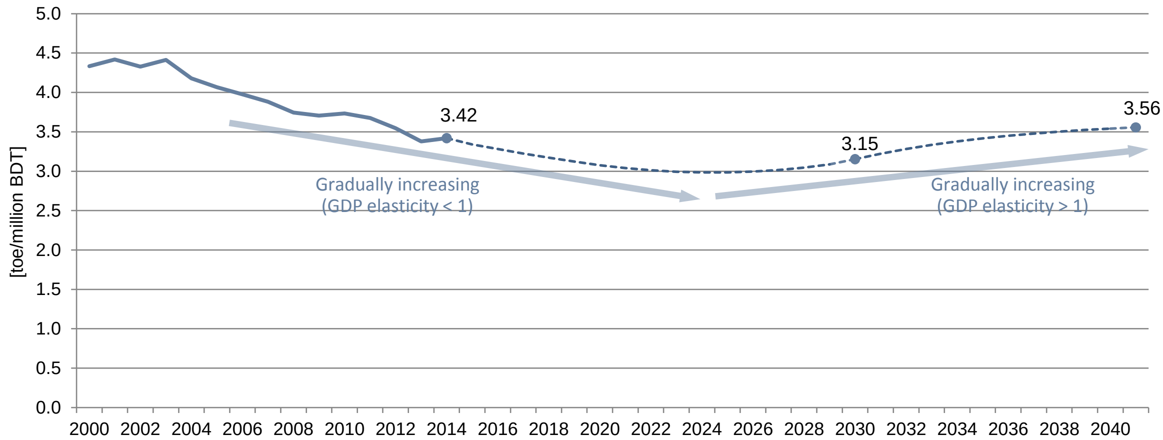


Figure 7-44 Historical Trend and Projection of Energy Intensity – BAU Scenario

The study suggests that energy efficiency measures are to be implemented in Bangladesh for mitigating the rapid increase of energy consumption. Referring to "Energy Efficiency and Conservation Master Plan up to 2030" (ECMP), which was published by Sustainable and Renewable Energy Development Authority (SREDA) and Power Division in March 2015 with the technical assistance by JICA, this study recommends that the following targets will be achieved by implementing the measures as specified in ECMP.

- 2.64 toe/million BDT in 2030 (down -23% from 2014);
- 2.56 toe/million BDT in 2041 (down -25% from 2014);

In this case, the energy intensity is expected to decrease continuously, though the pace may become moderate. GDP elasticity of the projection period will become lower than 1.

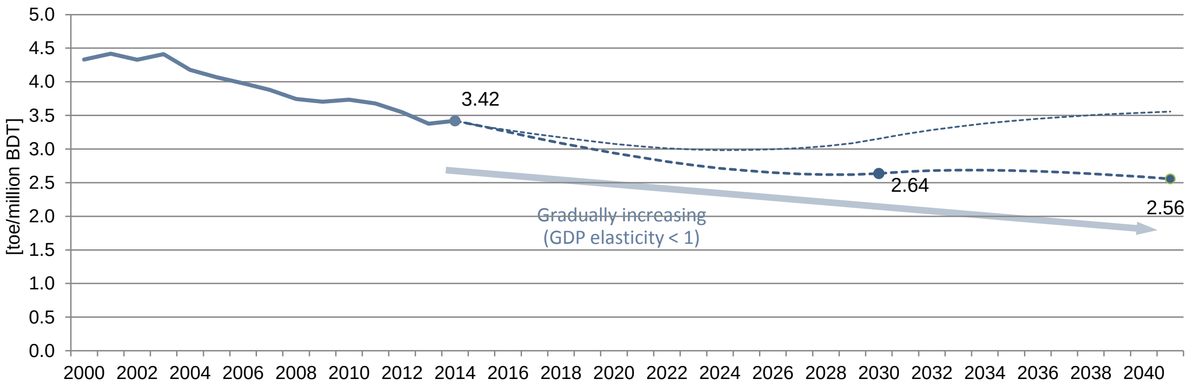


Figure 7-45 Historical Trend and Projection of Energy Intensity (Considering Energy Efficiency)

The definition of energy intensity of this study is different from that of ECMP. Energy intensity in ECMP does not include the whole energy consumption of the transport sector and biofuel consumption of the residential sector.
Using the same definition as that of ECMP, the energy intensity as of 2030 is 2.44 toe/million BDT, down -20% from 3.04 toe/million BDT in 2014, and the energy intensity will be around 2.33 toe/million BDT in 2041, which is around 23% decrease from 2014. Therefore, this study's target meets the target proposed in ECMP, which stipulates a target that the energy intensity will be lowered by 20% by 2030.
Sector-wise target of energy efficiency is shown in Table 7-11. Implementing energy efficiency measures in the transport sector, that are discussed in 7.4.2 , will be critical for achieving the target of reducing energy intensity, especially in 2020s and afterwards.

Table 7-11 Sector-wise Energy Efficiency Target

Sectors	Reduction from BAU Scenario			Energy Intensity: Down from 2014		
	2021	2030	2041	2021	2030	2041
Residential	6%	21%	30%			
Industrial	5%	15%	25%			
Commercial & Public Service	3%	10.5%	15%			
Transport	6.6%	16.5%	33%			
Agriculture	3%	10.5%	15%			
Total	**5.3%**	**16.3%**	**28.1%**	**15.8%**	**22.9%**	**25.2%**

Projection of total energy consumption considering the achievement of aforementioned energy efficiency targets is shown in Figure 7-46 and Table 7-12. The average growth rate of total final energy consumption will be 5.0% p.a. from 2014 to 2041. GDP elasticity of energy consumption during the projection period is lower than 1 (about 0.81).

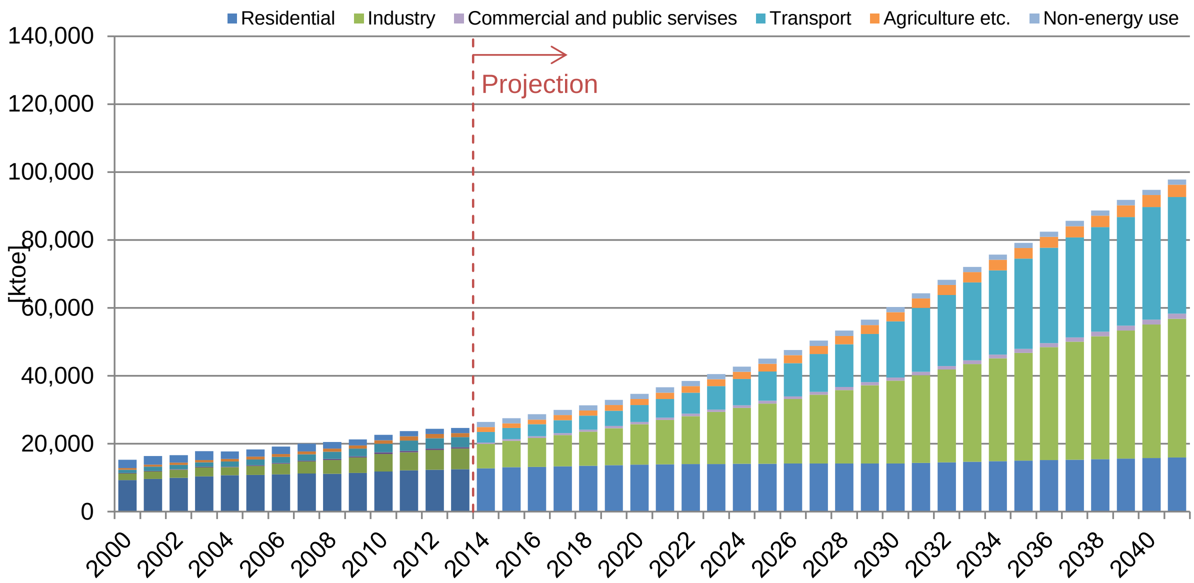


Figure 7-46 Projection of Total Final Energy Consumption – Energy Efficiency Scenario

Table 7-12 Projection of Total Final Energy Consumption – Energy Efficiency Scenario

Sectors	2014		2041		Average growth rate ('14-'41)
	ktoe	(share)	ktoe	(share)	
Residential	12,815	(48%)	**15,958**	**(16%)**	**0.8% p.a.**
Industrial	7,116	(27%)	**40,894**	**(42%)**	**6.7% p.a.**
Commercial & Public Service	468	(2%)	**1,510**	**(4%)**	**4.4% p.a.**
Transport	3,080	(12%)	**34,295**	**(35%)**	**9.3% p.a.**
Agriculture	1,409	(5%)	**3,568**	**(4%)**	**3.5% p.a.**
Others	47	(0%)	**47**	**(0%)**	**0.0% p.a.**
Non-energy use	1,534	(6%)	**1,534**	**(2%)**	**-**
Total	**26,469**	**(100%)**	**94,805**	**(100%)**	**5.0% p.a.**

7.6.2 Projection of Total Primary Energy Supply

Based on the projection of total final energy consumption in the energy efficiency scenario, which was discussed in the previous sections, the total primary energy supply (TPES) in Bangladesh up to 2041 is projected. Methodologies for projecting TPES are as follows.

- Breakdown of the modes of energy supply to end consumption, such as electricity, gas, oil products, is determined for each sector.
  - Industrial sector:
    Considering that the share of each mode of energy supply has been almost constant for the past years, the same share as the current level will be maintained for several years to come, that is "Electricity: about one-third, Natural gas: about half, Coal: about 10%, Oil: remainder". A gradual shift from natural gas to electricity will occur in the long run, considering that the natural gas usage for captive power generation will be gradually replaced by the power supply from the grid.
  - Transport sector:
    Since 2000s, conversion to CNG has been promoted in Bangladesh, but recently opinion to review this trend has been raised, reflecting the possible shortage of domestic gas production. On the contrary, there's also an argument that increasing dependence on oil products (including

LPG) should be avoided and that continued promotion of CNG using imported LNG is preferred.
Because there appears to be no decisive direction with this regard at the moment, this study assumes that the same share as the current level, that is “Natural gas: about one-third, Oil: two-thirds”. Decision on the fuel usage for road transport can be a big variation factor for the future primary energy supply.
In addition, usage of electricity in the transport sector following the development of modernized railway system (including MRT in Dhaka area) is also considered, though its impact on the total energy consumption is not very large.

- Residential sector:
  A shift from conventional energy sources (e.g. firewood etc.) will be gradually replaced by modern energy sources such as electricity and gas, as discussed in Section 7.2.3 .
  This study’s assumption reflected the opinion of some local stakeholders that the natural gas supply to new residential customers and that it will be substituted by LPG. As a result, the share of LPG in residential sector will be significantly increased.
- Commercial & public services sector:
  Because the historical trend of the share is “Electricity: about half, Natural gas: about half” and this ratio has been almost constant, this study assumed that the same share as the current level will be maintained.
- Agriculture, others:
  This study assumed that the same share as the current level will be maintained.

- Conversion and transfer from primary energy supply to final energy consumption
  - Regarding the energy conversion from primary to electricity supply, several scenarios of fuel mix for power generation was considered, as discussed more specifically in Chapter 12. There are six scenarios of fuel mix varying the composition of natural gas and coal for power generation, among which the Scenario 1 depends maximally on coal usage whereas the Scenario 6 relies maximally on natural gas, as well as some optional scenarios that stretch the promotion of renewable energy.
  - Loss of fuel and electricity in transferring to end consumption is considered referring to the historical trend.
  - Thermal loss in fuel combustion for electricity generation is considered referring to the projection as discussed in in Chapter 12.
- In this chapter, necessary volume of primary energy supply to meet the final energy consumption was calculated. How to procure this primary energy supply, such as domestic production, import, and export of energy, will be discussed in the following chapters.

The projection of primary energy supply is shown in the following figures and tables. Figure 7-47 and Table 7-13 are the results based on the Scenario 1 in Chapter 12, Figure 7-48 and Table 7-14 based on the Scenario 2, Figure 7-49 and Table 7-15 based on the Scenario 3, Figure 7-50 and Table 7-16 based on the Scenario 4, Figure 7-51 and Table 7-17 based on the Scenario 5, and Figure 7-52 and Table 7-17 based on the Scenario 6.

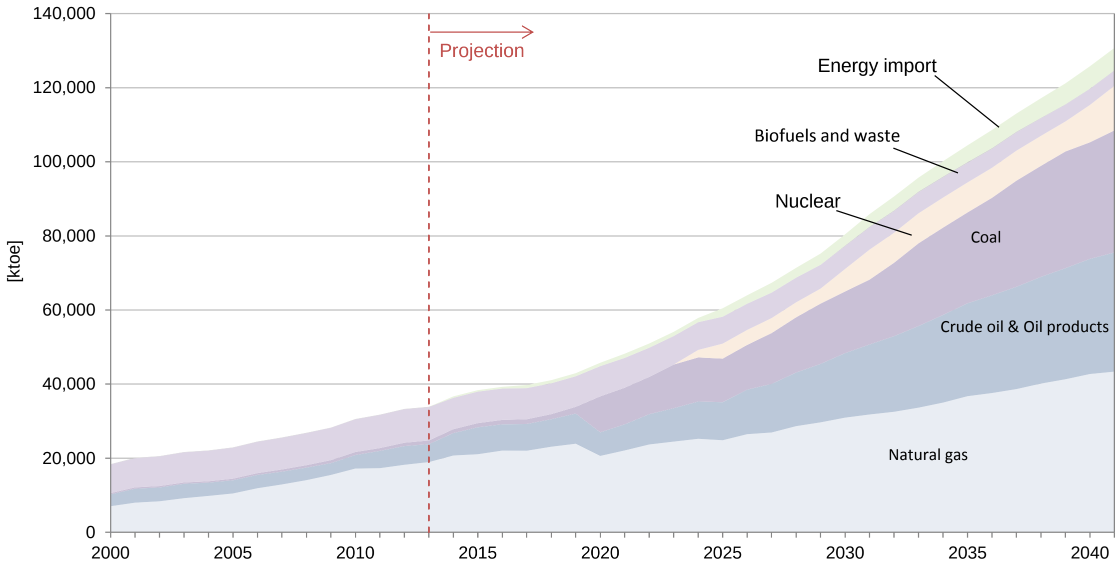


Figure 7-47 Projection of Total Primary Energy Supply –Scenario 1

Table 7-13 Projection of Total Primary Energy Supply –Scenario 1

Primary Energy	2014		2041		Average growth rate ('14-'41)
	ktoe	(share)	ktoe	(share)	
Natural gas	20,728	(57%)	**43,370**	**(33%)**	**2.8% p.a.**
Oil (crude oil + oil products)	6,060	(17%)	**32,163**	**(25%)**	**6.4% p.a.**
Coal	1,081	(3%)	**32,934**	**(25%)**	**13.7% p.a.**
Nuclear	-	-	**12,030**	**(9%)**	**-**
Hydro, Solar, Wind etc.	36	(0%)	**127**	**(0%)**	**4.8% p.a.**
Biofuels & Waste	8,449	(23%)	**4,086**	**(3%)**	**-2.7% p.a.**
Electricity (import)	377	(1%)	**6,027**	**(5%)**	**10.8% p.a.**
Total	**36,688**	**(100%)**	**130,736**	**(100%)**	**4.8% p.a.**

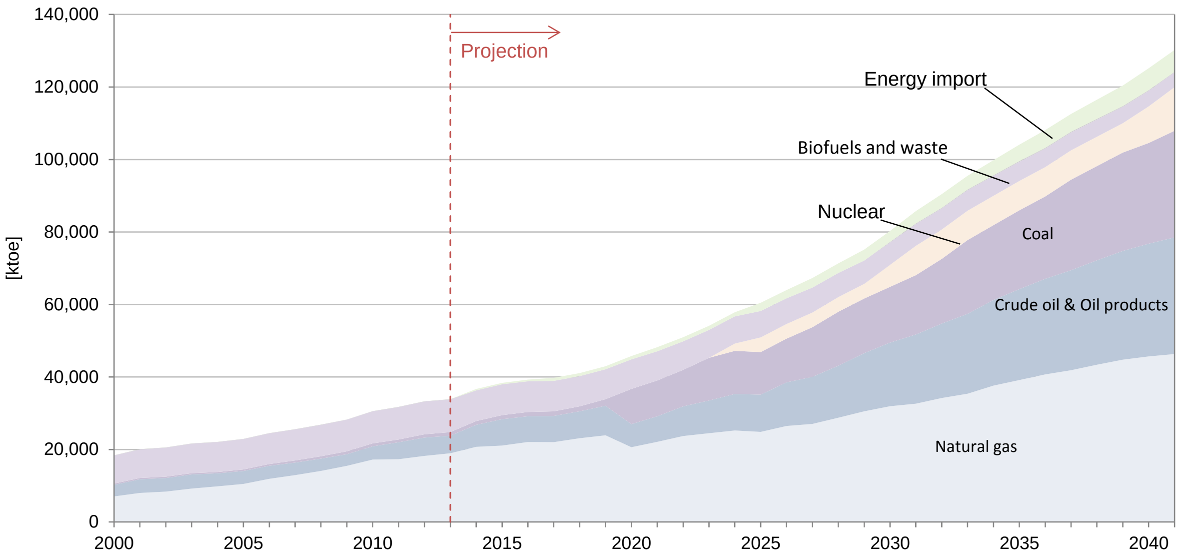


Figure 7-48 Projection of Total Primary Energy Supply –Scenario 2

Table 7-14 Projection of Total Primary Energy Supply –Scenario 2

Primary Energy	2014		2041		Average growth rate ('14-'41)
	ktoe	(share)	ktoe	(share)	
Natural gas	20,728	(57%)	**46,331**	**(36%)**	**3.0% p.a.**
Oil (crude oil + oil products)	6,060	(17%)	**32,176**	**(25%)**	**6.4% p.a.**
Coal	1,038	(3%)	**29,411**	**(23%)**	**13.2% p.a.**
Nuclear	-	-	**12,041**	**(9%)**	**-**
Hydro, Solar, Wind etc.	36	(0%)	**155**	**(0%)**	**5.6% p.a.**
Biofuels & Waste	8,449	(23%)	**4,086**	**(3%)**	**-2.7% p.a.**
Electricity (import)	377	(1%)	**6,027**	**(5%)**	**10.8% p.a.**
Total	**36,688**	**(100%)**	**130,227**	**(100%)**	**4.8% p.a.**

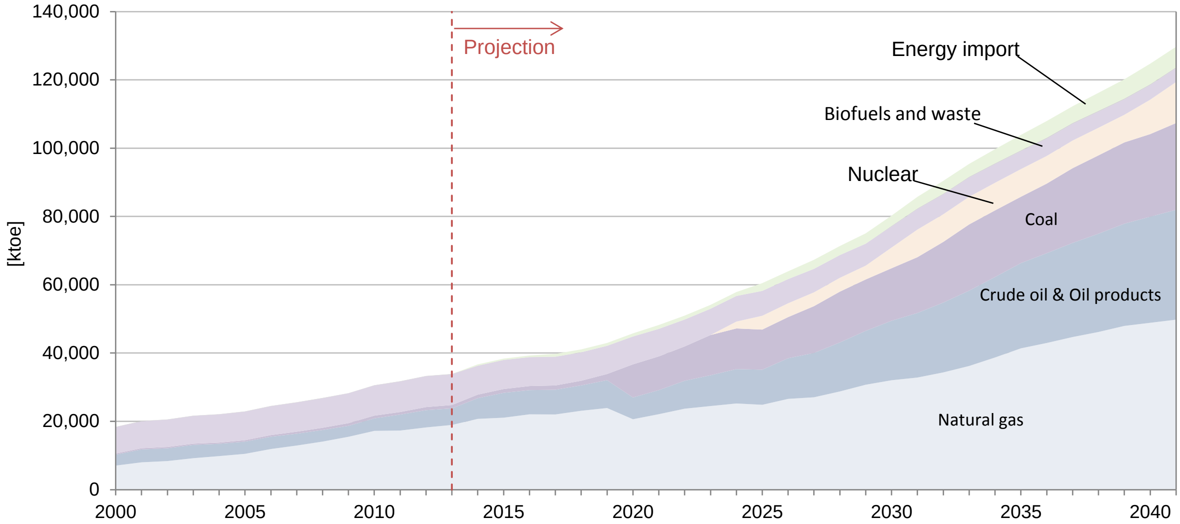


Figure 7-49 Projection of Total Primary Energy Supply –Scenario 3

Table 7-15 Projection of Total Primary Energy Supply –Scenario 3

Primary Energy	2014		2041		Average growth rate ('14-'41)
	ktoe	(share)	ktoe	(share)	
Natural gas	20,728	(57%)	**49,783**	**(38%)**	**3.3% p.a.**
Oil (crude oil + oil products)	6,060	(17%)	**32,162**	**(25%)**	**6.4% p.a.**
Coal	1,038	(3%)	**25,401**	**(20%)**	**12.6% p.a.**
Nuclear	-	-	**12,029**	**(9%)**	**-**
Hydro, Solar, Wind etc.	36	(0%)	**199**	**(0%)**	**6.6% p.a.**
Biofuels & Waste	8,449	(23%)	**4,086**	**(3%)**	**-2.7% p.a.**
Electricity (import)	377	(1%)	**6,027**	**(5%)**	**10.8% p.a.**
Total	**36,688**	**(100%)**	**129,687**	**(100%)**	**4.8% p.a.**

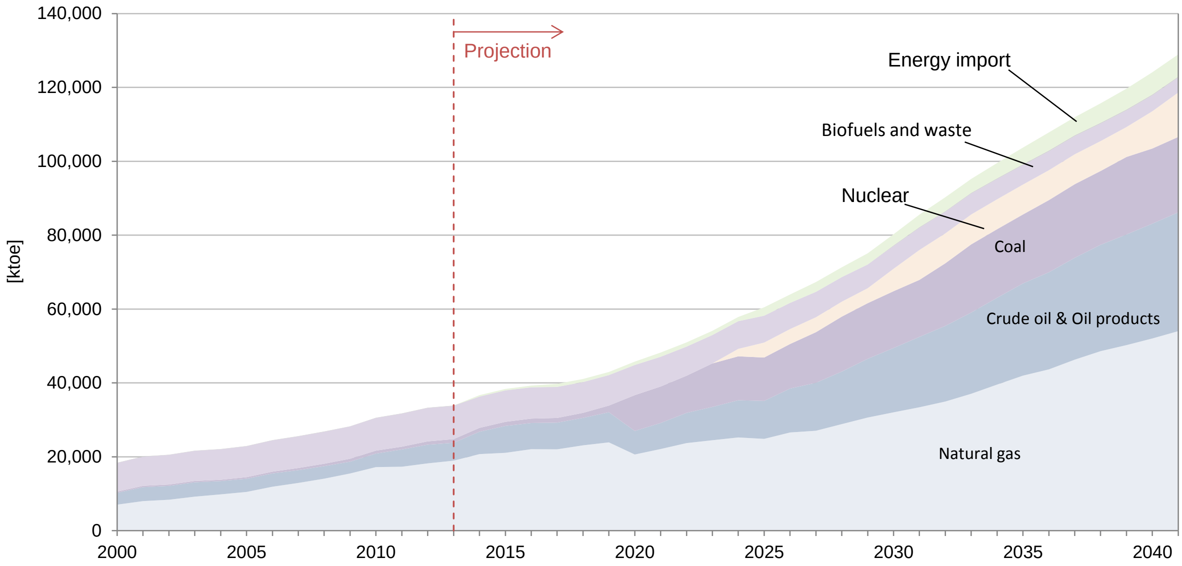


Figure 7-50 Projection of Total Primary Energy Supply –Scenario 4

Table 7-16 Projection of Total Primary Energy Supply –Scenario 4

Primary Energy	2014		2041		Average growth rate ('14-'41)
	ktoe	(share)	ktoe	(share)	
Natural gas	20,728	(57%)	**54,020**	**(42%)**	**3.6% p.a.**
Oil (crude oil + oil products)	6,060	(17%)	**32,163**	**(25%)**	**6.4% p.a.**
Coal	1,038	(3%)	**20,415**	**(16%)**	**11.7% p.a.**
Nuclear	-	-	**12,031**	**(9%)**	**-**
Hydro, Solar, Wind etc.	36	(0%)	**204**	**(0%)**	**6.7% p.a.**
Biofuels & Waste	8,449	(23%)	**4,086**	**(3%)**	**-2.7% p.a.**
Electricity (import)	377	(1%)	**6,027**	**(5%)**	**10.8% p.a.**
Total	**36,688**	**(100%)**	**128,945**	**(100%)**	**4.8% p.a.**

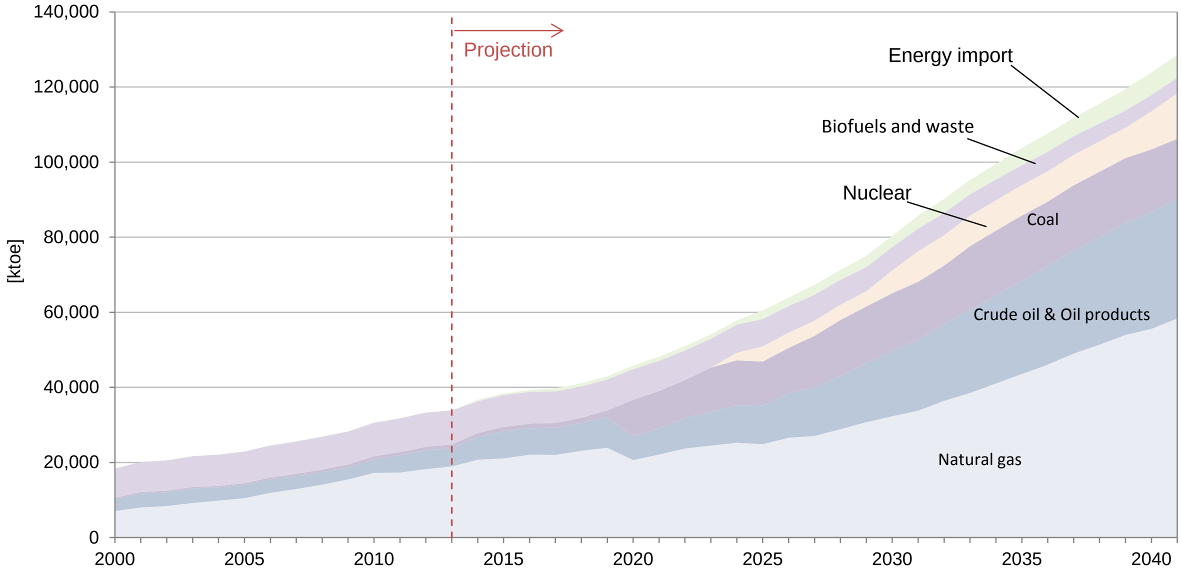


Figure 7-51 Projection of Total Primary Energy Supply –Scenario 5

Table 7-17 Projection of Total Primary Energy Supply –Scenario 5

Primary Energy	2014		2041		Average growth rate ('14-'41)
	ktoe	(share)	ktoe	(share)	
Natural gas	20,728	(57%)	**58,346**	**(45%)**	**3.9% p.a.**
Oil (crude oil + oil products)	6,060	(17%)	**32,161**	**(25%)**	**6.4% p.a.**
Coal	1,038	(3%)	**15,717**	**(12%)**	**10.6% p.a.**
Nuclear	-	-	**12,153**	**(9%)**	**-**
Hydro, Solar, Wind etc.	36	(0%)	**51**	**(0%)**	**1.3% p.a.**
Biofuels & Waste	8,449	(23%)	**4,086**	**(3%)**	**-2.7% p.a.**
Electricity (import)	377	(1%)	**6,027**	**(5%)**	**10.8% p.a.**
Total	**36,688**	**(100%)**	**128,541**	**(100%)**	**4.8% p.a.**

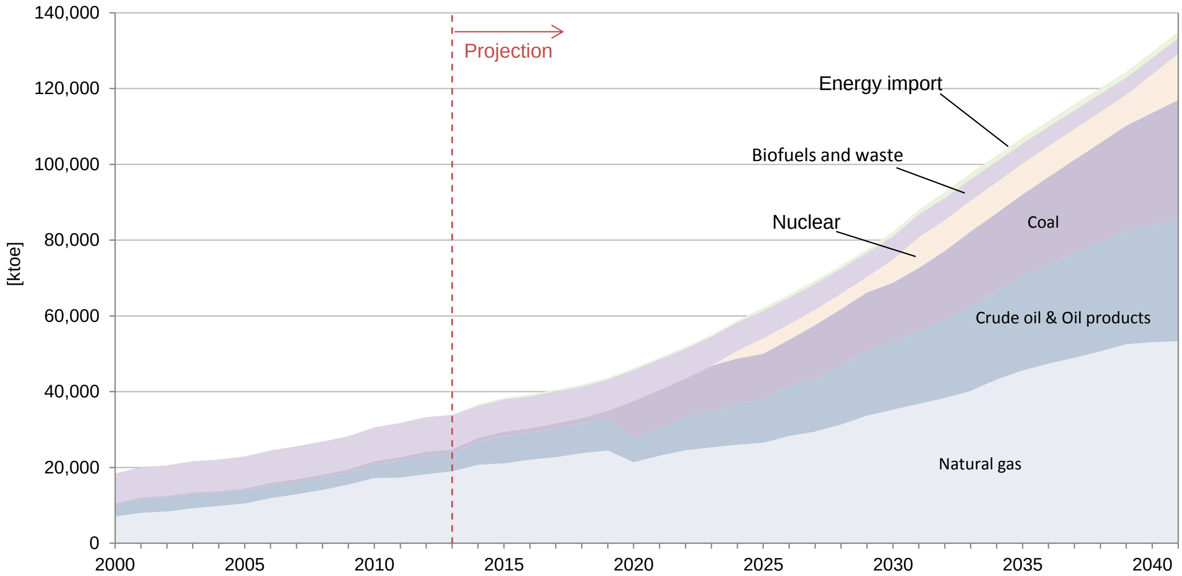


Figure 7-52 Projection of Total Primary Energy Supply –Scenario 6

Table 7-18 Projection of Total Primary Energy Supply –Scenario 6

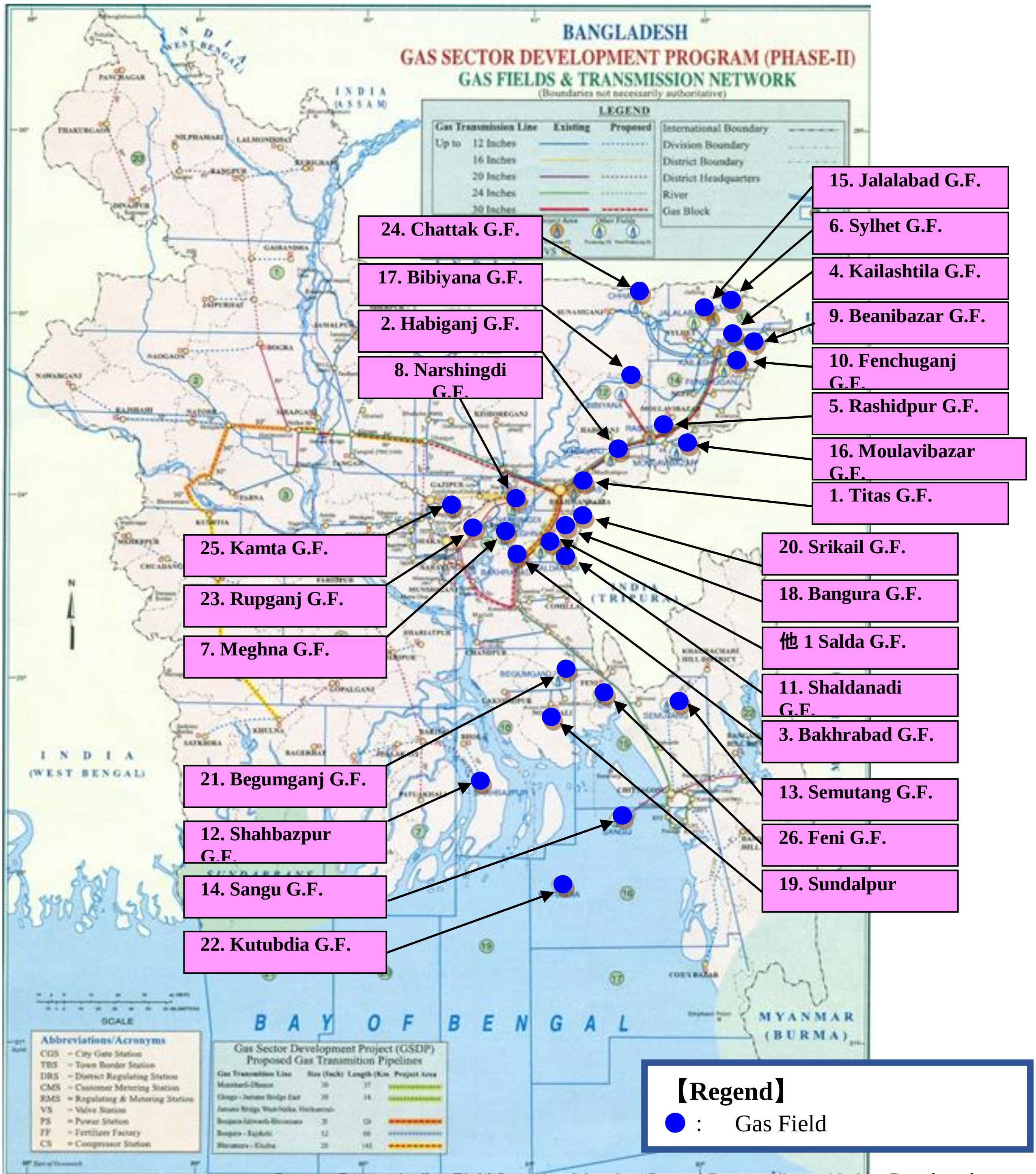
Primary Energy	2014		2041		Average growth rate ('14-'41)
	ktoe	(share)	ktoe	(share)	
Natural gas	20,728	(57%)	**53,335**	**(40%)**	**3.6% p.a.**
Oil (crude oil + oil products)	6,060	(17%)	**32,186**	**(24%)**	**6.4% p.a.**
Coal	1,038	(3%)	**31,502**	**(23%)**	**13.5% p.a.**
Nuclear	-	-	**12,153**	**(9%)**	**-**
Hydro, Solar, Wind etc.	36	(0%)	**51**	**(0%)**	**1.3% p.a.**
Biofuels & Waste	8,449	(23%)	**4,086**	**(3%)**	**-2.7% p.a.**
Electricity (import)	377	(1%)	**1,582**	**(1%)**	**5.5% p.a.**
Total	**36,688**	**(100%)**	**134,895**	**(100%)**	**4.9% p.a.**

Chapter 8 Natural Gas Supply

8.1 Natural Gas Reserve

8.1.1 Gas field location

To date 26 gas fields has been discovered in Bangladesh as shown in Figure 8-1



Source: Domestic Gas Field Location Map for "Proved Reserves" provided by Petrobangla

Figure 8-1 Gas Field Location Map

Geology of Bangladesh started from Upper Paleozonic time when eastern Gondwanaland was broken up. Part of the fragment, Indian Plate, drifted and collided with Asian Plate, and subsided in the period of Oligocene-Holocene Orogenic, and up to now.

The country is divided into three major lithostratigraphic units as follows:

- Folding Bed in the Eastern part of Bangladesh
- Fore Deep in the Central part of Bangradesh
- Stable Shelf and Hinge Zone in the West and North West part of Bangladesh

Majority of gas fields discovered in Bangladesh to date are located in the Folding Bed and adjacent eastern part of Foredeep areas.

These areas are extended from east part of Dhaka to the west and Sylhet Division to the north and Comilla, Chittagon and Cox's Bazar to the south.

The gas of this area has been generated at the depth of 6,000-8,000 m below the surface and migrated up through multi-kirometer sand shale sequence for long vertical distance before being accumulated in the Mio-Pliocene sand reservoirs at the depth of 1,000-4000 m. Some amounts of gases are accumulated at the depth of 1,000 m, known as Pocket Gas.

Special care is required to develop gas in this area due to a fragile nature of strata and reservoir sandstones. They are young and not fully solidified. Four major blowouts have occurred in the Sylhet area, and lost significant amount of gas resources. Gas is still leaking out to the atmosphere from these blown out wells.

Stable Shelf and Hinge Zone in the West and North West part of the country is covered by a sedimentation deposit of Upper Paleozonic to Lower Cretazeous era. According to the report by USGS/Petrobangra 2001, potential of gas and oil deposit in the area is not as high as Folding Bed area, and commercial scale gas field has not been discovered in this area so far.

Natural gas produced in Bangladesh contains 95-99% methane and all others are hydrocarbon components. It contains almost no other impurities such as hydrogen sulfide, carbon dioxide and/or nitrogen.

Produced gas entrains significant amount of condensate. Production of condensate in Bangladesh is 7,800 bpd, with the gas production of 2,500 mmscfd, or 3 bbl/mmscfd, in December 2014. Rate of condensate production per unit gas production is higher in the Sylhet area, and Beanibazar produces 16 bbl/mmcf.

8.1.2 Gas reserve evaluation

The gas reserves shown in the "Draft Five Year Gas Supply Strategy 2015-2019" prepared by Petrobangla is provided as a basis for production forecasts in this study.

Data of gas reserves shown in the "Draft Five Year Gas Supply Strategy 2015-2019" is considered updates of those used in the Petrobangla Annual Report 2013. The updated points are as follows:

- Addition of the data on the Rupganj gas field discovered in 2014
- Remaining 2P reserves are as of January 2015

Gas reserves used for production forecasts in PSMP2010 were based on the report by Hydrocarbon Unit (HCU) (2011) (called as "HCU report" hereafter).

On the other hand, the gas reserves in this Study are based on the "Draft Five Year Gas Supply Strategy 2015-2019"

The reserves (except for the Rupganj field) shown in the draft policy are updates of those shown in Petrobangla Annual Report 2013 and are also the same as those shown in Petrobangla Annual Report 2014.

Comparison of the gas reserves between the HCU report and Petrobangla's "Draft Five Year Gas Supply Strategy 2015-2019" was shown in the Figure 8-1. The summary is as follows:

- The gas reserves shown in the HCU report were originally prepared by Gustavson Associates, US-based consulting company. On the other hand, the gas reserves shown in the "Draft Five Year Gas Supply Strategy 2015-2019" were prepared by updating those in the Petrobangla Annual Report 2013, which were derived from different sources such as RPS Energy, a UK-based consulting company, and Petrobangla.

- The HCU report was prepared in 2011, whereas the RPS Energy's report was prepared in 2009, which was cited for the estimates of the gas reserves on most of the fields shown in the Petrobangla Annual Reports 2011 to 2014. However, some of the gas reserves shown in the "Draft Five Year Gas Supply Strategy" (or Petrobangla Annual Report 2014) are updated.

- Gas reserves estimated by HCU are not used in the Petrobangla's annual reports.

- There are significant differences for recoverable 2P reserves between the HCU report and "Draft Five Year Gas Supply Strategy" for the fields including Titas and Bibiyana.

- In the PSMP2010 report (JICA, 2011), the recoverable 2P reserves for Moulavi Bazar and Bibiyana gas fields were corrected upward significantly and were estimated to be 889 BCF and 5,197 BCF, respectively.

Table 8-1 Comparison of Natural Gas Reserves Estimated by HCU (2011) and Petrobangla (2015)

Unit: BCF

Sl. No.	Gas Field	Year of Discovery	Reserves Estimated by				GIIP		Recoverable Reserves Proved (1P)		Recoverable Reserves Proved + Probable (2P)		Remaining 2P Reserves	
			HCU (2011)		Petrobangla (2015)		HCU	Petrobangla	HCU	Petrobangla	HCU	Petrobangla	HCU	Petrobangla
			Company	Year	Company	Year	Dec. 2009	Dec. 2014	Dec. 2009	Dec. 2014	Dec. 2009	Dec. 2014	Dec. 2009	Jan. 2015
A. Producing														
1	Titas	1962	Gustavson Assoc.	2010	RPS Energy	2009	9,039	8,148.9	6,838	5,384.0	7,582	6,367.0	4,514	2,515.7
2	Habiganj	1963	Gustavson Assoc.	2010	RPS Energy	2009	3,981	3,684.0	2,413	2,238.0	2,787	2,633.0	1,116	523.8
3	Bakrabad	1969	Gustavson Assoc.	2010	RPS Energy	2009	1,825	1,701.0	1,201	1,052.9	1,387	1,231.5	689	456.4
4	Kailashtila	1962	Gustavson Assoc.	2010	RPS Energy	2009	3,463	3,610.0	2,553	2,390.0	2,880	2,760.0	2,400	2,163.6
5	Rashidpur	1960	Gustavson Assoc.	2010	RPS Energy	2009	3,887	3,650.0	2,416	1,060.0	3,134	2,433.0	2,677	1,889.8
6	Sylhet/Haripur	1955	Gustavson Assoc.	2010	RPS Energy	2009	580	370.0	323	256.5	408	318.9	219	113.6
7	Meghna	1990	Gustavson Assoc.	2010	RPS Energy	2009	122	122.1	76	52.5	101	69.9	65	16.8
8	Narshingdi	1990	Gustavson Assoc.	2010	RPS Energy	2009	405	369.0	317	218.0	345	276.8	239	116.4
9	Beani Bazar	1981	Gustavson Assoc.	2010	RPS Energy	2009	225	230.7	108	150.0	137	203.0	77	115.3
10	Fenchuganj	1988	Gustavson Assoc.	2010	RPS Energy	2009	483	553.0	195	229.0	329	381.0	258	256.2
11	Saldanadi	1996	Gustavson Assoc.	2010	RPS Energy	2009	393	379.9	156	79.0	275	279.0	215	197.4
12	Shahbazpur	1995	Gustavson Assoc.	2010	Petrobangla	2011	415	677.0	214	322.0	261	390.0	260	379.5
13	Semutang	1969	Gustavson Assoc.	2010	RPS Energy	2009	654	653.8	318	151.0	318	317.7	318	308.0
14	Sundulpur Shahzadpur	2011	Gustavson Assoc.	2010	BAPEX	2012	—	62.2	—	25.0	—	35.1	—	27.1
15	Srikail	2012	Gustavson Assoc.	2010	BAPEX	2012	—	240.0	—	96.0	—	161.0	—	135.6
16	Jalalabad	1989	Gustavson Assoc.	2010	D & M	1999	1,346	1,491.0	1,013	823.0	1,128	1,184.0	583	281.2
17	Moulavi Bazar	1997	Gustavson Assoc.	2010	Unocal	2003	630	1,053.0	402	405.0	494	428.0	342	160.5
18	Bibiyana	1998	Gustavson Assoc.	2010	D & M	2008	5,321	8,350.0	4,075	4,415.0	4,532	5,754.0	4,056	3,873.2
19	Bangura	2004	Gustavson Assoc.	2010	Tulllow	2011	730	1,198.0	558	379.0	621	522.0	522	241.0
B. Non-Producing														
20	Begumganj	1977	Gustavson Assoc.	2010	BAPEX	2014	47	100.0	10	14.0	33	70.0	33	70.0
21	Kutubdia	1977	Gustavson Assoc.	2010	HCU	2003	65	65.0	46	45.5	46	45.5	46	45.5
22	Rupganj	2014	—	—	BAPEX?	2014	—	48.0	—	—	—	33.6	—	33.6
C. Production Suspended														
22	Chhatak	1959	Gustavson Assoc.	2010	HCU	2000	677	1,039.0	265	265.0	474	474.0	448	447.5
23	Kamta	1981	Gustavson Assoc.	2010	Niko/BAPEX	2000	72	71.8	21	50.3	50	50.3	29	29.2
24	Feni	1981	Gustavson Assoc.	2010	Niko/BAPEX	2000	185	185.2	63	125.0	130	125.0	67	62.6
25	Sangu	1996	Gustavson Assoc.	2010	Cairn/Shell	2010	976	899.6	678	544.4	771	577.8	304	89.9
Total (A + B + C) in BCF							**35,522**	**38,952.2**	**24,255**	**20,770.1**	**28,222**	**27,121.1**	**19,476**	**14,549.4**
Total (A + B + C) in TCF							**35.5**	**39.0**	**24.3**	**20.8**	**28.2**	**27.1**	**19.5**	**14.5**

Source: Prepared based on HCU (2011) and Petrobangla (2015) ("Draft Five Year Gas Supply Strategy 2015-2019")

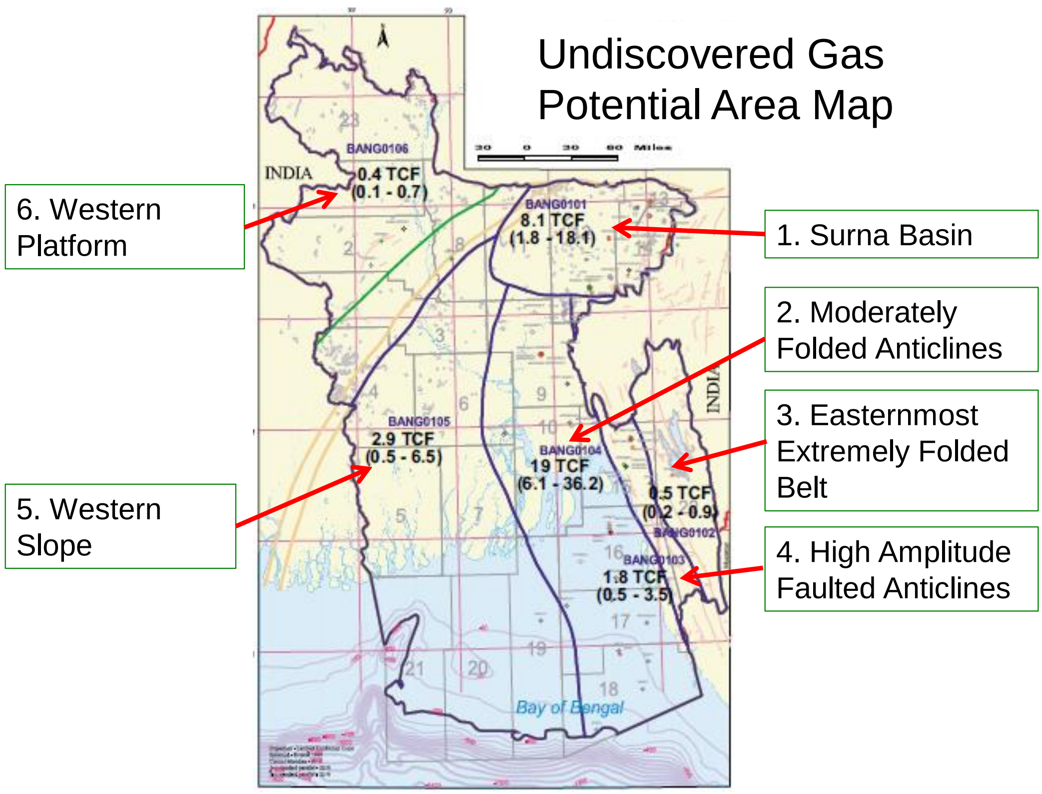
8.1.3 Gas Reserves and Resources

(1) Yet to find resources

According to the report by USGS/Petrobangla joint Study in 2001, Gas resources Yet to Find is considered as follows:

- 8.43 TCF（95% probability）
- 65.7 TCF（5% probability）
- 32.1 TCF（mean）

A geological characteristic of Bangladesh described in the previous section is further broken down by the report of USGS/Petrobangla 2001. Figure 8-2 shows potential of Yet to Find Resources in Bangladesh estimated by a joint effort of Petrobangla and USGS in 2001.



Source: Petrobangla/USGS Bulletin 2208-A, 2001

Figure 8-2 Yet to Find Resources

According to USGS Report, higher probability is indicated in the Eastern Folding Bed area and assumed 90% of Yet to Find resources in the area. On the other hand, Western and North Western area shows lower probability than eastern Folding Bed. The report indicates that main target area for gas exploration should be in the Folding Bed and East part of Foredeep area.

Table 8-2 Yet to Find Resources

Geological Characteristics	USGS Classification	Mean Probability (TCF)	95% Probability (TCF)	5% Probability (TCF)
East Folding Bed	Surma Basin	8.1	1.8	18.1
	Easternmost Extremely Folded Belt	0.5	0.2	0.9
	High Amplitude Faulted Anticlines	1.8	0.5	3.5
	Moderately Folded Anticlines	18.5	6.1	36.2
Central Foredeep	Western Slope	2.9	0.5	6.5
West and North West	Western Platform	0.4	0.1	0.7
合計		32.1	8.4	65.7

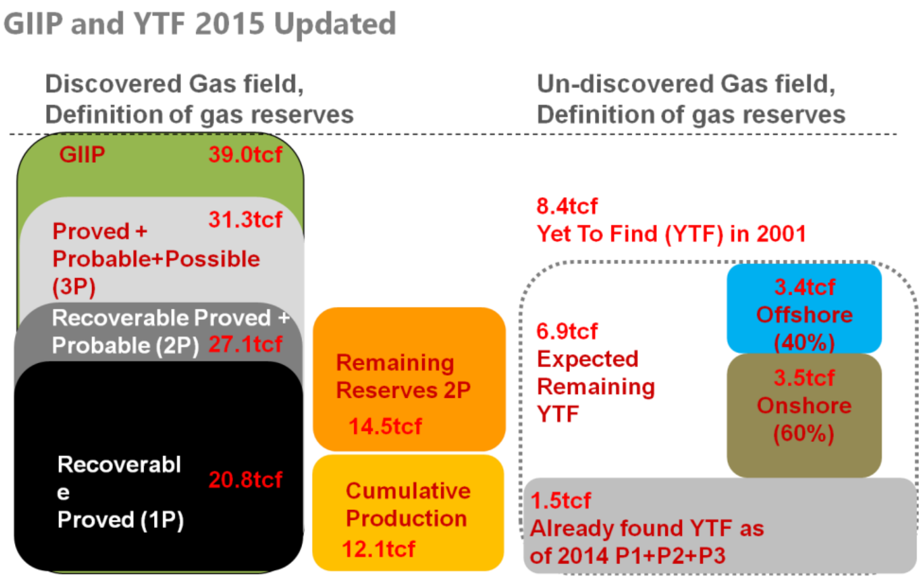
Source: Petrobangla/USGS Bulletin 2208-A, 2001

Note that Onshore portion of mean Yet to Find reserve is estimated 23.3 TCF out of 32.1 TCF of mean probability resources, and Offshore portion is remaining 8.8 TCF. Higher probability is indicated in onshore areas.

After the USGS/Petrobangla Joint Study in 2001, four gas fields, i.e., Bangura, Srikail, Sundalpur and Rupganj were discovered in the Folding Belt and east of Foredeep areas, and total of these confirmed reserves is 1.54TCF.

According to a draft Five year Gas Supply Strategy (2015-2019) by Petrobangla, GIIP of existing gas field is estimated 39 TCF, Recoverable Proved (1P) is 20.8 TCF, Recoverable Proved + Probable (2P) is 27.1 TCF and Recoverable Proved + Probable + Possible (3P) is 31.3TCF. Produced gas to date is 12.1 TCF and remaining 2P Reserve is estimated 14.5 TCF. Undiscovered Conventional gas resources are also estimated by Petrobangla and USGS in 2001. According to the report, undiscovered gas with 95% confidence is estimated 8.4TCF. Since the time 1.5TCF was newly discovered and the balance would be 6.9TCF.

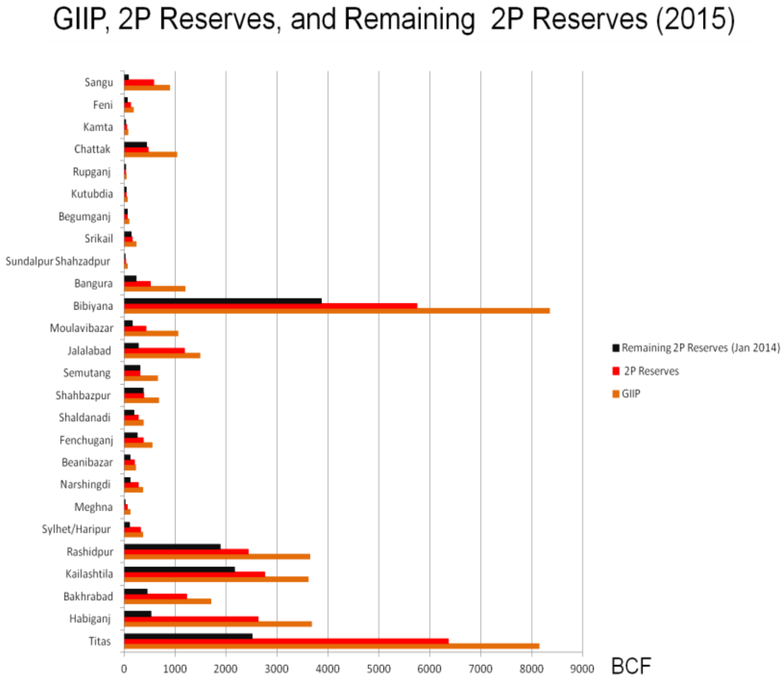
Gas Reserve Balance in Bangladesh is illustrated as follows. Undiscovered gas is assumed based on a statistical approach covering all of the Bangladesh. On the other hand, GIIP, 1P, 2P, and 3P are based on existing gas fields. Based on the reasonable assumption that higher potential of undiscovered gas can be reserved in the existing gas field area, the illustration is useful to understand the gas reserve situation in Bangladesh.



Source: Field-wise natural gas reserve estimates (Petrobangla, Nov. 2014), and Draft Five Year Gas Supply Strategy 2015-2019)

Figure 8-3 Gas Resource Balance

Following is a comparison of GIIP, Recoverable 2P gas Reserves, and Remaining 2P Gas Reserves. This illustrates that major gas fields of Titas、Habiganj、Bakrabad、Jalalabad are aging and the largest gas field of Bibiyana is coming to the peak of production.



Source: Petrobangla2013

Figure 8-4 GIIP, 2P Gas Reserves 2P and Remaining 2P Gas Reserves

(2) Gas reserves of suspended wells/ gas fields

According to Draft Five Year Gas Supply Strategy 2015-2019, gas production from some of the gas bearing sands have been suspended mainly due to an excessive water production from wells in those sands. Amount of such reserve is 761.13 BCF and might be or might not be deducted from the reserves shown in the Table 8-1. The report indicates that systemic study would be required to ascertain the status of these suspended sands.

8.1.4 discovery of new gas field and probability

Probability of discovery of new gas fields are higher in Folding Bed area and recommended to forcus more on this area. On the other hand, unexploited area will also need to be explored although statistics indicates negative. The JICA report entitled the "Preparatory Survey on the Natural Gas Efficiency Project in the People's Republic of Bangladesh (March 2014)" (hereinafter "JICA (2014) Report"), the following exploration programs are proposed.

- Underexplored areas: 2D seismic survey over the Bogra-Lalmai low amplitude broad regional structure and exploratory deep drilling
- Underexplored areas: 2D seismic survey and exploration drilling in the Madarganj and Sariakandi areas
- Difficult areas: 2D seismic survey over the marshy-swampy areas of the Sunamganj-Kishorganj and surrounding areas and deep drilling
- High resolution 2D seismic survey to identify CBM potential in Gondwana basin

Further accumulation of date is required to evaluate the probability of these areas.

8.2 Petrobangla Companies and Cost Structure

8.2.1 Petrobangla companies

Activities of Petrobangla have expanded to manage from gas exploration, production, transmission, distribution, to product marketing. Currently there are following specialized companies operating under Petrobangla.

(1) BAPEX (Bangladesh Petroleum Exploration and Production Company)

Exploration right for new onshire gas fields or concessions is granted to BAPEX exclusively. BAPEX owns six gas fields (Saldanadi, Fenchuganj, Shahbazpur, Semutang, Sundalpur and Srikail) and producing 105 MMCFD of gas in 2014 FY. This accounts for 4% of gas supply in Bangladesh. In addition to six existing gas fields, two other gas fields, Rupganj and Begumganj, are about to produce gas, on completion of pipeline infrastructure.

BAPEX owns and operates drilling rigs and develops its own gas fields, and also provides drilling services to other gas producing companies under Petrobangla. BAPEX has 2D/3D seismic survey units and provides also services to other gas producing companies under Petrobangla in addition to its own concession exploration activities.

(2) Gas producing company

Role of gas production is assigned to BAPEX、BGFCL（Bangladesh Gas Field Company Ltd）and SGFL (Sylhet Gas Field Limited) under Petroangla, and also to Chevron and Tullow, called IOC (International Oil Company).

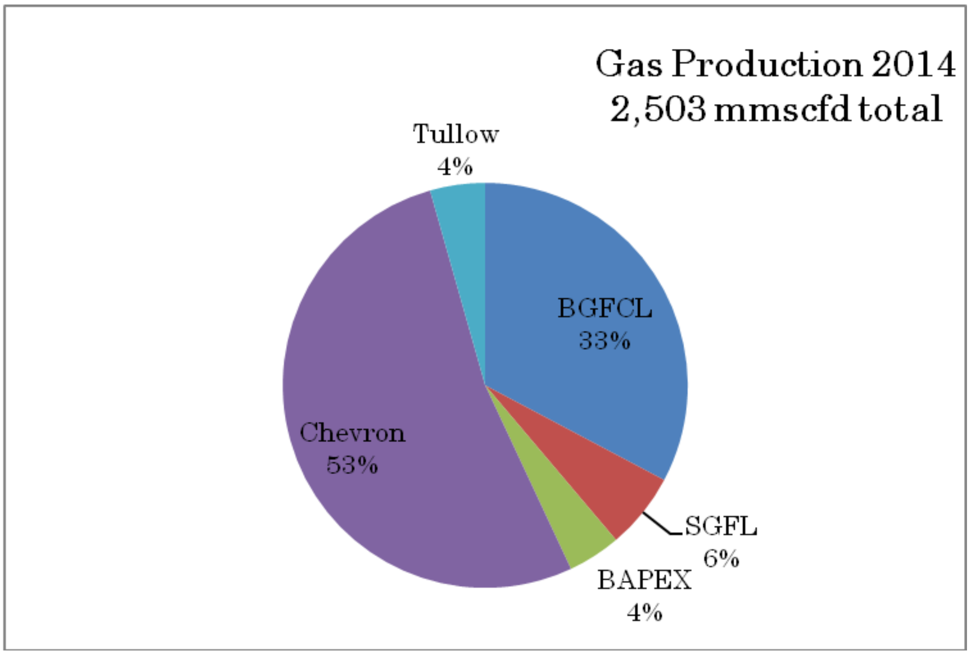
BGFCL owns and operates five gas fields, including Titas, Bakrabad, Habigan, Narshingdi and Meghna.

SGFL owns and operates four gas fields including Sylhet, Kailashtila, Rashidpur and Beani Bazarin.

Chevron and Tullow produces gas based on Product Sharing Contract (PSC) in 1996.

Chevron operates three gas fields including Bibiyana, Jalalabad and Moulavi Bazar and started production in 2006. Cheveon is known as the first company that introduced 3D seismic survey in Bangradesh. Tullow operates Bangura gas field.

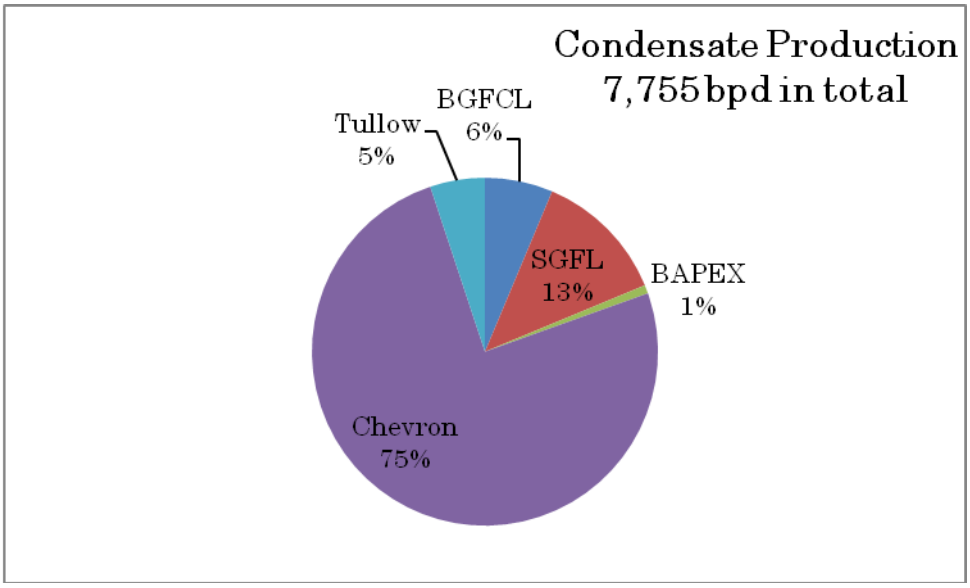
Following figure shows that contribution by Chevron and Tullow is significant in gas production in Bangladesh and accounts for 60 % of overall production.



Source: Petrobangla Annual report 2014

Figure 8-5 Gas Production in 2014- by Company

Significant amount of condensate is associated with gas production. Production rate of the condensate was 7,755 bpd in Dec 2014. Revenue from the sale of condensate is contributing the economics of gas producing companies, in addition to gas revenue. SGFL relies on 75% of revenue from the sale of oil products produced from condensate.



Source: Petrobangla Annual report 2014

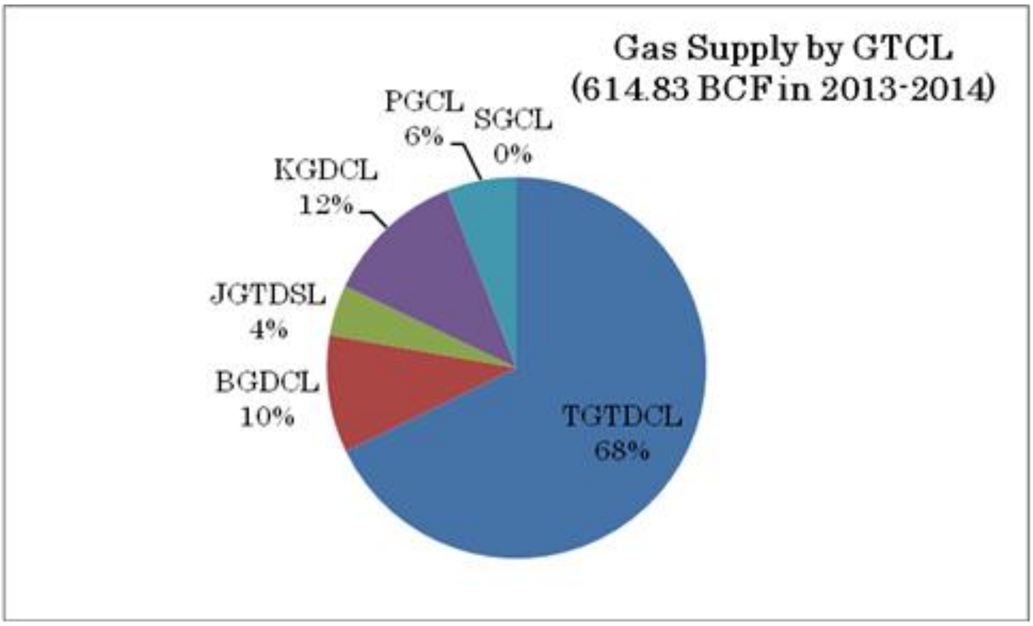
Figure 8-6 Condensate and NGL Production- by Company

Produced condensate is transported via. Pipeline to Titas Gas Field and Bakhrabad Gas Field for refining and produced oil products are sold national and private oil marketing companies.
SGFL is constructing new fractionators and reformer (gasoline production) by its own finance.

(3) Gas transmission company

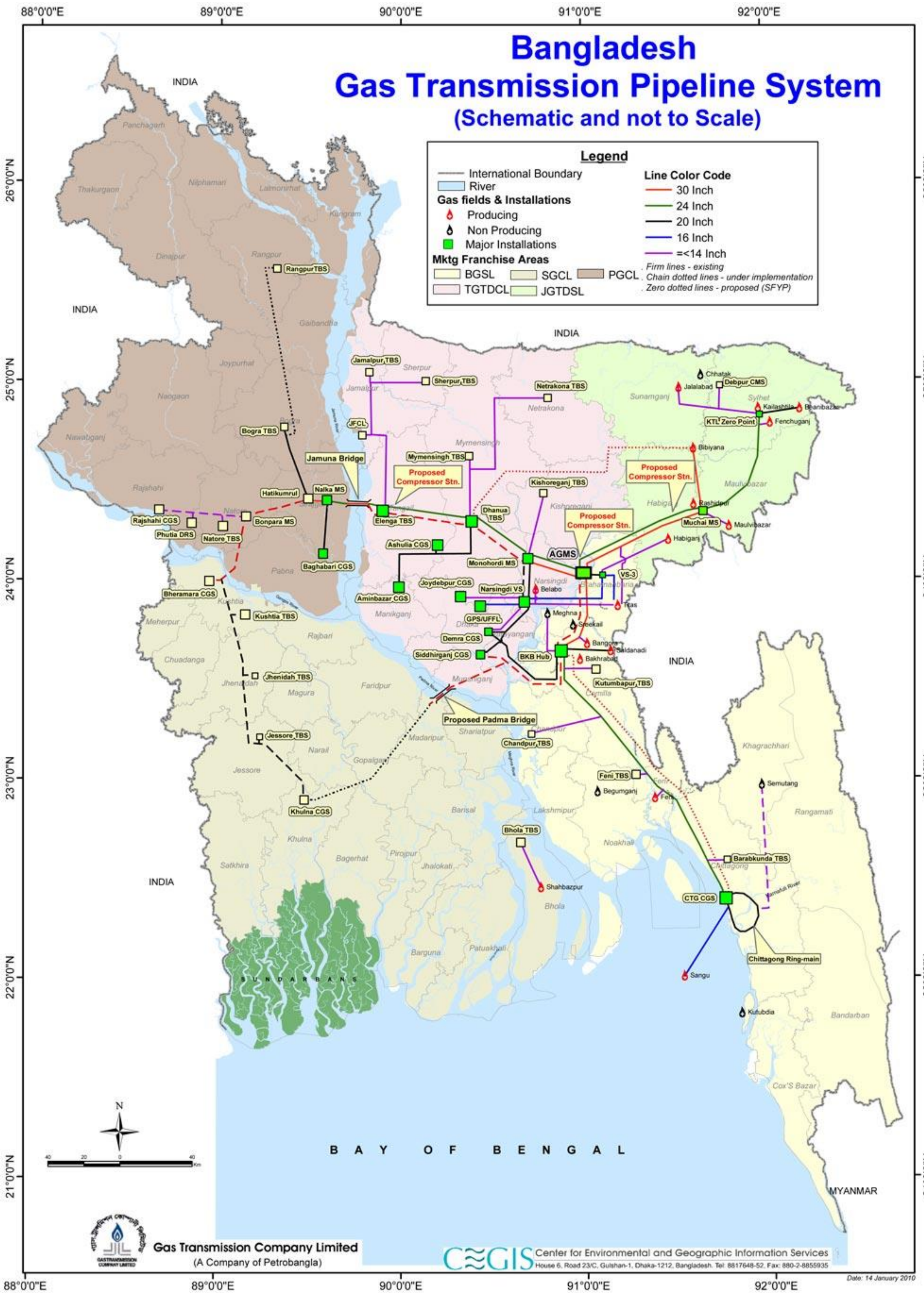
GTCL (Gas Transmission Company Limited) was incorporated in 1993 with the objectives of centralized operation and maintenance of national grid, and expanding the system as required, ensuring balanced supply and usage of natural gas in all regions of the country.

GTCL transported 614.83 BCF of gas in 2014 FY and this account for 70 % of gas produced in Bangladesh. Gas transmission infrastructure has improved significantly since the time of GTCL incorporation. In near future volume of gas from LNG will increase significantly and reinforcement of the current infrastructure may be required to cater to an increasing gas volume from LNG.



Source: Petrobangla Annual Report 2014

Figure 8-7 Gas Transmission by GTCL- by Customer 2013-2014



Source: GTCL

Figure 8-8 GTCL Gas Transmission System

(4) Gas Distribution and Marketing Company

There are six regional gas distribution companies under Petrobangla. These companies are given gas quota allocated sector-by-sector and/or project-by-project basis under the limited supply situation. Total supply of gas to end users was 826.65 BCF in 2014 FY, and considered much lower than actual demand.

1) Titas Gas Transmission Distribution Company Limited (TGTDCL)

TGTDCL is supplying gas to Dhaka Division, and the largest gas distribution and Sale Company. Gas supply is 520.28 BCF in 2014 FY

2) Karnaphuli Gas Distribution Company Limited (KGDCL)

KGDCL is supplying gas to Chittagong, Rangamati, and Cox’s Bazar divisions. Gas supply to endusers in 2014 FY was 82.32 BCF.

3) Bakhrabad Gas Distribution Company Limited (BGDCL)

BGDCL is supplying gas to Comilla, Brahamanbaria, Feni, Noakhali and Lakxmipur provinces. Gas supply to endusers in 2014 FY is 110.31 BCF.

4) Jalalabad Transmission and Distribution Systems Limited (JTDSL)

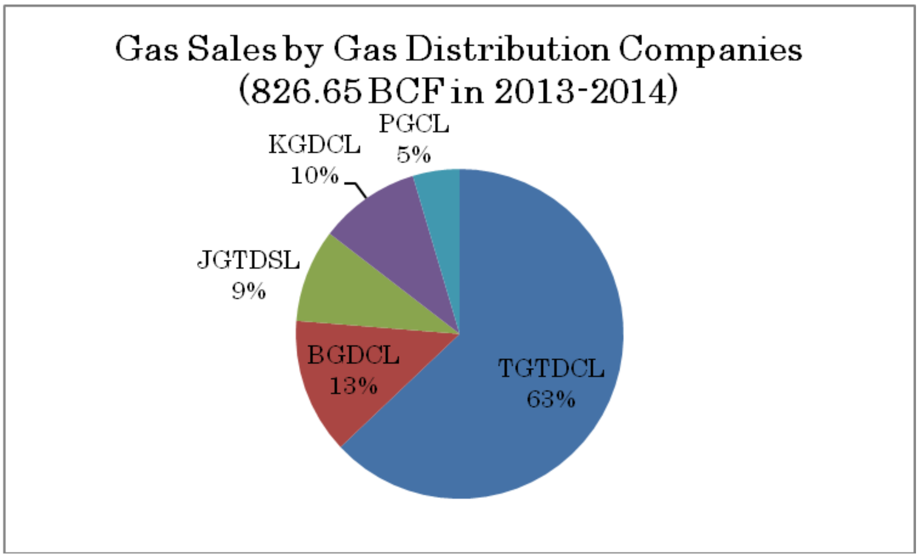
JTDSL is supplying gas to Sylhet Division. Gas supply to end users in 2014 FY was 75.68 BCF.

5) Pashchimanchal Gas Company Limited (PGCL)

PGCL is supplying gas to Rajshahi Division. Gas supply to end users in 2014 FY is 38.06 BCF. PGCL is expected to supply gas to Rangpur Division also.

6) Sundarban Gas company Limited (SGCL)

SGCL is formed in Nov 2009. Its franchise areas is Khulna and Barisal Division



Source: Petrobangla Annual Report 2014

Figure 8-9 Gas Sale by Gas Distribution Companies

(5) CNG and LPG

Pupantarita Prakritik Gas Company Limited (RPGCL) was formulated in 1987 to promote the use of CNG and LPG. RPGCL and private entrepreneurs have set up 587 CNG filling stations and 180 conversion workshop as of June 2014. These filling stations are supplying CNG to almost 220 thousand vehicles daily. This account for 3.58 BCF per month or 5% of total gas supply. RPGCL owns and operate LPG Extraction Plant in Golapgonj, Sylhet.

8.2.2 Gas price and cost structure

Gas pricing system is prepared and decided by the Bangladesh Energy Regulatory Commission (BERC). There are eight market sectors and each has its own pricing structure. These price figures are revised from time to time under the circumstances to suit.

Table 8-3 Gas Price by Sector

	Sector	BDT/M3	USD/MMBTU
1	Power	2.820	1.02
2	Captive Power	8.360	3.03
3	Fertilizer	2.580	0.94
4	Industry	6.740	2.44
5	Tea Garden	6.450	2.34
6	Commercial	11.360	4.12
7	CNG	27.000	9.79
8	Domestic	7.000	2.54

Source: BERC September 2014

Cost component of each sector consists of following:

(1) Government Tax: 55%

(2) Charge by Petrobangla: 45%

1) Petroleum Development Fund: Petrobangla is custodian of the fund and used for petroleum development
2) BAPEX Margin: Allocated to BAPEX as a revenue
3) Price Deficit Wellhead Margin: Created in Dec 1998 to meet up the deficit arisen from sale of gas at a rate lower than the purchase rate by Petrobangla from IOCs
4) Wellhead Gas Margin: Gas producer receive as a revenue
5) Transmission Charge: Wheeling fee for gas transmission. Revenue for GTCL
6) Distribution Charge: Distribution fee for gas distributors
7) Gas Development Fund Margin: In Aug 2009, BERC ordered to create GDF which currently in use for oil and gas exploration and production activities. Petrobangra is custodian of the fund.
8) Gas Asset Price: BERC ordered gas marketing and distribution companies in sep 2015 to create fund kept in a separate account. This fund will be used for future energy project such include LNG etc.

Table 8-4 Gas Price Component

Unit: BDT/M3

	Sector	Government Tax	Petroleum Development Fund	BAPEX Margin	Price Deficit Wellhead Margin	Wellhead Gas Margin	Transmission Charge	Distribution Charge	Gas Development Margin	Gas Asset Price	End User Price
1	Power	1.4363	0.3170	0.0480	0.0400	0.2250	0.1565	0.2650	0.2087	0.1235	2.8200
2	Captive Power	4.3519	0.4560	0.0480	0.0400	0.2250	0.1565	0.1550	0.4474	2.4802	8.3600
3	Fertilizer	1.2362	0.2680	0.0000	0.0400	0.2250	0.1565	0.2650	0.3358	0.0535	2.5800
4	Industry	3.3621	0.7660	0.0480	0.0400	0.2250	0.1565	0.2450	0.6279	1.2695	6.7400
5	Tea Garden	3.2026	0.7660	0.0480	0.0400	0.2250	0.1565	0.2450	0.6279	1.1390	6.4500
6	Commercial	5.5710	1.3355	0.0480	0.0400	0.2250	0.1565	0.2450	1.2350	2.5040	11.3600
7	CNG	14.8500	6.1000	0.1100	0.2000	0.3000	0.1565	0.1550	3.1640	1.9645	27.0000
8	Domestic	3.5344	0.7090	0.0480	0.0400	0.2250	0.1565	0.2450	0.5739	1.4682	7.0000

Source: BERC Sep 2014

Translation to USD/MMBTU is as follows:

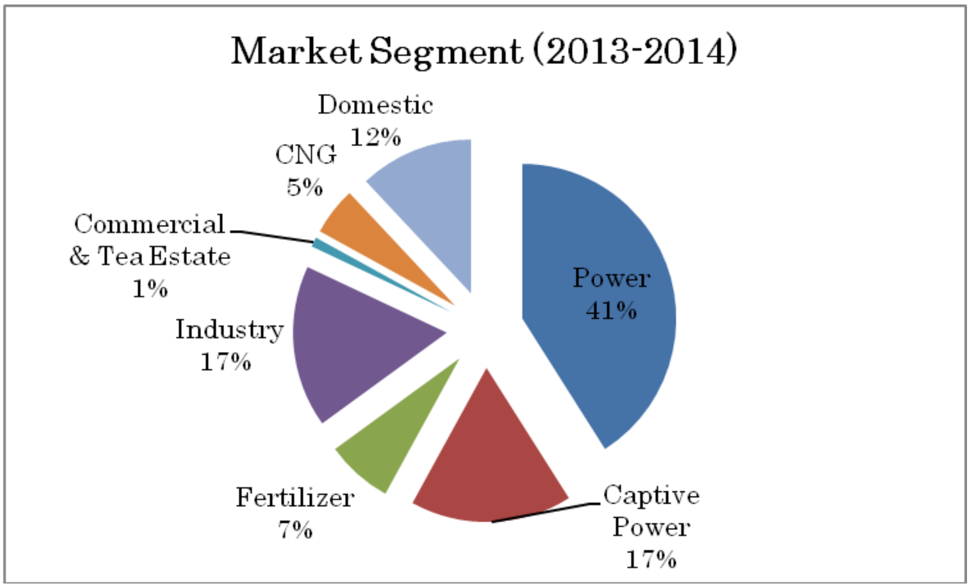
Table 8-5 Gas Price Component

Unit: USD/MMBTU

	Sector	Government Tax	Petroleum Development Fund	BAPEX Margin	Price Deficit Wellhead Margin	Wellhead Gas Margin	Transmission Charge	Distribution Charge	Gas Development Margin	Gas Asset Price	End User Price
1	Power	0.52	0.11	0.02	0.01	0.08	0.06	0.10	0.08	0.04	1.02
2	Captive Power	1.58	0.17	0.02	0.01	0.08	0.06	0.06	0.16	0.90	3.03
3	Fertilizer	0.45	0.10	0.00	0.01	0.08	0.06	0.10	0.12	0.02	0.94
4	Industry	1.22	0.28	0.02	0.01	0.08	0.06	0.09	0.23	0.46	2.44
5	Tea Garden	1.16	0.28	0.02	0.01	0.08	0.06	0.09	0.23	0.41	2.34
6	Commercial	2.02	0.48	0.02	0.01	0.08	0.06	0.09	0.45	0.91	4.12
7	CNG	5.38	2.21	0.04	0.07	0.11	0.06	0.06	1.15	0.71	9.79
8	Domestic	1.28	0.26	0.02	0.01	0.08	0.06	0.09	0.21	0.53	2.54

Source: BERC Sep 2014

8.2.3 Financial status of companies under Petrobangla



Source: Petrobangla Annual Report 2014

Figure 8-10 Gas Market by Sector

Due to a shortage of gas supply and also under the gas quota system, actual gas demand for each sector will be potentially larger than current consumption, and demand spectrum may also be different.

Gas producing companies under Petrobangla receives Wellhead Margin of USD 0.08/MMBTU, while IOC receives USD 2.48/MMBTU. SGFL has worked to maximize the recovery of condensate and produce oil products produced for sale. 75% of revenue comes from the sale of oil product. In order to enhance the revenue further, SGFL is constructing 4,000 bpd fractionators and 3,000 bpd reformer to manufacture gasoline by its own finance.

GTCL receives Gas Transmission Charge. The rate has reduced to half i.e., USD 0.06/MMBTU after Sep 2014, assuming that growth of flow rate would compensate the reduced unit rate. GTCL is constructing 36 inch Bibiyana-Dhanua pipeline with the length of 137 Km by its own finance. GTCL expects that this project will bring some more revenue and contribute to the financial status of the company. GTCL is caring out other investment projects supported by dinners such includes ADB, World Bank, and JICA, and also government funding.

Major portion of revenue for Gas distribution companies comes from Distribution Charge, which varies from sector to sector but no significant difference among the sectors. Since there are no significant differences between large scale customers and Domestic customers, major marketing effort favors large customers.

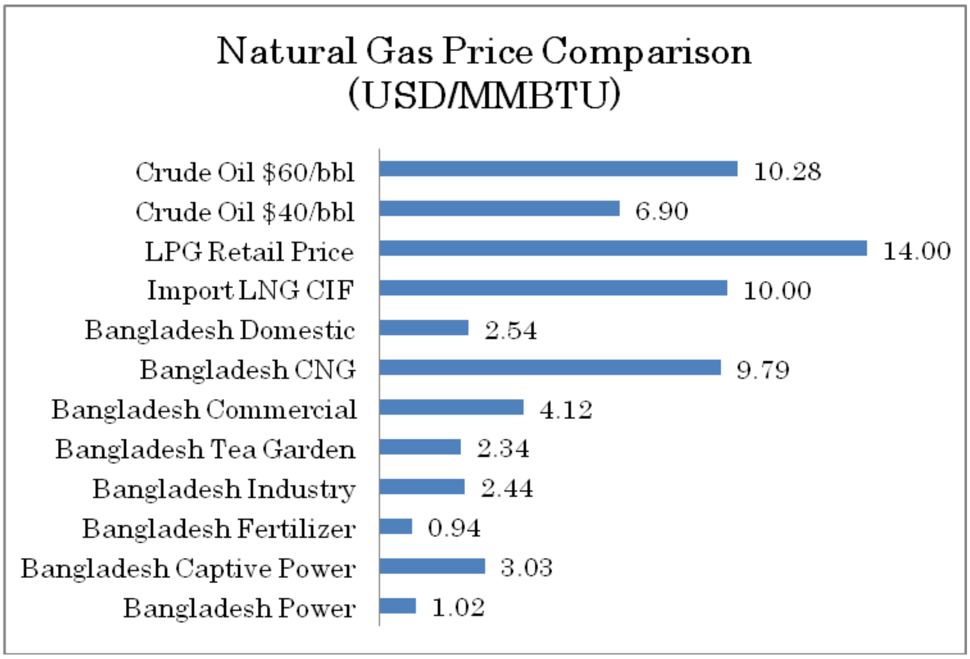
Gas distribution companies are trying to increase the revenue by making investment on Transmission Pipeline Project and receive Transmission Charge if economics favors. They are also utilizing Security Charge from their customers to raise revenue from fund operation.

Petrobangla is promoting LPG for domestic use, discouraging the use of natural gas. Petrobangla is also promoting the use of gasoline in lieu of CNG to save natural gas.

To balance out the price difference between natural gas and alternative fuels, Distribution Charge for domestic sector and CNG to be raised.

Average gas market price in Bangladesh in 2014FY in terms of USD/MMBTU is USD 2.34 /MMBTU, and on the other hand, purchase price from IOC is USD 2.48/MMBTU.

Comparison of Energy Price in Bangladesh is shown in the Figure 8-11. Gas price for power and fertilizer are significantly low in comparison and need to be adjusted considering envisaged future introduction of LNG. Raising the gas price might necessitate the enhancement of gas use efficiency for these sectors.



Source: BERC Sep 2014and others

Figure 8-11 Gas Price Comparison

8.3 Gas Production Forecast

8.3.1 Assessment of existing gas fields and fast track program

(1) Assessment of existing gas fields

Tracing of production record of the existing gas fields helps to make forecast of future gas production. A comparison of actual production (average daily production) from each gas field over the years from 2010 to 2014 and the production forecast by PSMP2010 is shown in Table 8-6.

Table 8-6 Comparison between Actual Average Daily Production and PSMP2010 Forecasts

Unit: mmscfd

Sl. No.	Gas Field	Average Daily Production							
		Actual					PSMP2010 Forecasts		
		2010	2011	2012	2013	2014	2010	2014: Case1	2014: Case 2
1	Titas	404	445	450	490	515	408	578	560
2	Habiganj	235	260	227	225	225	240	260	260
3	Bakhrabad	35	33	32	41	41	36	51	51
4	Kailashtila	91	86	89	84	74	87	97	97
5	Rashidpur	49	49	47	47	61	49	84	85
6	Sylhet/Haripur	3	10	9	9	8	7	30	30
7	Meghna	0	10	10	11	10	0	5	5
8	Narshingdi	33	30	30	28	28	35	25	25
9	Beanibazar	15	9	11	10	10	15	15	15
10	Fenchuganj	25	23	36	37	39	24	65	60
11	Saldanadi	8	18	16	15	12	8	8	8
12	Shahbazpur	6	0	7	7	8	8	10	10
13	Semutang	0	14	8	6	5	0	15	15
14	Sundalpur	0	0	10	10	4	0	60	60
15	Srikail	0	0	0	42	39	0	60	60
16	Sangu	37	14	23	0	0	40	0	0
17	Jalalabad	163	165	232	249	246	130	250	200
18	Moulavi Bazar	58	42	94	77	63	60	160	80
19	Bibiyana	658	753	792	822	1,007	716	900	850
20	Bangura	105	102	86	111	110	120	120	120
21	Begumganj	0	0	0	0	0	0	0	0
22	Kutubdia	0	0	0	0	0	0	0	0
23	Chattak	0	0	0	0	0	0	0	0
24	Kamta	0	0	0	0	0	0	0	0
25	Feni	2	0	0	0	0	2	2	2
Total		**1,926**	**2,062**	**2,210**	**2,323**	**2,435**	**1,995**	**2,765**	**2,563**

Note: A production rate of 60 mmscfd for Sundalpur and Srikal by the PSMP2010 forecasts means that the sum of production from Sundalpur and Srikail should be equal to 60 mmscfd in this case.

Source: Prepared based on Petrobangla Annual Reports 2010 to 2014 and PSMP2010 report (JICA, 2011)

Based on the information/data about remaining 2P reserves shown in the “Draft Five Year Gas Supply Strategy 2015-2019”, and also description about the drilling and work-over activities shown in the Petrobangla Annual Reports, assessment of current gas field status and the future outlook are investigated (refer to the Attachment 6-1)

As a result of study, followings are understood.

- Only Bibiyana gas field has shown a steady increase in production since 2010 in Bangladesh.
- The Jalalabad gas field also significantly increased production in 2012, but after that production from the field has not increased significantly.

- Production from the Sangu gas field was suspended from October 1, 2013.
- Measures to be taken prevent the excessive water production from sands
- Develop new gas field for further gas production while maintaining current production level as much as possible.
- Installation of wellhead gas compressors to maintain gas production.

(2) First truck program

To meet the increasing gas demand within the soonest possible time, decision was made as per Government directives and under the Speedy Supply of Power and Energy-Special Provision- Act 2010, to drill a total of 10 wells by Gazprom EP, Russia. The Contract was signed in April 2012 and Drilling work was carried out 2013-2014, as follows:

Titas Gas Field (BGFCL): Well No.19, 20, 21, 22
Rasidpur Gas Field (SGFCL): Well-No.8
Semutang gas Field (BAPEX): Well No. 6
Begumganji Gas Field (BAPEX): Well No. 3
Shrikail Gas Field (BAPEX): Well No. 3
Shahbazpur Gas Field (BAPEX): Well No. 3, 4

Expected gas production by the contract was 300 MMCFD, however, actual confirmed gas production ended up with 150 MMCFD. Five wells are producing gas. Three wells are waiting for completion of processing facilities and connecting pipeline infrastructure. Titas No. 21 well produced gas at 10 MMCFD for the first 6 months, and suspended due to an excessive water production. Work-over is underway by BAPEX at the cost of Petrobangla. Semutang No. 6 well was relinquished due to an excessive water production.

Additional contract was signed in end 2015 with Gazprom to drill following five wells:

Bhakrabad Gas Field (BGFCL): Well No. 10
Rashidpur Gas Field (SGFCL): Well No. 9, 10, 12
Shrikail Gas Field (BPEX): Well No. 4

Russian oil and gas exploration and drilling technology has been lagged behind the western world and modernization of their technologies has been exercised, especially in the area of offshore development. Western technology is considered inevitable for their offshore development.

(3) Introduction of “Best Industrial Practice” through competitive bidding

BGFCL has introduced “Best Industrial Practice” through competitive bidding for Titas Gas Field Well No. 23、24、25、26, financed by ADB under “Gas Seepage Control and Appraisal and Development of Titas Gas Field” As a result, SINOPEC China was awarded the contract at the price of 25% lower than that of Gazprom paid for the First Truck Program, and the result was satisfactory. This project indicates that there is an alternative way for the future exploration project in addition to the First Truck Program.

8.3.2 Production forecast for existing gas fields 2015-2019

Production forecast for the existing gas fields for the next five years will provide a base for preparing long-term production forecast. In this Study, production forecasts for the period of 2015 to 2019 are prepared by reviewing the Draft Five Year Gas Supply Strategy 2015-2019 (Petrobangla Five Year Plan 2015).

As a result of the review, it is considered that the production rate shown in the Draft Five Years Gas Supply Strategy is considered a little too optimistic. And therefore, correction factor is introduced. (Refer to Attachment 6-1)

(1) Review of schedule and performance of wells in the Petrobangla Five-Year Plan

Well completion schedule and production rate shown in the in the "Gas Evacuation Plan 2010-2015" prepared in 2010 was reviewed by comparing against Petrobangla Five year Plan 2015. The summary of the review outcome is as follows:

- Times of well completion: At least one year behind the schedule
- Production rates for new wells: About 70% of initial estimates (Gazprom performance is reflected)

(2) Correction factors for schedule delay and production rate is introduced as follows:

Impact of schedule delay on the production rate is expressed as a discount factor for production rate. One-year delay in a five-year period is discounted by 20% from the initial estimate.

- Times of well completion: 80% of the initial estimates
- Production rates for new wells: 70% of the initial estimates

The values of production rates are corrected by multiplying 0.8 and 0.7 for all wells scheduled to be completed after 2016.

(3) Production forecasts for 2015-2019

Taking above review result into account, Production forcast in Pertobangla Five year Plan was modified. The modified production forecasts are shown in Table 8-7.

Note that:

- Production profiles are basically the same as those shown in the Petrobangla Five-Year plan 2015.
- According to the Petrobangla Five-Year Plan 2015 include the production of 5 mmscfed from Shahbazpur gas field after 2018 is not taken into consideration in this study because there is no clear development plan is publicized yet.
- Peak gas production will be in July-December 2016 and the rate is estimated 2,811 mmscfd. While production forecasts by the Petrobangla Five-Year Plan 2015 also shows a peak production in the same period with the estimatedrate of 2,916 mmscfd. Differential of Production rate between the cases are about 100 mmscfd, or discounted by 5% .

Table 8-7 Daily Gas Production Forecast for 2015-2019

Unit: mmscfd

Company	Field	2015		2016		2017		2018		2019		Remarks
		Jan-Jun	Jul-Dec	Jan-Jun	Jul-Dec	Jan-Jun	Jul-Dec	Jan-Jun	Jul-Dec	Jan-Jun	Jul-Dec	
1. BGFCL	Titas	525	520	520	510+56	556	546	489	489	441	441	Production start-up: Jul-Dec 2016—Well nos. 23, 24, 25 and 26
	Bakrabad	40	38	36	34	30	26	23	23	30	30	
	Habiganj	224	224	224	224	220	218	215	215	200	200	
	Narsingdi	28	28	28	28	26	25	24	24	23	23	
	Meghna	10	10	10	10	10	10	9	9	9	9	
	Sub-total	**827**	**820**	**818**	**862**	**842**	**825**	**760**	**760**	**703**	**703**	
2. SGFL	Sylhet	8	8	7	7+6	12	11	11	10	10	9	Production start-up:Jul-Dec 2016—Well no. 9
	Kailashtila	72	70+8	78+14	92+8	100	96	96	92	92	88	Production start-up: Jul-Dec 2015—Well no. 1&5, Jan-Jun 2016—Well no. 9, Jul-Dec 2016—Well no. 7
	Rashidpur	60	59	58	57	56	61	72	70	67	67	Production start-up: Jul-Dec 2017--Well no. 9, Jan-Jun 2018--Well nos. 10 & 11
	Beani Bazar	9	9	9	9	8	8	8	8	8	8	
	Sub-total	**149**	**154**	**166**	**179**	**176**	**176**	**187**	**180**	**177**	**172**	
3. BAPEX	Saldanadi	10	6+10	16	13	12	11	10	10	10	10	Prpduction start-up: Jul-Dec 2015—Well no. 4
	Fenchuganj	35	34	32	30	30	29	28	28	28	28	
	Shahbazpur	10	10+9	29	29	29	29	29	29	29	29	Production start-up: Jul-Dec 2015—Well no. 4
	Semutang	4	3	2	2	2+4	6+4	10	10	10	10	Production start-up: Jan-Jun 2017—Well no. 7, Jul-Dec 2017—Well no. 8
	Sundalpur	3	3	2	0+4	4	4	4	4	4	4	Production start-up: Jul-Dec 2016—Well no.2
	Srikail	38	36	35+11	46	41	41	41	41	36	36	Production start-up: Jan-Jun 2016—Well no. 4
	Rupganj	0	8	8	8	8	8	7	7	7	7	
	Begumganj	4	4+8	12	12	10	10+8	16	16	12	9	Jan-Jun 2015: Actual production, Production start-up: Jul-Dec 2015—Well no. 3, Jul-Dec 2017—Well no. 4
	Sub-total	**104**	**141**	**147**	**144**	**140**	**150**	**145**	**145**	**136**	**133**	
	Sub-total (1+2+3)	**1,080**	**1,115**	**1,131**	**1,185**	**1,158**	**1,151**	**1,092**	**1,085**	**1,016**	**1,008**	
4. Chevron	Jalalabad	250	250	250	250	220	220	220	220	220	220	
	Maulavibazar	50	50	50	50	45	45	45	45	45	45	Jan-Jun 2015: Actual production
	Bibiyana	1,100	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	Jan-Jun 2015: Actual production
5. Tullow	Bangora	110	110	109	109	81	81	69	69	58	58	Jan-Jun 2015: Actual production
	Sub-total (4+5)	**1,510**	**1,610**	**1,609**	**1,609**	**1,546**	**1,546**	**1,534**	**1,534**	**1,523**	**1,523**	
6.	Feni				6	6+6	12	12	11	9	8	Resumption of production: Jul-Dec 2016—Well no. 6, Jan-Jun 2017—Well no. 7
7.	Chhatak				11	11+11	22	22	19	19	16	Resumption of production: Jul-Dec 2016—Well no. 3, Jan-Jun 2017—Well no. 4
Ground Total (1+2+3+4+5+6+7)		**2,590**	**2,725**	**2,740**	**2,811**	**2,738**	**2,731**	**2,660**	**2,649**	**2,567**	**2,555**	

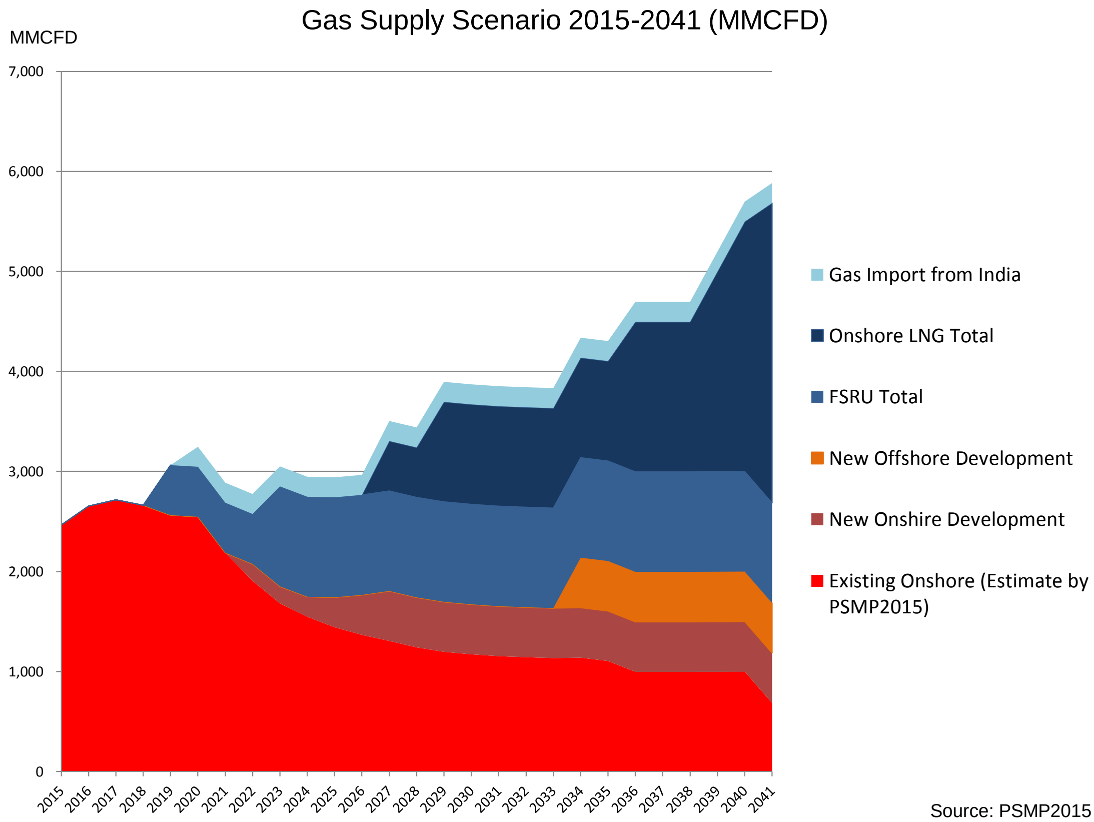
Note: 1) Production rates in yellow cells were modified from those shown in the Petrobangala's five-year plan based on the actual production data or corrected production rates shown in Table 1.4-2.
2) The expression such as "510+56" means a daily production rate without additional production plus an additional daily production rate.

Source: Petrobangla's "Draft Five Year Gas Supply Strategy" (2015) and JICA SurveyTteam

8.3.3 Natural gas supply scenarios 2015-2041

Natural gas Supply Scenario 2015-2014 is based on the following assumptions:

1) Primary supply scenario is based on the existing gas production profile by Petrobangla.
2) 95 % of discount factor is introduced based on the assessment by PSMT2015.
3) Assuming new Onshore Gas Fields are developed as follows:
   - 2022 and After: Supply of 170 MMSCFD by BAPEX as shown in the Petrobangla Five Year Plan
   - 2024 and After: 30 MMCFD from new gas field
   - 2025 and After: 100 MMCFD from new gas field
   - 2026 and After: 100 MMCFD from new gas field
   - 2027 and After: 100 MMCFD from new gas field
4) Assuming new Offshore Gas Field are developed as follows:
   - 2035 and After: 500MMCFD from new gas field
5) FSRU Project
   - 2019 and After: 500 MMSCFD is supplied by FSRU Phase 1
   - 2023 and After: Additional 500MMSCFD is supplied by FSRU Phase 2
6) Onshore LNG Terminal
   - 2027 and After: Initial Phase of 2 x 200,000 kl tanks is operational and start supply 500MMSCFD
   - By 2041, Capacity is increased to 3,000 MMSCFD
7) Gas Introduction from abroad
   - 2020and After: 200 MMCFD from India



Source: PSMP2015

Figure 8-12 Gas Supply Scenarios 2015-2040

In near future, introduction of a large amount of LNG is inevitable choice for Bangladesh.

8.3.4 Cost estimate for future investment on gas field development

The investment costs required for the exploration, drilling, and constructions of the gas production facility were estimated. The construction costs for the new gas production facility were estimated based on Bangladesh's gas field development plan. Cost Estimate was made by using cost estimate software developed by SIMENS. (See Attachment 6-2 for detail)

Some area is not covered by the Software and these are assumed based on the following figures:

1) Significant labor works and time/cost will be required to identify oil and gas deposit in the green field in general, and cost for these area will also differ from country to country and also to the local conditions. In case of Bangladesh, it is assumed that potential of gas borne area is identified already, and actual cost information used for particular field is used as a benchmark cost, i.e., 2D Seismic Survey: USD 3 million (80 L Km), 3D Seismic Survey: USD 28 million (400 km2)

2) Drilling cost assumes four development wells and used as a production well at later stage. Based on the recent experience by BGFCL, total of 4 wells cost USD 60 million.

3) Assuming that production rate from future onshore wells is 500 MMSCFD, cost for production facilities will be assumed USD 90 million as per SIMENS Cost Estimate Software.

4) LNG Receiving Onshore terminal assumes 2x 200,000 M3 LNG tanks at the initial phase, with jetty and re-gasification facilities. Total estimated cost is USD 500 million.

Table 8-8 Total Investment Costs for Gas Development

	Item	Cost [mill. USD]
A	**Domestic Gas Development Costs for the Remaining Reserves 2P**	
A1	Field Exploration Costs	*30*
A2	Field Development Costs	
A2.1	Drilling Costs	*60*
A2.2	Facility Construction Costs	
(1)	Facility construction costs for domestic gas which has already been discovered	302.8
(2)	Gas transmission pipelines from gas production facilities for domestic gas which has already been discovered	9.0
(3)	Facility construction costs for domestic gas which has not been discovered	*90*
(4)	Gas distribution pipelines for future power plants	5.0
	Subtotal (A)	*496.8*
B	**Import Gas Development Costs**	
B1	Facility Construction Costs	
(1)	LNG Receiving Terminal	*500*
(2)	LNG transmission pipeline	115.1
	Subtotal (B)	*615.1*
C	**Contingency (= (A+B) x 50%)**	
	Subtotal (C)	*556*
	Total (A+B+C)	***1,667.8***

Source: PSMP2016

Numbers of assumptions were made to make cost estimate and the result is not necessarily close enough to predict future cost.

(1) Reinforcement cost for Existing Pipeline Infrastructure is not included in the cost estimate.
(2) Impact of LNG introduction to existing gas infrastructure and to gas field processing facilities/wellhead compressors is not included.
(3) All the cost data and assumed infrastructure models used for cost estimate to be reviewed.

8.3.5 Condensate production

Significant amount of condensate has been produced from gas field in Bangladesh. Revenue from the sale of oil product from condensate has been an important side revenue for gas producing companies. Investment for condensate fractionation facilities has been made to recover and monetize the condensate.

Recovered condensate is fractionated to LPG, Gasoline, Kerosene and Diesel products and soled to National Oil and/or LPG Marketing Companies and private oil refining and marketing companies

Production rate for condensate in Dec. 2014 was 7,800 BPD. On the other hand, Eastern Refining Co., National Refining Company with 30,000 BPD throughput capacity, produces 15,000-20,000 BPD of white oil products. This translates that 30-35% of white oil products are supplied from the distillates of condensate.

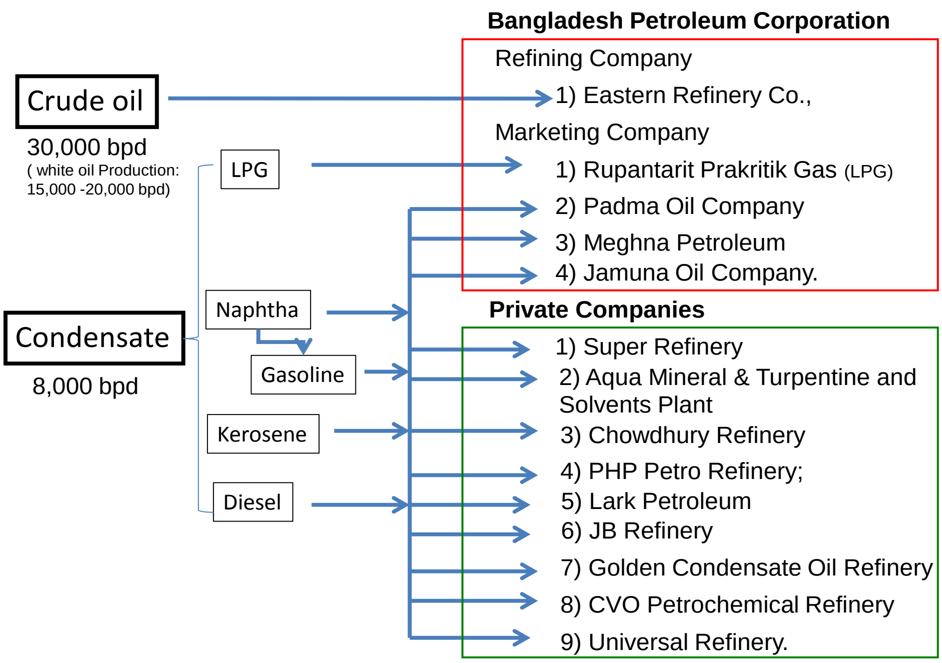


Figure 8-13 Overview of Condensate Marketing

Condensate recovery relies on the pressure drop or pressure differential. Recovery of the condensate has not necessarily been maximized yet. Once wellhead pressure declines, recovery of the condensate will also decline and flooding the transmission pipeline/ downstream distribution systems with condensate. Enhancement of the condensate recovery should be also be considered at the time of wellhead compressor installation, considering the impact of the LNG introduction.

8.4 Gas Field Development and PSC

8.4.1 Future gas field development

As discussed, hydrocarbon bearing potential in Bangladesh is divided into three onshore areas geologically. Offshore areas are categorized into Shallow Water and Deep Water as indicated in the model PSC.

- Folding Bed area in the east
- Foredeep area in the central
- Stable Shelf and Hinge Zone area in the west and north west
- Offshore (Shallow and Deep Waters)

Current operating gas fields are mostly in the Folding Bed area. Production from these existing gas fields are declining. Higher probability of new gas field discovery is expected in this Folding Bed area. On the other hand, Probability of the discovery in Central and West/North West part of the country is considered not high. No commercial scale gas field has been discovered in these areas.

Regarding offshore exploration in Myanmar, Daewoo of Korea discovered Shwa gas field on the east side of Bengal Bay in 2004. Confirmed reserve is 9.1 TCF with significant production of associated condensate. Commercial operation commenced in 2014 and all the gas and condensate are sold to CNPC China, via pipeline. Production rate is 700 MMCFD. Some new gas field discoveries were also reported at adjacent area of this Shwa Gas Field. Due to a geological similarity, there would be a potential of new gas field discoveries on the east part of Bengal Bay.

Oil and gas exploration has been exercised on the west side of Bengal Bay for a decade. No significant discovery has been made yet except Krishna-Godavari basin

Gas development in future areas will be more difficult and risky. It requires higher technological skills and financial backup to manage the oil and gas exploration. In 90's and after, significant advancement has been made in the oil and gas development area. A performance in exploration, and gas and oil recovery has been improved significantly.

In order to minimize exploration risks and maximize the recovery of resources, it is worth to consider partnership with internationally known IOCs, through attractive PSC.

8.4.2 2012 model PSC

Gas pricing in 2012 Model PSC offered by Bangladesh shows that Government of Bangladesh (GoB) has the first right to purchase Contractor's Gas. The Contractor will be assumed a domestic market outlet within 6 months of commercial discovery of gas failing which the Contractor would be free to find outlet within the country. Gas Pricing is as follows;

(1) Onshore Gas Field: 75% of Market Price with biddable discount. The price will have a floor of USD 100 /metric ton and ceiling of USD 200 /metric ton of HSFO. (Note that these figures translate that gas floor price would be USD 2.25 /MMBTU and ceiling price will be USD 4.5/MMBTU.)
(2) Offshore (Shallow Water): 100% of Market Price
(3) Offshore (Deep Water): 110% of Market Price
(4) Onshore Western area: 90% of Market Price

With the development of oil and gas market in US and UK, world oil and gas prices have been linked with these market prices, and affected world oil and gas development activities. Fiscal terms of PSC by the GoB may need to be linked with the international market pricing system to make the PSC attractive.

After the lift of economic sanction on Myanmar, oil and gas exploration through PSC has been accelerated. Recent PSC prepared by the Government of Myanmar require that 25% of product to be supplied to domestic market (Domestic Requirement) at 90% of Fair Market Value but the rest volume can be sold by Contractor by its own free will. This indicates that natural gas from Myanmar can be exported to Bangladesh. The price may be at Fair Market Value.

After the resolution of the maritime boundary dispute with Myanmar by virtue of the judgment awarded in March 2012 by the International Tribunal for the Law of the Sea (ITLOS), the Deep Water blocks on the eastern part were re-arranged.

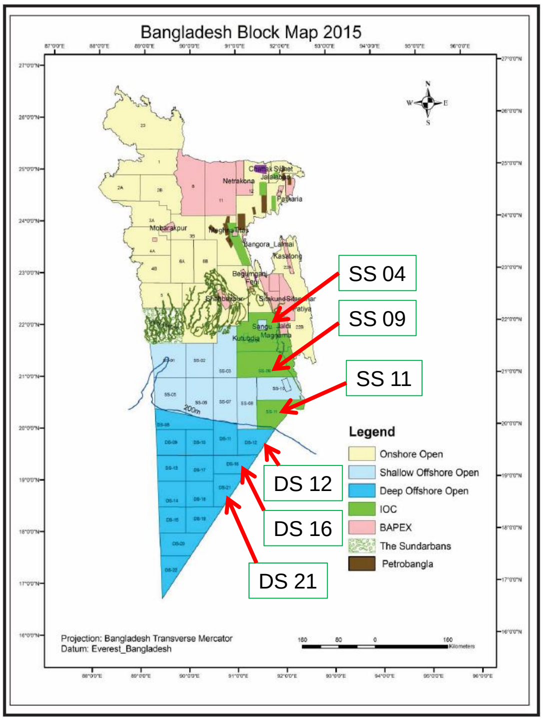
Current PSC for offshore blocks are as follows:

(1) Shallow Water Blocks

- JV of ONGC Videsh, Oil India, and BAPEX signed PSC with GoB for Block SS-04 and SS-09
- JV of Santos, Kris Energy, and BAPEX signed PSC with GoB for Block SS-11

(2) Deep Water Blocks

JV ConocoPhillips and Statoil negotiated with GoB for DS-12, DS-16 and DS-21, however, did not reach agreement.



Source: Petrobangla Annula Report 2014

Figure 8-14 Offshore Concession Blocks

8.4.3 Attractive PSC and partnership

Current target for gas exploration and development activates can be as follows:

1) Maintain production rate from existing gas field as much as possible
2) Develop new gas field in the Folding Bed area

To maximize the production and recovery of gas and condensate, the latest technologies need to be introduced. It is worth to consider preparing attractive terms of PSC and formulate partnership with experienced IOCs.

8.4.4 Role of BAPEX

There may be a resource limitation to achieve i) Enhancement of technological capabilities, ii) Own and operate 2D/3D survey units and drilling rigs, and iii) Produce oil and gas at the same time. Speed of advancement in technology is so fast to catch up. It is the management skill needed to be developed, not to use its own resources for operating drilling rigs.

Role of national oils has been changed responding to changing times and social needs. ONGC of India, Petronas of Malaysia, and CNPC of China are typical example how they have been evolved. These national oils are responsible for developing their own resources and also acquire recourses in overseas. As a result, they have increased the “Domestic Energy Resources” and contribute to the energy supply security of the country.

BAPEX has played a very important role in the area of domestic oil development and provision of associated services. BAPEX has made significant effort to build up capability of 2D and 3D seismic survey and operating drilling rigs, however, the performance of these may not necessarily be satisfactory. On the other hand, there may be opportunities to work jointly with other national oil companies in neighboring countries, or develop oil and gas fields jointly with the international oil companies in overseas. It may be a time to review role of BAPEX thoroughly.

8.5 Improvement of Gas Supply Infrastructure and Gas Use Efficiency

8.5.1 Improvement of gas supply infrastructure

There are following issues for gas transmission and distribution system in Bangladesh to be solved and improved.

(1) Condensate recovery

It appears that gas heating value may differ from location to location due to a condensate fraction in the pipeline system. Gas Transmission Company and Distribution Companies need to evacuate the built up condensate regularly. It is recommended to dry the gas as much as possible at the wellhead gas treatment facilities. Benefit of the improvement will be:

1) Increase the revenue by the sale of oil products produced from condensate
2) Save investment cost for installation of knock out drums and/or heaters
3) Life time of the pipeline infrastructure can be extended

(2) Gas meter installation and gas leak monitoring

Gas will be a very valuable energy resource and it should be used efficiently and safely, and inflow and outflow of gas must be monitored. All of the gas inlet and outlet points must have gas meters. Gas leak monitoring works will contribute to the process safety, protecting the people from fire/explosion, and also preventing energy loss from the system. Note that JICA is assisting in the installation of gas meters (pre-paid) to Dhaka Area (200,000 locations for domestic customers) and Chittagong Area (60,000 locations for domestic customers).

(3) Digitized and Computerized Gas Infrastructure Management System

Digitized and Computerized Gas Infrastructure Management System should be installed sooner since “older the infrastructure is higher the risk of accident can be”.

Gas transmission and distribution system is considered as a lifeline Infrastructure. All the process information including gas flow rate and pressure, and abnormal signals need to be collected and stored and processed, and all the history of maintenance, expansion/replacement record need to be stored. All of these data should be made available for all the parties concerned.

Significant advancement has been made in the area of such lifeline Infrastructure Management System for the last two decades. Appearance of new technology, a concept of Object-Oriented Database applied for Infrastructure Management, will be one of the choices to be introduced.

(4) Improvement of Gas Transmission System

Significant volume of gas will be supplied from LNG in near future and the system need to be reinforced to accommodate the increasing volume of gas. Integrated gas flow and pressure monitoring system (or SCADA system) will need to be introduced. In addition to advanced SCADA system, introduction of gas flow simulator to predict gas flow and pressure in the system will also be required.

(5) Impact of LNG introduction

After LNG introduction, gas flow rate and pressure balance will change. This could affect the performance of gas field production facilities and condensate recovery system. Also affect plan for wellhead compressor installation projects. Impact of LNG introduction will need to be studied further.

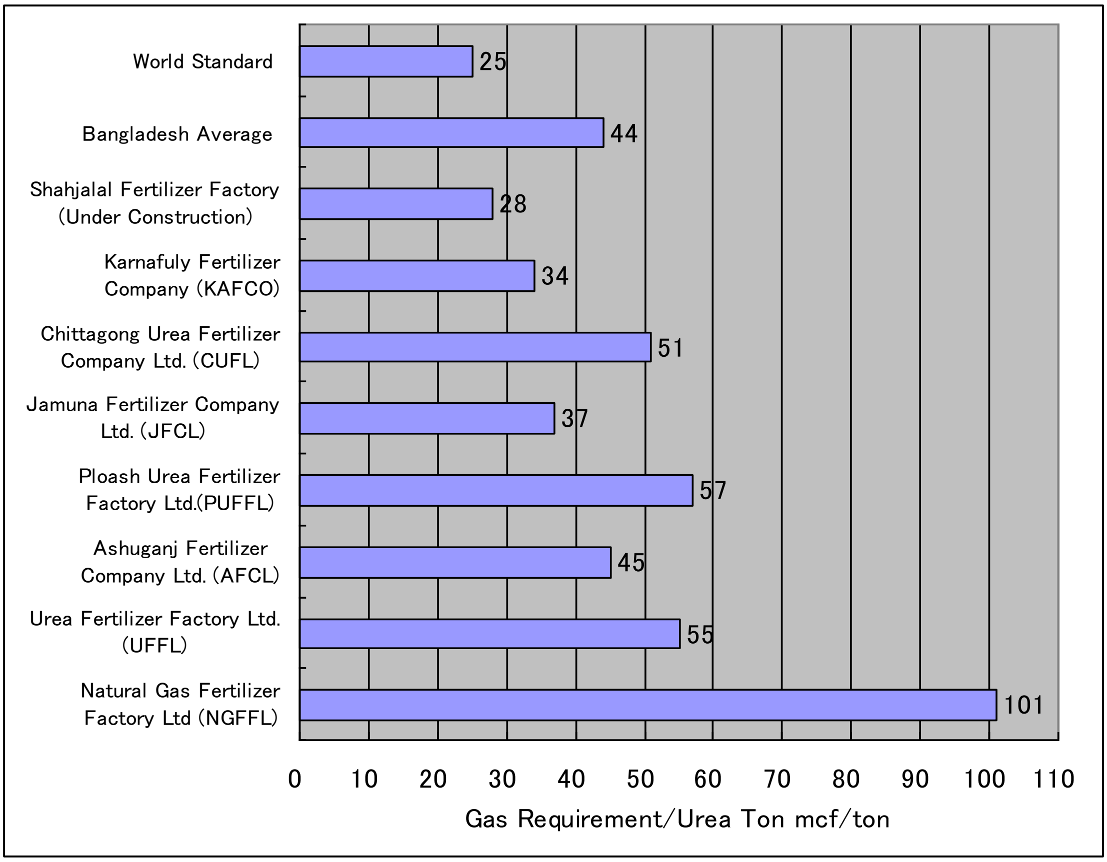
8.5.2 Improvement of gas use efficiency

Gas Use Efficiency is one of the critical issuers need to be addressed. “Cheap gas” will not be available in future and gas users need to enhance the efficiency to save indigenous gas resource in the country. It appears that both Urea Manufacturing and Power Sectors have a significant room for energy efficiency enhancement.

(1) Efficiency Enhancement in Urea Manufacturing

Urea is manufactured from natural gas. World benchmark efficiency in Urea Manufacturing is 25mcf/ton. On the other hand, average efficiency in Bangladesh is 44 mcf/ton as of 2014 FY, and much higher than that of international benchmark.

Provided that annual Urea production in Bangladesh is 2,375,000 ton, 130 mmcfd of natural gas is wasted due to an inefficient use of gas. This figure will be translated into the equivalent of 1000 MW of power plant.



Source: Five Year Gas Supply Strategy 2015-2019

Figure 8-15 Comparison of Urea Efficiency

(2) Efficiency enhancement in power sector

Gas Consumption for Power Sector (under BPDB) is 337.4 BCF in 2014 FY while Power Generation Capacity was 8,340 MW and Generated Power was 42,200 GWh. From these figures, it is assumed that current power generation efficiency is around 38%. Provided that efficiency can be raised to 45%, which is considered as a international benchmark as a gas based power plant, Energy gas consumption will be reduced to 285 BCF, and differential of 52 BCF is wasted. This is equivalent of 1,300 MW power plant.

8.6 Possible Assistance from Japan

Japan has a long history of LNG technology development and facility operation. Numbers of LNG facilities have installed and operated efficiently and safely. Japan has been proud of a safety record in operation and maintenance of Gas Distribution Systems.
The area of possible assistance from Japan will be as follows:

(1) LNG Facility Design Review and Management (operation and maintenance) Assistance.
(2) Digitized and Computerized Gas Distribution System
(3) Gas Leak and Safety Management Assistance

8.7 Environmental and Social aspects of Natural Gas development

8.7.1 Environmental Impact Assessment

Basic rules of Environmental Impact Assessment are given by Environment Conservation Act 1995. The clause 12 of the Act "No industrial unit or project shall be established or undertaken without obtaining, in the manner prescribed by rules, an Environmental Clearance Certificate from the Director General". Environment Conservation Rules 1997 (subsequent amendments in 2002 and 2003) stipulate the procedures and required documents by categories (see Table 8-9).

Table 8-9 EIA Categories and Required Clearance and Documents

Category	Required clearance	Required documents
Red	Location clearance, Environmental Clearance	Feasibility Study report (FS report), IEE or EIA, Resettlement Action Plan (RAP), No Objection Certificate of the local authority (NOC), Emergency and pollution minimization Plan
Orange B	Location clearance, Environmental Clearance	FS report, IEE, NOC, Emergency and pollution minimization Plan, RAP
Orange A	Location clearance, Environmental Clearance	General Info, Raw materials and the manufactured product, NOC, Process flow, Layout, Effluent discharge arrangement, RAP
Green	Environmental Clearance	General Info, Raw materials and the manufactured product, NOC

Source: Environment Conservation Rules 1997

MOE has prepared various guidelines of EIA such as Guidelines for Industries in 1997, EIA Guideline for Project in the Natural Gas Sector, Guideline for Gender Responsive Environmental Management. All the coal and gas development projects have to apply Environmental Clearance to DOE of Dhaka, Chittagong, Khulna, or Rajshahi Division. It is not clear that which categories should be applied to various kinds of Gas and coal projects (see Table 8-10)

Table 8-10 EIA Guidelines for Gas and Coal Sector

Activities	Category	Guidelines to be referred
Gas and Oil exploration	?	EIA Guideline for Project in the Natural Gas Sector
Gas and Oil extraction	Red	EIA Guideline for Project in the Natural Gas Sector
Gas and Oil refinery	Red	EIA Guideline for Project in the Natural Gas Sector
Gas pipeline	Red	EIA Guideline for Project in the Natural Gas Sector
Gas distribution line	?	EIA Guideline for Project in the Natural Gas Sector
Gas and Oil storage	Red	EIA Guideline for Project in the Natural Gas Sector
Gas and Oil Power Plant	Red	EIA Guideline for Project in the Natural Gas Sector

8.7.2 Experienced Environmental and Social impact of gas development

(1) Impact during exploration

Bangladesh Petroleum Exploration Company (BAPEX) is the only company which is conducting exploration work in Bangladesh. BAPEX has conducted more than ten exploration works so far. It is not clear how many EIAs have been prepared for the exploration works.

(2) Impact during Construction and Operation

There are more than 20 gas fields are operating in Bangladesh. Environmental, Health, and Safety Guidelines for Onshore Oil and Gas Development (IFC, 2007) identifies major environmental impact as air emissions, wastewater discharges, solid and liquid waste management, Noise generation, Terrestrial impacts and project footprint and Spills. But in terms of the gas development in Bangladesh water and air pollution issues are relatively lower than the other countries like Middle Eastern countries, Indonesia, and Australia. It is because the component of the Gas in Bangladesh is very pure. Gas of Middle Eastern countries contains hydrogen sulfide. But no hydrogen sulfide is contained in the gas in Bangladesh. Then there is no need to install hydrogen sulfide recovery unit and no production water is discharged in Bangladesh. The content of CO_2 is very lower in Bangladesh than the other countries (see Table 8-11). Then there is no need to install CO_2 recovery unit and recharge in the aquifer layer. pH of the production water in Middle Eastern countries is very low but it is near-neutral in Bangladesh. Then neutralization facility is not required too. Heavy metal such as mercury is not found in produced water in Bangladesh.

Table 8-11 Rates of Gas Component by Gas Fields

	Australia A	Australia B	Sakhalin	Bangladesh Titas
Methane（CH_4）	76.8	66.6	92	96.76
Ethane（C2）	3.5	3.8	4.62	1.8
Propane（C3）	1.3	1.3	1.73	0.36
Butane（C4）	0.5	0.4	0.62	0.14
Pentane (+C5)	0.6	0.7	0.32	0.26
N_2	4.3	15.4	0.46	0.37
CO_2	13	11.8	0.25	0.31

When it comes to biological and social issues not so serious problems are reported during operation. Hearing survey at Bangladesh Gas Fields Company Ltd.(BGFCL), Sylhet Gas Fields Limited (SGFL), Gas Transmission Company Limited (GTCL) did not find any serious problem during operation. The reasons of the little impact on biological and social issues are that the drilling holes can be angled and houses and ecological important areas can be avoided at the location selection stage.

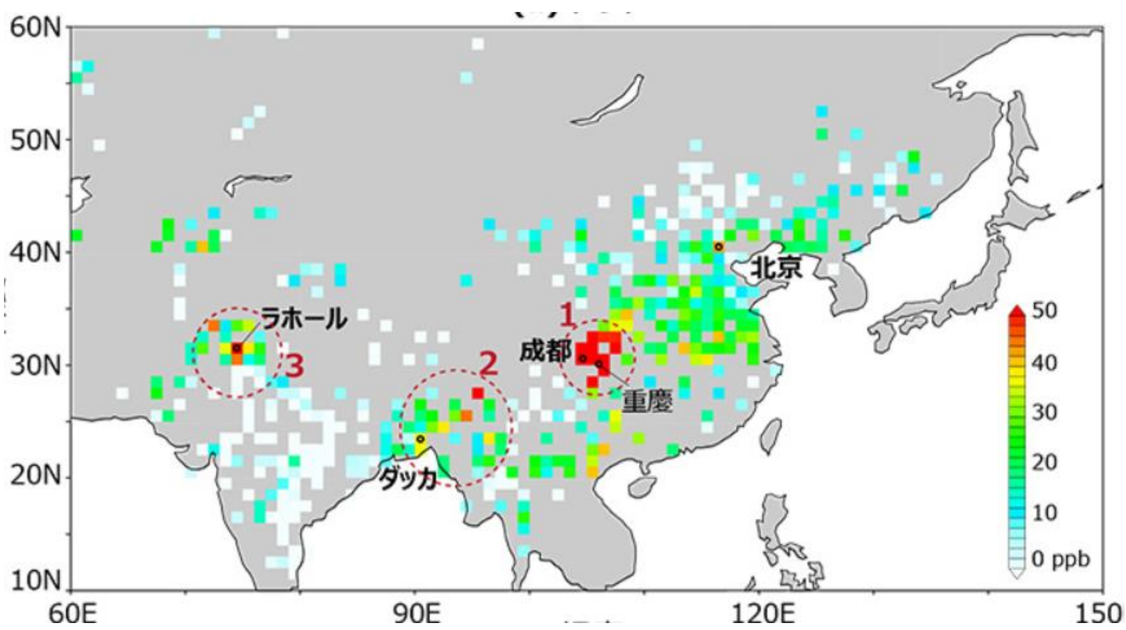
(3) Blowout Accident

According to Khan (2014) there are some serious blowout accidents happened during exploration activities which are Sylhet 1, Sylhet 4, Moulvibazar-1 and Chattak-2. The impacts are furious and wide expanses of areas are affected (see Table 8-12). Unfortunately the killing well activities are failed and compensation is not enough. Then the effects are continuing still now. And to make matters worse the methane gas which keeps running out still now is one of the global warming gas. The satellite observation result also shows the high concentration of methane gas over the Sylhet area too (see Figure 8-16). The blowout during exploration is the highest risk of the gas development in Bangladesh.

Table 8-12 Main Blowouts in Bangladesh

Well	Year	Blowout type	Reasons	Effect
Sylhet-1	1955		Drilling mistake	A crater was formed and filled with water, creating a large pond which is still there today and vent gas from the subsurface into the year
Sylhet-4	1962		Drilling mistake	Well was abandoned then and gas is still venting out from the fissures in the well site and nearby hill side which often cause fire.
Moulvibazar-1	1997		Casing mistake	About 96 acres of Lawachara forest were completely burnt. Fifty percent of the forest resources on 111.15 acres of land and 30 percent resources on 106.21 acres of land were also damaged. An estimated Tk 9000 crore loss to the nation and gas reserve of about 245 billion cubic feet was burnt in the explosion while the environment, ecology and wildlife of the area were also severely affected.
Chattak-2	2005	Surface type	Casing mistake	Homestead area, forest trees, and hilly fruit bearing trees were affected by the fire. Underground sand and clay soil were throughout with gas from the main field to 2-3 km areas of the Tengratila.

Source: Md. Ashraful Islam Khan, Fuad Bin Nasir (2014) Review Over Major Gas Blowouts In Bangladesh, Their Effects And The Measures To Prevent Them In Future (INTERNATIONAL JOURNAL OF SCIENTIFIC & TECHNOLOGY RESEARCH VOLUME 3, ISSUE 9)

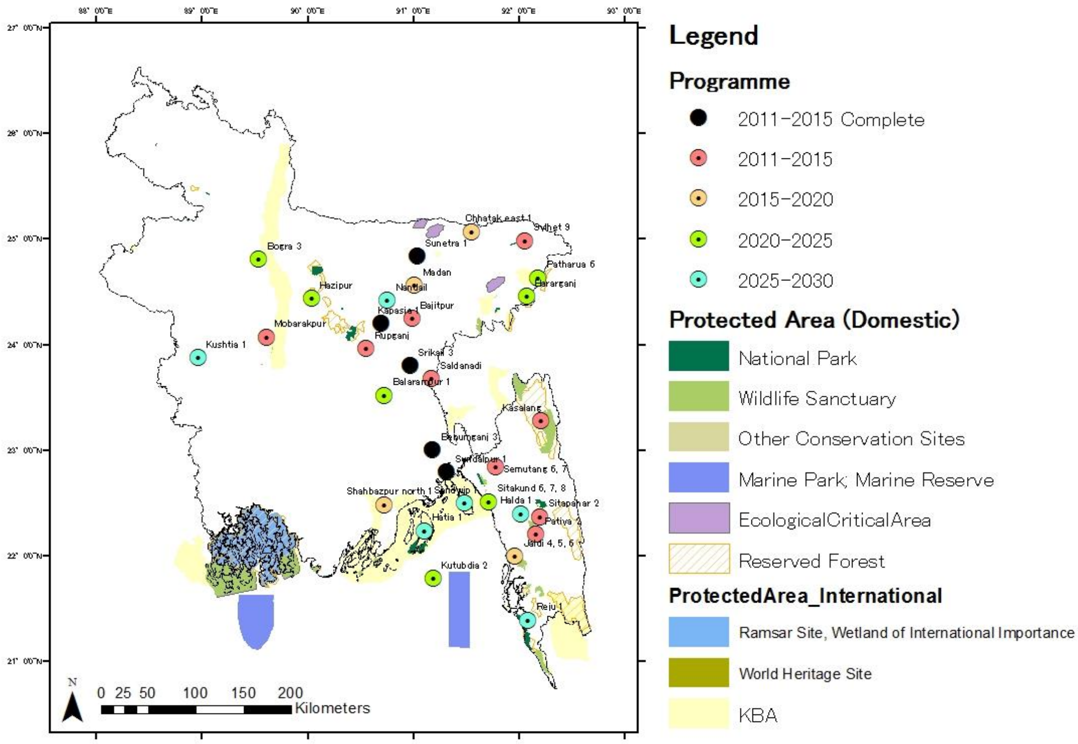


Source: JAXA (2015) Greenhouse gases Observing Satellite "IBUKI" (GOSAT)

Figure 8-16 Methane Gas Concentration by Human Activities in Asia

8.7.3 Environmental and social risk of Gas development

According to Preparatory Survey on The Natural Gas Efficiency Project in The People's Republic of Bangladesh (2014, JICA), planned gas fields are 24 on shore and 1 off shore. Six locations are in the domestic or international protected areas. 21 fields are in the known distribution areas of five mammals listed in IUCN red list as Endangered (EN) category. No EIA report is confirmed for the planned projects. Kasalang, Hararganj, Hazipur, Hatia 1, Reju 1, Sandwip 1 are located in the National parks or other protected areas. Then the layout should be planned to avoid the impacts on the protected areas (See Table 8-13). Saldanadi, Sylhet 9, Chhatak east 1, and Patharua 6 are located in the habitats of more than three protected species. Then detail biological survey before identifying the location and off-set mitigation planning is recommended. Although 16 fields locate in the agricultural areas, the resettlements will be avoided by carefully site selection (Table 8-14). The most anxious risk is a blowout. In order to lower the risk of blowout, the exploration companies with high technic should be selected.



Source: Preparatory Survey on The Natural Gas Efficiency Project in The People's Republic of Bangladesh (2014, JICA)

Figure 8-17 Protected Areas and Possible Gas Fields

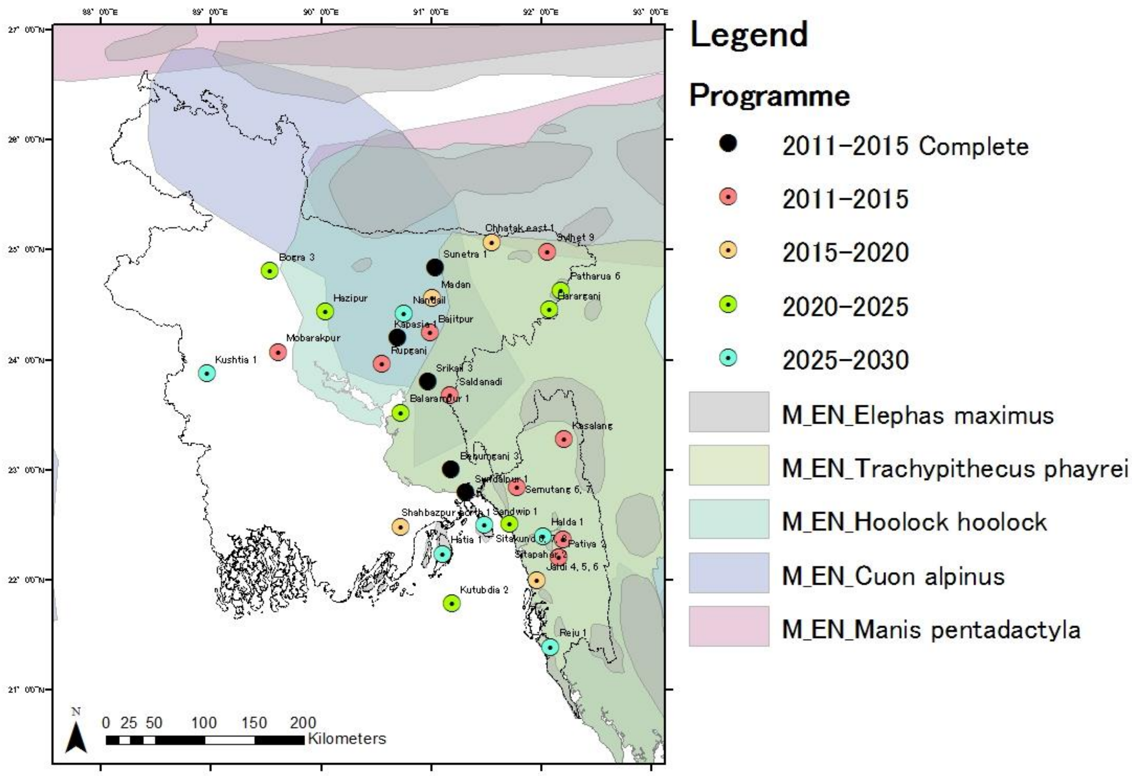


Figure 8-18 Habitat of Protected Mammals and Possible Gas Fields

Table 8-13 Possible Gas Fields and Protected Areas and Protected Mammals

Programme	Name	Protected Area	IUCN Red list species (Mammal, Endangered)				
			Elephas maximus	Trachypithecus phayrei	Hoolock hoolock	Cuon alpinus	Manis pentadactyla
2011-2015	Bajitpur				*	*	
	Kasalang	Reserved Forest		*	*		
	Mobarakpur						
	Patiya 2			*	*		
	Rupganj				*	*	
	Saldanadi			*	*	*	
	Semutang 6, 7			*	*		
	Sitapahar 2			*	*		
	Sylhet 9			*	*		*
2015-2020	Chhatak east 1			*	*		*
	Jaldi 4, 5, 6			*	*		
	Madan				*	*	
	Shahbazpur north 1						
2020-2025	Balarampur 1			*	*		
	Bogra 3						
	Hararganj	Reserved Forest		*	*		
	Hazipur	Reserved Forest			*		
	Kutubdia 2						
	Patharua 6		*	*	*		
	Sitakund 6, 7, 8			*	*		
2025-2030	Halda 1			*	*		
	Hatia 1	KBA, Reserved Forest	*				
	Kushtia 1						
	Nandail				*	*	
	Reju 1	National Park		*	*		
	Sandwip 1	KBA	*				

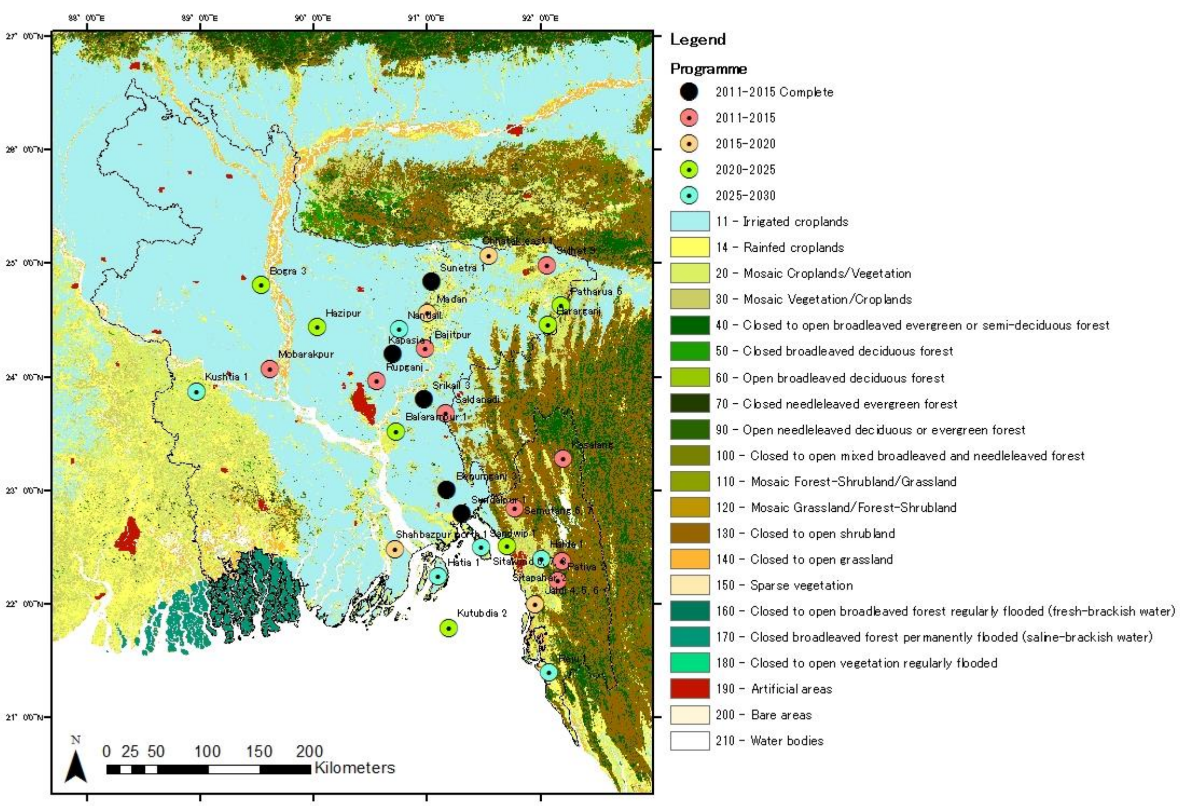


Figure 8-19 Land Use and Possible Gas Fields

Table 8-14 Possible Gas Fields and Land Use

Programme	Name	Farm land	Forest	Water
2011-2015	Bajitpur	Irrigated croplands		
	Kasalang		Closed to open shrub land	
	Mobarakpur	Irrigated croplands		
	Patiya 2		Closed to open shrub land	
	Rupganj	Irrigated croplands		
	Saldanadi	Mosaic Croplands/Vegetation		
	Semutang 6, 7	Mosaic Vegetation/Croplands		
	Sitapahar 2		Closed to open shrub land	
	Sylhet 9	Mosaic Croplands/Vegetation		
2015-2020	Chhatak east 1	Mosaic Croplands/Vegetation		
	Jaldi 4, 5, 6		Closed to open shrub land	
	Madan	Mosaic Croplands/Vegetation		
	Shahbazpur north 1	Irrigated croplands		
2020-2025	Balarampur 1	Irrigated croplands		
	Bogra 3	Irrigated croplands		
	Hararganj		Closed to open broadleaved evergreen or semi-deciduous forest	
	Hazipur	Irrigated croplands		
	Kutubdia 2			Water bodies
	Patharua 6		Closed to open shrub land	
	Sitakund 6, 7, 8		Closed to open shrub land	
2025-2030	Halda 1		Closed to open shrub land	
	Hatia 1	Irrigated croplands		
	Kushtia 1	Mosaic Vegetation/Croplands		
	Nandail	Irrigated croplands		
	Reju 1		Closed to open shrub land	
	Sandwip 1	Mosaic Vegetation/Croplands		

Attachment 8-1

Natural Gas Supply Analysis

1. Current Status of Existing Gas fields

Understanding of the current status of the existing gas fields is very important for production forecasts for each gas field. Therefore, a comparison of actual production (average daily production) from each gas field over the years of 2010 to 2014 and the forecasts by PSMP 2010 is shown in Table 1.

Based on the information/data such as the remaining 2P reserves shown in the "Draft Five Year Gas Supply Strategy" and the results of drilling and workover shown in Petrobangla Annual Reports, The current status of the existing gas fields in Bangladesh and the future outlook are summarized in Table 2.

Table 1and Table 2 indicates the following points.

- Only Bibiyana gas field has shown a steady increase in production since 2010 in Bangladesh.
- The Jalalabad gas field also significantly increased production in 2012, but after that production from the field has not increased significantly.
- Production from the Sangu gas field was suspended from October 1, 2013.
- Measures for troubles associated with excessive water production need to be taken
- Successes of new development wells are important to increase production in the future.
- Additions of recoverable reserves by introduction of wellhead gas compressors in mature gas fields resulting in the extension of the field life are expected.

Table 1 Comparison between Actual Average Daily Production and PSMP2010 Forecasts

Unit: mmscfd

Sl. No.	Gas Field	Average Daily Production							
		Actual					PSMP2010 Forecasts		
		2010	2011	2012	2013	2014	2010	2014: Case1	2014: Case 2
1	Titas	404	445	450	490	515	408	578	560
2	Habiganj	235	260	227	225	225	240	260	260
3	Bakhrabad	35	33	32	41	41	36	51	51
4	Kailashtila	91	86	89	84	74	87	97	97
5	Rashidpur	49	49	47	47	61	49	84	85
6	Sylhet/Haripur	3	10	9	9	8	7	30	30
7	Meghna	0	10	10	11	10	0	5	5
8	Narshingdi	33	30	30	28	28	35	25	25
9	Beanibazar	15	9	11	10	10	15	15	15
10	Fenchuganj	25	23	36	37	39	24	65	60
11	Saldanadi	8	18	16	15	12	8	8	8
12	Shahbazpur	6	0	7	7	8	8	10	10
13	Semutang	0	14	8	6	5	0	15	15
14	Sundalpur	0	0	10	10	4	0	60	60
15	Srikail	0	0	0	42	39	0	60	60
16	Sangu	37	14	23	0	0	40	0	0
17	Jalalabad	163	165	232	249	246	130	250	200
18	Moulavi Bazar	58	42	94	77	63	60	160	80
19	Bibiyana	658	753	792	822	1,007	716	900	850
20	Bangura	105	102	86	111	110	120	120	120
21	Begumganj	0	0	0	0	0	0	0	0
22	Kutubdia	0	0	0	0	0	0	0	0
23	Chattak	0	0	0	0	0	0	0	0
24	Kamta	0	0	0	0	0	0	0	0
25	Feni	2	0	0	0	0	2	2	2
	Total	**1,926**	**2,062**	**2,210**	**2,323**	**2,435**	**1,995**	**2,765**	**2,563**

Note: A production rate of 60 mmscfd for Sundalpur and Srikal by the PSMP2010 forecasts means that the sum of production from Sundalpur and Srikail should be equal to 60 mmscfd in this case.

Source: Prepared based on Petrobangla Annual Reports 2010 to 2014 and PSMP2010 report (JICA, 2011)

Table 2 Evaluation of Current Status of Existing Gas Fields

as of February 2015

Sl. No.	Gas Field	No. of Producing Wells as of Dec. 2014	Average Daily Production in 2014: Forecasts by PSMP2010 (MMscfd) Case 1	Case 2	Production Capacity (MMscfd)	Actual Production (MMscfd)	Recoverable 2P Reserves as of the end of 2014 (BCF)	Remaining 2P Reserves as of Jan. 2015 (BCF)	Evaluation of Production Status
1	Titas	21	578	560	518	515.2	6,367.0	2,515.67	• The actual daily production rate was lower than that predicted by PSMP2010 study because the drilling of new development wells was delayed from initilal schedule. • Production rates for recently drilled development wells Titas-19, 20, 21 and 22 were significantly lower than expected (see Table 1.4-1). • Production from the Titas-21 well has been suspended from late June 2014. • It is expected that an increase in the production capacity depending on the plan and results of future development drilling. • It is possible to add the reserves and extend the field life by installation of the wellhead gas compressors being scheduled around 2016. The installation of the wellhead gas compressors will be limited to a part of the production sites, it is necessary to intstall them in other production sites in future.
2	Habiganj	7	260	260	225	225.1	2,633.0	523.81	• The actual production in 2014 was slightly lower than that predicted by PSMP2010. • A significant increase in production will not be expected because the remaining 2P reserves are only 20% of recoveralbe (2P) reserves, although the size of the remaining recoverable (2P) reserves are evaluated as medium.
3	Bakhrabad	7	51	51	43	41.0	1,231.5	456.37	• The overall field's production has not increased because workover of the existing suspended wells were unsuccessful, although the well Bakharabad-9 resulted in success. • An increase in production is expected by drilling of new development wells in the future.

Evaluation of Current Status of Existing Gas Fields (continued)

as of February 2015

Sl. No.	Gas Field	No. of Producing Wells as of Dec. 2014	Average Daily Production in 2014: Forecasts by PSMP2010 (MMscfd) Case 1	Case 2	Production Capacity (MMscfd)	Actual Production (MMscfd)	Recoverable 2P Reserves as of the end of 2014 (BCF)	Remaining 2P Reserves as of Jan. 2015 (BCF)	Evaluation of Production Status
4	Kailashtila	4	97	97	80	73.5	2,760.0	2,163.60	• The field's production has not increased. This is due to in part the delay in drilling of new development well Kailashtila-7. • The future production performance will be dependent on whether new development drilling and well workover operations will be sucessful or not. • Prior to preparing the programs for the future development drilling the review of 3D seismic data over the field is required.
5	Rashidpur	5	84	85	64	60.7	2,433.0	1,889.79	• An increase in production is small at present because drilling of new development wells, including the Rashipur-8 well from which production was started in August 2014, has been delayed from the initial schedule. • According to the Petrobangla's five-year plan, drilling of three development wells is planned. • Gas production will not increase to the level such as over 500 MMscfd in the future, which was predicted by PSMP2010.
6	Sylhet/Haripur	2	30	30	11	8.4	318.9	113.64	• Based on recent development activities an increase in production can be expected, depending on the results of future development wells, although a significant increase in production will not be expected from the development plan shown in the Petrobangla's five-year plan. • The installation of wellhead gas compressor scheduled around 2017 makes it possible to add substantial reserves to the current reserves and extend the field life.

Evaluation of Current Status of Existing Gas Fields (continued)

as of February 2015

Sl. No.	Gas Field	No. of Producing Wells as of Dec. 2014	Average Daily Production in 2014: Forecasts by PSMP2010 (MMscfd) Case 1	Case 2	Production Capacity (MMscfd)	Actual Production (MMscfd)	Recoverable 2P Reserves as of the end of 2014 (BCF)	Remaining 2P Reserves as of Jan. 2015 (BCF)	Evaluation of Production Status
7	Meghna	1	5	5	11	10.0	69.9	16.84	• The field life will be short because the remaining 2P reserves are small. According to the production forecasts by PSMP2015, the field production will continue up to 2022, whereas it will continue only up to 2015 by PSMP2010's forecasts.
8	Narshingdi	2	25	25	30	28.1	276.8	116.40	• Gas production has been continuing as forecasted by PSMP2010 since 2010. • The installation of wellhead gas compressor scheduled around 2017 makes it possible to have substantial quantity of additional reserves and extend the field life.
9	Beanibazar	1	15	15	14	9.6	203.0	115.28	• Average daily production of 9.5 MMscfd in 2014 is significantly lower than that predicted by PSMP2010.
10	Fenchuganj	3	65	60	40	38.7	381.0	256.21	• There is no increase in production because the Fenchuganj-5 well drilled in 2014 resutlted in unsuccessful. • An increase in production will not be expected for some time because any programs of development drilling are not shown in the Perobangla's five-year plan.
11	Saldanadi	1	8	8	20	12.0	279.0	197.44	• The reserves are small. Therefore the field's production will not increase significantly in the future, although this may be dependent on the results of new development wells. However, the size of the remaining 2P reserves indicates that the field can produce gas at a rate of about 20 MMscfd, about twice as much as the average daily production as of December 2014, in the near future. • According to the Petrobangla's five-year plan, development well Saldanadi-4 are to be drilled and then completed in May 2015.

Evaluation of Current Status of Existing Gas Fields (continued)

as of February 2015

Sl. No.	Gas Field	No. of Producing Wells as of Dec. 2014	Average Daily Production in 2014: Forecasts by PSMP2010 (MMscfd) Case 1	Case 2	Production Capacity (MMscfd)	Actual Production (MMscfd)	Recoverable 2P Reserves as of the end of 2014 (BCF)	Remaining 2P Reserves as of Jan. 2015 (BCF)	Evaluation of Production Status
12	Shahbazpur	2	10	10	30	7.9	390.0	379.50	• Daily production in 2014 is almost the same as that predicted by PSMP2010. • Development wells Shahbazpur-3 and 4 were completed in September 2014 and November 2014, respectively, and a flow rate of about 19 MMscfd of gas from well no. 3 and about 32 MMscfd of gas from well no. 4 were confirmed by the flow tests, respectively. But gas production from both wells have not started yet. • According to the Petrobangla's five-year plan, any new development wells are not planned. However, from the viewpoin of the size of recoverable reserves, drlling of new development wells for increasing production is expected in the near future
13	Semutang	2	15	15	12	4.6	317.7	308.03	• Gas production in 2014 was significantly lower than that predicted by PSMP2010. This is because the field development may have not progressed as planned. • Regarding the actual production as of December 2014, an average daily production rate of 4.7 MMscfd from 2 wells is very low. • The future production will depend on the results of the planned two development wells shown in the Petrobangla's five-year plan.

Evaluation of Current Status of Existing Gas Fields (continued)

as of February 2015

Sl. No.	Gas Field	No. of Producing Wells as of Dec. 2014	Average Daily Production in 2014: Forecasts by PSMP2010 (MMscfd) Case 1	Case 2	Production Capacity (MMscfd)	Actual Production (MMscfd)	Recoverable 2P Reserves as of the end of 2014 (BCF)	Remaining 2P Reserves as of Jan. 2015 (BCF)	Evaluation of Production Status
14	Sundalpur Shahzadpur	1	60	60	10	3.6	35.1	27.10	• According to the production forecasts by PSMP2010, this field is considered to be one of newly discovered gas fields, and an average daily production is estimated to be 60 MMscfd including production from other new fields in 2014. • From the viewpoint of the size of the remaining reserves, a significant increase in production is not expected. • According to the Petrobangla's five-year plan, drilling of one development wells is planned.
15	Srikail	2	60	60	44	38.7	161.0	135.57	• Gas production from the field started in March 2013. • According to the production forecasts by PSMP2010, this field is considered to be one of newly discovered gas fields, and an average daily production is estimated to be 60 MMscfd including production from other new fields in 2014. • According to the Petrobangla's five-year plan, drilling of one development wells is planned and production from the well is expected to start 2016..
16	Sangu	0	0	0	0	0.0	577.8	89.85	• Gas production from the field has been suspended from 1 October 2013. The production facilities have been handed over to Petrobangla as per contract. However, whether Petrobangla resume production from this field is unknown. • According to the forecasts by PSMP2010, production was not expected after 2014. • According to the forecasts by PSMP2015, production is also not expected over the years from 2015 through 2041.

Evaluation of Current Status of Existing Gas Fields (continued)

as of February 2015

Sl. No.	Gas Field	No. of Producing Wells as of Dec. 2014	Average Daily Production in 2014				Recoverable 2P Reserves as of the end of 2014	Remaining 2P Reserves as of Jan. 2015	Evaluation of Production Status
			Forecasts by PSMP2010 (MMscfd)		Production Capacity	Actual Production			
			Case 1	Case 2	(MMscfd)	(MMscfd)	(BCF)	(BCF)	
17	Jalalabad	4	250	200	246	246.2	1,184.0	281.15	• The results of case 1 in the production forecasts by PSMP2010 shows that the production rate of 250 MMscfd in 2014 is almost the same as that of actual production. • Even in case 2 by PSMP2010, in which the field life is longer life compared to case 2, production will continue only to 2022. On the other hand, PSMP2015 forecasts that the field production will be sustained up to 2027. • The field life can be extended by, for example, introduction of wellhead gas compressors.
18	Moulavi Bazar	6	160	80	60	62.6	428.0	160.51	• Cases 1 and 2 in the production forecasts by PSMP2010 were 160 MMscfd and 80 MMscfd, respectively, whereas gas was produced at a rate of 60 MMscfd in 2014. • An increase in production could not be expected in the future from recent decrease in production. The field's production was less than 40 MMscfd in late February 2015.
19	Bibiyana	18	900	850	960	1,006.7	5,754.0	3,873.19	• Actual production rate in 2014 was significantly higher than those of both cases 1 and 2 by PSMP2010. • Production increased in November 2014 and February 2015, respectively. • A peak daily production rate of 1,200 MMscfd, following the production rate shown in the Petrobangla's five-year plan, is expected to be maintained over the period of 2015 to 2019 in the long-term production forecasts. Based on the information of the processing capacity of 1,200 MMscfd in the current production facilities, an average daily production rate of 1,200 MMscfd will continue at least until 2019.

Evaluation of Current Status of Existing Gas Fields (continued)

as of February 2015

Sl. No.	Gas Field	No. of Producing Wells as of Dec. 2014	Average Daily Production in 2014: Forecasts by PSMP2010 (MMscfd) Case 1	Case 2	Production Capacity (MMscfd)	Actual Production (MMscfd)	Recoverable 2P Reserves as of the end of 2014 (BCF)	Remaining 2P Reserves as of Jan. 2015 (BCF)	Evaluation of Production Status
20	Bangura	4	120	120	100	110.0	522.0	241.00	• According to the production forecasts by PSMP2010, the average production rate of 120 MMscfd in 2014 in both of cases 1 and 2. However, gas was produced actually at a rate of 109 MMscfd which was slightly lower than the expected. • Accoding to the production forecasts by PSMP2010, the field' production was expected to continue up to 2023. However, the production is expected to further continue because gas has been produced constantly at a rate of about 110 MMscfd since early 2014.
21	Begumganj	0	0	0	0	0.0	70.0	70.00	• According to the production forecasts by PSMP2010, the field's production will start in 2017. On the other hand, according to the Petrobangla's five-year plan, the production will start soon (from the Begumganj-3 well). • According to the Petrobangla's five-year plan, drilling of one development well is planned and production from the well is expected to start in 2017.
22	Kutubdia	0	0	0	0	0.0	45.5	45.50	• According to the forecasts by PSMP2010, the field's production is expected to be from Block 16, and the start-up of production is scheduled to be 2017. However, from the information available at present it is difficult to start production. • No production from the field is expected in the long-term production forecasts in this survey.
23	Chhatak	0	0	0	0	0.0	474.0	447.54	• According to the forecasts by PSMP2010, any gas production is not expected. • According to the Petrobangla's five-year plan, drilling of two development wells is planned at Chhatak West, and production from the field is expected to start in 2016.

Evaluation of Current Status of Existing Gas Fields (continued)

as of February 2015

Sl. No.	Gas Field	No. of Producing Wells as of Dec. 2014	Average Daily Production in 2014: Forecasts by PSMP2010 (MMscfd) Case 1	Case 2	Production Capacity (MMscfd)	Actual Production (MMscfd)	Recoverable 2P Reserves as of the end of 2014 (BCF)	Remaining 2P Reserves as of Jan. 2015 (BCF)	Evaluation of Production Status
24	Kamta	0	0	0	0	0.0	50.3	29.20	• Production was not estimated by the PSMP2010. Production is also not estimated in the Petrobangla's five-year plan. • Based on the above situation, the field's production is not expected in this survey..
25	Feni	0	2	2	0	0.0	125.0	62.60	• There was no production from the field in 2014, whereas according to the production forecasts by PSMP2010, gas was produced at a rate of 2 MMscfd. • According to the Petrobangla's five-year plan, drilling of two development wells is planned and production from the field is expected to resume in 2016.

Note: 1) Remaining 2P reserves = Recoverable 2P reserves - Cumulative production
2) The rcoverable 2P reserves as of the end of 2014 and remaining 2P reserves are based on the Draft Five Year Gas Supply Strategy prepared by Petrobangla.

Source: Prepared based on PSMP2010 report (JICA, 2011), Petrobangla Anuual Reports 2010 to 2014 and Petrobangla's “Draft Five Year Gas Supply Strategy” (2015)

2. Production forecast for existing gas fields 2015-2019

Production forecasts for the existing gas fields for the next five years are necessary for long-term production forecasts. In this survey production forecasts for the period of 2015 to 2019 are conducted based on the production forecasts shown in the Petrobangla's five-year plan
The production rates are overestimated as a whole in the production forecasts for the period of 2015-2019 shown in the Petrobangla's five-year plan. Therefore, as described below, the production rates estimated by Petrobangla were corrected, if necessary, based on the comparison of between expected and actual for the times of well completion and production rates.

(1) Evaluation of Times of Well Completion and Production Rates Shown in the Petrobangla's Five-Year Plan

Evaluation of times of well completion and production rates shown in the Petrobangla's five-year plan is carried out based on a comparison between expected and actual for times of well completion and production rates for the wells shown in the "Gas Evacuation Plan 2010-2015" prepared in 2010. The comparison is shown in Table 3 It is noted that the wells whose actual data were not available are excluded from the table. As a result, the data evaluation was made only on the development and exploratory wells.

Table 3 indicates that the times of completion for newly drilled wells were more than one year behind schedule except for exploratory well Sundalpur-1. Regarding daily production rates it is evaluated as about 70% of the initial estimates, although the actual values ranges from 52 to 167% of the initial estimates. Averaged value of the ratio of actual/expected for daily production rate shows 0.78 for all wells (12 wells) listed in Table 3 and 0.69 for development wells (10 wells), respectively. Production forecasting is focused on development wells in the existing gas fields. Therefore a value of 0.69 was chosen because the evaluation is to be performed on the development wells, and then 0.69 rounded off to one decimal place is 0.7.

Based on these results the times of well completion and production rates shown in the Petrobangla's five-year plan are evaluated as follows,

- Times of well completion: At least one year behind schedule
- Production rates: About 70% of initial estimates

(2) Revision of Production Forecasts by Petrobangla for Existing Gas Field

Based on the comparison described above, correction factors for times of well completion and production rates shown in the Petrobangla's five-year plan are basically assumed as follows.

The risk of the delay in the time of well completion is expressed as decrease in production rate. Based on the idea that if one-year delay occurs in a five-year period, production decreases by 20% of the initial estimate, the production rates shown in the Petrobangla's five-year plan were corrected. The values of production rates are corrected by multiplying 0.8 for the wells to be completed in and after 2016.

- Times of well completion: 80% of the initial estimate
- Production rates: 70% of the initial estimates

Thus, the corrected production rates for the wells shown in the Petrobangla's five-year plan are listed in Table 4.

(3) Production Forecasts for 2015-2019

The production forecasts for the period of 2015-2019 were conducted by party modifying those shown in the “Draft Five Year Gas Supply Strategy” by Petrobangla, if necessary, based on the comparison of between expected and actual for the times of well completion and production rates as described above. Thus, the modified production forecasts are shown in Table 5.

- Patterns of production profiles are basically the same as those shown in the Petrobangla’s five-year plan.
- According to the Petrobangla’s five-year plan, an increase in production by 5 mmscfed from the Shahbazpur gas field since 2018 is planned. However, this increase in production was not taken into consideration in this survey because any development plans are not presented in the plan.
- The grand total shows a peak production rate of 2,811 mmscfd at the period of July-December in 2016 (Table 5). On the other hand, the production forecasts shown in the Petrobangla’s five-year plan also shows a peak production rate of 2,916 mmscfd at the same period as shown above. As a result, the production rate estimated by the survey team is lower than that by Petrobangla by about 100 mmscfd.

Table 3 Times of Well Completion and Production Rate for Wells Shown in Gas Evacuation Plan 2010-2015: Expected vs Actual

As of February 2015

Well Name	Owner/ Operator	Time of Well Completion			Daily Production Rate			Remarks
		Excpected	Actual	Difference (Delay) (month)	Excpected	Actual	Ratio of Actual/Expected	
Development Wells								
Fenchuganj-4	BAPEX	Oct 2010	Feb 2012	16	20	20	1	
Saldanadi-3	BAPEX	Nov 2010	Jan 2012	13	15	15	1	
Saldanadi-4	BAPEX	Mar 2011	—	47+	15	0	0	During drilling
Titas-17	BGFCL	Jun 2011	Mar 2013	21	25	15	0.60	
Fenchuganj-5	BAPEX	Aug 2011	Apr 2014	32	20	0	0	Dry
Titas-18	BGFCL	Nov 2011	Aug 2013	21	25	16	0.64	
Bakhrabad-9	BGFCL	Apr 2012	Aug 2013	16	20	16	0.80	
Titas-19	BGFCL	Jun 2012	May 2014	23	100	15	0.52	
Titas-20	BGFCL		Oct 2013	?		10		
Titas-21	BGFCL		Dec 2013	?		15		Suspended in July 2014 due to production of exccesive amount of water
Titas-22	BGFCL		Mar 2014	?		12		
Rashidpur-8	SGFL	Jun 2012	Aug 2014	26	20	15	0.75	
Exploratory Wells								
Sundalpur-1	BAPEX	Oct 2010	Sep 2011	11	15	12	0.80	Production started in March 2012
Srikail-2	BAPEX	Feb 2011	Jun 2012	16	15	25	1.67	Production started in March 2013
Kapasia-1	BAPEX	Mar 2011	Apr 2012	13	15	0	0	Dry
Mubarakpur-1	BAPEX	Sep 2011	—	41+	15	0	0	During drilling

Source: Prepared based on Petrobangla's "Gas Evacuation Plan (2010-2015)" (2010), Petrobangla Annual Reports, etc.

Table 4 Data Used for Correction of Production Rate in Production Forecast for Existing Gas Fields by Petrobangla

As of February 2015

Gas Field	Development Drilling/Workover		Estimates of Production Rate			Reasons for Correction of Production Rate	Production Outlook
	Well Name	Type of Operations	Estimates by Petrobangla (MMscfd)	Correction Factor	Production Rate after Correction (MMscfd)		
Titas	No. 23	Dev. Drlg	20	0.7	14	• Production rates estimated based on the actual productio rates in recently drilled development wells • Correction: Production rates only	• It is expected that an increase in the production capacity depending on the plan and results of future development drilling. • It is possible to add the reserves and extend the field life by installation of the wellhead gas compressors being scheduled around 2016. The installation of the wellhead gas compressors will be limited to a part of the production sites, it is necessary to intstall them in other production sites in future.
	No. 24	Dev. Drlg	20	0.7	14		
	No. 25	Dev. Drlg	20	0.7	14		
	No. 26	Dev. Drlg	20	0.7	14		
Bakhrabad	No. 10	Dev. Drlg	10	0.8	8	• Correction: Time of production start-up only	• An increase in production is expected by drilling of new development wells in the future.
Kailashtila	No. 7	Dev. Drlg	15	0.56	8	• Workover operational risk is relatively high • Correction: 0.7 for production rate × 0.8 for time of production start-up (= 0.56)	• The future production performance will be dependent on whether new development drilling and well workover operations will be sucessful or not.
	No. 1&5	Workover	15	0.56	8		
	No. 9	Dev. Drlg	25	0.56	14		
Rashidpur	No. 9	Dev. Drlg	10	0.56	6	• Correction: 0.7 for production rate × 0.8 for time of production start-up (= 0.56)	• An increase in production is small at present because drilling of new development wells, including the Rashipur-8 well from which production was started in August 2014, has been delayed from the initial schedule. • According to the Petrobangla's five-year plan, drilling of three development wells is planned.
	No. 10	Dev. Drlg	20	0.56	11		
	No. 11	Dev. Drlg	20	0.56	11		
Sylhet/Haripur	No. 9	Dev. Drlg	10	0.56	6	• Correction: 0.7 for production rate × 0.8 for time of production start-up (= 0.56)	• Based on recent development activities an increase in production can be expected, depending on the results of future development wells, although a significant increase in production will not be expected from the development plan shown in the Petrobangla's five-year plan.

Data Used for Correction of Production Rate in Production Forecast for Existing Gas Fields by Petrobangla (continued)

As of February 2015

Gas Field	Development Drilling/Workover		Estimates of Production Rate			Reasons for Correction of Production Rate	Production Outlook
	Well Name	Type of Operations	Estimates by Petrobangla (MMscfd)	Correction Factor	Production Rate after Correction (MMscfd)		
Saldanadi	No. 4	Dev. Drlg	10	1	10	• Evaluated based on the production performance of well No. 1	• The reserves are small. Therefore the field's production will not increase significantly in the future, although this may be dependent on the results of new development wells. However, the size of the remaining 2P reserves indicates that the field can produce gas at a rate of about 20 MMscfd, about twice as much as the average daily production as of December 2014, in the near future. • According to the Petrobangla's five-year plan, development well Saldanadi-4 are to be drilled and then completed in May 2015.
Shahbajpur	No. 4	Dev. Drlg	25	—	19	• Production rate is estimated based on the well test results conducted after completion of drilling	
Semutang	No. 7	Dev. Drlg	8	0.56	4	• Correction: 0.7 for production rate × 0.8 for time of production start-up (= 0.56)	• The future production will depend on the results of the planned two development wells shown in the Petrobangla's five-year plan.
	No. 8	Dev. Drlg	8	0.56	4		
Sundupur Shahzadpur	No. 2	Dev. Drlg	8	0.56	4	• Correction: 0.7 for production rate × 0.8 for time of production start-up (= 0.56)	• From the viewpoint of the size of the remaining reserves, a significant increase in production is not expected. • According to the Petrobangla's five-year plan, drilling of one development wells is planned.
Srikail	No. 4	Dev. Drlg	20	0.56	11	• Correction: 0.7 for production rate × 0.8 for time of production start-up (= 0.56)	• According to the Petrobangla's five-year plan, drilling of one development wells is planned and production from the well is expected to start 2016..

Data Used for Correction of Production Rate in Production Forecast for Existing Gas Fields by Petrobangla (continued)

As of February 2015

Gas Field	Development Drilling/Workover		Estimates of Production Rate			Reasons for Correction of Production Rate	Production Outlook
	Well Name	Type of Operations	Estimates by Petrobangla (MMscfd)	Correction Factor	Production Rate after Correction (MMscfd)		
Bibiyana	Specific well names or numbers are not disclosed	Dev. Drlg	150	1	150	• Correnction for production rates was not made because the field's average daily production rate was increased to about 980 MMscfd in November 2014 and then will be increased to about 1,200 MMscfd soon.	• A peak daily production rate of 1,200 MMscfd, following the production rate shown in the Petrobangla's five-year plan, is expected to be maintained over the period of 2015 to 2019 in the long-term production forecasts. Based on the information of the processing capacity of 1,200 MMscfd in the current production facilities, an average daily production rate of 1,200 MMscfd will continue at least until 2019.
Begumganj	No. 3	Dev. Drlg	12	0.7	8	• Drilling of well No. 3 has already been completed. • Correction for well No. 3: 0.7 for production rate only • Correction for well No. 4: 0.7 for production rate × 0.8 for time of production start-up (= 0.56)	• According to the production forecasts by PSMP2010, the field's production will start in 2017. On the other hand, according to the Petrobangla's five-year plan, the production will start soon (from the Begumganj-3 well). • According to the Petrobangla's five-year plan, drilling of one development well is planned and production from the well is expected to start in 2017.
	No. 4	Dev. Drlg	15	0.56	8		
Chattak	No. 3	Dev. Drlg	20	0.56	11	• Correction: 0.7 for production rate × 0.8 for time of production start-up (= 0.56)	• According to the Petrobangla's five-year plan, drilling of two development wells is planned at Chhatak West, and production from the field is expected to start in 2016.
	No. 4	Dev. Drlg	20	0.56	11		
Feni	No. 6	Dev. Drlg	10	0.56	6	• Correction: 0.7 for production rate × 0.8 for time of production start-up (= 0.56)	• According to the Petrobangla's five-year plan, drilling of two development wells is planned and production from the field is expected to resume in 2016.
	No. 7	Dev. Drlg	10	0.56	6		

Table 5 Daily Gas Production Forecast for 2015-2019

Unit: mmscfd

Company	Field	2015		2016		2017		2018		2019		Remarks
		Jan-Jun	Jul-Dec	Jan-Jun	Jul-Dec	Jan-Jun	Jul-Dec	Jan-Jun	Jul-Dec	Jan-Jun	Jul-Dec	
1. BGFCL	Titas	525	520	520	510+56	556	546	489	489	441	441	Production start-up: Jul-Dec 2016—Well nos. 23, 24, 25 and 26
	Bakrabad	40	38	36	34	30	26	23	23	30	30	
	Habiganj	224	224	224	224	220	218	215	215	200	200	
	Narsingdi	28	28	28	28	26	25	24	24	23	23	
	Meghna	10	10	10	10	10	10	9	9	9	9	
	Sub-total	**827**	**820**	**818**	**862**	**842**	**825**	**760**	**760**	**703**	**703**	
2. SGFL	Sylhet	8	8	7	7+6	12	11	11	10	10	9	Production start-up:Jul-Dec 2016—Well no. 9
	Kailashtila	72	70+8	78+14	92+8	100	96	96	92	92	88	Production start-up: Jul-Dec 2015—Well no. 1&5, Jan-Jun 2016—Well no. 9, Jul-Dec 2016—Well no. 7
	Rashidpur	60	59	58	57	56	61	72	70	67	67	Production start-up: Jul-Dec 2017--Well no. 9, Jan-Jun 2018--Well nos. 10 & 11
	Beani Bazar	9	9	9	9	8	8	8	8	8	8	
	Sub-total	**149**	**154**	**166**	**179**	**176**	**176**	**187**	**180**	**177**	**172**	
3. BAPEX	Saldanadi	10	6+10	16	13	12	11	10	10	10	10	Prpduction start-up: Jul-Dec 2015—Well no. 4
	Fenchuganj	35	34	32	30	30	29	28	28	28	28	
	Shahbazpur	10	10+9	29	29	29	29	29	29	29	29	Production start-up: Jul-Dec 2015—Well no. 4
	Semutang	4	3	2	2	2+4	6+4	10	10	10	10	Production start-up: Jan-Jun 2017—Well no. 7, Jul-Dec 2017—Well no. 8
	Sundalpur	3	3	2	0+4	4	4	4	4	4	4	Production start-up: Jul-Dec 2016—Well no.2
	Srikail	38	36	35+11	46	41	41	41	41	36	36	Production start-up: Jan-Jun 2016—Well no. 4
	Rupganj	0	8	8	8	8	8	7	7	7	7	
	Begumganj	4	4+8	12	12	10	10+8	16	16	12	9	Jan-Jun 2015: Actual production, Production start-up: Jul-Dec 2015—Well no. 3, Jul-Dec 2017—Well no. 4
	Sub-total	**104**	**141**	**147**	**144**	**140**	**150**	**145**	**145**	**136**	**133**	
	Sub-total (1+2+3)	**1,080**	**1,115**	**1,131**	**1,185**	**1,158**	**1,151**	**1,092**	**1,085**	**1,016**	**1,008**	
4. Chevron	Jalalabad	250	250	250	250	220	220	220	220	220	220	
	Maulavibazar	50	50	50	50	45	45	45	45	45	45	Jan-Jun 2015: Actual production
	Bibiyana	1,100	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	Jan-Jun 2015: Actual production
5. Tullow	Bangora	110	110	109	109	81	81	69	69	58	58	Jan-Jun 2015: Actual production
	Sub-total (4+5)	**1,510**	**1,610**	**1,609**	**1,609**	**1,546**	**1,546**	**1,534**	**1,534**	**1,523**	**1,523**	
6.	Feni				6	6+6	12	12	11	9	8	Resumption of production: Jul-Dec 2016—Well no. 6, Jan-Jun 2017—Well no. 7
7.	Chhatak				11	11+11	22	22	19	19	16	Resumption of production: Jul-Dec 2016—Well no. 3, Jan-Jun 2017—Well no. 4
Ground Total (1+2+3+4+5+6+7)		**2,590**	**2,725**	**2,740**	**2,811**	**2,738**	**2,731**	**2,660**	**2,649**	**2,567**	**2,555**	

Note: 1) Production rates in yellow cells were modified from those shown in the Petrobangala's five-year plan based on the actual production data or corrected production rates shown in Table 1.4-2.
2) The expression such as “510+56” means a daily production rate without additional production plus an additional daily production rate.

Source: Petrobangla’s “Draft Five Year Gas Supply Strategy” (2015) and JICA Survey Team

Attachment 8-2

Cost Estimation for Natural Gas Exploration and Development

Cost Estimation for Natural Gas Exploration and Development

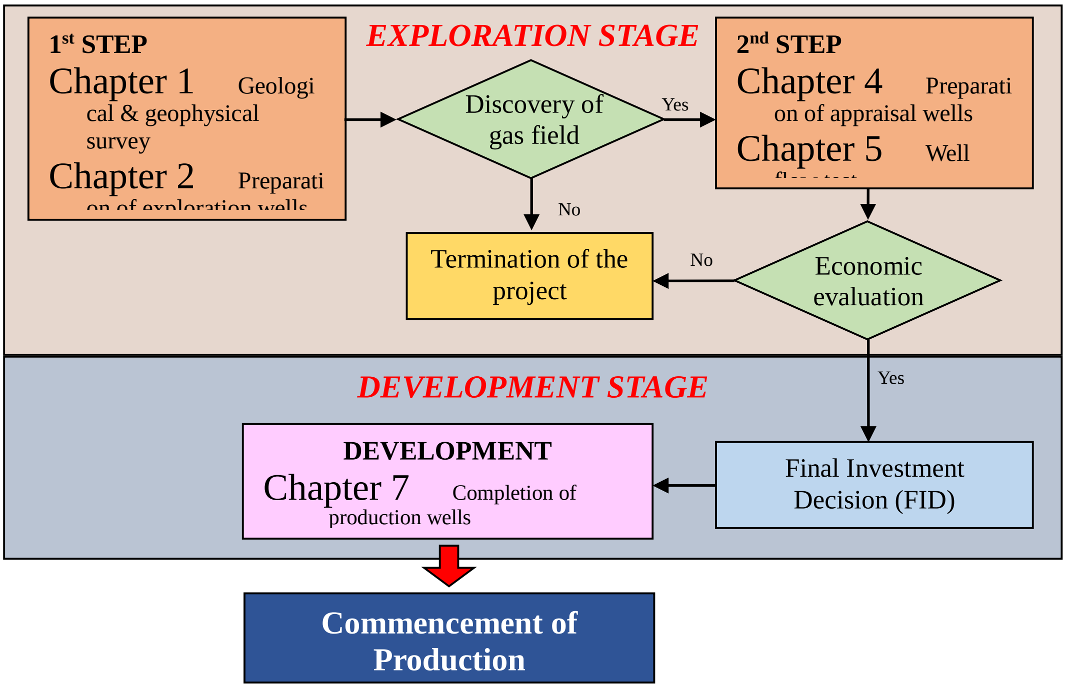
1. Introduction

(1) General

In order to grasp the approximate future gas development costs, the investment costs required for the exploration, drilling, and construction of the gas production facility were estimated. The construction costs for the construction of the new gas production facility – intended to increase the nation's gas production - were estimated based on Bangladesh's gas field development plan as scheduled at present.

(2) Cost Estimation Objects

Generally, a flow of natural gas development is divided into "Exploration stage" and "Development stage", and the related activities proceed as shown in Figure 1.



Source: JICA Survey Team

Figure 1 Flow Chart of Gas Field Development

In the exploration stage, the potential of the gas field is mainly ensured and the risk of gas development is reduced by measures including 3D seismic surveys. The gas reservoir is evaluated on a commercial basis and if there are no problems here, the gas field is able to move to the development stage. At this point the final investment decision on the gas field development is made by the company.

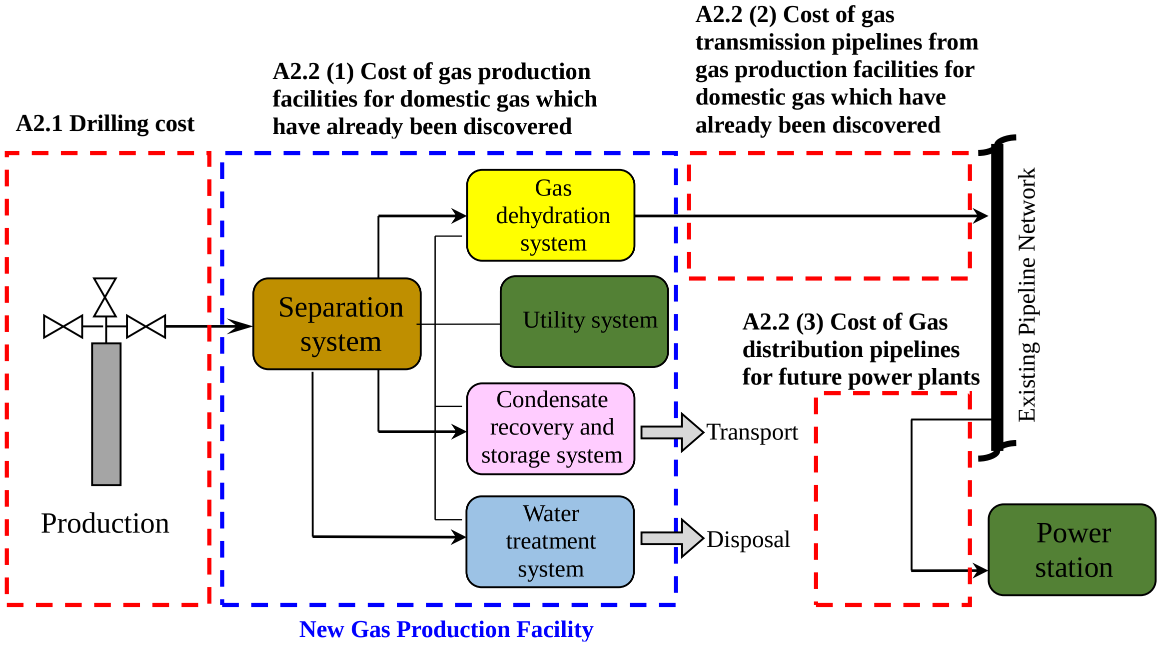
In the development stage, the gas production wells are completed with drilling works. Following this, the gas production and related facilities with appropriate plant capacity are constructed to start production.

Accordingly, the investment costs are estimated separately and divided into the two stages mentioned above. The facility construction costs are also separately estimated into around four categories including gas production facilities and pipelines. Furthermore, to properly meet the country's expected future rising gas demand, imports of LNG from overseas as well as domestic gas development is planned by the government. Therefore, the overall investment costs are divided into domestic gas development costs and import gas development costs.

The objectives (and their content) for these cost estimations are listed below, and the scope of these estimations are shown in Figure 2

A. Domestic Gas Development Costs
  A.1 Field Exploration Costs
    A.1.1.Seismic Survey Cost
    A.1.2.Well Drilling Cost

  A.2 Field Development Costs
    A.2.1 Drilling Costs
    A.2.2 Facility Construction Costs
      (1) Gas production facilities for alredy-discovered domestic natural gas
      (2) Gas transmission pipelines for alredy-discovered domestic natural gas
      (3) Gas distribution pipelines for future power plants



Source: JICA Survey Team

Figure 2 Scope of Cost Estimations

B. Import Gas Development Costs
  B1. Facility Construction Costs
      (1) LNG receiving terminal
      (2) LNG transmission pipeline

(3) Cost Estimation Procedure

Prior to conducting the cost estimation, a facility development concept of the future gas field and/or the existing gas field to be enhanced is examined based on the data and information provided by Petrobangla. Following this, a typical gas treatment process – including a separation system, a gas dehydration system, a condensate recovery and storage system, and a water treatment system – is examined through consideration of matters such as fluid property and characteristics.

As the result of the above examinations, the facility construction costs are estimated based on appropriate conditions and assumptions. These costs are estimated using the worldwide industry standard Siemens' Oil and Gas Manager (OGM) software project design tool. OGM is a suite of computer programs for performing field development planning, feasibility studies and cost estimates for oil and gas field development. OGM is used to specify the particular case to be modeled by defining the various production facilities, and then filling in forms to specify the flow connections between each facility, with the estimation results being summarized in a comprehensive database.

One of OGM's major advantages is that the facility design process (including process calculations, utility consumption calculations, conceptual facility design, selection of equipment, cost estimations) can all be processed at the same time through inputting the appropriate data. Accordingly, when compared to the facility design work time, OGM enables effective cost estimation with sufficient accuracy in a short time. Although OGM is widely used internationally in the oil and gas industry, as at February 2015 Japan Oil Engineering Co., Ltd. is the only user in Japan.

The OGM cost estimation procedure using OGM is described below:

Step 1:
In this step the type of the facility necessary for successful gas treatment is specified. Based on the data and information collected in various surveys, the OGM can establish the configurations for the of gas production facility, including for the gas/liquid separation system, the gas dehydration system, the condensate recovery and storage system, and the water separation system.

Step 2:
Input data for the facility configuration established in step 1 is prepared for modeling before running the OGM program. Based on this data, the cost estimation is then carried out utilizing OGM.

The main input data is described below and other data is listed in the Table 6.

- Project construction site information
  Depending on the particular project location, localized data, such as wage levels, are formulated and adjusted by OGM.

- Required facilities (such as the separator, the gas dehydrator, the condensate storage, and the water treatment facilities)
  Facility configuration is entered to model a fluid treatment process. The main equipment in each facility is selected by the OGM database in consideration of the facility specifications and requirements.

- Process conditions
  Process conditions such as flow rate, pressure, temperature and fluid composition are entered so that OGM database may select the proper equipment.

- Gas handling capacity
  By entering a flow rate, simplified sizing for equipment is operated, and the equipment capacity is examined in the software.

- Gas dehydration requirement
  The scale of the gas dehydration facility is examined based on the gas dehydration level specified.

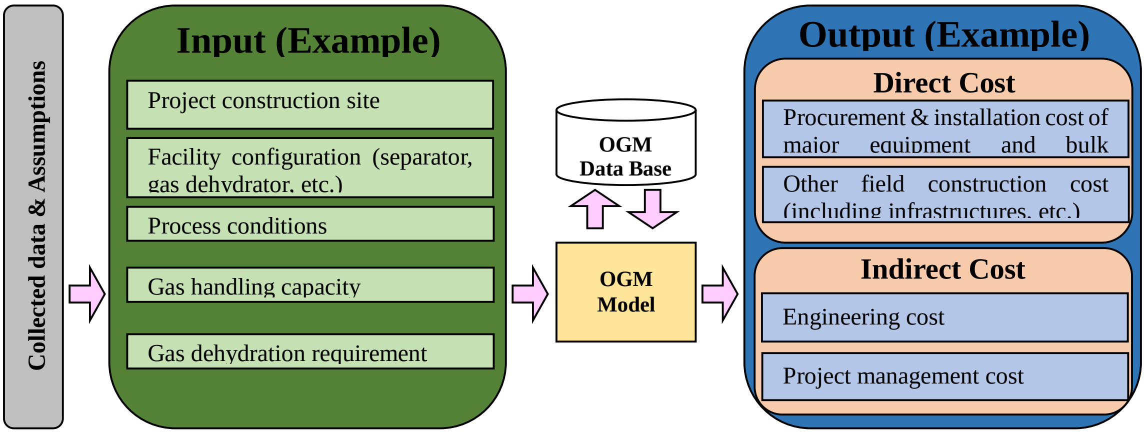
Step 3:
The direct and indirect costs of the total construction costs estimated are analyzed based on the OGM output. The costs breakdown from OGM are as follows:

- Direct costs
  - Procurement and installation costs of main equipment and bulk materials
  - Other field construction costs (including for infrastructure)

- Indirect costs
  - Engineering costs
  - Project management costs

Step 4:
The accuarcy and validity of the OGM cost estimation results is checked in line with data from the previous construction of similar scale gas production facilitiese.

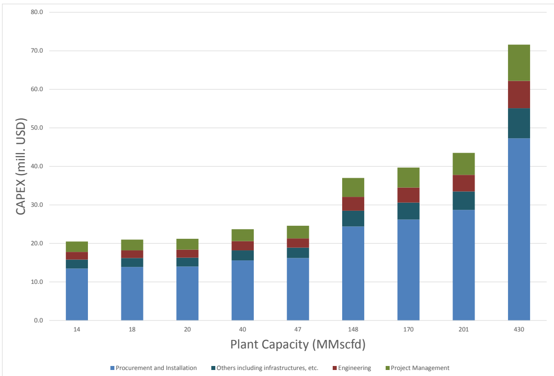
The cost estimation image by OGM is shown in Figure 3.



Source: JICA Survey Team

Figure 3 OGM Output Image

A more detailed cost estimation procedure for a gas production facility modeled using OGM is described below.

	Procedure	Description
Step 1	Preparation of input data	Southeast Asia was designated as the construction site. In relation to the configuration of the gas production facility, five facilities, such as the separation system, the dehydration system, the condensate recovery and storage system, and the water treatment facility, were specified for proper gas treatment. The following were also prepared as the input data: the gas treatment volume, the process conditions (gas composition, pressure, and temperature), the plant capacity, the level of gas dehydration, the number of facility trains, and the equipment required.
Step 2	Modeling the gas production facility and execution of OGM	In modeling the gas production facility, approximately five cases were set at the gas treatment volume within the range of 20 MMscfd to 400 MMscfd in order to cover all the cases at any gas treatment volume established in this study. OGM was used for each of these cases based on the above input data.
Step 3	Review of the OGM output	The OGM output is reviewed as the cost estimation results. In this review, the direct and indirect costs were analyzed separately, and the total construction costs were checked for their gas treatment volume. 
Step 4	Check of the cost estimation results	The accuracy and validity of the OGM output data was checked through comparing it with past construction cost data.

Source: JICA Survey Team

Figure 4 Cost Estimation Image from OGM

(4) Import Gas Development Plan

(a) Construction of a LNG Receiving Terminal

2 x 200,000 kl LNG tanks at south Chittagon is assumed as an initial stage.

(b) Construction of a LNG transmission pipeline

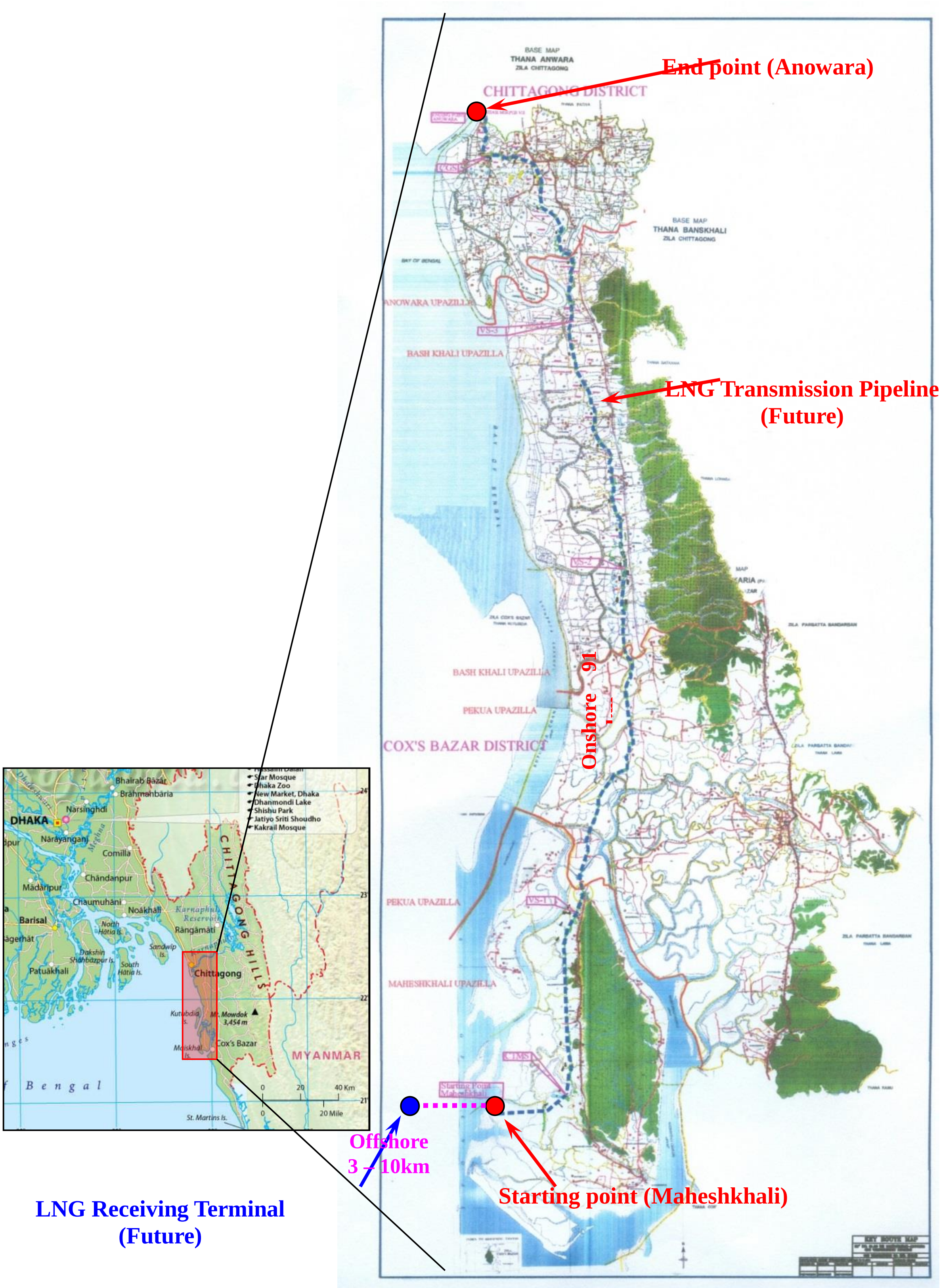
A proposed LNG transmission pipeline is to be constructed as part of a future program to transfer regasified gas of 500 MMscfd from the afore-mentioned proposed offshore LNG receiving terminal to the Chittagong RingMain (Anowara) via Moheshkhali. In this construction project, a 100 km (length) x 30 inch (width) transmission pipeline is to be installed; the pipeline shall be divided into an offshore portion of between 3 km to 10 km and a 91 km onshore portion. Please refer toFigure 5.

The operating conditions for the pipeline have been planned as indicated in Table 1.

Table 1 Operating Condition in LNG Transmission Pipeline

	Location	Flow rate [MMscfd]	Pressure [psig]
Starting point	Moheshkhali	500	1000
End point	Anowara		300

Source: information provided by Petrobangla



Source: information provided by Petrobangla

Figure 5 Pipeline Route Map of LNG Transmission Pipeline

2. Estimation Bases and Assumptions for Exploration Stage

As a part of cost estimation of natural gas development, seismic survey and well drilling costs were roughly estimated based on the information available from the websites of Petrobangla and its subsidiaries and news media.

Oil and gas exploration involves significant cost, time, and also high risk. It is important first step to gather geophysical data to narrow down the target area in the potential gas or oil field prior to start further exploratory activities.

For the last two-three decade, drilling technology has advanced significantly and exploration approach has also changed drastically. Recovery rate of oil and gas has improved due to the technological advancement. Key technological advancements are:

1) 3D seismic survey and 3D modeling technology
2) Directional and horizontal drilling technologies

Oil and gas exploration in Bangladesh started in mid 1950s. Majority of existing wells were designed and installed before 1990, and there may be some room for technological improvement to the existing facilities and also for new potential areas.

(1) Geophysical Survey:

Geophysical survey in the area of oil and gas exploration refers to a gravity survey, a magnetic survey, and a seismic survey. Gravity survey and magnetic survey are called air borne survey and used to identify size and depth of sedimentary basin as a whole and assist in modeling of subsurface structure.

Seismic survey provides more information about subsurface structures and indicates potential of subsurface deposits of crude oil and natural gas in the area. Seismic survey uses artificial seismic energy generated on land by vibrator mounted on specialized trucks if the area is accessible by trucks, otherwise use of explosives in the shallow borehole to generate shock wave. In offshore, air gun is used to generate highly compressed air bubbles which go into the water and transmit seismic wave energy into the subsurface layers.

Seismic waves reflect and refract off subsurface rock formations and travel back to acoustic receivers called geophones (on land) or hydrophones (in water). Based on the travel time data of the returned seismic energy, and also integrated with the existing strata information, feature of subsurface formation will be estimated, such as rock type, relative depth of folding, faulting, depositional environment, and nature of the fluid. This information facilitates to decide the location of prospective drilling targets.

Cost Indication for these activates will be as follows:

Type of Survey	Location	Survey Items	Cost Indication	Major Cost Element
Air Borne Survey	Onshore and Offshore	Gravity	not expensive	Airplane Lease Cost Equipment Lease cost
		Magnetic	not expensive	Airplane Lease Cost Equipment Lease cost
Seismic Survey	Onshore	2D	not expensive	Vibrator Truck Lease Cost Geophone Lease Cost
		3D	not so expensive	Vibrator Truck Lease Cost Geophone Lease Cost
	Offshore	2D	expensive	Survey Ship Day-rate
		3D	very expensive	Survey Ship Day-rate

(2) Drilling Works:

Drilling work for oil and gas exploration is carried out by specialized drilling rigs and experienced personals. These rigs are equipped with all necessary facilities to circulate the drilling fluid, hoist and turn the pipe, control down-hole, remove cuttings from the drilling fluid, safety facilities to prevent blowout events, and generate on-site power for these operations.

Size of the drilling hole in general is 40-36 inch initially and down to 5 inch. Soon after the hole is drilled as per the design, sections of steel pipe called casing, slightly smaller in diameter than the borehole, are placed in the hole. Cement will be placed between the outside of the casing and the borehole (annulus). The casing provides structural integrity to the newly drilled wellbore, in addition to isolating potentially dangerous high pressure zones from each other and from the surface.

Drilling fluid called "Mud" is used to pumped down the inside of the drill pipe and exits at the drill bit for the purpose of cooling the bit, lifting rock cuttings to the surface, preventing destabilization of the rock in the wellbore walls, and overcoming the pressure of fluids inside the rock so that these fluids do not enter the wellbore.
The principal components of drilling fluid are usually water and bentonite and also contain a complex mixture of solids and chemicals that must be carefully tailored to provide the correct physical and chemical characteristics required to safely drill the well. Mud logging is carried out to study the lithology of the formation and monitoring the characteristics of the formation.

Drilling is carried out with following purposes,

1) Exploratory drilling is carried out to gather information about the subsurface around the area of drilling through mud logging analysis.
2) Appraisal well is used to evaluate characteristics (flow rate etc.) of a proven hydrocarbon accumulation.
3) Production well is for production of oil and gas, once the evaluation of the well is completed and commercial production is proven.

Drilling cost is mostly affected by equipment lease cost and also depending on the depth/length (case of directional drilling), field location, and factors. Offshore is more expensive than onshore. General cost element for drilling work is as follows:

1) Hiring cost for geoscientists, geologists, mud loggers, engineers
2) Contractors for logistics and casing /cementing
3) Drilling rig lease cost with operation personals

(3) Drilling Cost

1) Onshore Drilling Cost:

Typical cost for onshore drilling in US is in the range of USD 0.5 million to 15 million per well and lease day rate for drilling rig capable of drilling most exploratory wells will be USD 10,000-15,000/day.

Unit drilling cost in Bangladesh is considered in the range of USD 10-20 million per well as shown in the Annural Reports by Petrobangla. Recent driling cost based on a competitive bidding using Best Practice is USD 15 million, and this figure can be used as a benchmrk cost for futre cost estimate.

2) Offshore Drilling cost:

High performance jack up rig lease rate in 2015 is USD 177,000/day in accordance with Rigzone. With the use of similar facility, operating cost in the duration of 100 days can cost USD 30 million, including mobilization and demobilization, but varies to the local factors and location.

3. Construction Cost Estimate

The following assumptions were used for making cost estimate.

(1) Gas Productio and Processing Facilities in the Existing Gas Fields

At present there are no new gas fields which are at the development stage. However, in order to increase future domestic gas supply, Petrobangla has a natural gas enhancement program for several of its existing gas fields. These programs run from 2014 to 2017 and are shown in Table 2.

Table 2 Gas Production Enhancement Program (Petrobangla)

Production Enhancement Program (Nov. 2014 – June 2015)

Sl. No.	Gas Fields & Wells	Well type	Flow (MMcfd)	Completion Date
1	Shahbazpur # 4	Development	25	November 2014
2	Bibiyana (sevem wells)	Development	220	Drilling completed, awaiting completion production facilities, will be in production within June 2015 in phases.

Production Enhancement Program (July 2015 - June 2016)

Sl. No.	Gas Fields & Wells	Well type	Flow (MMcfd)	Completion Date
	Titas # 25	Development	20	December 2015
	Kailashtila # 9	Development	25	December 2015
	Kailashtila 1& 5	W/O	15	June 2016
	Titas # 23	Development	20	June 2016
	Begumganj # 4	Development	15	June 2016
	Srikail # 4	Development	20	June 2016
	Titas # 26	Development	20	March 2016
	Salda # 4	Development	15	June 2016

Production Enhancement Program (July 2016 - June 2017)

Sl. No.	Gas Fields & Wells	Well type	Flow (MMcfd)	Completion Date
	Titas # 24	Development	20	September 2016
	Sundalpur # 2	Development	8	December 2016
	Semutang #7	Development	8	December 2016
	Semutang # 8	Development	8	June 2017
	Rashidpur # 9	Development	10	June 2017
	Sylhet # 9	Development	10	December 2016
	Rashidpur # 10, 11	Development	20	December 2017

Source: information provided by Petrobangla (Petrobangla reply to JICA survey team questionnaire).

The production enhancement programs are planned at 17 gas fields, as well as new installations and workovers are being conducted at 25 production wells. In these programs, 23 gas production wells are being newly installed at the existing gas fields, and the workovers of two existing wells being carried out at the Kailashtila gas field in order to improve the present declining gas production rate.

The program outline is shown in Table 3.

Table 3 Production Enhancement Program for the Existing Gas Fields

As at December 2014

Serial No.	Gas Field	Well #	Development Type & Number of Wells		Production Increment [MMscfd]	Completion Date (*2)	Necessity of New Gas Production Facility (*3)
1	Titas	23	Development x 1		20	June 2016	○
		24	Development x 1		20	September 2016	○
		25	Development x 1		20	December 2015	○
		26	Development x 1		20	March 2016	○
4	Kailashtila	1, 15		Workover x 2	15	June 2016	X
		9	Development x 1		25	December 2015	X
5	Rashidpur	9	Development x 1		10	June 2017	X
		10, 11	Development x 2		20	December 2017	X
6	Sylhet	9	Development x 1		10	December 2016	X
12	Shahbazpur	4	Development x 1		25	November 2014	X
13	Semutang	7	Development x 1		8	December 2016	X
		8	Development x 1		8	June 2017	X
17	Bibiyana (*1)	-	Development x 7		220	June 2015	X
19	Sundalpur	2	Development x 1		8	December 2016	X
20	Srikail	4	Development x 1		20	June 2016	X
21	Begumganj	4	Development x 1		15	June 2016	X
Other 1	Salda	4	Development x 1		15	June 2016	X
TOTAL		-	23	2	479	-	-
			25				

Source: Information based on Table 2 "Gas Production Enhancement Program (Petrobangla)"

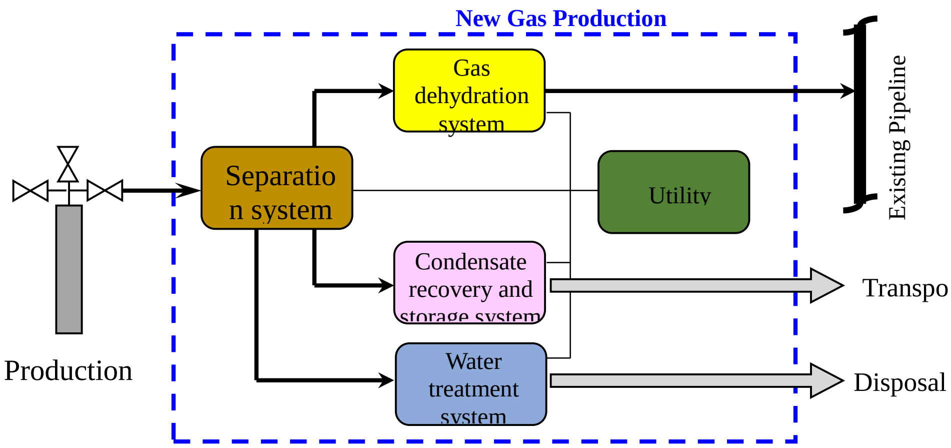
NOTE:
*1: In Bibiyana Gas Field, gas of total 220 MMscfd will be additionally produced from seven wells.
*2: "Completion Date" means that construction or workover of the gas production well will be completed at that time.
*3: The information regarding the necessity of a new gas production facility was obtained at the time of the meeting with Petrobangla

As shown inTable 3, the production enhancement program scheduled until 2017 has been planned, and the gas production wells are expected to be newly completed by and the workover of the existing wells should be carried out up to the date indicated in the table. The gas produced from these wells, except for that from the Titas Gas Field, is expected to be treatable within the plant capacity of the existing gas treatment facility. Accordingly, the construction of a new gas treatment facility should not be required for those production increments.

Regarding the four wells (23, 24, 25, and 26) in the Titas Gas Field – which should increase production to a total of 80 MMscfd – all the gas produced at these wells is planned to be collected at a site through gathering pipelines and treated in a newly-constructed gas production facility. The construction of this facility will be financed under an ADB project.

To treat produced gas properly, new gas production facility is to be composed of the following five main systems. The typical treatment process is shown in Figure 6 and Table 4.

- ✓ Separation system
- ✓ Gas dehydration system
- ✓ Condensate recovery and storage system
- ✓ Water treatment system
- ✓ Utility system



Source: JICA Survey Team

Figure 6 Typical Gas Treatment Process

Table 4 Function of Gas Treatment System

FACILITY	FUNCTION	PICTURE
Separation system	➢ Separation of gas, liquid and water ➢ Removal of foreign substances in well fluid	
Gas dehydration system	➢ Removes water vapour from the separated gas stream	
Condensate recovery and storage system	➢ Storage and unloading of condensate separated in the separation system	
Water treatment system	➢ Recovery of oil content in produced water using a CPI separator and a flotation unit ➢ Disposal of produced water	
Utility system	➢ Supply of fuel gas, instrument air, cooling water, utility air and water for maintenance, and electrical power.	 (The above picture shows instrument air compressor.)

Source: JICA Survey Team

(2) Parameter for OGM software of cost estimation

(a) Trains at the gas production facility
There shall be no standby train at the proposed new gas production facility.

(b) Equipment standby philosophy
None of the main equipment in the gas production facility will have a standby unit.

(c) Wellhead fluid composition
The gas composition of the Titas Gas Field – Bangladesh's largest gas field – was applied to all cases in this study. This gas composition is shown in Table 5.

Table 5 Typical Wellhead Fluid Composition

Component	mol%
Nitrogen	0.37
Carbon Dioxide	0.31
Methane	96.76
Ethane	1.80
Propane	0.36
i-Butane	0.09
n-Butane	0.05
i-Pentane	0.02
n-Pentane	0.02
n-Hexane	0.04
n-Heptane	0.02
n-Octane	0.01
n-Nonane	0.00
n-Decane+	0.04
H2O	0.11
Total	100.00

Source: Information prepared based on Petrobangla data

Based on the standard gas sales contract in Bangladesh, as allowable water content in treated gas is restricted to below 7 lb/MMscf, this water content value has been applied to the planning of the gas dehydration facility.

(d) Operating conditions at the wellhead
- ✓ Pressure: 1,700 psig
- ✓ Temperature: 142 deg.F

(e) Cost estimation software (OGM) input data

The estimation of the costs for the gas production facility using OGM, was carried out with the input items and the input methods described in Table 6

Table 6 OGM Input Data

No.	Input Item	Input Method
1.	Project Construction Site Information	
1-1	Project Construction Site	The project construction site is specified from major oil/gas production areas worldwide such as the Arabian Gulf, Gulf of Mexico, North Sea, West Africa, Brazil, Venezuela, Southeast Asia, Northeast Asia and Malaysia. In this case, Southeast Asia was specified due to the proximity of Bangladesh. The appropriate wage rate for the specified project construction site was then applied – the same data is inputted for to all the cases regardless of the gas handling capacity.
2.	Required Facilities (Separator, Gas Dehydrator, Condensate Storage, Water Treatment Facilities)	
2-1	Main Facilities	The required main facilities (separator, gas dehydrator, condensate storage tank, and water treatment facility) for gas production are specified. Here, as there are no sour components (H2S) in the gas the general facility configuration for normal gas production was selected. As the facility configuration is the same for all the cases, the same data was inputted regardless of the gas handling capacity.
3.	Process Conditions	
3-1	Gas Production Rate	The gas production rate is specified. In this case, gas handling capacities were specified to cover the wide range of gas production rates in Bangladesh. The facilities required to handle the specified gas production rate are designed in connection with gas handling capacity, and then the costs are estimated.
3-2	Composition Basis	The gas composition is specified and the gas/liquid separation calculation is conducted based on the inputted composition. The facilities required to handle the separated gas and liquid are designed, and then the costs are estimated. The typical gas composition in Bangladesh is inputted in all cases regardless of the gas handling capacity. In case that the toxic substances such as sour component (H2S) and mercury are included in the produced gas, requisite removal facilities will be required. However, as the gas produced in Bangladesh is classified in

No.	Input Item	Input Method
		sweet gas, the installation of such facilities is not necessary.
4.	Separation System	
4-1	Flowing Wellhead Pressure	The wellhead pressure is specified. The pressure level at the highest upstream part of the facilities is defined, then the wall thickness is calculated and designed based on the inputted pressure, after which the the costs are estimated. The typical wellhead pressure in Bangladesh was inputted in all the cases regardless of the gas handling capacity.
4-2	Flowing Wellhead Temperature	The wellhead temperature is specified. Temperature level at the highest upstream part of the facilities is defined, then the wall thickness is calculated and designed based on the inputted temperature, after which the costs are estimated. The typical wellhead temperature in Bangladesh was inputted in all the cases regardless of the gas handling capacity.
4-3	Production Manifold Design Pressure	The manifold design pressure is specified. The pressure level at the manifold is defined, then the wall thickness is calculated and designed based on the inputted pressure, after which the costs are estimated. The typical design pressure was inputted in all the cases regardless of the gas handling capacity.
4-4	Production Separator Design Pressure	The separator design pressure is specified. The pressure level of the separator is defined, then the wall thickness is calculated and designed based on the inputted pressure, after which the costs are estimated. The typical design pressure was inputted in all the cases regardless of the gas handling capacity.
4-5	Production Separator Operating Pressure	The separator operating pressure is specified. The gas/liquid separation calculation is conducted based on the inputted pressure, then the separator size and wall thickness required to handle the separated gas and liquid are designed, after which the costs are estimated. The typical separator operating pressure in Bangladesh was inputted in all the cases regardless of the gas handling capacity.
4-6	Test Separator	The necessity of the test separator is specified. The test separator is normally required to monitor the production rate of one well and to manage the gas reservoir. “Allocated” was selected for all the cases regardless of the gas handling capacity.
4-7	Residence Time	The oil/condensate residence time in a separator that is required to segregate water droplets from oil/condensate phase was inputted. The As the separator is designed based on the residence time, the typical

No.	Input Item	Input Method
		residence time is inputted in all the cases regardless of the gas handling capacity.
4-8	Separator per Stage	The number of separators per stage is inputted. Normally, vessels such as separators do not have any spares. Also, as the facility configuration without any spares is a design premise in the study, the number of train was inputted as one for all the cases regardless of the gas handling capacity.
4-9	Percent Flow per Separator	In relation to the "separator per stage", the percentage of the handling flow rate per train in the total flow rate was inputted. As the facility configuration without any spares is a design premise in the study, the percent flow per separator is inputted as one hundred (100%) for all the cases regardless of the gas handling capacity.
4-10	Water Separation Option	The necessity of water separation in a separator is specified. The produced water is normally removed from the oil/condensate and gas. "Allocated" was selected for all the cases regardless of the gas handling capacity.
5.	Gas Dehydration System	
5-1	Gas Dehydration Medium	The gas dehydration medium is specified. "Glycol" is specified as a typical medium (chemical) used in gas dehydration process for all the cases regardless of the gas handling capacity.
5-2	Number of Gas Dehydration Trains	The number of gas dehydration trains is inputted. Vessels such as gas dehydration facility normally do not have any spares, and facility configuration without any spare is a design premise in the study, therefore number of train is inputted as one for all the cases regardless of gas handling capacity.
5-3	Percent Flow per Dehydration Train	In relation to the "number of gas dehydration trains", the percentage of the handling flow rate per train in the total flow rate is inputted. As the facility configuration without any spares is a design premise in the study, the percent flow per gas dehydration train is inputted as one hundred (100%) for all the cases regardless of the gas handling capacity.
5-4	Outlet Water Dew Point Temperature	The outlet water dew point temperature for the gas dehydration is inputted. The water dew point temperature of 32 F corresponding to 7 lb water in 1 MMscf gas, as regulated in the standard sales gas contract in Bangladesh, is inputted for all the cases regardless of the gas handling capacity.

No.	Input Item	Input Method
5-5	Dehydrator Column Design Pressure	The gas dehydrator column design pressure is specified. The pressure level of the dehydrator column is defined, then the wall thickness is calculated and designed based on the inputted pressure, after which the the costs are estimated. The typical design pressure is inputtedfor all the cases regardless of the gas handling capacity.
6.	Condensate Recovery and Storage System	
6-1	Oil/Condensate Tank Capacity	The oil/condensate tank capacity is specified. The required oil/condensate storage facilities are designed for the inputted tank capacity, then the costs are estimated.
6-2	Oil Pump Outlet Pressure	The oil pump outlet pressure required for shipping is specified. The Pressure level of the pump is defined, then the wall thickness is calculated and designed based on the inputted pressure, after which the costs are estimated. The typical design pressure is inputted for all the cases regardless of the gas handling capacity.
6-3	Number of Pumps	The number of pumps is inputted. As the facility configuration without any spares is a design premise in the study, the number of trains is inputted as one for all the cases regardless of the gas handling capacity.
6-4	Percent Flow per Pump	In relation to “number of pumps”, the percentage of the handling flow rate per train in the total flow rate is inputted. As the facility configuration without any spare is a design premise in the study, thepercent flow per pump is inputted in common as one hundred (100%) for all the cases regardless of the gas handling capacity.
7.	Water Treatment System	
7-1	Produced Water Design Rate	The produced water design rate is specified. The facilities required to handle the specified water rate are designed in connection with the produced water design rate, then the costs are estimated.
7-2	Sour Water Stripping Option	The necessity of a sour (H_2S) component stripping facility as one the of water treatment systems is specified. As gas produced from Bangladesh is classified as sweet gas a without sour (H_2S) component, the installation of such a facility is not required. “Not allocated” was selected for all the cases regardless of the gas handling capacity.
7-3	CPI Unit	The necessity of a CPI unit as the first stage of water treatment is specified. A CPI unit is normally used in the water treatment. “Allocated” was selected for all the cases regardless of the gas handling capacity.

No.	Input Item	Input Method
7-4	Floatation/Hydrocyclone Unit	The necessity of a floatation/hydrocyclone unit as the second stage of water treatment is specified. A floatation/hydrocyclone unit is normally used in the water treatment. "Allocated" was selected for all the cases regardless of the gas handling capacity.
8.	Utility System	
8-1	Type of Main Power Generator	The type of main power generator driver is specified. "Turbine" was specified as the typical most proven type of driver for all the cases regardless of the gas handling capacity.
8-2	Number of Main Power Generators	The number of main power generators is inputted. As the facility configuration without any spares is a design premise in the study, thethe number of trains was inputted as one for all the cases regardless of the gas handling capacity.
8-3	Percent of Main Power Load	In relation to the "number of main power generators", the percentage of power generation per train in the total power generation is inputted. As the facility configuration without any spares is a design premise in the study, the percent of the main power load was inputted as one hundred (100%) for all the cases regardless of the gas handling capacity.
8-4	Power Generator Selection	The manufacturer's model of the main power generator is specified. In this case, the required power for all the facilities was internally calculated in the software by specifying "internally determined" for all the cases regardless of the gas handling capacity. Also, the type of main power generator was automatically selected to cover the power demand required.
9.	Other Related Facilities	
9-1	Number of People in Operation Camp	The number of people to be accommodated in the operation camp is inputted. Based on three shift of eight hours , the number of people – including operators, supervisors, maintenance workers, administrators, and guests – are assumed for the required accommodation, then the costs are estimated.
9-2	Number of People in Construction Camp	The number of people to be accommodated in construction camp is inputted. The number of people is assumed for the required accommodation, then the costs are estimated.

Source: JICA Survey Team

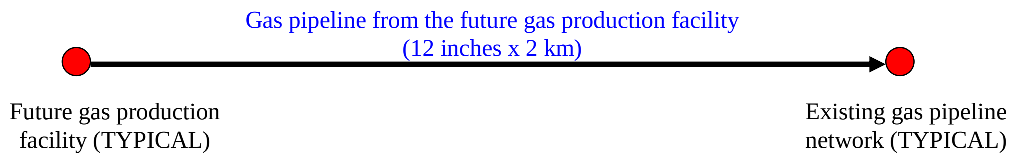
(3) Gas transmission pipelines for already-discovered domestic natural gas

For the costs estimation, the following conditions were uniformly applied for all the gas pipelines to be newly laid between the future gas production facility and the existing pipeline network.

- Pipe material: API5L Gr.X60 with 3LPE coating
- Nominal pipe size: 12 inches

- Wall thickness: 0.312 inches
- Pipeline length: 2 km (per each pipeline)
- Concrete coating: Not required
- Construction cost: 0.5 million USD/km

The overall view of the pipeline is as follows.

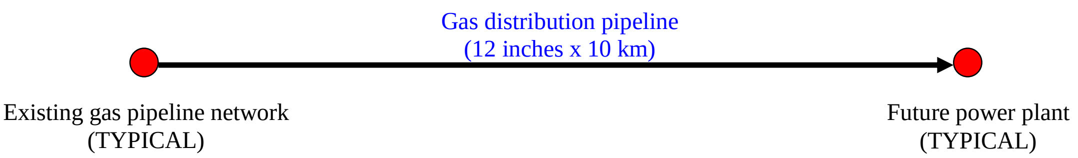


(4) Gas distribution pipelines for future power plants

For the costs estimation, the following conditions were uniformly applied for all the gas distribution pipelines to be newly laid for future power plants which will be constructed for the power supply increment.

- Pipe material: API5L Gr.X60 with 3LPE coating
- Nominal pipe size: 12 inches
- Wall thickness: 0.312 inches
- Pipeline length: 10 km (per each pipeline)
- Concrete coating: Not required
- Construction cost: 0.5 million USD/km

The overall view of the pipeline is as follows.



(5) Import Gas Development Cost

(a) LNG Receiving Terminal

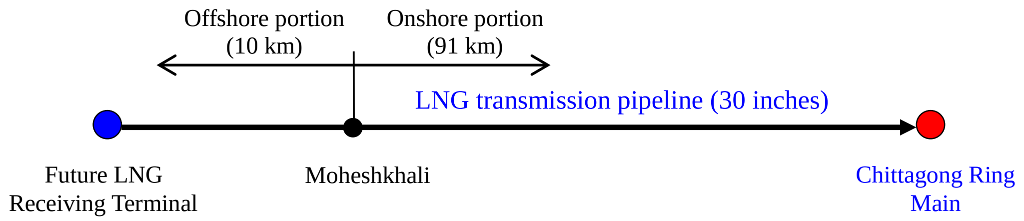
Cost for LNG Receiving terminal inclusive of Jetty and Loading facilities, 2 x 200,000 kl tanks and re-gasification facilities are estimated USD 500 million.

(b) LNG Transmission Pipeline

For the costs estimation, the following conditions were applied for the LNG transmission pipeline to be newly laid between the LNG receiving terminal to the Chittagong ring main.

- Pipe material: API5L Gr.X60 with 3LPE coating
- Nominal pipe size: 30 inches
- Wall thickness: 0.562 inches
- Pipeline length: 10/91 km (Offshore/Onshore)
- Concrete coating: Required for the offshore portion
- Construction cost: 1.5 million USD/km (Offshore)
  1.1 million USD//km (Onshore)

Overall view of the pipeline is shown as follows.



4. Results of Cost Estimate

Cost estimate for future gas exploration and production, and also cost for LNG introduction ware carried out based on various assumptions as mentioned in the previous sections.

(1) Exploration and Drilling Cost (Remaining reserves 2P)

Seismic survey and well drilling costs were roughly estimated based on the information available from the websites of Petrobangla and its subsidiaries and news media.

1) Seismic Survey Cost

(a) Seismic Data Acquisition

There are two different types of methods for the data acquisition in seismic surveys: two-dimensional (2D) seismic survey and three-dimensional (3D) seismic survey. A 2D seismic survey is conducted mainly in the exploration phase, and if promising amounts of oil and gas are confirmed by exploration drilling, a 3D seismic survey is conducted for confirming the size and structure of the field in the appraisal and development phases. In addition, a 3D seismic survey may be also conducted for better reservoir management in the field development phase.

The method for the cost estimation of a seismic survey depends on the type of survey: 2D or 3D survey. A total cost of seismic survey can be roughly estimated based on the seismic line length (line-km) for 2D seismic survey and survey area (km2) for 3D seismic survey, respectively. It should be noted that, for example, the specifications can be different depending on the environmental conditions of given area or location, and this makes it difficult to estimate the cost based on a given survey line length or survey area only.

(b) Cost Analysis of Seismic Survey

Regarding the seismic surveys conducted in recent 4 or 5 years in Bangladesh, the available data was organized in order to examine the relationships between the survey costs and the survey line length for a given 2D seismic survey and a survey area for a 3D seismic survey, respectively (Table 7). In addition, based on the collected data, rough estimates of the costs per line-km for 2D and per sq. km for 3D seismic surveys were also carried out, respectively (Table 7).
The data such as name of field/area, survey line length (2D seismic survey) and area (3D seismic survey), survey period and total survey cost is shown inTable 7.
In addition, as shown in the table, the surveys for which necessary data for cost analysis were available are three projects only, of which one project was 2D seismic survey and two projects were 3D seismic surveys. From the viewpoint of analysis of seismic survey cost, the data is considered to be insufficient for 2D seismic survey.
The results of the cost analysis of seismic surveys are summarized below, as also shown in Table 7:

- 2D seismic survey: US$5.1 thousand/line-km

- 3D seismic survey: US$12.0 to 18.5 thousand/$km^2$

Table 7 Analysis of Seismic Survey Costs

As of October 2015

Field/Area	Length	Area	Survey Period	Estimated Survey Cost		Cost Analysis		Remarks
						Cost per line-km	Cost per sq km	
	(line-km)	(sq km)		M BDT	M USD	K USD	K USD	
Dhaka, Manikganj, Shariatpur, Faridpur, Gopalganj, Madaripur, Khulna, Netrokona, Kishoreganj, Sunamganj, Habiganj, Sylhet, Maulavibazar and Bhola	1,800	—	Dec. 2012 (?) - (Underway)	711.3	9.15	5.1	—	
Titas	—	335	2010 - 2012 (Details unknown)	784.5 (for 2 fields)	10.09 (for 2 fields)	—	18.5	• Appraisal of Gas Field (3D Seismic) (Titas, Bakhrabad, Sylhet, Kailashtila and Rashidpur) Project (Revised)
Bakhrabad	—	210						
Rashidpur	—	325		859.5 (for 3 fields)	11.05 (for 3 fields)	—	15.7	
Kailashtila	—	190						
Sylhet	—	190						
Sunetra	—	260	May 2013 (?) - (Underway)	1,825.0 (for 6 fields/area, 1,950 sq km in total)	23.47 (for 6 fields/area, 1,950 sq km in total)	—	12.0	
Shahbazpur	—	600						
Sundalpur-Begumganj	—	440						
Srikail	—	150						
Narshingdi	—	250?						
Habiganj	—	250?						

Note: The BDT to USD exchange rate on January 1, 2015 (1 BDT = US$ 0.01286) is used.

Source: Prepared based on Petrobangla Annual Report 2012 and BAPEX Annual Reports 2013 and 2014

2) Well Drilling Cost

(a) Well Type

Two types of wells, exploration (or exploratory) and appraisal wells, are drilled in the exploration phase. An exploration or exploratory well is usually drilled in an area where any oil or gas has not been discovered yet. However, if a well is targeted for new oil or gas pool, for example, in a deeper horizon in the existing oil or gas field, the well is also called as exploration well. If promising oil and/or gas are discovered by exploration drilling, then an appraisal well will be drilled for confirming the size of the discovered oil and/or gas reservoir(s) in the next phase. Most of the wells to be drilled in the development phase are defined as development well.

(b) Factors Affecting Well Drilling Cost

The cost of a well depends mainly on the daily rate of the drilling rig and a well operation period in days, and a well drilling cost is basically determined by multiplying the rig day rate by duration of drilling operations in days. In the viewpoint of the estimation of a well drilling cost, the difference in types of wells shown above are not significant.
There are various factors affecting the duration of the well operations, and in general, for example, the factors are as follows:

However, the information on the factors except for well depth is not available or insufficient, those factors are not examined in this survey.

- Drilling depth
- Subsurface geological conditions

- Subsurface pressure and temperature conditions
- Well type (vertical, directional, horizontal)
- Duration of well test

However, the information on the factors except for well depth is not available or insufficient, those factors are not examined in this survey.

3) Well Drilling Cost Analysis

Based on the description in the above section, the cost analysis was performed on the wells which show the data of relatively high reliability listed below.

- Estimated cost per well
- Well depth (total depth)
- Well type (vertical or directional)
- Duration of drilling operations

Regarding the wells whose cost analysis was conducted, the data such as well name, well type, well drilling cost, well depth (drilling depth) and duration of drilling operations are shown in Table 8. The number of the wells whose cost analyses have been done to date is only 10. These wells consist of nine vertical wells (including wells whose types have not been confirmed yet) and one directional well. The relationship between well drilling cost and well depth for these wells are shown in
Figure 7 in which the well types are classified. Proposed well depths should be used as well depths in this type of plot because the estimated well drilling costs are only available. However, regarding the wells where the actual well depths are not available, the actual well depths were used instead of the proposed well depths in the plot.

In general, it is empirically known that a well drilling cost can be described as an exponential function of depth. Therefore, if a well depth is given, the corresponding well drilling cost can be roughly estimated. However, unfortunately such a relationship is not apparent in Figure 7. This is due to the following reasons:

- A small amount of data set
- Relatively narrow range of well depths (about 2,900 to 3,700 m)

In addition, it should be noted that the estimated well drilling cost varies largely depending on different drilling contractors in Bangladesh. Recently, Gazprom, a Russian company, was involved in the drilling of the wells in Bangladesh. The costs of the wells drilled by Gazprom are at least twice as high as compared with those of the wells drilled by BAPEX. For example, as shown in Table 8, Well Rashidpur-8, where the drilling operations were undertaken by Gazprom, was drilled to a proposed total depth of 2,902 m at an estimated cost of US$ 22.0 million. On the other hand, Well Fenchuganj-5, where drilling operations were undertaken by BAPEX, was drilled to a proposed total depth of 3,100 m at an estimated cost of US$ 9.8 million.

4) Estimates of Well Drilling Cost for Model Wells

Based on the results shown in the section (3), the estimated well drilling costs are tentatively proposed for two model cases having the well depths of 3,000 m and 4,500 m, respectively. The model well with a total depth of 3,000 m can be used as one of the model wells for estimating a well drilling cost in Bangladesh, taking into account the range of the well depths. The other model well with a total depth of 4,500 m is proposed based on the fact that the exploration well Mubarakpur-1 currently being drilled has a proposed total depth of 4,500 (+) m, indicating that the well is to be drilled at least to a total depth of 4,500 m, and the proposed total depth of the exploration well Sunetra-1 was also 4,500 m (actual total depth of 4,683 m).

- Model well with a total depth of 3,000 m:
  The cost of the model well having a total depth of 3,000 m is about US$ 9.5 million by calculation using the estimated cost of Well Fenchuganj-5 shown in Table 8.
- Model well with a total depth of 4,500 m:
  The cost of the model well having a total depth of 4,500 m is about US$ 10.9 million by averaging the estimated costs of both wells Mubarakpur-1 and Sunetra-1 shown in Table 8,

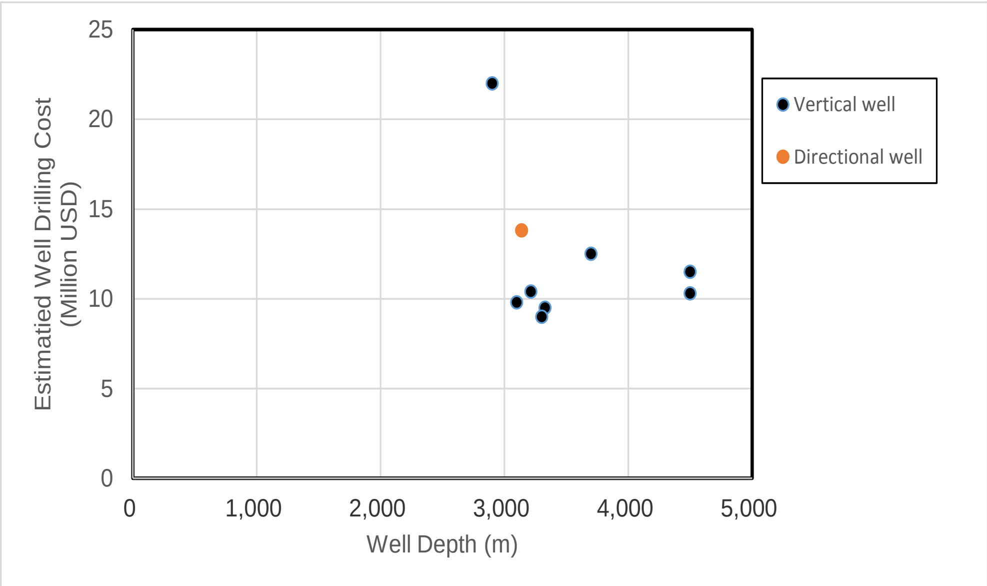
In this study, 4 development wells are assumed and converted to production wells at the later stage.Recent case shows that total cost of drilling of 4 wells in Bangladesh is assumed USD 60 million.

Table 8 Analysis of Well Drilling Costs

As of October 2015

Well Name	Expl./ Appr./ Dev.	Well Type	Well Depth (m)		Operation Period	Estimated Well Drilling Cost		Remarks
			Proposed	Actual		M BDT	M USD	
Titas-27	Dev.	Directional	(N/A)	3,138	Nov. 19, 2013 - Apr. 11, 2014	1,070.0	13.8	
Mubarakpur-1	Expl.	Vertical?	4,500 (+)	(Underway)	Aug. 22, 2014 - (Underway)	892.6	11.5	• Mubarakpur Oil/Gas Exploration Well Drilling Project
Sundalpur-1	Expl.	Vertical?	(N/A)	3,327	Dec. 21, 2010 - Mar. 11, 2011	736.5	9.5	• Discovery well
Kapasia-1	Expl.	Vertical?	(N/A)	3,301	Feb. 6, 2012 - Apr. 13, 2012	701.7	9.0	• Kapasia Oil/Gas Exploration Well Drilling (Revised) • Dry
Srikail-2	Appr.	Vertical?	(N/A)	3,214	May 5, 2012 - June 29, 2012	811.2	10.4	• Srikail Oil/Gas Exploration Well Drilling Project (Well #2) • Discovery well
Fenchuganj-5	Dev.	Vertical	3,100	3,137	Sept. 27, 2013 - (?)	760	9.8	• A part of Salda # 3, 4 & Fenchuganj # 4, 5 Gas Fields Development Project • Dry
Sunetra-1	Expl.	Vetical	4,500	4,683	Aug. 10, 2012 - Mar. 18, 2013	802.5	10.3	• Sunetra Oil/Gas Exploration Well Drilling Project • Dry
Rashidpur-8	Dev.	Vertical	2,902	2,990	(?) - Aug. 27, 2014	1,705.0	21.9	• Drilliing was undertaken by Gazprom.
Rupganj-1	Expl.	Vertical	3,700	3,615	May 19, 2013 - (?)	970.0	12.5	• Discovery well
Sundalpur-2	Dev.	Vertical?	3,250	—	—	754.5	9.7	• Well has not been drilled yet.

Note: The BDT to USD exchange rate on January 1, 2015 (1 BDT = 0.01286 USD) is used.



Source: Prepared based on Petrobangla Annual Reports 2012 and 2013, etc.

Figure 7 Estimated Well Drilling Cost vs. Well Depth Plot

(2) Facility Construction Costs

The facility construction costs necessary for supplying incremental gas in the future was estimated below in items 1) to 3).

(a) Gas Production Facilities

Gas production facilities for already-discovered domestic natural gas described earlier, there are no new gas fields which will move to the development stage in Bangladesh. Also, although several gas field enhancement plans have been scheduled at the existing gas fields, most of them do not require the construction of new gas production facilities because the increased gas should be able to be treated in the existing facilities. In relation to the Titas gas field requiring an additional gas production facility, the production of gas of 80 MMscfd is anticipated to be increased in the near future.

However, at present these plans have been scheduled only up until 2017; there is still no specific gas development plan for after 2018. Accordingly, it is difficult to frame a financial plan for the gas field development based on such a short term plan. Nevertheless, in December 2012 the World Bank published a long term production forecast for each gas field up until 2030 in its report entitled "Consulting Services for Preparation of Implementation and Financing Plan for Gas Sector Development". Thus, a financial plan can be made based on this long term plan.

In this study, as a yearly financial plan is required to properly conduct economic and financial analyses, the construction costs of gas production facility for future gas development were estimated based on the said long term production forecasts.

The future field wise gas production forecast is indicated in Table 9.

Table 9 Field Wise Gas Field Enhancement Plan

Field wise predicted production

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Titas																				
Daily Production, mmcfd		450	450	480	600	600	600	600	600	600	500	500	450	400	300	250	250	250	200	200
Yearly Production, tcf		0.1643	0.1643	0.1752	0.219	0.219	0.219	0.219	0.219	0.219	0.1825	0.1825	0.1643	0.146	0.1095	0.0913	0.091	0.091	0.073	0.073
Remaining Reserve, tcf	3.073	2.9088	2.7445	2.5693	2.3503	2.1313	1.9123	1.6933	1.4743	1.2553	1.0728	0.8903	0.7261	0.5801	0.4706	0.3793	0.288	0.197	0.1238	0.051
Habiganj																				
Daily Production, mmcfd		250	250	250	250	200	200	100	100	50	50	50	50	50	50	50	50	50	50	20
Yearly Production, tcf		0.0913	0.0913	0.09125	0.0913	0.073	0.073	0.0365	0.0365	0.01825	0.0183	0.0183	0.0183	0.0183	0.0183	0.0183	0.018	0.018	0.0183	0.007
Remaining Reserve, tcf	0.8363	0.7451	0.6538	0.56255	0.4713	0.3983	0.3253	0.2888	0.2523	0.23405	0.2158	0.1976	0.1793	0.1611	0.1428	0.1246	0.106	0.088	0.0698	0.063
Bakhrabad																				
Daily Production, mmcfd		30	30	30	50	50	80	80	80	80	80	80	80	70	70	50	50	50	50	20
Yearly Production, tcf		0.011	0.011	0.01095	0.0183	0.01825	0.0292	0.0292	0.0292	0.0292	0.0292	0.0292	0.0292	0.0256	0.0256	0.0183	0.018	0.018	0.0183	0.007
Remaining Reserve, tcf	0.514	0.5031	0.4921	0.48115	0.4629	0.44465	0.4155	0.38625	0.3571	0.32785	0.2987	0.2695	0.2403	0.2147	0.1892	0.1709	0.153	0.134	0.1162	0.109
Meghna																				
Daily Production, mmcfd		10	10	10	10	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0
Yearly Production, tcf		0.0037	0.0037	0.00365	0.0037	0.00365	0.0037	0.00365	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Reserve, tcf	0.0312	0.0276	0.0239	0.02025	0.0166	0.01295	0.0093	0.00565	0.0057	0.00565	0.0057	0.0057	0.0057	0.0057	0.0057	0.0057	0.006	0.006	0.0057	0.006
Narsingdi																				
Daily Production, mmcfd		30	30	30	30	30	30	30	30	20	20	20	20	20	20	15	15	10	0	0
Yearly Production, tcf		0.011	0.011	0.01095	0.011	0.01095	0.011	0.01095	0.011	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0055	0.005	0.004	0	0
Remaining Reserve, tcf	0.1547	0.1438	0.1328	0.12185	0.1109	0.09995	0.089	0.07805	0.0671	0.0598	0.0525	0.0452	0.0379	0.0306	0.0233	0.0178	0.012	0.009	0.0087	0.009
Sylhet																				
Daily Production, mmcfd		10	10	10	25	25	25	25	25	25	25	20	20	20	20	15	10	10	0	0
Yearly Production, tcf		0.0037	0.0037	0.00365	0.0091	0.009125	0.0091	0.00913	0.0091	0.00913	0.0091	0.0073	0.0073	0.0073	0.0073	0.0055	0.004	0.004	0	0
Remaining Reserve, tcf	0.1255	0.1219	0.1182	0.11455	0.1054	0.0963	0.0872	0.07805	0.0689	0.0598	0.0507	0.0434	0.0361	0.0288	0.0215	0.016	0.012	0.009	0.0087	0.009
Beanibazar																				
Daily Production, mmcfd		14	14	14	14	14	14	14	14	14	14	14	14	10	10	10	0	0	0	0
Yearly Production, tcf		0.0051	0.0051	0.00511	0.0051	0.00511	0.0051	0.00511	0.0051	0.00511	0.0051	0.0051	0.0051	0.0037	0.0037	0.0037	0	0	0	0
Remaining Reserve, tcf	0.136	0.1309	0.1258	0.12067	0.1156	0.11045	0.1053	0.10023	0.0951	0.09001	0.0849	0.0798	0.0747	0.071	0.0674	0.0637	0.064	0.064	0.0637	0.064
Rashidpur																				
Daily Production, mmcfd		50	70	70	100	150	200	200	250	250	250	250	250	250	250	250	200	200	200	200
Yearly Production, tcf		0.0183	0.0256	0.02555	0.0365	0.05475	0.073	0.073	0.0913	0.09125	0.0913	0.0913	0.0913	0.0913	0.0913	0.0913	0.073	0.073	0.073	0.073
Remaining Reserve, tcf	1.949	1.9308	1.9052	1.87965	1.8432	1.7884	1.7154	1.6424	1.5512	1.4599	1.3687	1.2774	1.1862	1.0949	1.00	0.9124	0.839	0.766	0.6934	0.62
Kailashtilla																				
Daily Production, mmcfd		100	100	100	150	150	200	200	250	250	250	250	250	250	250	250	200	200	200	200
Yearly Production, tcf		0.0365	0.0365	0.0365	0.0548	0.05475	0.073	0.073	0.0913	0.09125	0.0913	0.0913	0.0913	0.0913	0.0913	0.0913	0.073	0.073	0.073	0.073
Remaining Reserve, tcf	2.2229	2.1864	2.1499	2.1134	2.0587	2.0039	1.9309	1.8579	1.7667	1.6754	1.5842	1.4929	1.4017	1.3104	1.22	1.1279	1.055	0.982	0.9089	0.836

Field wise predicted production

Saldanadi

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Daily Production, mmcfd		20	25	20	18	15	14	10	9	7	0	0	0	0	0	0	0	0	0	0
Yearly Production, tcf		0.0073	0.0091	0.0073	0.0066	0.005475	0.0051	0.00365	0.0033	0.00256	0	0	0	0	0	0	0	0	0	0
Remaining Reserve, tcf	0.2149	0.2076	0.1985	0.19118	0.1846	0.17913	0.174	0.17037	0.1671	0.16453	0.1645	0.1645	0.1645	0.1645	0.16	0.1645	0.165	0.165	0.1645	0.165

Fenchuganj

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Daily Production, mmcfd		35	50	60	60	55	50	45	40	40	35	35	25	20	0	0	0	0	0	0
Yearly Production, tcf		0.0128	0.0183	0.0219	0.0219	0.020075	0.0183	0.01643	0.0146	0.0146	0.0128	0.0128	0.0091	0.0073	0	0	0	0	0	0
Remaining Reserve, tcf	0.30	0.2902	0.272	0.25008	0.2282	0.2081	0.1899	0.17343	0.1588	0.14423	0.1315	0.1187	0.1096	0.1023	0.10	0.1023	0.102	0.102	0.1023	0.102

Shahbazpur

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Daily Production, mmcfd		8	50	50	60	60	60	70	70	70	60	55	50	40	30	0	0	0	0	0
Yearly Production, tcf		0.0029	0.0183	0.01825	0.0219	0.0219	0.0219	0.02555	0.0256	0.02555	0.0219	0.0201	0.0183	0.0146	0.011	0	0	0	0	0
Remaining Reserve, tcf	0.27	0.2671	0.2488	0.23058	0.2087	0.18678	0.1649	0.13933	0.1138	0.08823	0.0663	0.0463	0.028	0.0134	0.002	0.002	0.002	0.002	0.0025	0.002

Semutang

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Daily Production, mmcfd		12	10	20	25	25	25	30	30	30	25	25	20	15	15	12	12	10	10	10
Yearly Production, tcf		0.0044	0.0037	0.0073	0.0091	0.009125	0.0091	0.01095	0.011	0.01095	0.0091	0.0091	0.0073	0.0055	0.0055	0.0044	0.004	0.004	0.0037	0.004
Remaining Reserve, tcf	0.3173	0.3129	0.3093	0.30197	0.2928	0.28372	0.2746	0.26365	0.2527	0.24175	0.2326	0.2235	0.2162	0.2107	0.205	0.201	0.196	0.193	0.1892	0.186

Jalalabad

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Daily Production, mmcfd		180	180	230	230	200	200	100	0	0	0	0	0	0	0	0	0	0	0	0
Yearly Production, tcf		0.0657	0.0657	0.08395	0.084	0.073	0.073	0.0365	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Reserve, tcf	0.565	0.4993	0.4336	0.34965	0.2657	0.1927	0.1197	0.0832	0.0832	0.0832	0.0832	0.0832	0.0832	0.0832	0.083	0.083	0.083	0.083	0.0832	0.083

Maulavibazar

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Daily Production, mmcfd		40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	0	0	0
Yearly Production, tcf		0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.015	0	0	0
Remaining Reserve, tcf	0.249	0.2344	0.2198	0.2052	0.1906	0.176	0.1614	0.1468	0.1322	0.1176	0.103	0.0884	0.0738	0.0592	0.045	0.030	0.015	0.015	0.0154	0.015

Bibiana

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Daily Production, mmcfd		760	760	1000	1000	1000	1200	1200	1200	1200	1200	800	600	400	200	150	100	100	100	50
Yearly Production, tcf		0.2774	0.2774	0.365	0.365	0.365	0.438	0.438	0.438	0.438	0.438	0.292	0.219	0.146	0.073	0.0548	0.037	0.037	0.0365	0.018
Remaining Reserve, tcf	4.8998	4.6224	4.345	3.98	3.615	3.25	2.812	2.374	1.936	1.498	1.06	0.768	0.549	0.403	0.330	0.275	0.239	0.202	0.1657	0.147

Sangu

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Daily Production, mmcfd		9	8	8	8	8	8	8	8	0	0	0	0	0	0	0	0	0	0	0
Yearly Production, tcf		0.0033	0.0029	0.00292	0.0029	0.00292	0.0029	0.00292	0.0029	0	0	0	0	0	0	0	0	0	0	0
Remaining Reserve, tcf	0.1	0.0967	0.0938	0.09088	0.088	0.085035	0.0821	0.0792	0.0763	0.07628	0.0763	0.0763	0.0763	0.0763	0.076	0.076	0.076	0.076	0.0763	0.076

Bangura

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Daily Production, mmcfd		103	100	100	100	100	100	100	70	50	40	30	20	10	10	0	0	0	0	0
Yearly Production, tcf		0.0376	0.0365	0.0365	0.0365	0.0365	0.0365	0.0365	0.0256	0.01825	0.0146	0.011	0.0073	0.0037	0.0037	0	0	0	0	0
Remaining Reserve, tcf	0.364	0.3264	0.2899	0.25341	0.2169	0.180405	0.1439	0.10741	0.0819	0.06361	0.049	0.0381	0.0308	0.0271	0.023	0.023	0.023	0.023	0.0235	0.023

Source: Annexure 3, FINAL REPORT "Consulting Services for Preparation of Implementation and Financing Plan for Gas Sector Development」 (prepared in December 2012)

In Table 10, the production enhancement plan for the existing gas fields is comparatively recent information that was reported in December 2012; the contents of the plan were approved by Petrobangla with certain corrections. Hence the investment costs were estimated on the assumption that the existing gas production facilities would be expanded in accordance with the plan.

In Annexure 3 of the said World Bank report, the field wise daily production rate and timing of the field expansion has been predicted up until 2030. Thus "the peak production rate (a)" and the peak production year may be for each gas field. Data for the field wise "current plant capacity (b)" is available in the Petrobangla Annual Report 2012. (Please refer to Appendix 3 for this.)

The value of (a) and (b) are listed in Table 10.

Table 10 Predicted Peak Production Rate versus Current Plant Capacity

Serial No.	Gas Field	Operating Company	Predicted Peak Production Rate (a) [MMscfd]	Current Plant Capacity (b) [MMscfd]	Additional Capacity Required (a – b) [MMscfd]	Peak Production Year [MMscfd] (See Note *2)
1	Titas	BGFCL	600	452	148	2015
2	Habiganj	Ditto	250	240	0 (See Note *1)	2012
3	Bakhrabad	Ditto	80	33	47	2017
4	Kailashtila	Ditto	250	80	170	2019
5	Rashidpur	Ditto	250	49	201	2019
6	Sylhet	SGFL	25	11	14	2015
7	Meghna	Ditto	10	11	0 (See Note *1)	2012
8	Narshingdi	Ditto	30	30	0	2012
9	Beanibazar	Ditto	14	14	0	2012
10	Fenchuganj	Ditto	60	40	20	2014
11	Saldanadi	BAPEX	25	20	0 (See Note *1)	2013
12	Shahbazpur	Ditto	70	30	40	2018
13	Semutang	Ditto	30	12	18	2018
14	Sangu	SANTOS	9	9	0	2012
15	Jalalabad	CHEVRON	230	230	0	2014
16	Moulavibazar	Ditto	40	60	0	2012
17	Bibiyana	Ditto	1200	770	430	2017
18	Bangura	TULLOW	103	100	0 (See Note *1)	2012

Source: information based on Petrobangla Annual Report 2012 and FINAL REPORT "Consulting Services for Preparation of Implementation and Financing Plan for Gas Sector Development" reported in December 2012

Note:
*1: Since the predicted peak production rate (a) is almost same as the current plant capacity (b), further investment for the gas field is not be considered.
*2: The peak production year in each gas field is scheduled as in 2012.

As shown inTable 10, if gas at “predicted peak production rate (a)” is produced in future in excess of the “current plant capacity (b)”, the construction of new facility will be required to treat the excess volume of gas. Since the new facility must be able to treat the “additional capacity required (a minus b)” in the above table, this costs estimation is carried out based on the additional capacity required for the respective nine gas fields – Titas, Bakhrabad, Sylhet, Kailashtila, Rashidpur, Fenchuganj, Shahbazpur, Semutang, and Bibiyana). As for other gas fields, since the “predicted peak production rate (a)” is smaller than the “current plant capacity (b)” or almost same as (b), further investment for the gas field is not be considered.

For the Titas gas field, a new production facility having a capacity of 80 MMscfd will be constructed in the near future as mentioned in Paragraph 2.1.2 (1). It can be considered that the 148 MMscfd of “additional capacity required (a minus b)” in Table 10 includes the planned capacity of 80 MMscfd because the “predicted peak production rate (a)” of 600 MMscfd was forecasted before 2012. Accordingly, his means that the gas development plan for producing a part of the 148 MMscfd has now moved to its implementation stage as a construction project. Therefore, the construction costs of the new facility in the Titas gas field were estimated at 148 MMscfd.

Construction cost of the future gas production facilities which will be installed in each gas field is estimated as described below.

In Table 11, there is great variation in the “additional capacity required (a minus b)” between minimum 14 MMscfd and maximum 430 MMscfd. Typically, in plant construction the “six-tenths factor rule”, as a simplified calculation method, is often utilized for estimating approximate construction costs. In term of the rule, there is an empirical relationship between the cost and the size of a manufacturing facility; as the size increases, cost the increases by an exponent of six-tenths, that is cost1/cost2 = (size1/size2) 0.6.

However, in this study, a typical gas production facility with specific plant capacity of 20, 40, 150, 200 and 400 MMscfd was estimated using OGM and in-house cost data Also, the construction costs of the future gas production facilities stated above were estimated based on the costs estimation results for a typical gas production facility.

At first, construction cost of the plant capacity; 20, 40, 150, 200 and 400 MMscfd, was estimated using OGM. In the case of applying the input data in Table 21 (as attached on the last page of this chapter) the construction costs were estimated as listed in Table 11.

Table 11 OGM Output for Construction Costs of Gas Production Facility (20, 40, 150, 200 and 400 MMscfd)

Cost Item	Plant Capacity (MMscfd)				
	20	40	150	200	400
Procurement & Fabrication, Installation	**14,003.2**	**15,769.4**	**24,244.8**	**27,872.2**	**45,424.6**
Separation System	1,221.3	1,639.0	4,349.5	6,181.9	12,935.2
Production Manifold	464.3	738.3	1,505.1	2,268.7	5,143.8
Separation	757.0	900.7	2,844.4	3,913.2	7,791.4
Gas Dehydration System	1,655.1	2,506.3	5,989.6	6,982.3	13,717.5
GasDehydration1	1,655.1	2,506.3	5,989.6	6,982.3	13,717.5
Condensate Recovery & Storage System	3,256.3	3,488.5	4,504.9	4,881.8	6,300.2
Crude Metering & Export	137.6	132.2	123.3	123.3	121.5
Tankage	3,118.7	3,356.3	4,381.6	4,758.5	6,178.7
Water Treatment System	550.1	581.6	784.0	857.0	1,158.4
Produced Water	151.1	155.0	190.5	195.3	286.7
Drain Effluent Water	399.0	426.6	593.5	661.7	871.7
Utility & Support Systems, Others	7,320.4	7,554.0	8,616.8	8,969.2	11,313.3
GasCompression1	356.2	376.4	387.0	391.7	410.2
Relief	217.3	261.3	577.8	649.2	709.3
Flare	160.0	175.9	263.1	302.8	461.4
Power Generation	1,100.8	1,100.8	1,100.8	1,100.8	1,100.8
Power Distribution	1,273.3	1,330.2	1,283.7	1,303.4	1,383.4
Heating Medium	0.0	0.0	196.3	205.0	309.4
Instrument Air	295.8	298.3	312.2	330.6	363.8
Utility Air	70.4	73.3	89.2	95.0	109.6
Fuel Gas	97.8	99.8	128.0	131.8	141.5
Diesel Fuel	213.9	217.0	233.3	239.2	254.2
Fire Protection	729.9	741.7	841.0	884.8	982.5
Control Center	1,472.5	1,472.5	1,472.5	1,472.5	2,667.8
Buildings	576.6	583.6	583.0	584.3	602.3
Site Preparation	100.0	107.7	154.7	173.5	227.4
Site Mgt	655.9	715.5	994.2	1,104.6	1,589.7
Infrastructure & Other Cost	**2,735.5**	**2,762.0**	**4,389.2**	**4,443.6**	**7,206.8**
Infrastructure	2,500.0	2,500.0	4,000.0	4,000.0	6,500.0
Construction Camp	1,000.0	1,000.0	2,000.0	2,000.0	4,000.0
Operations Camp	1,500.0	1,500.0	2,000.0	2,000.0	2,500.0
Other Cost	235.5	262.0	389.2	443.6	706.8
Certification	70.0	78.8	121.2	139.4	227.1
Insurance	140.0	157.7	242.5	278.7	454.2
Land	25.5	25.5	25.5	25.5	25.5
Engineering & Project Management	**4,901.1**	**5,519.2**	**8,485.7**	**9,755.3**	**15,898.6**
Engineering	2,100.5	2,365.4	3,636.7	4,180.8	6,813.7
Project Management	2,800.6	3,153.8	4,849.0	5,574.5	9,084.9
CAPEX	**21,639.8**	**24,050.6**	**37,119.7**	**42,071.1**	**68,530.0**

Source: JICA Survey Team

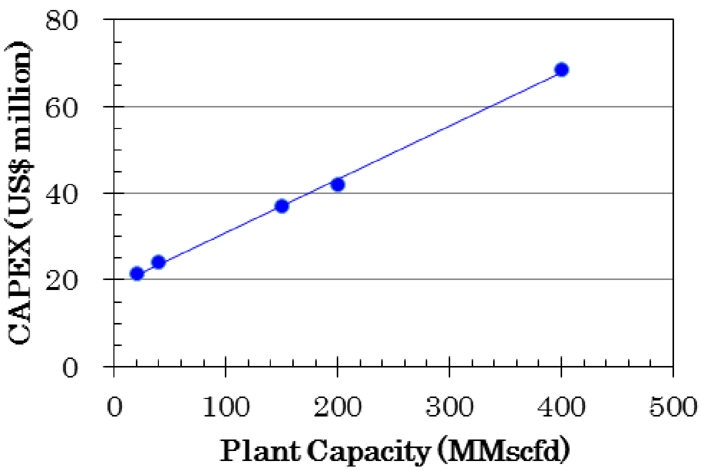
The OGM output in Table 11 may also be arranged by the principal cost items as listed in Table 12.

Table 12 Construction Costs of Gas Production Facility (20, 40, 150, 200 and 400 MMscfd)

Plant Capacity (MMscfd)	Total Construction Cost (million USD)	Cost Breakdown (mill. USD)			
		Direct Cost		Indirect Cost	
		Procurement and installation	Other field construction including infrastructures	Engineering	Project management
20	21.6	14.0	2.7	2.1	2.8
40	24.1	15.8	2.8	2.4	3.1
150	37.1	24.2	4.4	3.6	4.9
200	42.1	27.9	4.4	4.2	5.6
400	68.5	45.4	7.2	6.8	9.1

Source: JICA Survey Team

According to Table 12, the OGM costs estimation results for the typical gas production facilities can be plotted as shown in Figure 8.



Source: JICA Survey Team

Figure 8 Construction Cost of Gas Production Facility (20, 40, 150, 200 and 400 MMscfd)

As shown in Figure 8, it can be said that as the plant capacity increases CAPEX is also likely to increase by a certain percentage. As stated above, construction costs of the future gas production facilities can be predicted. The cost of the nine gas production facilities with the “additional capacity required (a minus b)” in Table 13 may be estimated.

Table 13 Construction Costs of the Gas Production Facility for Already-Discoverd Domestic Natural Gas (Predicted Cost based on OGM output)

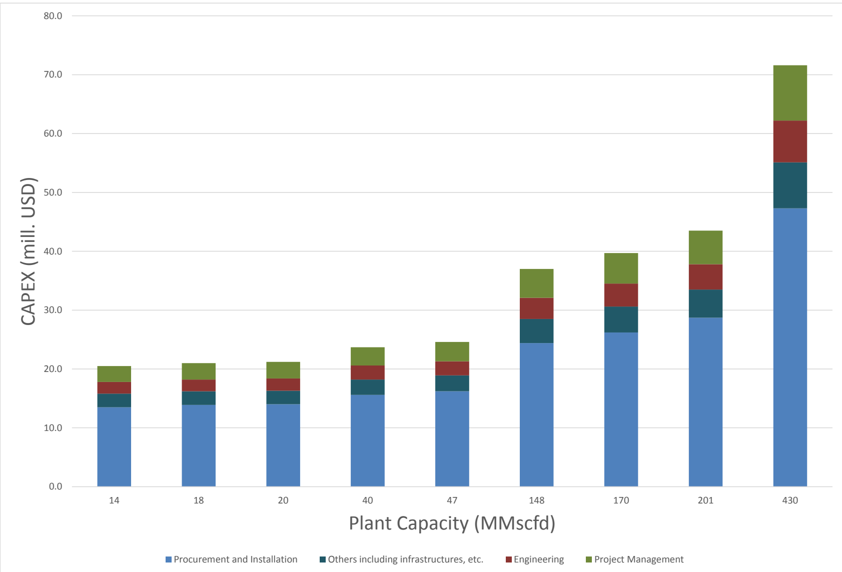
Field Name	Sylhet	Semutung	Fenchuganj	Shahbazpur	Bakhrabad	Titas	Kailashtila	Rashidpur	Bibiyana
Gas Production Rate (MMscfd)	14	18	20	40	47	148	170	201	430
Procurement & Fabrication, Installation	**13,533.4**	**13,857.6**	**14,019.7**	**15,640.7**	**16,208.0**	**24,393.9**	**26,176.9**	**28,689.4**	**47,249.4**
Separation System	1,180.3	1,208.6	1,222.7	1,625.6	1,684.5	4,376.2	4,696.1	6,363.2	13,454.9
Production Manifold	448.7	459.4	464.8	732.2	758.8	1,514.4	1,625.1	2,335.2	5,350.5
Separation	731.6	749.2	757.9	893.4	925.8	2,861.9	3,071.1	4,028.0	8,104.4
Gas Dehydration System	1,599.6	1,637.9	1,657.1	2,485.8	2,576.0	6,026.4	6,466.9	7,187.0	14,268.6
GasDehydration1	1,599.6	1,637.9	1,657.1	2,485.8	2,576.0	6,026.4	6,466.9	7,187.0	14,268.6
Condensate Recovery & Storage System	3,147.0	3,222.4	3,260.1	3,460.0	3,585.5	4,532.6	4,863.9	5,024.9	6,553.3
Crude Metering & Export	132.9	136.1	137.7	131.1	135.9	124.0	133.1	126.9	126.4
Tankage	3,014.1	3,086.3	3,122.4	3,328.9	3,449.6	4,408.6	4,730.8	4,898.0	6,426.9
Water Treatment System	531.6	544.4	550.7	576.8	597.8	788.8	846.5	882.1	1,205.0
Produced Water	146.0	149.5	151.3	153.7	159.3	191.6	205.6	201.0	298.3
Drain Effluent Water	385.6	394.8	399.4	423.1	438.4	597.2	640.9	681.1	906.7
Utility & Support Systems, Others	7,074.9	7,244.3	7,329.1	7,492.4	7,764.2	8,669.8	9,303.5	9,232.2	11,767.7
GasCompression1	344.3	352.5	356.7	373.3	386.9	389.3	417.8	403.2	426.7
Relief	210.0	215.1	217.6	259.2	268.6	581.3	623.8	668.2	737.8
Flare	154.6	158.3	160.2	174.4	180.8	264.7	284.1	311.6	479.9
Power Generation	1,063.9	1,089.4	1,102.1	1,091.8	1,131.4	1,107.6	1,188.5	1,133.1	1,145.0
Power Distribution	1,230.6	1,260.1	1,274.8	1,319.4	1,367.3	1,291.7	1,386.1	1,341.7	1,439.0
Heating Medium	0.0	0.0	0.0	0.0	0.0	197.5	211.9	211.0	321.8
Instrument Air	285.8	292.7	296.1	295.9	306.6	314.1	337.0	340.3	378.4
Utility Air	68.0	69.6	70.4	72.7	75.4	89.8	96.3	97.7	114.0
Fuel Gas	94.5	96.7	97.9	98.9	102.5	128.7	138.1	135.6	147.2
Diesel Fuel	206.8	211.7	214.2	215.2	223.0	234.7	251.9	246.2	264.4
Fire Protection	705.4	722.3	730.7	735.7	762.3	846.2	908.0	910.7	1,021.9
Control Center	1,423.2	1,457.3	1,474.4	1,460.6	1,513.6	1,481.7	1,590.0	1,515.8	2,775.1
Buildings	557.2	570.6	577.3	578.8	599.8	586.6	629.5	601.4	626.4
Site Preparation	96.6	99.0	100.1	106.8	110.7	155.7	167.0	178.6	236.5
Site Mgt	633.9	649.1	656.7	709.7	735.4	1,000.3	1,073.4	1,137.1	1,653.6
Infrastructure & Other Cost	**2,255.6**	**2,309.6**	**2,336.6**	**2,606.8**	**2,701.3**	**4,065.6**	**4,362.8**	**4,781.6**	**7,874.9**
Infrastructure	2,061.4	2,110.7	2,135.4	2,359.5	2,445.1	3,705.2	3,976.0	4,304.2	7,102.5
Construction Camp	824.5	844.3	854.2	943.8	978.0	1,852.6	1,988.0	2,152.1	4,370.8
Operations Camp	1,236.8	1,266.4	1,281.3	1,415.7	1,467.0	1,852.6	1,988.0	2,152.1	2,731.7
Other Cost	194.2	198.9	201.2	247.3	256.3	360.5	386.8	477.3	772.4
Certification	57.7	59.1	59.8	74.4	77.1	112.3	120.5	150.0	248.2
Insurance	115.5	118.2	119.6	148.8	154.2	224.6	241.0	299.9	496.4
Land	21.0	21.5	21.8	24.1	24.9	23.6	25.3	27.4	27.9
Engineering & Project Management	**4,716.2**	**4,829.2**	**4,885.7**	**5,450.5**	**5,648.2**	**8,500.9**	**9,122.3**	**9,997.8**	**16,465.7**
Engineering	2,021.2	2,069.6	2,093.9	2,335.9	2,420.7	3,643.2	3,909.5	4,284.8	7,056.7
Project Management	2,695.0	2,759.5	2,791.8	3,114.6	3,227.6	4,857.7	5,212.7	5,713.0	9,409.0
CAPEX	**20,505.2**	**20,996.4**	**21,242.0**	**23,698.0**	**24,557.6**	**36,960.4**	**39,662.0**	**43,468.8**	**71,590.0**

Then, the predicted costs in Table 13 can be arranged by the principal cost items as shown in Table 14.

Table 14 Construction Costs of the Gas Production Facility for Already-Discovered Domestic Natural Gas

Serial No.	Gas Field	Additional Capacity Required (MMscfd)	Total Construction Cost (mill. USD)	Cost Breakdown (mill. USD)			
				Direct Cost		Indirect Cost	
				Procurement and installation	Other field construction including infrastructures	Engineering	Project management
1	Titas	148	37.0	24.4	4.1	3.6	4.9
3	Bakhrabad	47	24.6	16.2	2.7	2.4	3.3
4	Kailashtila	170	39.7	26.2	4.4	3.9	5.2
5	Rashidpur	201	43.5	28.7	4.8	4.3	5.7
6	Sylhet	14	20.5	13.5	2.3	2.0	2.7
10	Fenchuganj	20	21.2	14.0	2.3	2.1	2.8
12	Shahbazpur	40	23.7	15.6	2.6	2.4	3.1
13	Semutang	18	21.0	13.9	2.3	2.0	2.8
17	Bibiyana	430	71.6	47.3	7.8	7.1	9.4
Total		1088	302.8	199.8	33.3	29.8	39.9

Source: JICA Survey Team



Source: JICA Survey Team

Figure 9 Construction Costs Breakdown of the Gas Production Facility for Already-Discovered Domestic Natural Gas

As shown in Figure 9, the construction cost of gas production facility varies according to the plant capacity. Even if the plant capacity is small, facility configuration required for the proposed gas treatment is same, and only the scale of the facility is reduced in connection with gas treatment volume. Therefore, approximately minimum 20 million USD is necessary even for Sylhet gas field case, which has the smallest facility scale (14 MMscfd) of the nine gas fields. The plant capacity of 14 MMscfd is classified in the minimum plant scale in regular gas development projects, and it is considered that the approximately 20 million USD is “base cost” of gas production facilities that are planned to be constructed in each gas field. Accordingly, the facility construction cost in each gas field may be estimated by adding this “base cost” and facility costs escalated by the increase of plant capacity.

The construction cost estimated in Table 14 includes not only the five main systems stated earlier, but also the related facilities such as: power generation and distribution systems, fuel gas systems, tankage systems, drain/effluent water systems, relief/flare systems, fire protection systems, instrument air systems, and buildings.

For the above costs estimation, the validity of the finally estimated costs for the future gas production facilities in Table 14 was checked below in comparison with past construction data. As stated above, since all the costs in these nine gas fields were predicted based on CAPEX increasing (indicated inFigure 8, the validity was checked in relation to the original costs shown in in Figure 8.

According to the past construction data, the total construction costs of gas production facilities having 45 MMscfd capacity was estimated at approximately 22.1 million USD whne applying the current exchange rate (1 USD = 117 YEN). In response, CAPEX of the facility with the same plant capacity can be considered at around 24.3 million USD in Figure 8. Thus it can be said that CAPEX in Figure 8 is almost same as that of the past construction experience, and that CAPEX inTable 14 also has sufficient validity in terms of its accuracy.

(b) Gas transmission pipelines from the gas production facilities for already-discovered domestic natural gas

It is proposed that nine gas pipelines shall be constructed to transfer gas treated in the future gas production facilities that are to be built in the gas fields shown in Table 15, and that this gas will be sent to the existing pipeline network for future incremental gas supply. Each pipeline will be tied-in to the nearest valve station and/or city gate station on the existing pipeline network.

Based on the pipeline data described in the paragraph 3(3), the unit costs of 0.5 million USD/km are applied, the total construction costs for the above pipelines is estimated at approximately 9 million USD. Please refer to Table 15.

Table 15 Construction Cost of the Gas Transmission Pipelines from the Gas Production Facilities for Domestic Natural Gas which has Already Been Discovered

Serial No.	Starting point	Length (km)	Unit cost (mill. USD/km)	Total cost (mill. USD)
1	Titas gas field	2	0.5	1.0
3	Bakhrabad gas field	2	0.5	1.0
4	Kailashtila gas field	2	0.5	1.0
5	Rashidpur gas field	2	0.5	1.0
6	Sylhet gas field	2	0.5	1.0
10	Fenchuganj gas field	2	0.5	1.0
12	Shahbazpur gas field	2	0.5	1.0
13	Semutang gas field	2	0.5	1.0
17	Bibiyana gas field	2	0.5	1.0
	Total	18	-	9.0

Source: JICA Survey Team

(c) Gas distribution pipelines for future power plants

It is proposed that gas distribution pipelines will be constructed to supply gas for future power plants which will be newly required based on an examination of the domestic power balance between supply and demand. Each pipeline it expected to be branched at the nearest valve station and/or city gate station on the existing pipeline network and tied-in to the respective appropriate delivery points in the future power plants.

Based on the pipeline data described in Paragraph 3 (4) if the unit costs of 0.5 million USD/km are applied, the construction costs for the 12 inch x 10 km pipeline is estimated at 5 million . Please refer to Table 16.

Table 16 Construction Cost of Gas Distribution Pipeline

Delivery point	Length (km)	Unit cost (mill. USD/km)	Total cost (mill. USD)
xxx power plant	10	0.5	5.0
Total	10	-	5.0

Source: JICA Survey Team

As a result, the estimated investment costs for the the future gas development is summarized as shown in Table 17.

Table 17 Investment Cost for Gas Field Development

Item			Predicted Peak Production Rate (a) [MMscfd]	Current Plant Capacity (b) [MMscfd]	Additional Capacity Required (a) – (b) [MMscfd]	Completion of New Facility Construction [Year]	Investment Cost											Total [mill. USD]
							Drilling				Facility construction			Pipeline				
							Quantity	Specification	Unit cost [mill. USD/well]	Subtotal [mill. USD]	Quantity [MMscfd]	Specification	Subtotal [mill. USD]	Quantity [km]	Specification	Unit cost [mill. USD/km]	Subtotal [mill. USD]	
Serial No.	**1.**	**Construction cost of gas production facilities for domestic gas which have already been discovered**																
1		Titas	600	452	148	2015				0	148	Wellhead press./temp.: 1,700psig/142 deg.F	37.0	2	API5L Gr.X60 w/3LPE coating, 12" x 0.312"wt	0.5	1.0	38.0
3		Bakhrabad	80	33	47	2017				0	47	Ditto	24.6	2	Ditto	0.5	1.0	25.6
4		Kailashtila	250	80	170	2019				0	170	Ditto	39.7	2	Ditto	0.5	1.0	40.7
5		Rashidpur	250	49	201	2019				0	201	Ditto	43.5	2	Ditto	0.5	1.0	44.5
6		Sylhet	25	11	14	2015				0	14	Ditto	20.5	2	Ditto	0.5	1.0	21.5
10		Fenchuganj	60	40	20	2014				0	20	Ditto	21.2	2	Ditto	0.5	1.0	22.2
12		Shahbazpur	70	30	40	2018				0	40	Ditto	23.7	2	Ditto	0.5	1.0	24.7
13		Semutung	30	12	18	2018				0	18	Ditto	21.0	2	Ditto	0.5	1.0	22.0
17		Bibiyana	1200	770	430	2017				0	430	Ditto	71.6	2	Ditto	0.5	1.0	72.6
		Subtotal (1)					0.0			0.0	1088	-	302.8	18	-	-	9.0	311.8
	2.	**Construction cost of gas production facilities for domestic gas which have not been discovered**																
			-	-	-					0							0	0
			-	-	-					0							0	0
		Subtotal (2)					0.0			0.0		-	0.0	0	-	-	0.0	0.0
	3.	**Gas distribution pipelines for future power plants**																
			-	-	-		-	-	-		-	-		10	API5L Gr.X60 w/3LPE coating, 12" x 0.312"wt	0.5	5.0	5
			-	-	-		-	-	-		-	-					0	0
		Subtotal (3)					-				-	-		10	-	-	5.0	5.0
		Total					-	-	-	0.0	-	-	302.8	-	-	-	14.0	316.8

Source: JICA Survey Team

Table 18 Investment Plan for Gas Field Development

Item			Predicted Max. Production Rate [MMscfd]	Current Plant Capacity [MMscfd]	Additional Capacity Required [MMscfd]	Completion of New Facility Construction	Investment Cost [mill. USD]																												
							Fisical Year																												
							2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	Total Cost
Serial No.	**1.**	**Gas production facilities for domestic gas which have already been discovered**																																	
1		Titas	600	452	148	2015		38.0																											38.0
3		Bakhrabad	80	33	47	2017				25.6																									25.6
4		Kailashtila	250	80	170	2019						40.7																							40.7
5		Rashidpur	250	49	201	2019						44.5																							44.5
6		Sylhet	25	11	14	2015		21.5																											21.5
10		Fenchuganj	60	40	20	2014	22.2																												22.2
12		Shahbazpur	70	30	40	2018					24.7																								24.7
13		Semutung	30	12	18	2018					22.0																								22.0
17		Bibiyana	1200	770	430	2017				72.6																									72.6
		Subtotal (1)					22.2	59.5	0.0	98.2	46.7	85.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	311.8
	2.	**Gas production facilities for domestic gas which have not been discovered**																																	
			-	-	-																														0.0
			-	-	-																														0.0
		Subtotal (2)					0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	3.	**Gas distribution pipelines for future power plants**																																	
			-	-	-																														0.0
			-	-	-																														0.0
		Subtotal (3)					0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Total					22.2	59.5	0.0	98.2	46.7	85.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	311.8

Source: JICA Survey Team

(3) Import Gas Development Cost

(a) LNG Receiving terminal

LNG Receiving Onshore terminal assumes 2x 200,000 M3 LNG tanks at the initial phase, with jetty and re-gasification facilities. Total estimated cost is USD 500 million.

(b) LNG transmission pipeline

Based on the pipeline data described in Paragraph 3 (5), if the onshore unit costs of 1.5 million USD/km and offshore unit costs of 1.1 million USD are applied, the total construction cost for the pipeline is estimated at approximately 115.1 million USD. Refer to Table 19.

Table 19 Construction Cost of LNG Transmission Pipeline

	Length (km)	Unit cost (mill. USD/km)	Total cost (mill. USD)
Offshore portion	10	1.5	15.0
Onshore portion	91	1.1	100.1
Total	101	-	115.1

Source: JICA Survey Team

5. Total Investment Cost

Some area is not covered by the Software and these are assumed based on the following figures:

1) Significant labor works and time/cost will be required to identify oil and gas deposit in the green field in general, and cost for these area will also differ from country to country and also to the local conditions. In case of Bangladesh, it is assumed that potential of gas borne area is identified already, and actual cost information used for particular field is used as a benchmark cost, i.e., 2D Seismic Survey: USD 3 million (80 L Km), 3D Seismic Survey: USD 28 million (400 km2)

2) Drilling cost assumes four development wells and used as a production well at later stage. Based on the recent experience by BGFCL, total of 4 wells cost USD 60 million.

3) Assuming that production rate from future onshore wells is 500 MMSCFD, cost for production facilities will be assumed USD 90 million as per SIMENS Cost Estimate Software.

Table 20 Total Investment Costs for Gas Development

	Item	Cost [mill. USD]
A	**Domestic Gas Development Costs for the Remaining Reserves 2P**	
A1	Field Exploration Costs	*30*
A2	Field Development Costs	
A2.1	Drilling Costs	*60*
A2.2	Facility Construction Costs	
(1)	Facility construction costs for domestic gas which has already been discovered	302.8
(2)	Gas transmission pipelines from gas production facilities for domestic gas which has already been discovered	9.0
(3)	Facility construction costs for domestic gas which has not been discovered	*90*
(4)	Gas distribution pipelines for future power plants	5.0
	Subtotal (A)	*496.8*
B	**Import Gas Development Costs**	
B1	Facility Construction Costs	
(1)	LNG Receiving Terminal	*500*
(2)	LNG transmission pipeline	115.1
	Subtotal (B)	*615.1*
C	**Contingency (= (A+B) x 50%)**	
	Subtotal (C)	*556*
	Total (A+B+C)	***1,667.8***

Source: PSMP2016

Numbers of assumptions were made to make cost estimate and the result is not necessarily close enough to predict future cost.

(1) Reinforcement cost for Existing Pipeline Infrastructure is not included in the cost estimate.

(2) Impact of LNG introduction to existing gas infrastructure and to gas field processing facilities/wellhead compressors is not included.

(3) All the cost data and assumed infrastructure models used for cost estimate to be reviewed.

Table 21 OGM Input Data for Plant Capacity (20, 40, 150, 200 and 400 MMscfd)

No.	Input Data	Gas Handling Capacity					Cost Impact	Note
		20 MMscfd	40 MMscfd	150 MMscfd	200 MMscfd	400 MMscfd		
1. Project Construction Site								
1-1	Project Construction Site	Southeast Asia	Southeast Asia	Southeast Asia	Southeast Asia	Southeast Asia	Large	The project construction site is specified from major oil/gas production areas worldwide such as the Arabian Gulf, Gulf of Mexico, North Sea, West Africa, Brazil, Venezuela, Southeast Asia, North East Asia and Malaysia. In this case, Southeast Asia was specified due to the proximity of Bangladesh. The appropriate wage rate for the specified project construction site was then applied –the same data is inputted for to all the cases regardless of the gas handling capacity
2. Required Facilities (Separator, Gas Dehydrator, Condensate Storage, Water Treatment Facilities)								
2-1	Main Facilities	Separator, Gas Dehydrator, Storage, Water Treatment	Separator, Gas Dehydrator, Storage, Water Treatment	Separator, Gas Dehydrator, Storage, Water Treatment	Separator, Gas Dehydrator, Storage, Water Treatment	Separator, Gas Dehydrator, Storage, Water Treatment	Large	The required main facilities (separator, gas dehydrator, condensate storage tank, and water treatment facility) for gas production are specified. Here, as there are no sour components (H_2S) in the gas the general facility configuration for normal gas production was selected. As the facility configuration is the same for all the cases, the same data was inputted regardless of the gas handling capacity.
3. Process Conditions								
3-1	Gas Production Rate	20 MMscfd	40 MMscfd	150 MMscfd	200 MMscfd	400 MMscfd	Large	The gas production rate is specified. In this case, gas handling capacities is specified to covers the wide range of gas production rates in Bangladesh. The facilities required to handle the specified gas production rate are designed in connection with gas handling capacity,then the costs are estimated.

No.	Input Data	Gas Handling Capacity					Cost Impact	Note
		20 MMscfd	40 MMscfd	150 MMscfd	200 MMscfd	400 MMscfd		
3-2	Composition Basis	Mole %	Mole %	Mole %	Mole %	Mole %	Large	The gas composition is specified and the gas/liquid separation calculation is conducted based on the inputted composition. The facilities required to handle the separated gas and liquid are designed, and then the costs are estimated. The typical gas composition in Bangladesh is inputted in all cases regardless of the gas handling capacity. In case that the toxic substances such as sour component (H2S) and mercury are included in the produced gas, requisite removal facilities will be required. However, as the gas produced in Bangladesh is classified in sweet gas, the installation of such facilities is not necessary. Due to the limitations of the software inputs, the heavier components of n-Hexane (and above) were inputted into all the cases as n-Hexane+
	Nitrogen (N2)	0.37	0.37	0.37	0.37	0.37		
	Carbon Dioxide (CO2)	0.31	0.31	0.31	0.31	0.31		
	Hydrogen Sulfide (H2S)	0.00	0.00	0.00	0.00	0.00		
	Methane (C1)	96.76	96.76	96.76	96.76	96.76		
	Ethane (C2)	1.80	1.80	1.80	1.80	1.80		
	Propane (C3)	0.36	0.36	0.36	0.36	0.36		
	i-Butane (iC4)	0.09	0.09	0.09	0.09	0.09		
	n-Butane (nC4)	0.05	0.05	0.05	0.05	0.05		
	i-Pentane (iC5)	0.02	0.02	0.02	0.02	0.02		
	n-Pentane (nC5)	0.02	0.02	0.02	0.02	0.02		
	n-Hexane+ (nC5+)	0.22	0.22	0.22	0.22	0.22		
4. Separation System								
4-1	Flowing Wellhead Pressure	1,700 psig	1,700 psig	1,700 psig	1,700 psig	1,700 psig	Medium	The wellhead pressure is specified. The pressure level at the highest upstream part of the facilities is defined, then the wall thickness is calculated and designed based on the inputted pressure, after which the the costs are estimated. The typical wellhead pressure in Bangladesh was inputted in all the cases regardless of the gas handling capacity.The normal range of wellhead pressure at the gas fields is approximately 500 to 3,000 psig.
4-2	Flowing Wellhead Temperature	142 F	142 F	142 F	142 F	142 F	Small	The wellhead temperature is specified. Temperature level at the highest upstream part of the facilities is defined, then the wall thickness is calculated and designed based on the inputted temperature, after which the costs are estimated. The typical wellhead temperature in Bangladesh was inputted in all the cases regardless of the gas

No.	Input Data	Gas Handling Capacity					Cost Impact	Note
		20 MMscfd	40 MMscfd	150 MMscfd	200 MMscfd	400 MMscfd		
								handling capacity. The normal range of the wellhead temperature is approximately 100 to 180 F
4-3	Prod. Manifold Design Pressure	1,100 psig	1,100 psig	1,100 psig	1,100 psig	1,100 psig	Medium	The manifold design pressure is specified. The pressure level at the manifold is defined, then the wall thickness is calculated and designed based on the inputted pressure, after which the costs are estimated. The typical design pressure was inputted in all the cases regardless of the gas handling capacity.The normal range of the manifold design pressure is approximately 500 to 1,500 psig.
4-4	Prod. Separator Design Pressure	1,100 psig	1,100 psig	1,100 psig	1,100 psig	1,100 psig	Medium	The separator operating pressure is specified. The gas/liquid separation calculation is conducted based on the inputted pressure, then the separator size and wall thickness required to handle the separated gas and liquid are designed, after which the costs are estimated. The typical separator operating pressure in Bangladesh was inputted in all the cases regardless of the gas handling capacity.The normal range of the separator design pressure is approximately 500 to 1,500 psig.
4-5	Prod. Separator Operating Pressure	1,000 psig	1,000 psig	1,000 psig	1,000 psig	1,000 psig	Medium	The separator operating pressure is specified. The gas/liquid separation calculation is conducted based on the inputted pressure, then the separator size and wall thickness required to handle the separated gas and liquid are designed, after which the costs are estimated. The typical separator operating pressure in Bangladesh was inputted in all the cases regardless of the gas handling capacity.The normal range of the separator operating pressure is approximately 500 to 1,500 psig.

No.	Input Data	Gas Handling Capacity					Cost Impact	Note
		20 MMscfd	40 MMscfd	150 MMscfd	200 MMscfd	400 MMscfd		
4-6	Test Separator	Allocated	Allocated	Allocated	Allocated	Allocated	Medium	The necessity of the test separator is specified. The test separator is normally required to monitor the production rate of one well and to manage the gas reservoir. “Allocated” was selected for all the cases regardless of the gas handling capacity.
4-7	Residence Time	3 min.	3 min.	3 min.	3 min.	3 min.	Small	The oil/condensate residence time in a separator that is required to segregate water droplets from oil/condensate phase was inputted. The As the separator is designed based on the residence time, the typical residence time is inputted in all the cases regardless of the gas handling capacity.The normal value of the oil/condensate residence time is approximately 3 minutes.
4-8	Separator per Stage	1	1	1	1	1	Medium	The number of separators per stage is inputted. Normally, vessels such as separators do not have any spares. Also, as the facility configuration without any spares is a design premise in the study, the number of train was inputted as one for all the cases regardless of the gas handling capacity.
4-9	Percent Flow per Separator	100%	100%	100%	100%	100%	Medium	In relation to the “separator per stage”, the percentage of the handling flow rate per train in the total flow rate was inputted. As the facility configuration without any spares is a design premise in the study, the percent flow per separator is inputted as one hundred (100%) for all the cases regardless of the gas handling capacity.
4-10	Water Separation Option	Allocated	Allocated	Allocated	Allocated	Allocated	Medium	The necessity of water separation in a separator is specified. The produced water is normally removed from the oil/condensate and gas. “Allocated” was selected for all the cases regardless of the gas handling capacity.
5. Gas Dehydration System								

No.	Input Data	Gas Handling Capacity					Cost Impact	Note
		20 MMscfd	40 MMscfd	150 MMscfd	200 MMscfd	400 MMscfd		
5-1	Gas Dehydration Medium	Glycol	Glycol	Glycol	Glycol	Glycol	Medium	The gas dehydration medium is specified. "Glycol" is specified as a typical medium (chemical) used in gas dehydration process for all the cases regardless of the gas handling capacity.
5-2	Number of Gas Dehydration Train	1	1	1	1	1	Medium	The number of gas dehydration trains is inputted. Vessels such as gas dehydration facility normally do not have any spares, and facility configuration without any spare is a design premise in the study, therefore number of train is inputted as one for all the cases regardless of gas handling capacity.
5-3	Percent Flow per Dehydration Train	100%	100%	100%	100%	100%	Medium	In relation to the "number of gas dehydration trains", the percentage of the handling flow rate per train in the total flow rate is inputted. As the facility configuration without any spares is a design premise in the study, the percent flow per gas dehydration train is inputted as one hundred (100%) for all the cases regardless of the gas handling capacity.
5-4	Outlet Water Dew Point Temperature	32 deg.F	32 deg.F	32 deg.F	32 deg.F	32 deg.F	Medium	The outlet water dew point temperature for the gas dehydration is inputted. The water dew point temperature of 32 F corresponding to 7 lb water in 1 MMscf gas, as regulated in the standard sales gas contract in Bangladesh, is inputted for all the cases regardless of the gas handling capacity.
5-5	Dehydrator Column Design Pressure	1,100 psig	1,100 psig	1,100 psig	1,100 psig	1,100 psig	Medium	The gas dehydrator column design pressure is specified. The pressure level of the dehydrator column is defined, then the wall thickness is calculated and designed based on the inputted pressure, after which the the costs are estimated. The typical design pressure is inputtedfor all the cases regardless of the gas handling capacity.The normal range of the dehydrator column design pressure is approximately 500 to 1,500 psig.
6. Condensate Recovery and Storage System								

No.	Input Data	Gas Handling Capacity					Cost Impact	Note
		20 MMscfd	40 MMscfd	150 MMscfd	200 MMscfd	400 MMscfd		
6-1	Oil/Condensate Tank Capacity	15 kbbl	20 kbbl	40 kbbl	50 kbbl	100 kbbl	Large	The oil/condensate tank capacity is specified. The tank capacities for above 150 MMscfd cases were determined and inputted in proportion to the actual gas field development/construction record (25 kbbl for 90 MMscfd). Regardign the tank capacities for small development cases (20 and 40 MMscfd), appropriate capacities were inputted so as to reduce the shipping frequency of the condensate stored. The required oil/condensate storage facilities are designed for the inputted tank capacity, then the costs are estimated.
6-2	Oil Pump Outlet Pressure	100 psig	100 psig	100 psig	100 psig	100 psig	Medium	The oil pump outlet pressure required for shipping is specified. The Pressure level of the pump is defined, then the wall thickness is calculated and designed based on the inputted pressure, after which the costs are estimated. The typical design pressure is inputted for all the cases regardless of the gas handling capacity.
6-3	Number of Pumps	1	1	1	1	1	Medium	The number of pumps is inputted. As the facility configuration without any spares is a design premise in the study, the number of trains is inputted as one for all the cases regardless of the gas handling capacity.
6-4	Percent Flow per Pump	100%	100%	100%	100%	100%	Medium	In relation to "number of pumps", the percentage of the handling flow rate per train in the total flow rate is inputted. As the facility configuration without any spare is a design premise in the study, thepercent flow per pump is inputted in common as one hundred (100%) for all the cases regardless of the gas handling capacity.
7. Water Treatment System								
7-1	Produced Water Design Rate	0.2 kbpd	0.4 kbpd	1.5 kbpd	2 kbpd	4 kbpd	Large	The produced water design rate is specified. The facilities required to handle the specified water rate are designed in connection with the produced water design rate, then the costs are estimated.

No.	Input Data	Gas Handling Capacity					Cost Impact	Note
		20 MMscfd	40 MMscfd	150 MMscfd	200 MMscfd	400 MMscfd		
								10 bbl of water was assumed to be produced with 1 MMscf gas.
7-2	Sour Water Stripping Option	Not Allocated	Not Allocated	Not Allocated	Not Allocated	Not Allocated	Medium	The necessity of a sour (H2S) component stripping facility as one the of water treatment systems is specified. As gas produced from Bangladesh is classified as sweet gas a without sour (H2S) component, the installation of such a facility is not required. "Not allocated" was selected for all the cases regardless of the gas handling capacity.
7-3	CPI Unit	Allocated	Allocated	Allocated	Allocated	Allocated	Medium	The necessity of a CPI unit as the first stage of water treatment is specified. A CPI unit is normally used in the water treatment. "Allocated" was selected for all the cases regardless of the gas handling capacity.
7-4	Floatation/Hydrocyclone Unit	Allocated	Allocated	Allocated	Allocated	Allocated	Medium	The necessity of a floatation/hydrocyclone unit as the second stage of water treatment is specified. A floatation/hydrocyclone unit is normally used in the water treatment. "Allocated" was selected for all the cases regardless of the gas handling capacity.
8. Utility System								
8-1	Type of Main Power Generator	Turbine	Turbine	Turbine	Turbine	Turbine	Small	The type of main power generator driver is specified. "Turbine" was specified as the typical most proven type of driver for all the cases regardless of the gas handling capacity.
8-2	Number of Main Power Generators	1	1	1	1	1	Medium	The number of main power generators is inputted. As the facility configuration without any spares is a design premise in the study, the number of trains was inputted as one for all the cases regardless of the gas handling capacity.
8-3	Percent of Main Power Load	100%	100%	100%	100%	100%	Medium	In relation to the "number of main power generators", the percentage of power generation

No.	Input Data	Gas Handling Capacity					Cost Impact	Note
		20 MMscfd	40 MMscfd	150 MMscfd	200 MMscfd	400 MMscfd		
								per train in the total power generation is inputted. As the facility configuration without any spares is a design premise in the study, the percent of the main power load was inputted as one hundred (100%) for all the cases regardless of the gas handling capacity.
8-4	Power Generator Selection	Internally Determined	Internally Determined	Internally Determined	Internally Determined	Internally Determined	Medium	The manufacturer's model of the main power generator is specified. In this case, the required power for all the facilities was internally calculated in the software by specifying "internally determined" for all the cases regardless of the gas handling capacity. Also, the type of main power generator was automatically selected to cover the power demand required.
9. Other Related Facilities								
9-1	Number of People in Operation Camp	30	30	40	40	50	Medium	The number of people to be accommodated in the operation camp is inputted. Based on three shift of eight hours , the number of people – including operators, supervisors, maintenance workers, administrators, and guests – are assumed for the required accommodation, then the costs are estimated.
9-2	Number of People in Construction Camp	50	50	100	100	200	Medium	The number of people to be accommodated in construction camp is inputted. The number of people is assumed for the required accommodation, then the costs are estimated.

Source: JICA Survey Team

Chapter 9 Import LNG

9.1 Background of LNG Import in Bangladesh

According to the natural gas supply and demand balance forecast study from 2009 to 2030 in Bangladesh by PSMP2010, the tremendous shortage data of natural gas supply from the domestic gas well in 2015 onward was shown to us.
In this study, as one of the methods to compensate the huge gap between natural gas supply and demand, onshore LNG receiving terminal will be studied and the technical challenges at the earliest stage will be shown.
In the process of the study, the main objective is to pursue the stable natural gas supply to bulk user like power station and fertilizer nearby and we will find the technical challenges to have an economic and energy effective LNG receiving terminal, while looking at the design, construction, and O&M procedure of LNG receiving terminal in Japan and studying the gas tie-in condition with the local gas pipeline.

Source: Osaka Gas Brochure

Figure 9-1 Overview of LNG Receiving Terminal Owned by Osaka Gas

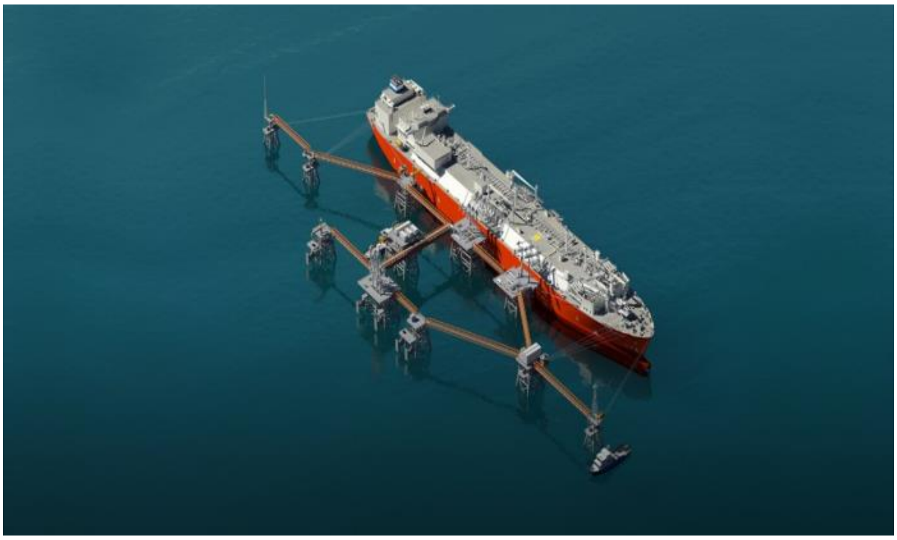
9.2 Status of FSRU Planning in Bangladesh

The Bangladeshi Government has focused on the LNG supply technology of FSRU to recover quickly the natural gas supply and demand gap and agreed the charter party of one unit of FSRU in 2014.

DHAKA, BANGLADESH – Excelerate Energy and Petrobangla have reached agreement on terms for the development and operation of Bangladesh's first LNG import terminal. The agreement includes the provision of one of Excelerate's existing floating storage and regasification units (FSRU) under a 15-year long-term charter, as well as the design and construction of the facility. Located offshore near Maheshkhali Island in the Bay of Bengal, the terminal will provide much needed natural gas to the southeastern Chittagong region of Bangladesh.

The facility will include the installation of a subsea buoy system anchored offshore. The buoy system will act as both the mooring mechanism for the FSRU and as the conduit through which natural gas is delivered to shore through a subsea pipeline. The FSRU will have 138,000 cubic meters of LNG storage capacity and a base regasification capacity of 500 million standard cubic feet per day.

Source: Excelerate Energy web site



Source: Excelerate Energy web site

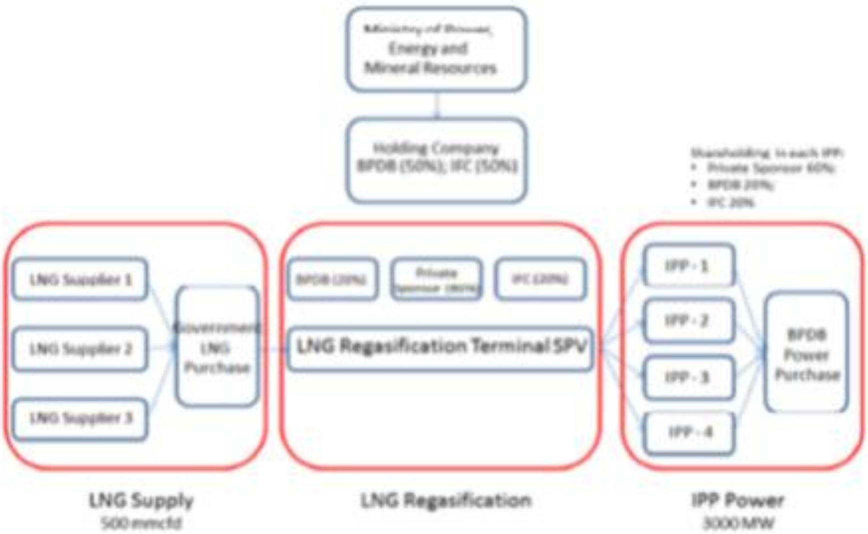
Figure 9-2 FSUR Image

FSRU has some advantages over onshore LNG receiving terminal, in terms of up-front construction cost, construction period, easiness of dismantling, etc. (for further detail of economic cost comparison, refer to the following section). But on the other hand, FSRU operation is largely influenced by weather and sea phenomena condition. This is because onshore LNG receiving terminal is needed to utilize LNG for a long time and supply stably natural gas to the customer. Thus the technical challenges for the basic plan and main specification of LNG receiving terminal will be shown here.

9.3 Status of Lan-base LNG terminal Planning

In parallel with the introduction of FSRU, the Government is also processing on-shore (land based) LNG terminal project.

This “Land Based LNG Terminal Project” is expected to be operated on BOO (build-own-operate) basis, operated by LNG consortium mainly sponsored by private finance, and LNG itself will be procured by the Government (see the below figure). The gasified LNG will be mainly supplied to newly built or existing 3,000MW gas-fired power plants (IPPs expected).



Source: Power Cell

Figure 9-3 Structure of On-shore LNG Terminal and IPPs

The candidate site of this land-based LNG terminal is Matarbari/Maheshkhali area, which is adjacent to the JCA-supported Matarbari Ultra Super Critical coal power plant. Power Cell is the executing agency of this on-shore LNG terminal project, BPDB is the off-taker of LNG and power, and International Financial Corporation (IFC) is an advisor as part of their power sector private sector investment promotion.

The four contractors have been short-listed including one Japanese firm[12]. The employment process of the feasibility study consultant have been in progress since 2015. Design and construction schedule of the LNG will be determined in the feasibility study.

As described above, this Power Cell driving LNG terminal plan is expected to serve for power generation plants. To meet the growing national gas demand including non-power sector (e.g. Transport), more comprehensive LNG plan (e.g. LNG master plan) would be required.

9.4 Economic Comparison between FSRU and Land-based LNG Receiving Terminal

This Section is primarily intended to make comparison of the two different LNG Import infrastructure, FSRU and Land LNG terminal, in terms of economics. However, it should be understood that each method has its own features and advantages. Therefore this Section also covers all the design factors to be considered for the introduction and construction of LNG infrastructures.

9.4.1 Overview

At the moment (as of May 2016) negotiation on the introduction of FSRU (Floating Storage and Re-gasifying Unit) is underway between Petrobangla and Excelerate Energy from US. According to press report (Bangladesh Energy and Power News) general description of the FSRU Project is as follows:

Location	:	Maheshkhali
Storage Capacity	:	138,000 M3
Re-Gasification Capacity	:	500 mmcfd
Start of Commercial Operation	:	2019
Contract Term	:	15 years, on BOOT base
Service Charge	:	USD 0.49 per mcf

The facility will include FSRU (Floating Storage and Re-gasifying Unit) and Single Point Mooring Buoy system anchored to the sea bottom. Gas produced from LNG is delivered through a conduit of the Buoy system and submarine pipeline and tied into the onshore pipeline system. LNG loading to FSRU will be carried out by Ship to Ship transfer. In order to supply 500mmcfd of gas, more than 60 shipments will be required in a year. Capacity of the shuttle tanker will be the same or smaller than that of FSRU. Construction of FSRU is almost the same as that of LNG tanker. Retired LNG tankers can be remodeled as FSRU to save construction cost. Operation of FSRU in general is vulnerable to weather condition and emergency evacuations plan must be in place if it is operating in the cyclone prone area.

Land LNG Terminal requires larger space near shore, capable of accommodating more than 10 tanks. This is to minimize investment to the infrastructure and also to secure freedom to construct additional tanks to meet the incremental demand. Initial tank numbers are assumed to be two to match with the performance of FSRU under negotiation, and to be expanded with the increase of demand.

[12] According to Power Cell, these four companies are: Mitsui & Co. Ltd., Japan, Royal Dutch Shell (Netherland), China Huanqui Contracting & Engineering Corp. (HQC) (China) and PetroNet LNG Limited (India).

Tank size has been designed larger to meet the increasing size of LNG tankers. Recent trend of tank size constructed in Asia (Korea) is 180,000 kl and larger to accommodate Q-Flex size. Berth size is designed for Q-Max (2650,000 kl) size.

9.4.2 Land-based LNG Terminal Specifications and Construction Cost

Land LNG Terminal Specification and Construction Cost Estimate to be used for cost comparison with FSRU is as follows:

(1) Specification for Land –based LNG Terminal

Objectives of Land LNG Terminal may differ from case to case and sometimes designed for specific power plant only. But in Asia in general, LNG is constructed by taking emergency factor into consideration and therefore some allowance in the storage capacity is included.
In general, annual tank rotation is 12 times as an operational Index. However, Bangladesh is gas producing country and significant amount of gas is supplied domestically, and therefore storage allowance can be trimmed off in case of Bangladesh. In the economic comparison, 20 times of rotation is used. This 20 times is considered low enough in comparison with the case of FSRU with 60 times and more to supply 500 mmcfd of gas

Following are assumed terminal specification

Terminal Size	:	90 ha
Tank Size	:	180,000 kl
Initial tank Numbers and gas supply	:	3 (500 mmcfd)
Final tank Numbers and gas supply	:	14 (3,000 mmcfd max.)
Jetty	:	Initially 1
Berth Number and capacity	:	1(Q-Max-127,000ton/265,000M3）
Berth will be expanded to suit.		

Note that Re-Export capability and loading arms may be added to allow LNG trading in future, Break water may be required to allow stable off loading.

Tank Utilization	:	18/Year/tank
Capacity	:	1.8 Million ton/yr/tank

(2) Initial Land LNG –based Terminal Construction Cost

Assuming that Initially 2 tanks are constructed to commence commercial operation and supply 500 mmcfd of gas. Initial EPC cost inclusive of 3 tanks, re-gasification, Jetty, Loading Arms, operation rooms are USD 550 Million. 90ha of Land acquisition cost capable of constructing 14 tanks in total is assumed USD 200 million, and project development cost of USD 10 million. Initial Project Cost is assumed to be 760 million. Numbers of tanks will be increased with the increase of gas demand. Final construction cost after completion of 14 tanks will be USD 2,260, and gas supply capacity will be 3,000 mmcfd as maximum.

9.4.3 Operation Cost Comparison

FSRU appears to be constructed as a private enterprise project. To make fair comparison, operation charge of land LNG terminal, inclusive of tugboat operation is circulated based on the economic factors of 10% of IRR, 20% of Corporate Tax, and 20 years of Depreciation.
Economic data of FSRU is given in the News Press “Bangladesh Energy and Power News”. According to the press, Operation Charge of tugboat (Port Operation Cost) is excluded and need to be covered by Petrobangla.

Table 9-1 Operation Cost Comparison between FSUR and Land-based LNG Terminal

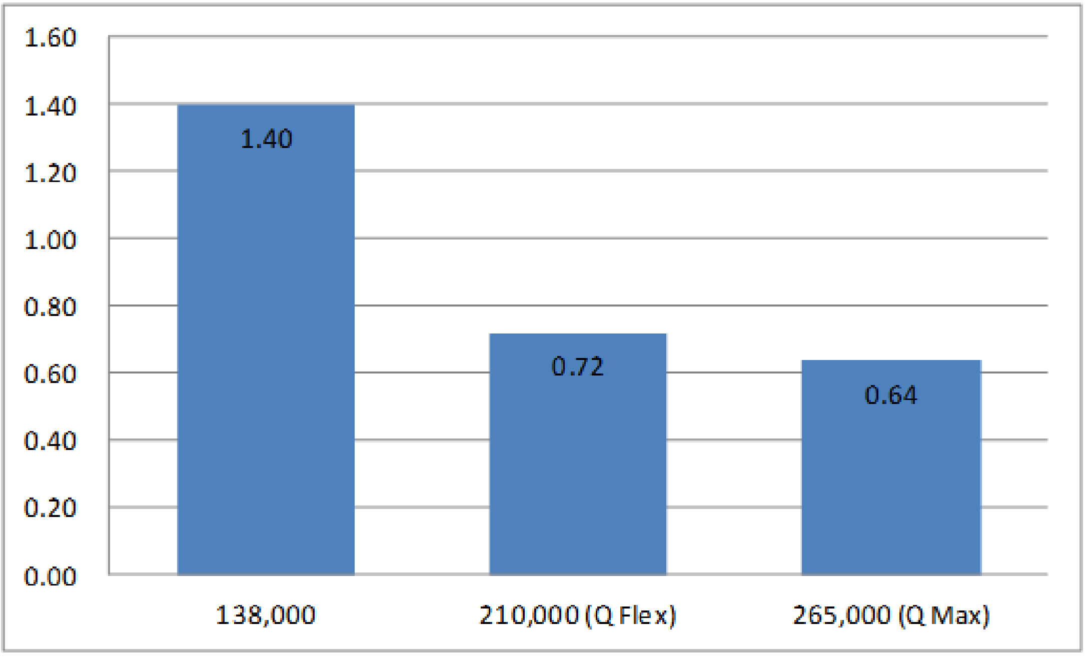
		FSRU (See Note 1)	Land LNG (See Note2)	
			Initial 3 Tanks	Expanded to 14 Tanks
Tank Capacity	M3	138,000	3X180,000	14x180,000
Annual LNG Delivery	Times/Year	59	40	186
Re-Gasification Capacity	MMscfd	500	500	3,000
Construction Cost	MM USD		760	2,260
Operation Charge	USD/Mcf	0.49	0.64 (See Note3)	0.33 (See Note 3)
Note:				
1: Data from Bangladesh Energy and Power News				
2: Land Acquisition Cost for Terminal assumed USD 200 million				
3: Tax Rate 20% and IRR 10% assumed, Including Port Operation Cost				

Source: JICA Survey Team

9.4.4 Freight Cost Comparison

Freight cost of LNG differs to the size of LNG tankers. To reduce the unit freight cost, size of the tanker has become larger. In this report LNG freight cost from Middle East (Ras Laffan) to Chittagong is assumed based on the data from Middle East to Korea/Japan.

Storage capacity of FSRU is 138,000m3. To supply LNG to FSRU, the same and/or smaller sized shuttle tankers will be used. For Land LNG Terminal, freight of Q-Flex is used for this economics comparison. Following is a comparison of unit freight cost:

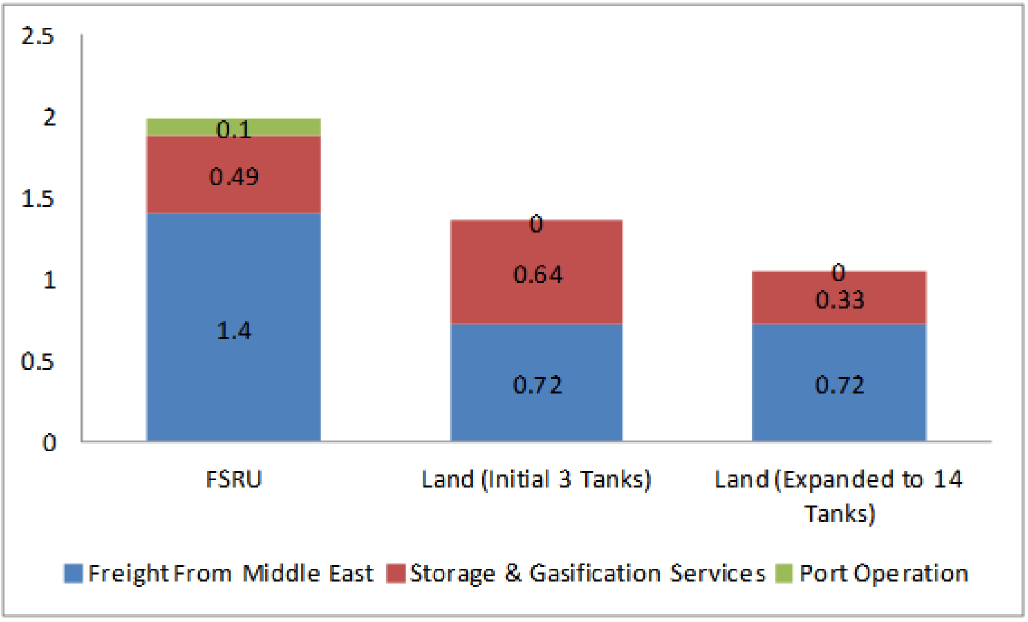


Source:
Base data from Freight Study by KOGAS in 2011, N.M is adjusted to the Port of Chittagong (from NM 6156 to NM 3833)

Figure 9-4 Transport Cost (dollr/MMTBU)by Tanker Sixe

9.4.5 Operation Cost Comparison

Assuming that LNG is shipped out from port of Middle East at the same FOB price, cost structure of the gas at the terminal outlet in Maheshkhali is as follows:



Source: JICA Survey Team

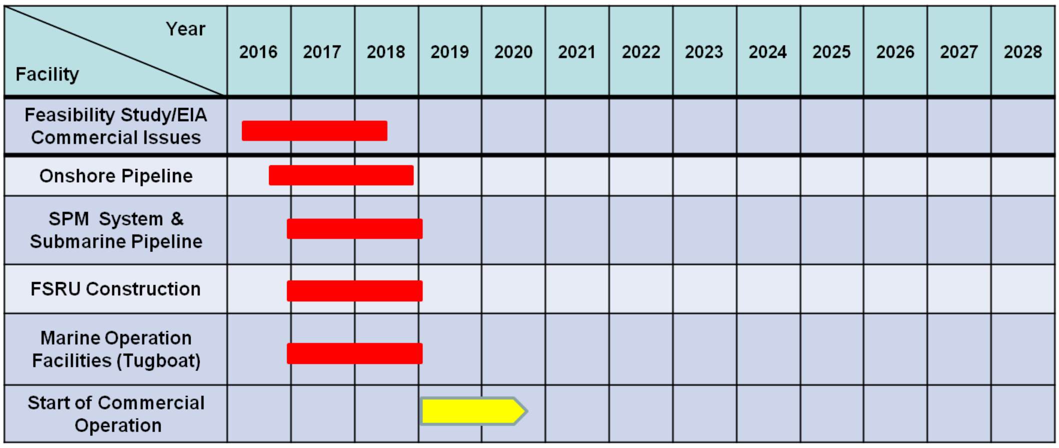
Figure 9-5 Operation Cost by Number of Tanks

In view of the comparison of overall cost from the port of origin to gas delivery point, Land LNG terminal has a potential to minimize the cost associated with LNG introduction.

FSRU uses small shuttle tanker to deliver LNG and therefore cost of the transportation is higher. Operation Charge (Storage/re-gasification and port operation) of Land LNG terminal is higher at the initial stage of the operation due to a heavier investment cost for land acquisition and associated infrastructure construction. However, Operation Charge will be lower with the increase of handling volume. Note that Port Operation Charge is included in the Land LNG terminal operation, but not in FRSU case.

9.4.6 Construction Time Schedule

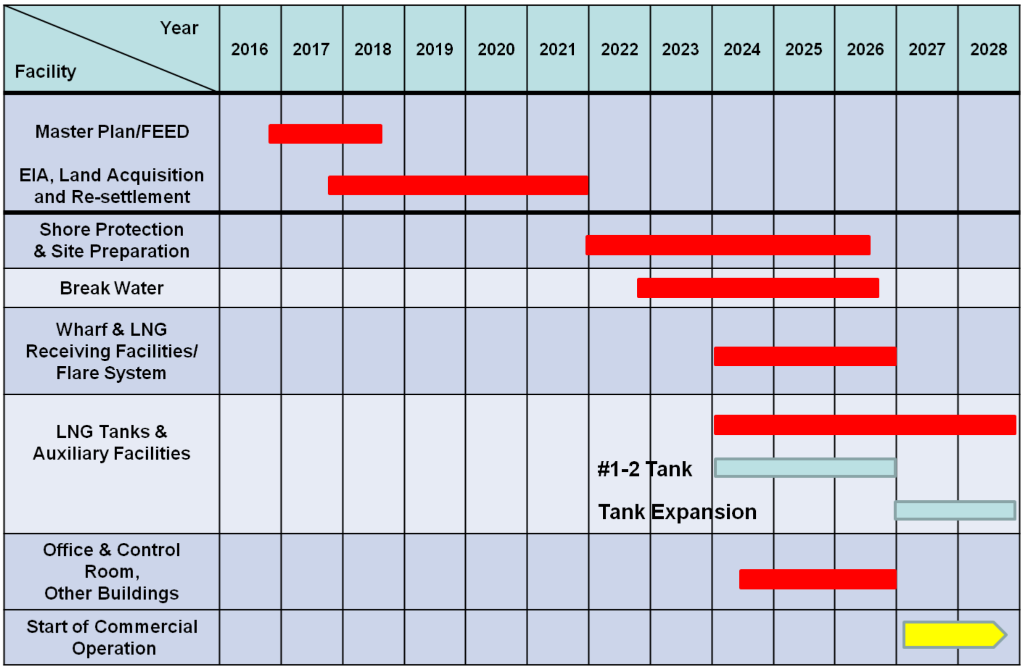
Majority of construction work of FSRU is carried out at a shipyard and amount of on-site construction work is very small. Project schedule from EIA (Environmental Impact Assessment) to the commencement of operation is short and takes less than 3 years.



Source: JICA Survey Team

Figure 9-6 Time Schedule for FSRU Construction

Project schedule for land LNG terminal is longer than that of FSRU. Significant time and effort to be injected to EIA including agreement with the local people and re-settlement plan associated with land acquisition. Large scale land preparation work and infrastructure construction such as breakwater if necessary will be carried out. Construction of tank foundation to avoid uneven settlement is also time consuming work. Overall project schedule from EIA to commencement of operation will be 8-10 years.

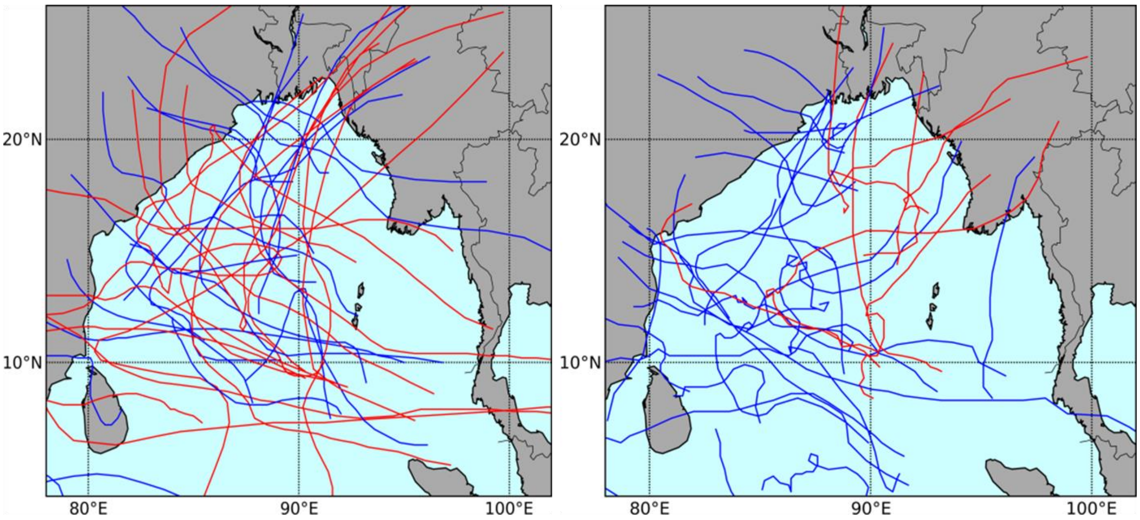


Source: JICA Survey Team

Figure 9-7 Time Schedule for Land-based LNG Terminal Construction

9.4.7 Cyclone Risks for FSRU

Operation of FSRU is vulnerable to whether condition. Bay of Bengal is known as Cyclone. Frequency of Cyclone landing at Maheshkhali area is not many in comparison with other areas, but influences every year. Scale of Cyclone is reported to be increasingly larger than before. Operational risk of FSRU should be investigated.



Source: Nippon Koei Research Institute

Figure 9-8 Cyclone Outbreak in Bay of Bengal

9.4.8 LNG Master Plan

Prior to introduce LNG, several issues such as construction of LNG infrastructures, operation of gas distribution systems, impact to existing infrastructures and strategy for LNG procurement should be investigated further and need to be strategically prepared as a Master Plan.

Nature of gas is changing from domestic to LNG. It is understood that the change of process parameter requires thorough investigation based on the procedures so called “Management of Change”, i.e., how the change of gas composition, the dryer circumstance, the change of pressure balance impact to the existing facilities to be investigated.

Through the Master Plan, capacity building and human resource development also should be considered.

9.5 Cross-border LNG Trade

JICA Survey Team will conduct further survey in June 2015.

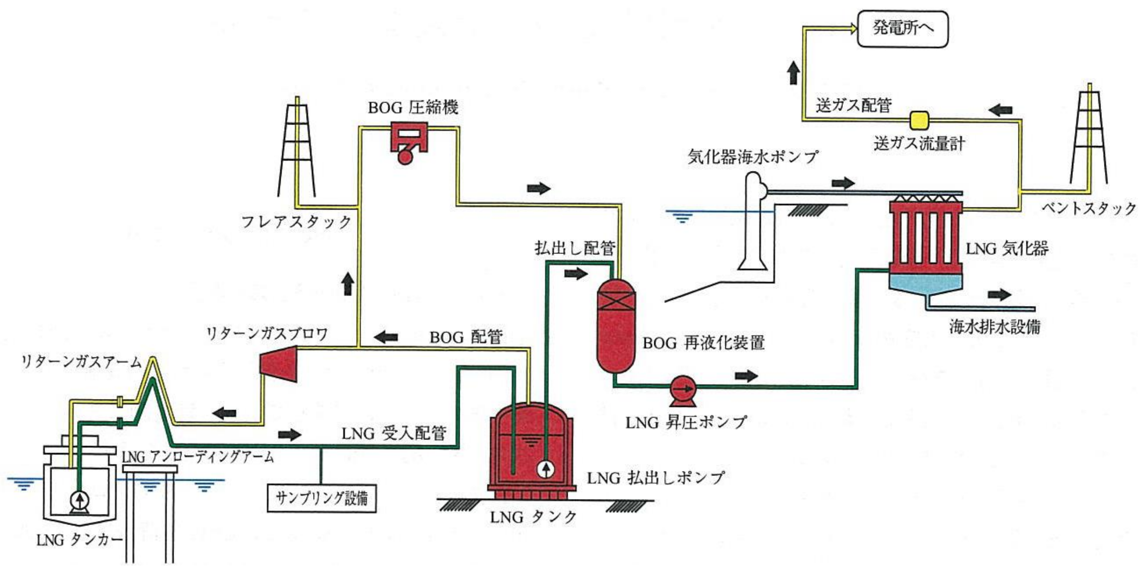
9.6 Land-based LNG Receiving Terminal Planning

9.6.1 General Planning

At the first, gas send out capacity and its related main equipment should be specified.
Key points to specify them are summarized.

(1) Annual LNG operation capacity (fixed by LNG tanker capacity and annual number of docking to LNG jetty)
(2) LNG Tank storage capacity (number of tank revolutions is considered.)
(3) Selection of vaporizer by sea water temperature and quality
(4) Gas send out pressure (This will specify the LNG secondary pump.)
(5) Necessity of BOG re-liquefaction system
(6) Necessity of heat value adjustment by LPG or air
(7) Necessity of odorization system
(8) Spare unit arrangement of main equipment
(9) Future expansion plan (road map to expansion)

Typical schematic flow diagram of LNG receiving terminal will be shown in the below Figure.



Source: IHI Technical Report Vol.50, No.2 (2010)

Figure 9-9 Flow Diagram of LNG Receiving Terminal

9.6.2 Current Planning Status

At the second, gas production capacity will be studied and then main equipment specification will be clarified. Now the capacity of LNG receiving terminal is assumed as same as that of FSRU (500mmcfd, 3mm LNG ton per annum) because the same gas amount can be delivered to the customer even if FSRU is removed by the contract. Main equipment specifications and plot plan will be shown in the below Tables and Figure below respectively.

Table 9-2 Design Criteria for Terminal Layout and Main Facility

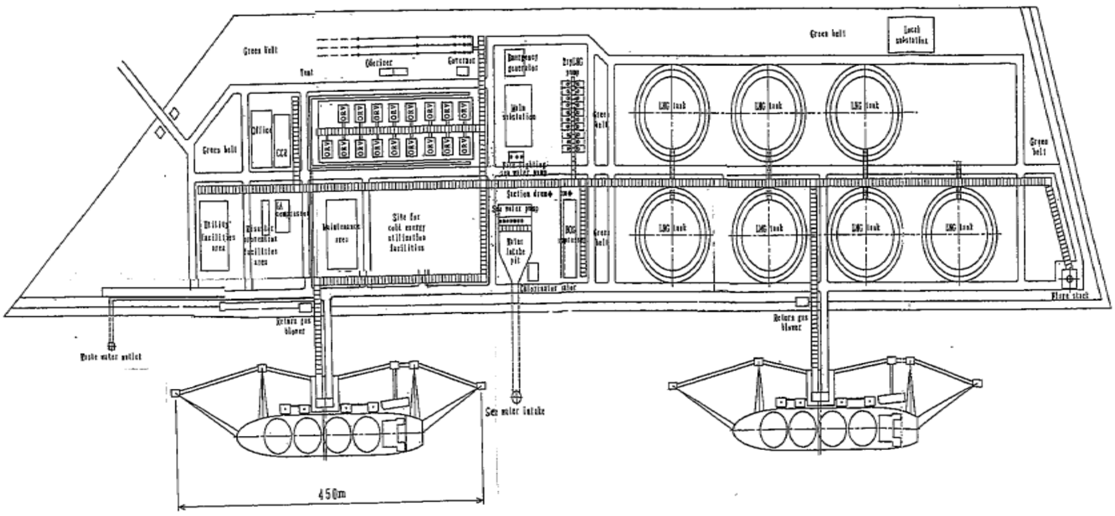
Layout plan	Necessary land space for the final stage (1,500MMCFD) should be secured. Main facility will be expanded in accordance with the demand growth after the first stage completion (500MMCFD).
LNG storage tank specification and code & standard for tank	Bangladesh is an earthquake country, so full containment double dome roof type tank will be recommendable. Code & standard for tank design should be API for inner tank and EN for outer tank, which is applied world widely. Maximum storage capacity per unit can be 180,000 m3. The distance between tanks should be 0.5 times of tank diameter.
Number of LNG storage tank	20 times of 180,000m3 tank capacity will be needed annually. By this, necessary number of LNG storage tank can be set up.
NG send out condition from the terminal and tie-in condition with pipeline	NG send out pressure will be 1,100 psig (76barg). Tie-in point is on the way of new pipeline from Maheshkhali to Anawara.
Assumption of availability of the harbor	It is assumed as 95%. The planned availability of FSRU is 96.2% by Excelerate Energy.
Number of Jetty for terminal expansion	If standard sized LNG vessel (140,000m3) will be mooring 86 times a year, annual LNG receiving amount will come to 5.5 MTPA. Thus one jetty at the first stage and two jetties at the final stage will be needed.
Vaporizer specification	Peak hourly send out ratio during a day can be assumed as 9.5%. By this, capacity of vaporizer can be set up. ORV type vaporizer can be selected.
Other facility	1. BOG treatment facility will be designed. 2. Odorant injection facility will be designed for safety. 3. Metering facility will be designed. 4. Heating value adjustment will be not designed due to the almost equality of LNG and domestic NG. 5. Dual electric power system will be designed in substation. 6. Automatic control system in CCR will be designed. 7. As a preventive disaster system, firefighting and monitoring system will be designed. 8. Cooling water, IA, Nitrogen, and portable water supply system will be designed.
Layout plan	Necessary land space for the final stage (1,500MMCFD) should be secured. Main facility will be expanded in accordance with the demand growth after the first stage completion (500MMCFD).
LNG storage tank specification and code & standard for tank	Bangladesh is an earthquake country, so full containment double dome roof type tank will be recommendable. Code & standard for tank design should be API for inner tank and EN for outer tank, which is applied world widely. Maximum storage capacity per unit can be 180,000 m3. The distance between tanks should be 0.7 times of tank diameter.
Number of LNG storage tank	20 times of 180,000m3 tank capacity will be needed annually. By this, necessary number of LNG storage tank can be set up.
NG send out condition from the terminal and tie-in condition with pipeline	NG send out pressure will be 1,100 psig (76barg). Tie-in point is on the way of new pipeline from Maheshkhali to Anawara.
Assumption of availability of the harbor	It is assumed as 95%. The planned availability of FSRU is 96.2% by Excelerate Energy.

Number of Jetty for terminal expansion	If standard sized LNG vessel (140,000m3) will be mooring 86 times a year, annual LNG receiving amount will come to 5.5 MTPA. Thus one jetty at the first stage and two jetties at the final stage will be needed.
Vaporizer specification	Peak hourly send out ratio during a day can be assumed as 9.5%. By this, capacity of vaporizer can be set up. ORV type vaporizer can be selected.
Other facility	1. BOG treatment facility will be designed. 2. Odorant injection facility will be designed for safety. 3. Metering facility will be designed. 4. Heating value adjustment will be not designed due to the almost equality of LNG and domestic NG. 5. Dual electric power system will be designed in substation. 6. Automatic control system in CCR will be designed. 7. As a preventive disaster system, firefighting and monitoring system will be designed. 8. Cooling water, IA, Nitrogen, and portable water supply system will be designed.

Source: JICA Survey Team

Table 9-3 Main Facility Specifications

	First stage (500MMCFD,3.5MTPA)	Final stage (1,500MMCFD, 10.4MTPA)
LNG storage tank	180,000 m3 X 3 units	180,000 m3 X 7 units
LNG pump	Primary pump; 300 t/h X 6 units + 3 spare units: total 9 units Secondary pump; 150 t/h X 6 units + 2 spare units: total 8 units	Primary pump; 300 t/h X 14 units + 7 spare units: total 21 units Secondary pump; 150 t/h X 18 units + 2 spare units: total 20 units
Jetty	1 jetty	2 jetties
Vaporizer	180 t/h X 5 units + 2 spare units: total 7 units ORV type is recommendable.	180 t/h X 15 units + 2 spare units: total 17 units ORV type is recommendable.
BOG treatment system	BOG compressor: 15 t/h X 4 units + 1 spare units: total 5 units BOG recondensor: 30 t/h X 2 units + 1 spare units: total 3 units Flare stack: 50 t/h X 1 unit (in long term blackout, BOG will be burnt to open air at flare stack.)	No expansion plan
Sea water intake pump	13,000 t/h X 3 units + 2 spare units: total 5 units	13,000 t/h X 9 units + 2 spare units: total 11 units



Source: JICA Survey Team

Figure 9-10 Typical Plot Plan of LNG Receiving Terminal (50ha, 10MTPA)

9.6.3 Impact of the LNG Vaporized Gas to the Existing Gas Distribution Network

Natural Gas produced at the terminal will be transferred to new pipeline (30 inch, 91km, from Maheshkhali to Anawara CGS) through metering station nearby and then delivered to Chittagong division.

In Chittagong division, LNG vaporized gas and domestic gas will be mixed each other but it will not cause a big damage for the end user by the following study.

First, when each heating value is focused on, LNG heating value (HHV) in RasGas, Qatar is around 1,055 BTU/ cft (source: JICA survey) and domestic gas heating value (HHV) is averagely 1,042 BTU/cft (source: Petrobangla), which is almost equal. However if imported from other countries on a spot basis, the special attention will be needed.

Second, LNG vaporized gas will be sent out to the transmission line and then 290 MMCFD of it will consumed in the power plant and fertilizer near to Chittagong division and remaining 210 MMCFD will be spread nation widely. However this 210 MMCFD is relatively smaller when compared to the total gas send out amount of 2,740 MMCFD supplied from all domestic gas fields.

Table 9-4 Sector Wise Gas Demand and Supply

Unit: MMCFD

Sectors	Customer Category	Demand	Supply
Bulk	Power	1454	1070
	Fertilizer	317	200
	Power	70	68
Non-Bulk	Industry	452	448
	Captive	489	467
	CNG	128	125
	Domestic	332	330
	Commercial and others	33	32
	Total	**3275**	**2740**

Source: Petrobangla

9.6.4 Specification of LNG Tanker and Harbor Conditions

(1) Specification of LNG tanker

LNG taker will be designed larger in capacity year by year but、Q-max class tanker is huge and is limited by the project, so Q-flex class tanker will be applied in Bangladeshi terminal.

Table 9-5 LNG Tanker Size

LNG Tanker		Class (DWT[13])	Length L (m)	Breadth B (m)	Loaded Draft D (m)
LNG Tanker	Q-max	130,000	350	55	13.7
	Q-Flex	110,000	315	50	12.5
	Conventional	80,000	300	50	12.0
Reference: Collier		80,000	220	36	13.0

Source: JICA Survey Team

(2) Performance requirements for waterways and basins

Performance requirements for waterways and basins are defined as follows in Technical Standard and Commentaries for Port and Harbor Facilities in Japan. (http://www.ocdi.or.jp/technical-st.html)

1) Performance Criteria of Waterways

- Breath of channel：In the channel where ships may meet each other, not less than the breadth over the ship's total length will be needed.
- Water depth of the channel：1.1 times as much as ship's loaded draft will be needed.
- When the channel has an elbow-shaped bend, the angle of intersection of the centerline at the bend of the channel is around less than 30 degree and the radius of curvature is more than about 4 times as long as the length between perpendiculars of the ships.

2) Performance Criteria of Basins

- Width of basins：in case of turning around by tugboat, a circle space of which diameter is 2 times as long as the ship's total length should be secured.
- Water depth of basins：enough water depth more than the loaded draft of the ship (maximum loaded draft plus affordable water depth) should be secured under the standard space by the port authority
- Calmness of basins：calmness which can make more than 97.5% unloading possible through the year should be secured.

[13] DWT: Dead Weight Ton

Table 9-6 Reference Values of Threshold Wave Height for Cargo Handling Works Not Affected by Swell, or Long Period Waves

Ship type	Threshold Wave height for cargo handling works ($H_{1/3}$)
Small craft	0.3m
Medium/large ship	0.5m
Very large ship	0.7-1.5m

Source: JICA Survey Team

(3) Harbor condition

Specification of LNG Harbor (Waterways & Turning Basin)
Based on Technical Standard and Commentaries for Port and Harbor Facilities in Japan, LNG Harbor will be specified.

Table 9-7 Specification of LNG Harbor for Receiving Q-Flex Class LNG Tanker

Vessel		Class (DWT)	Waterways(Channel)			Turning Basin	
			Width 1L (m)	Length 5L(m)	Depth 1.1d(m)	Diameter 2L (m)	Depth 1.1d (m)
LNG Tanker	Q-Flex	110,000	315	-	14.0	630	14.0
Reference: Collier		80,000	250	1200	15.0	600	15.0

Source: JICA Survey Team

(4) Port entrance and leaving condition of LNG tanker, Unloading condition at LNG jetty

With reference to Technical Standard and Commentaries for Port and Harbor Facilities in Japan and Japanese port entrance and leaving condition of LNG tanker and unloading condition at LNG jetty, maximum wave height (H1/3) for pier docking and undocking in the terminal can be defined as 1.5 meter.
In case of LNG tanker, due to the small specific gravity of LNG, above water surface area is large, so ship operation and unloading work is likely to be influenced by the wind power. In the "Technical Standard and Commentaries for Port and Harbor Facilities in Japan", there is no limitation of pier docking and undocking under the windy condition but the maximum allowable wind speed is set up to 8 to 15m/sec in almost Japanese LNG receiving terminal. Thus it will be also set up to 15m/sec here in Bangladesh. Calmness should be more than 95 %

Table 9-8 Calmness Condition in the Channel and Basins

		Threshold Wave Height $H_{1/3}$ (m)	Threshold Wind Speed (m/sec)
LNG Tanker	Entrance of Channel	1.5	15
	Berth	1.5	15
Reference: Collier	Entrance of Channel	1.5	-
	Berth	1.0	-

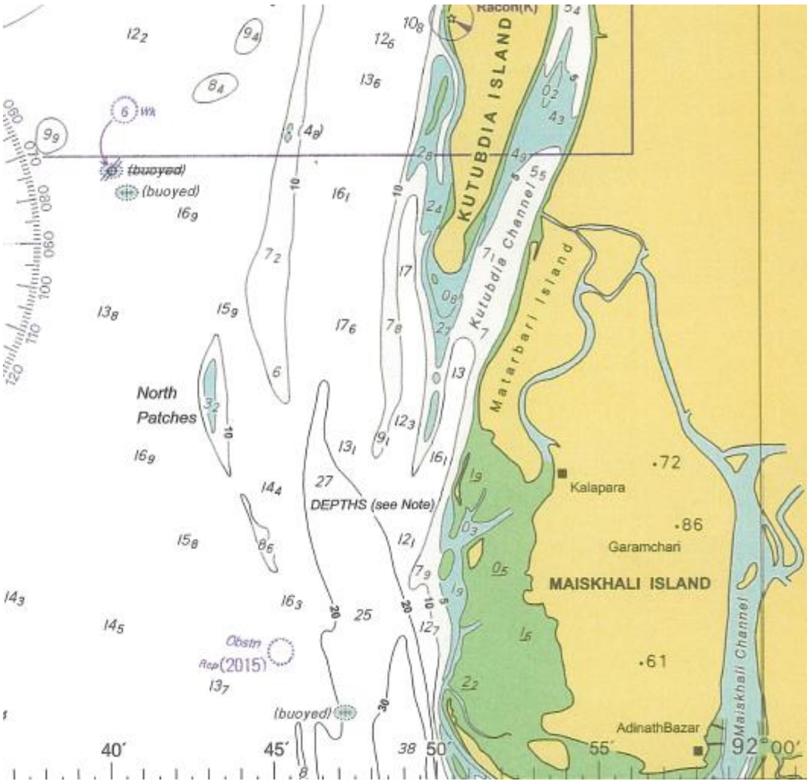
Source: JICA Survey Team

(5) Study of geographical and marine phenomenon condition near to the candidate site of LNG receiving terminal

1) Sea Water Depth

The chart of the candidate site of LNG receiving terminal will be shown in below Figure. The candidate site is located in the north of Bay of Bengal. Partially some reefs and shoals can be found but they are not barriers for the entrance of LNG tanker.

Marshy areas are spread along with the coast where the range of the tide will influence largely. The criteria of LNG receiving terminal construction are to avoid the marshy area, to set up LNG berth at offshore, and to dredge and cut the channel. When dredging and cut is applied for the channel, a long term maintenance of dredge area should be studied.

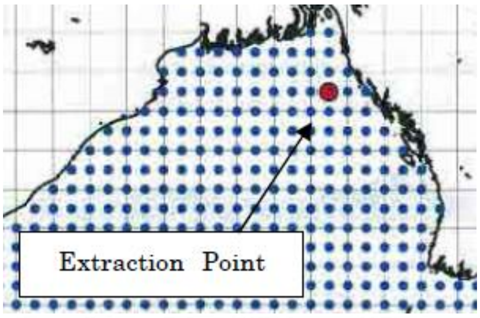


Source: JICA Survey Team

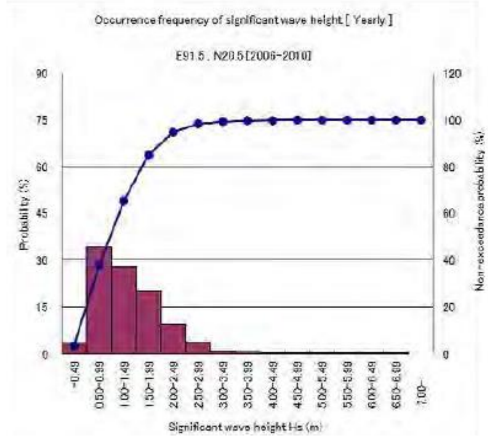
Figure 9-11 Chart of Candidate Site

2) Deep water waves data

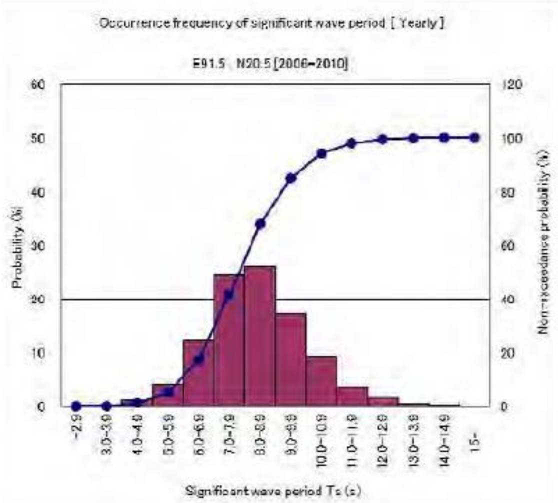
Deep water waves data at the planning site of coal fired power station in Chittagong. It is forecasted by the expected deep water waves data for the next 50 years based on the data at the extraction point in the north Bengal bay.
The expected frequency of deep water waves through the year from 2006 to 2010 will be shown. The expected frequency of over 1.5 meter wave height is around 65%、wave direction is most likely to be SSW.



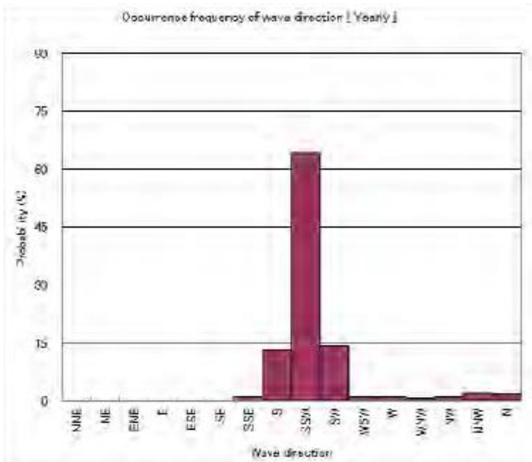
- Period : 2006.1.1～2010.12.31
- Extraction Point : Long. 91°30’ E, Long. 20°30’ N
- Time Interval : 1 hour
- Data Elements : Significant wave height、period and direction



Predominant Wave Height
- 0.50m～0.99m ;34%
- 1.00m～1.49m ;28%
- 1.50m～1.99m ;20%



Predominant Wave Period
- 8.0s~8.9s ;64%
- 7.0s~7.9s ;25%
- 9.0s~9.9s ;17%



Predominant Wave Direction
- SSW ;64%
- SW ;14%
- S ;13%

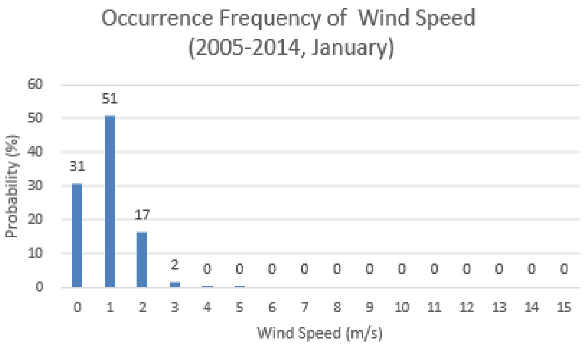
Source: “Preparatory Survey on Chittagong Area Coal Fired Power Plant Development Project in Bangladesh Final Report”(March 2015, JICA/TEPSCO/TEPCO)

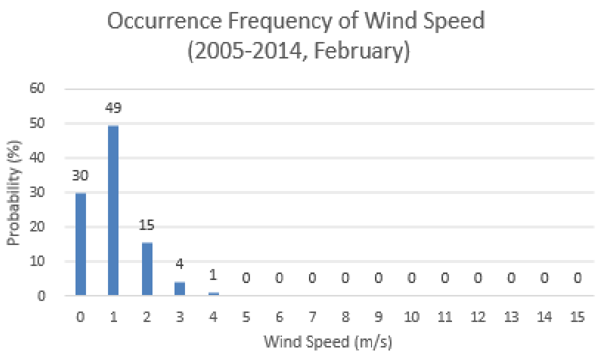
Figure 9-12 Deep Water Waves Data

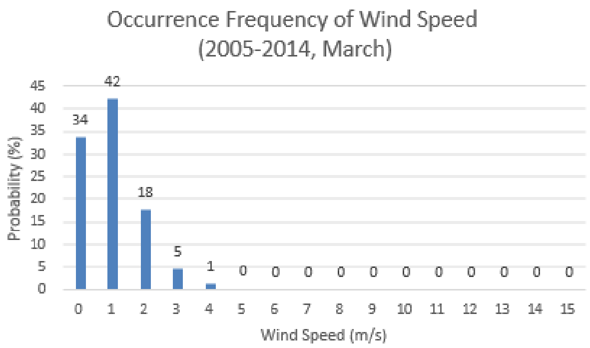
3) Wind Data

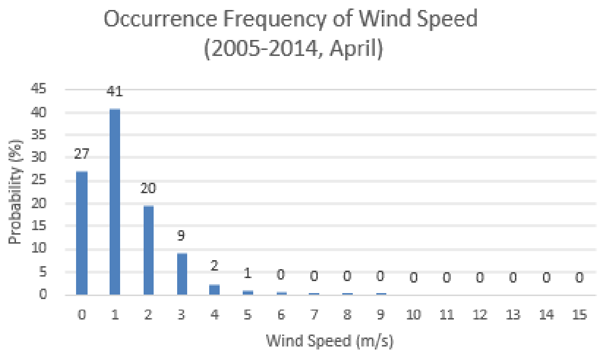
Based on “THREE HOURLY WIND SPEED AND DIRECTION” at Kutubdia which is close to the candidate site, the occurrence frequency of wind speed and direction was summarized and the result will be shown.
Wind speed of more than 30knots was found only one time at 40knots at 15 :00 PM on 17 Apr. 2009. The occurrence frequency of less than 30knots (15.4m/sec) was 99.99%. Therefore maximum allowable wind speed of 15m/sec or less for docking/ undocking and unloading work can be found to be so appropriate.
In terms of wind direction, North winds from November to February and South winds from April to October are most likely to be occurred. In winter season, “Calm” (wind speed
0.5m/sec or less) condition will be kept for a long time.

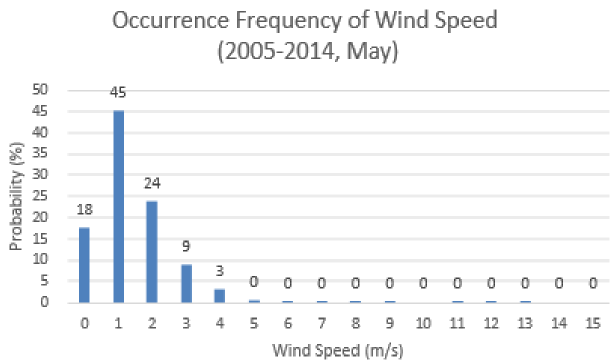
<u>Occurrence Frequency of Wind Speed</u>

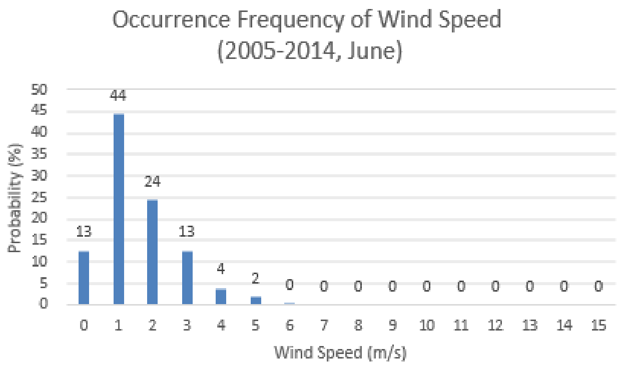


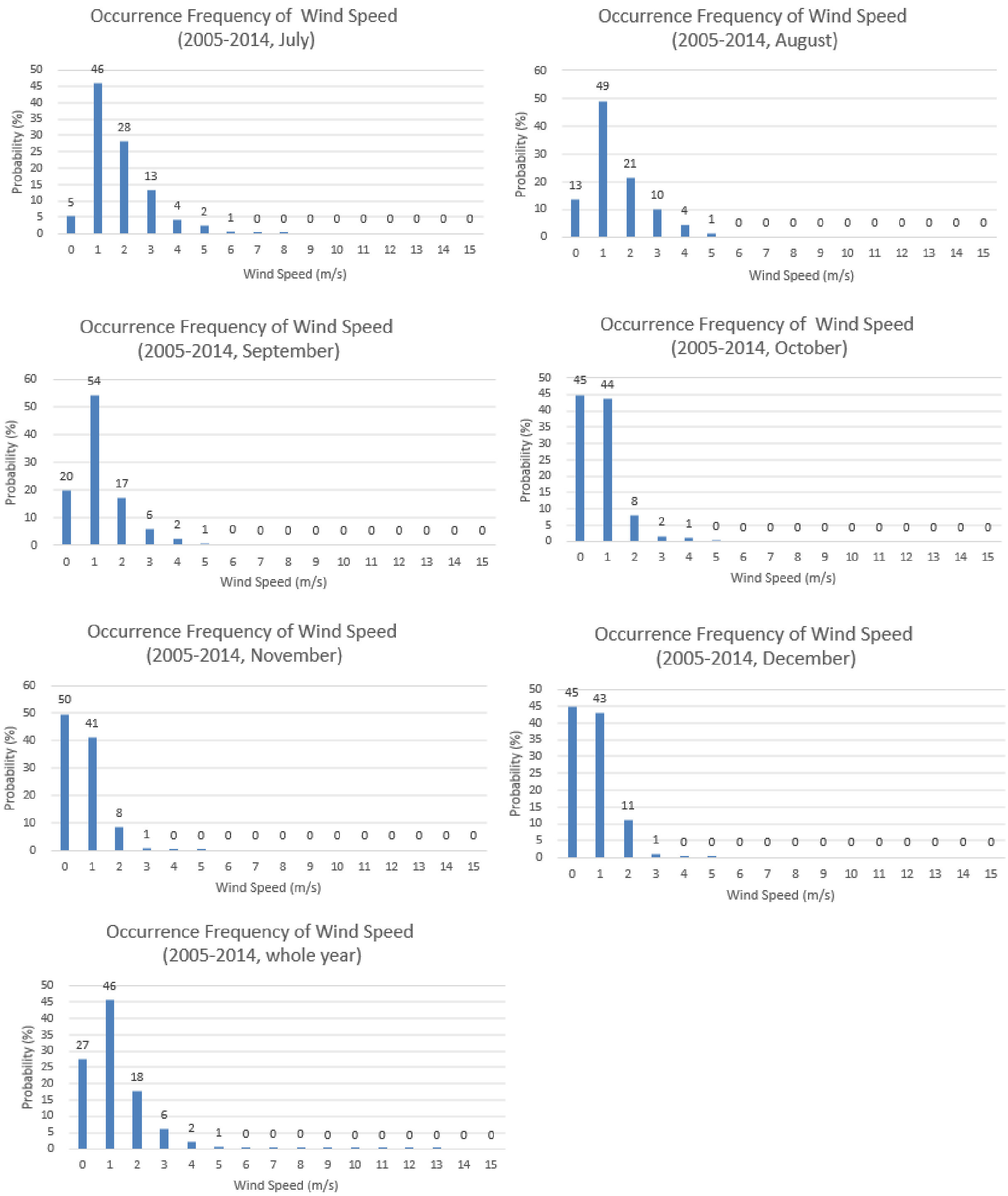










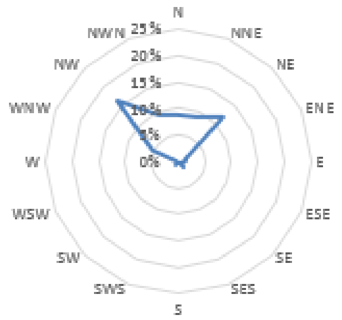


Source: JICA "Preparatory Survey on Chittagong Area Coal Fired Power Plant Development Project in Bangladesh Final Report"(March 2015, JICA/TEPSCO/TEPCO)

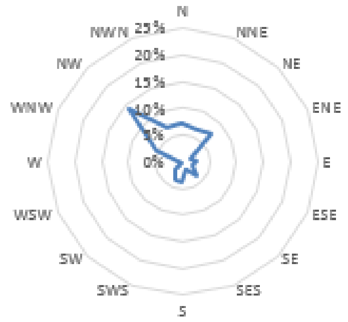
Figure 9-13 Occurrence of Wind Speed

Occurrence Ratio of Wind Direction

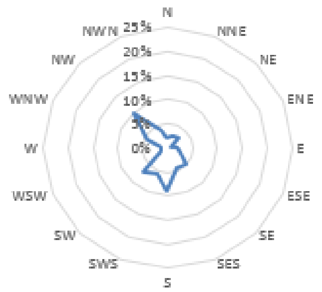
Occurrence ratio of Wind Direction
(2005-2014 January)
No Wind 32%



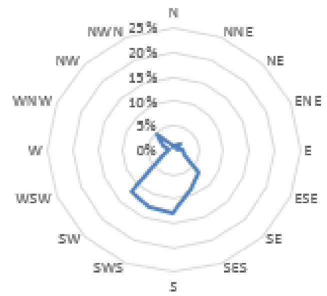
Occurrence ratio of Wind Direction
(2005-2014 February)
No Wind 31%



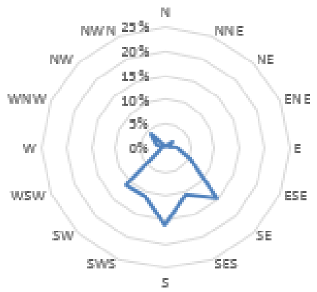
Occurrence ratio of Wind Direction
(2005-2014 March)
No Wind 35%



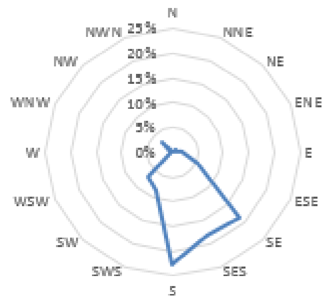
Occurrence ratio of Wind Direction
(2005-2014 April)
No Wind 28%



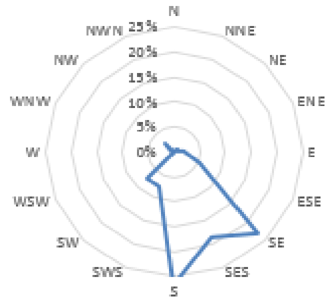
Occurrence ratio of Wind Direction
(2005-2014 May)
No Wind 18%



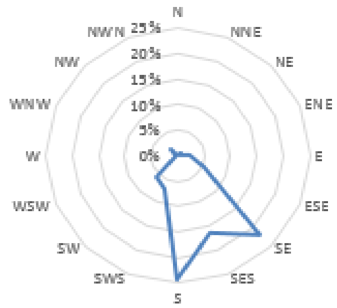
Occurrence ratio of Wind Direction
(2005-2014 June)
No Wind 13%

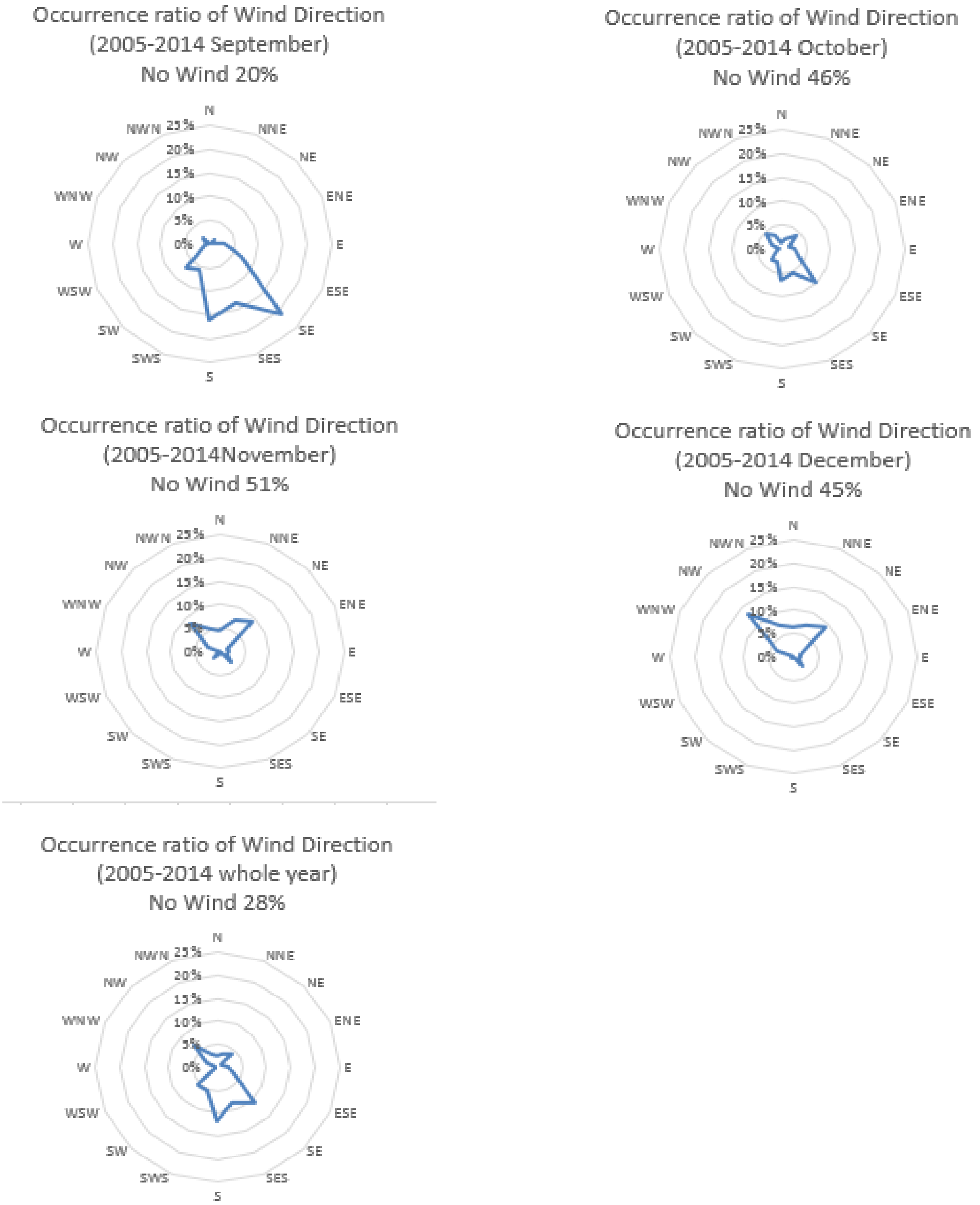


Occurrence ratio of Wind Direction
(2005-2014 July)
No Wind 5%



Occurrence ratio of Wind Direction
(2005-2014 August)
No Wind 14%





Source: JICA "Preparatory Survey on Chittagong Area Coal Fired Power Plant Development Project in Bangladesh Final Report"(March 2015, JICA/TEPSCO/TEPCO)

Figure 9-14 Occurrence of Wind Direction

〔Remark〕

In terms of wind conditions, 1 hour measurement data could not be obtained, so instead of it, "THREE HOURLY WIND SPEED AND DIRECTION" data at Kutubdia was utilized and the occurrence frequency was studied. 1 hour measurement data at near the site will be needed for the detail study.

(6) Site Selection of LNG Receiving Terminal

1) Site Selection

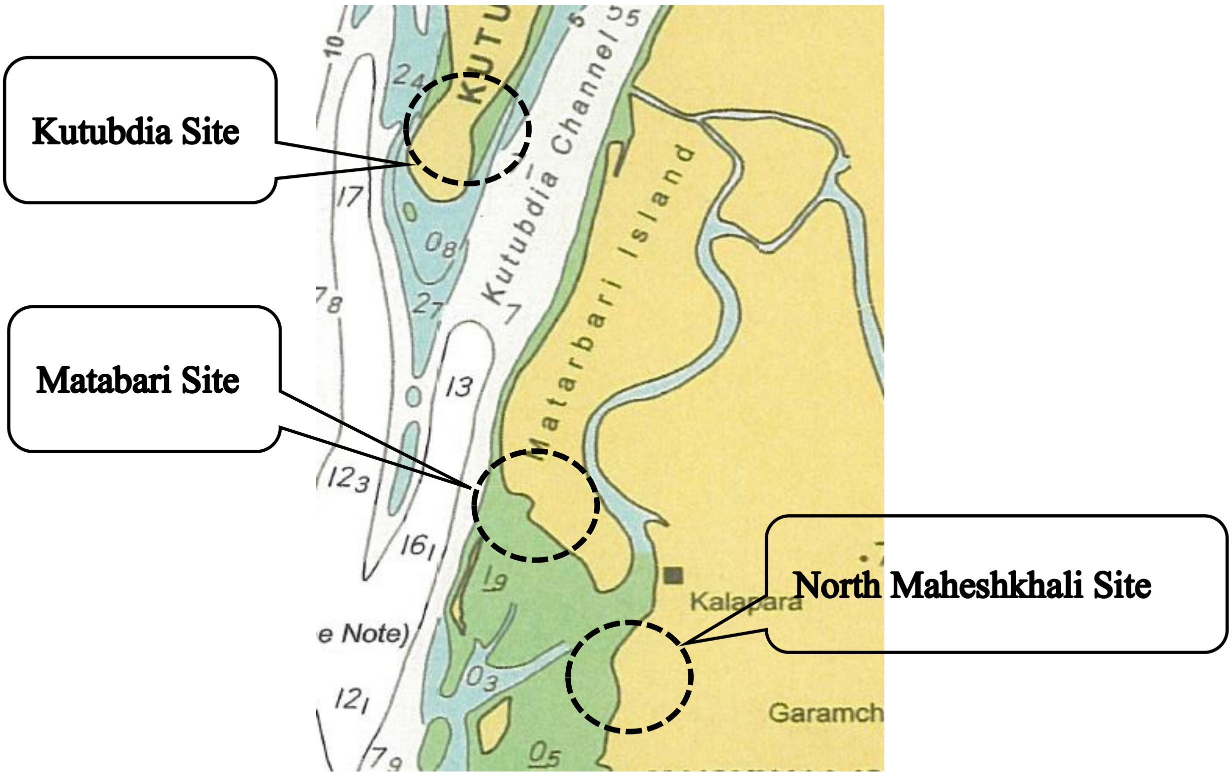
Three candidate sites of “Matarbari”, “North Maheshkhali”, and “Kutubdia” was selected in accordance with the above (1) to (5) criteria.

Furthermore the calmness was studied and compared in each candidate site. Above all, for Matarbari site, detail case study with three different ideas of LNG jetty design was done.

Table 9-9 Candidates of LNG Receiving Terminal LNG and Harbor/jetty Design Conditions

Case	Candidate site and condition		Remark
Case1-1	Matarbari Site	Jointly owned port	Jointly own port by coal power station and LNG receiving terminal
Case1-2		Individual port (without breakwater)	Construct LNG jetty in front of the ocean without breakwater
Case1-3		Individual port (with breakwater)	Construct LNG jetty and breakwater in front of the ocean
Case2	North Maheshkhali Site		Dredge shallow beach and construct channel and LNG jetty
Case3	Kutubdia Site		Dredge Kutubdia Channel and construct LNG jetty

Source: JICA PMSP2015 Survey Team



Source: JICA Survey Team

Figure 9-15 Candidate Sites of Land-based LNG Receiving Terminal

2) Evaluation by calmness (unloading availability)

Table 9-10 Case1-1 Jointly Owned Port Plan in Matabari (Excavated Type Plan)

	Area	Threshold Wave Height	Rate of Effective Working Days
LNG port	Entrance of channel	1.5m	94.7%＜95% By the Owner's judgement
	LNG berth	1.5m	more than 99.9% ＞ 95% Good
(Ref.)Coal port	Entrance of channel	1.5m	99.4% ＞ 96% Good
	Coal berth	1.0m	99.9% ＞ 96% Good

Source: JICA Survey Team

Note: In the feasibility study of collier, calmness was evaluated at the entrance of channel but for LNG tanker, calmness will be evaluated at the entrance of channel after turning around and root change.

Table 9-11 Case1-2 Matarbari Plan (Conventional Type Plan：Without Breakwater)

	Area	Threshold Wave Height	Rate of Effective Working Days
LNG port	LNG berth	1.5m	94.7%＜95% By the Owner's Judgement
(Ref.)Coal port	Entrance of channel	1.5m	94.7% ＜ 96% Not Sufficient
	Coal berth	1.0m	93.5% ＜ 96% Not Sufficient

Source: JICA Survey Team

Table 9-12 Case1-3 Matarbari Port Plan (Conventional Type Plan：Breakwater Construction)

	Area	Threshold Wave Height	Rate of Effective Working Days
LNG port	LNG Berth	1.5m	more than 96.5% ＞ 95% Good
(Ref.)Coal port	Entrance of channel	1.5m	99.2% ＞ 96% Good
	Coal berth	1.0m	96.5% ＞ 96% Good

Source: JICA Survey Team

Table 9-13 Case2 North Maheshkhali Plan

	Area	Threshold Wave Height	Rate of Effective Working Days
LNG port	Entrance of channel	1.5m	96.8% ＞ 95%　Good
	LNG berth	1.5m	more than 96.2% ＞ 95%　Good
(Ref.)Coal port	Entrance of channel	1.5m	96.8% ＞ 96%　Good
	Coal Berth	1.0m	96.2% ＞ 96%　Good

Source: JICA Survey Team

Table 9-14 Case3 Kutubdia Channel Plan

	Area	Threshold Wave Height	Rate of Effective Working Days
LNGport	LNG Berth	1.5m	more than 94.7%＜95% By the Owner's judgement

Source: JICA Survey Team

Remarks:

a) In this study calmness analysis was not done at the candidate port. To select the candidate site, detail calmness analysis should be implemented and studied.

b) Max allowable wind speed and wave height for unloading and criteria for docking and undocking at LNG port should be fixed by the Owner in consideration to the feasibility and operation of LNG receiving terminal.

c) Evacuation method, port for evacuation, and basins in case of bad weather should be considered.

3) Evaluation result of candidate site

Table 9-15 Candidate Site Evaluation Result

Case	Case1-1	Case1-2	Case1-3	Case2	Case3
calmness	◎	○	◎	◎	○
Comparison of Cost	Cost effective	Cost effective *Filling Soil Balance	Fairly expensive(Breakwater construction)	Expensive (Continuous dredging)	Expensive (Continuous dredging)
Natural Environment	-	-	-	Mangrove forest	-

Source: JICA Survey Team

Remarks

a) For the evaluation of breakwater construction cost, continuous dredging cost, and environmental cost, "the pre-FS report of coal fired power station in Chittagong" was referred.

b) It is uncertain how difficult it is to secure embankment material for land creation of LNG receiving terminal yard but case1-1, case2, and case 3 will be an effective plan in order to secure a certain amount of soil volume by dredging and cut for port preparation.

9.6.5 Ground Level

“The pre-FS of coal fired power station in Chittagong” shows the detail study of a flood tide caused by the ebb and flow and cyclone. With the same criteria, land creation can be planned in LNG receiving terminal.

Ground level of LNG receiving terminal facility yard can be fixed as +10.0m M.S.L with reference to the flood tide occurred in the next 50 years by cyclone. On the other hand, ground level of the port can be fixed as +5.0m M.S.L.

(1) Design Tidal Level

H.W.L. = +2.20m M.S.L M.S.L. = ±0.0m L.W.L. = -2.20m M.S.L.

(2) Storm Surge Height

Table 9-16 Storm Surge Height

Storm Surge Height	Average	25-year Return Period	50-year Return Period
Base on Maximum Data	4.2m	8.0m	9.0m
Base on Minimum Data	3.3m	6.2m	7.0m

Source: JICA Survey Team

(3) Design Ground Level

1) LNG Facilities Yard E.L. = +10.0m M.S.L.
2) Port Revetment E.L. = +5.0m M.S.L

9.6.6 Subsurface exploration

With "the pre-FS report of coal fired power station in Chittagong", the comprehensive subsurface exploration was implemented in 2012 and 2014. The result in 2014 will be shown in the following.

Subsurface at local site is composed by;

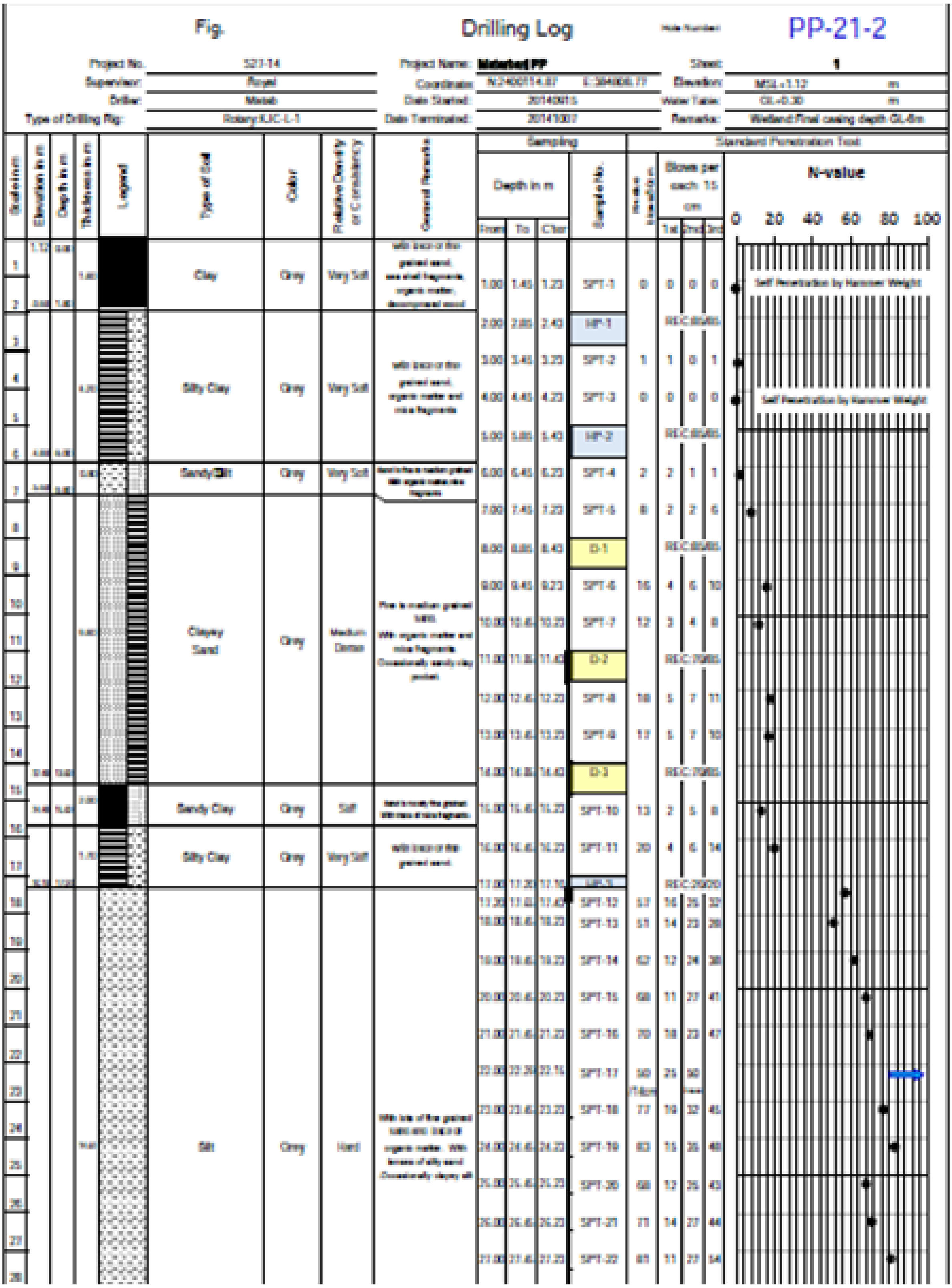
1. sand layer of 2 m thickness in the surface, then
2. alluvial sandy soil and alluvial clay of N value of 10 to 20 which thickness is 20 m, then
3. diluvial sandy and clay of N value of 30 to 40

Bearing pile for the main structure like LNG Storage Tank should be inserted to this diluvial sandy (DS).

Table 9-17 Subsurface Data (part.1)

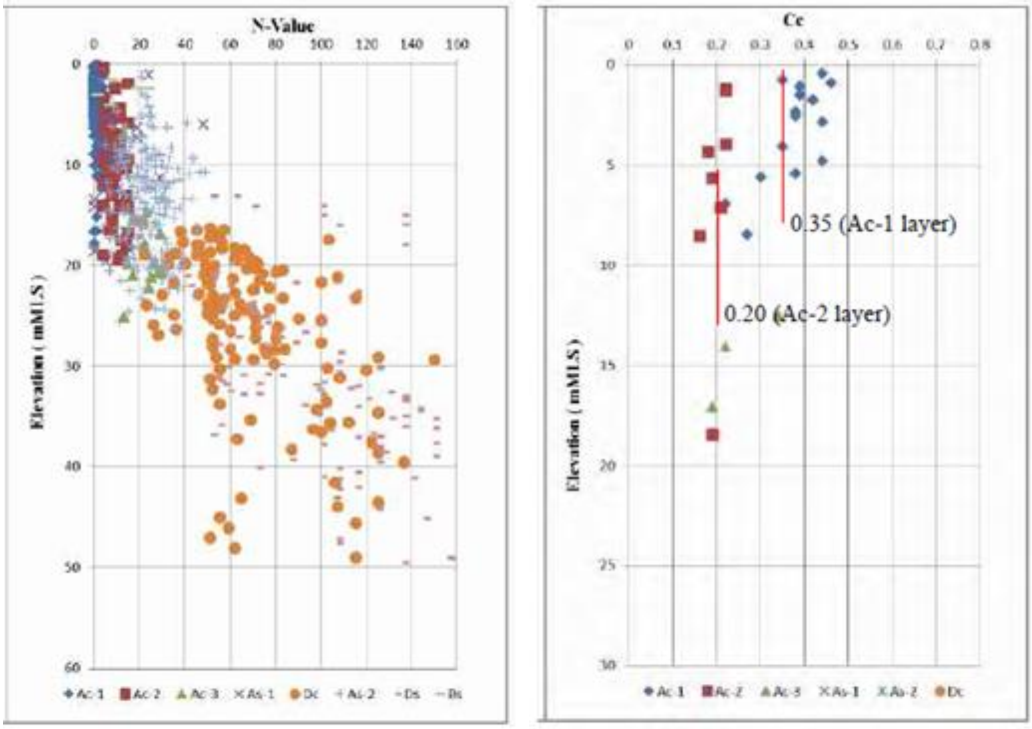
Layer	Material	Relative Density or Consistency	Thickness of Layer (m)	SPT(N) Values
Bs	Sandy Soil	Loose to Medium Dense	0.6 to 2.0	4 to 24
Ac-1	Clayey Soil	Very Soft to Soft	0.8 to 12.7	0 to 4
Ac-2	Clayey Soil	Medium Stiff to Stiff	0.9 to 8.7	4 to 15
Ac-3	Clayey Soil	Stiff to Hard	1.1 to 9.0	15-30
As-1	Sandy Soil	Very Loose to Loose	1.1 to 6.0	0 to 10
As-2	Sandy Soil	Medium dense to Dense	0.7 to 21.9	10 to 50
Dc	Clayey Soil	Hard	1.4 to 17.3	≧30
Ds	Sandy Soil	Very Dense	0.5 to 13.2	≧50

Source: "Preparatory Survey on Chittagong Area Coal Fired Power Plant Development Project in Bangladesh Final Report"(March 2015, JICA/TEPSCO/TEPCO)



Source: "Preparatory Survey on Chittagong Area Coal Fired Power Plant Development Project in Bangladesh Final Report"(March 2015, JICA/TEPSCO/TEPCO)

Figure 9-16 Drilling Log



Source: "Preparatory Survey on Chittagong Area Coal Fired Power Plant Development Project in Bangladesh Final Report"(March 2015, JICA/TEPSCO/TEPCO)

Figure 9-17 Subsurface Data (Part2, 3)

The surface layer, alluvial sandy and alluvial clay are relatively weak. And the foundation of LNG facility yard should be raised by 10 m as a countermeasure against the flood tide. Therefore the comprehensive soil stabilization will be needed.

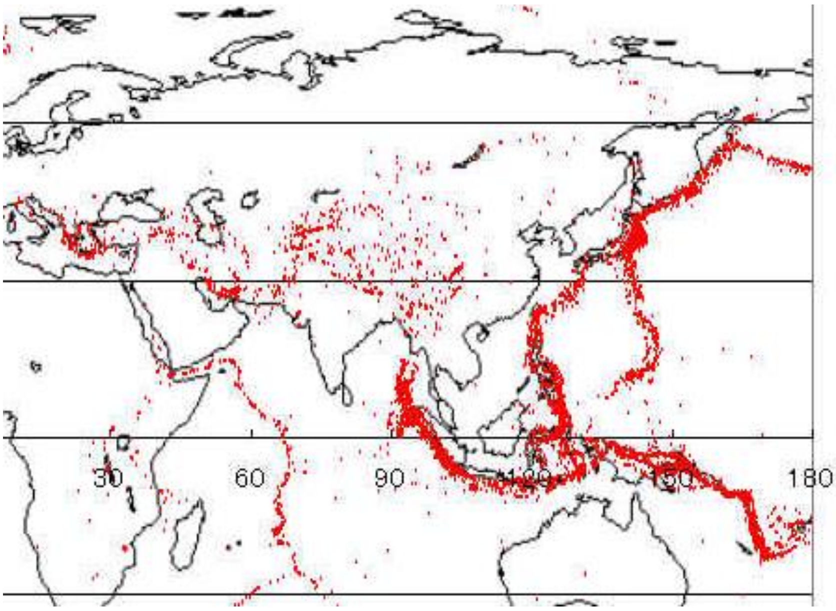
If spoil or excavated soil is used as an embankment material, the reinforcing ground of banking may be needed by the property of earth and sand.

Alluvial clay: PVD (Prefabricated Vertical Drain Method), DMM (Deep Mixing Method) Alluvial sandy: SCP (Sand Compaction Pile Method) Embankment material: DMM, etc.

9.6.7 Earthquake

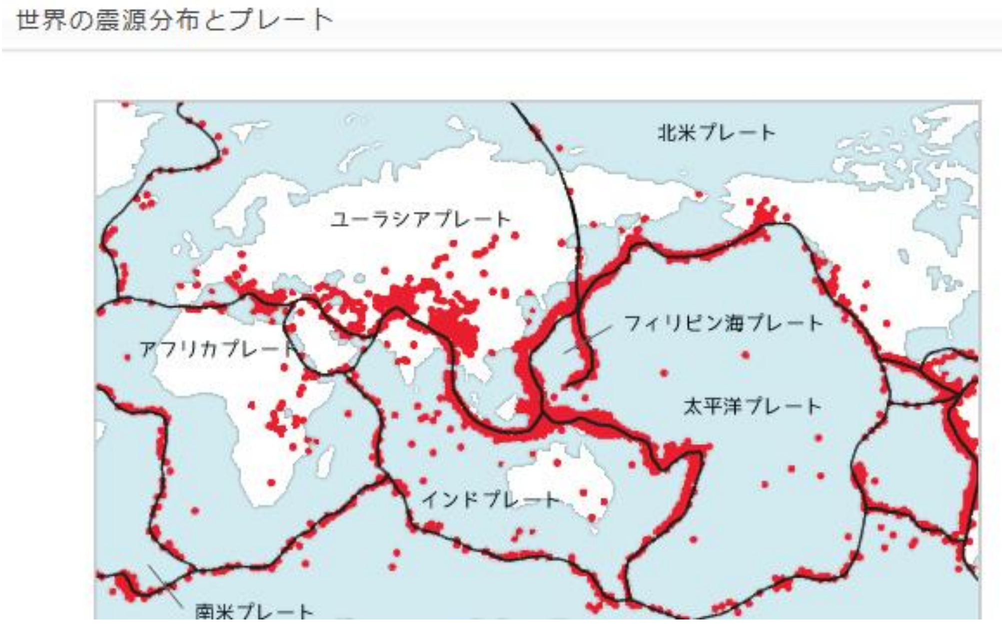
(1) Distribution of Earthquake Centre

Worldwide hypo central distribution and plate location will be shown in Fig.9 and 10.
The boundary between Indian plate and Eurasian plate is faced in Bengal Bay and here mega scaled earthquake has been frequently occurred in the past.



Source: White Paper on Disaster Management" (Cabinet Office, Government of Japan)

Figure 9-18 Worldwide Hypo Central Distribution Map (from 1 Jan,2004 to 24 June 2015, Depth: less than 100km, Magnitude 5 or more)



Source: White Paper on Disaster Management" (Cabinet Office, Government of Japan)

Figure 9-19 Worldwide Hypo Central Distribution and Plate Map

(2) Seismic Design

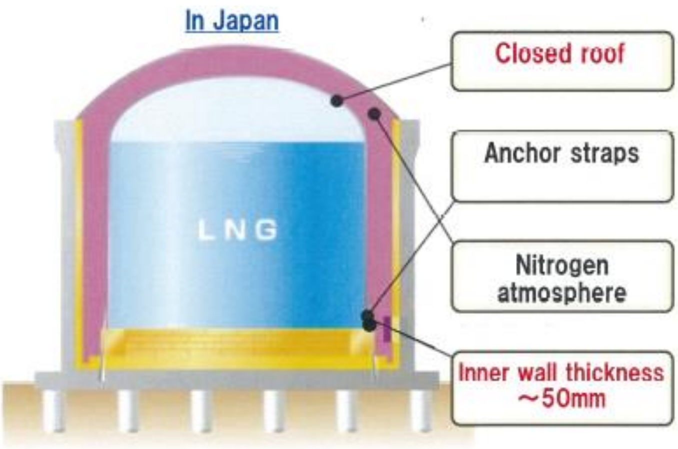
1) Seismic Design Standard

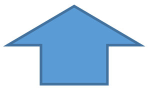
Bangladesh is a seismically active nation, so「BANGLADESH NATIONAL BUILDING CODE 2006」 was established and applied as an earthquake resistant design code.
LNG tank and other facility in the terminal are supposed to be designed in accordance with this standard

2) Earthquake- resistant LNG Storage Tank

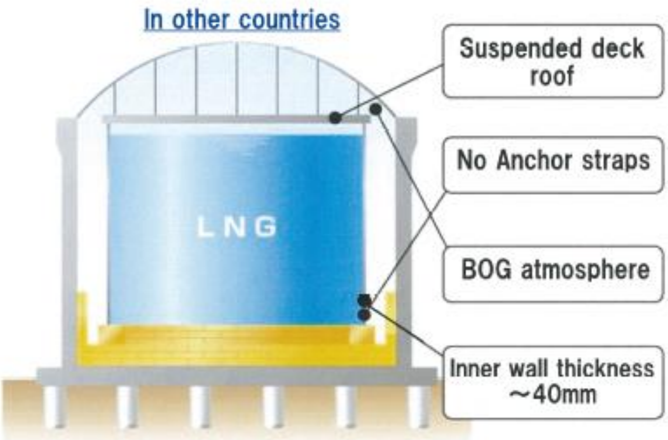
Normally design seismic coefficient of LNG Storage Tank is designed as SSE 0.2g and OGE 0.1g in Japan and other countries.
In no seismically active nations like Thailand and Singapore, the suspended deck type LNG Storage Tank can be applied but in Bangladesh dome roof type (full containment type) LNG Storage Tank will be recommended, which has been already applied in Taiwan and Japan.

Dome roof type PC LNG Storage Tank





Suspended deck type PC LNG Storage Tank



Source: JICA Survey Team

Figure 9-20 Structure of Earthquake- resistant LNG Storage Tank

Source: Osaka Gas Senboku terminal

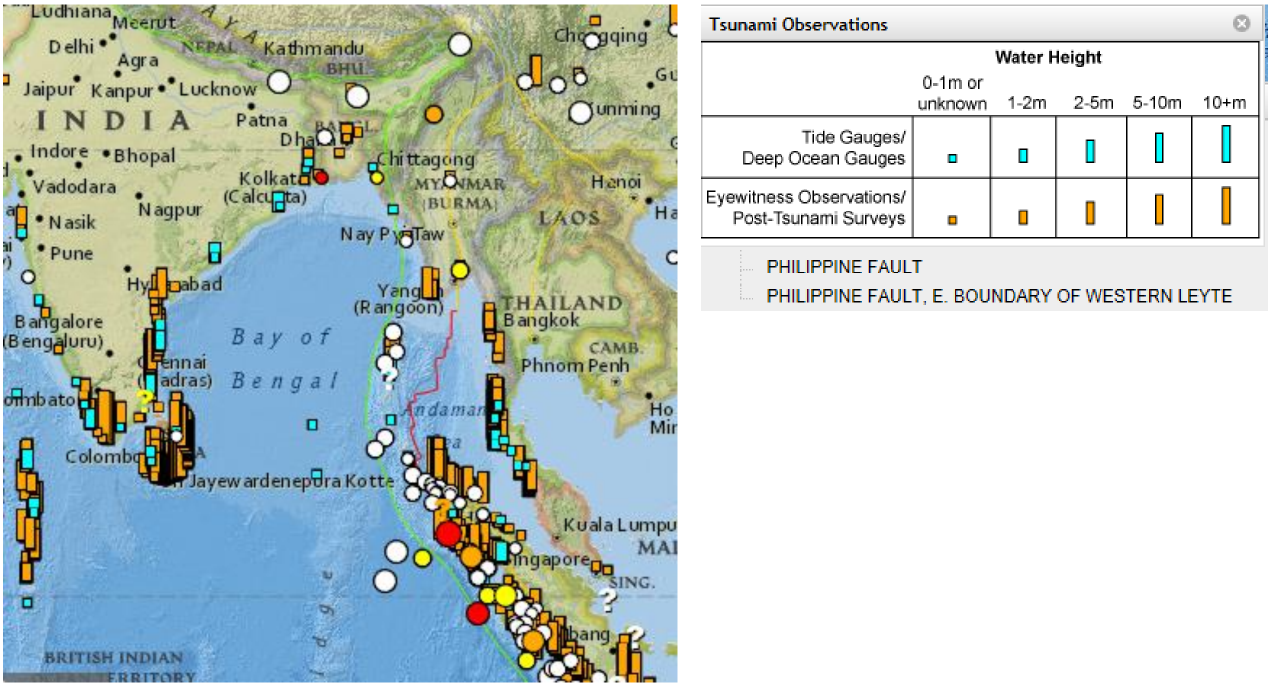
Figure 9-21 Overview of Above Ground Dome Roof Type PC LNG Storage Tank

Remarks
The material described an active fault in Bangladesh has not been disclosed yet but an active fault may be present near to the candidate site of LNG receiving terminal.
LNG Storage Tank should be designed to be far from the active fault as much as possible because the damage will be so large in case of the large scale disaster.
When feasibility study or FEED of LNG receiving terminal will be implemented, a geological survey at site should be done and the obtained data should be reflected to site selection, plot plan, and earthquake-resistant design of main equipment in the terminal.

9.6.8 Countermeasures to Tsunami

Bangladesh is very close to the border area between the plates, so Tsunami attack by large scale earthquake should be seriously considered. Tsunami hazard map in the Indian Ocean and Bay of Bengal will be shown in the below Figure.

The candidate site of LNG receiving terminal is located in the north peak of Bay of Bengal where the expected Tsunami height is 1 to 3 meter. This Tsunami height is less than that made by a cyclone, so Tsunami height may not be considered in the design of LNG eceiving terminal..



Source: NOAA: National Centers for Environmental Information Natural Hazards Viewer-Tsunami Observation

Figure 9-22 Tsunami Hazard Map in the Indian Ocean and Bay of Bengal

At the feasibility or FEED stage, the countermeasure should be studied again for the large scale earthquake occurred in the boundary area between the plates in Bay of Bengal.

9.6.9 CAPEX & OPEX of on shore LNG receiving terminal

With the average cost index in the existing on shore LNG receiving terminal, CAPEX at the 1st stage (500MMCFD of NG send out capacity, 3.5MTPA of LNG loading capacity) and the final stage (1,500MMCFD of NG send out capacity, 10.4 MTPA of LNG loading capacity) will be shown respectively in Table 9-18. Each specification of the 1st stage and final stage can be referred in the below Table.

Table 9-18 CAPEX Estimation

(Unit: US MM$)

	1st stage (500MMCFD, 3.5 MTPA)	Final stage (1,500MMCFD, 10.4 MTPA)
Land acquisition	200	200
Jetty and loading facility	100	200
Regasification facility	130	320
LNG storage tank	300	700
Others	30	80
Total	760	1,500

Source: JICA Survey Team

On the other hand, OPEX will be assumed to be varied from US$0.3/MMCF at 1st stage to US$0.6/MMCF at final stage when applied Japanese and Korean terminal operation record.

9.7 Challenges and Issues of LNG Terminal Implementation

9.7.1 Establishment of LNG Value Chain

(1) To ensure a stable LNG supply and reduce LNG stock period in tank by the diversification of LNG supply source and securement of LNG transportation route. In the LNG sale and purchase agreement, the Buyer should negotiate to mitigate “Take or Pay condition”, the change of destination and to induce the lower price by the cooperation with other Buyer. LNG transportation contract should be also competitive
(2) The reliable LNG unloading, storage, vaporization, and send out should be operated in as safety, stable, and low cost manner.
(3) LNG supply method should be diversified such as send out gas, LNG re-loading, LNG bunkering as ship fuel, LNG truck loading to the satellite station. At the same time, the stable LNG demand should be found in power plant, industrial/commercial/residential sector, and the third party operating the terminal.

9.7.2 Operation of LNG receiving terminal

LNG receiving terminal will apparently play an important role as one of energy infrastructure year by year. The terminal should be operated smoothly at start up period and then should be operated steadily to pursue the high availability and reliability.
To achieve it, various attention has to be needed from the point of operating organization, facility planning, maintenance, training, anti-disaster facility, and environmental protection, etc.

(1) Operating organization

Operation of the terminal needs operating team, maintenance team and engineering team as a whole. Each team needs a skillful engineer in the gas processing field as a team leader. The beginner should study through the Vendor’s seminar or others and should be given the opportunity to study in the similar LNG receiving terminal abroad, which will be very effective manner to enhance the understanding.

When the commercial operation has started, operating team should take a leadership to address the operating issues.
Next, main responsibility of each team will be clarified.

- Operating team is normally organized by 4 teams and will do a time shift work in 24 hours through the year. It will also designate operating facility regarding to the requested send out gas amount and also support LNG unloading operation in the terminal side when LNG vessel will reach to the terminal.
- Maintenance team works in a day time to grasp the operating condition of all facility though the daily check by database and establish the unique maintenance criteria designated for the terminal.
- Engineering team studies the reason of mal function in the commercial operation and will address the improvement of the facility when considering the optimum repairing plan and budget.

(2) Operation management

Operator will monitor and control all of the facility in the terminal from CCR. Especially the optimum LNG storage tank operation and the protection of tank stratification phenomenon should be paid the special attention.
The amount of send out gas and utility consumption should be managed for the stable operation and safety in the terminal.
Operator will also patrol the local site periodically and try to find the mal function point such as gas leakage, abnormal noise and vibration, etc.

(3) Maintenance of the facility

Maintenance team will prepare the monthly and yearly maintenance plan and the mid to long term maintenance plan with the budget by the enough discussion with operating team.
To cope with the unexpected equipment failure and system error, the utilization of "on-line call system" or remote maintenance contract with Vendor may be effective to solve. Further as a self-maintenance measure, the optimum management of the inventory and the update information exchange with maintenance service provider will be also crucial.

(4) Education and training

Through the internal discussion (QC circle activity) to initiate the operation manual and the optimum countermeasure at if case, the operation skill at normal and emergency situation will be developed. Operator should join with the purpose to the technical tour in other terminal and seminar and/or training program by Vendor, which will develop the operation skill of the team.
OTS (Operating training simulator) has been developed in a recent year, which enables to generate various mal function cases in the monitor and evaluate operator's skill to recover from such mal function cases logically.

9.7.3 Effective Terminal Management

With the growing gas demand in Bangladesh in the future, the enforcement of gas demand supply management system will be more needed nation widely. Namely if LNG receiving terminal will be constructed in many places to compensate the supply shortage of domestic gas, the integrated gas dispatch center will be needed to order the allocated gas send out amount to each LNG receiving terminal. Practically the SCADA system owned by TGCL should be highly upgraded to meet this requirement.

From the view point of stable NG supply, to cope with the serious mal function at major facility and natural disaster, back up operation manner among the plural terminals should be studied and trained. Moreover in preparation for terrorist attack and riot, the terminal security plan should be seriously considered and emergency training should be carried out as a routine work.

Chapter 10 Coal Supply

10.1 National Coal Development Policy

10.1.1 The present situation of the coal policy

Currently, the progress is not seen in Coal Policy, and the future prospect is not clear, too. On the other hand, the extension plan of production in Barapukuria coal mine is advancing.

As a specific example of the new coal mine development, there are Dighipara、Khalaspir and Phulbari .The application of the exploration license of Dighipara goes out from Perobanngla and the applications of new coal mine development of Khalaspir and Phulbari also go out, but they are a suspension state because the government does not accept it.

10.1.2 PSMP2010 Review

Table 10-1 shows the comparison between predicted production until 2041 by domestic coal mine and predicted value in PSMP2010.

In addition, the figures in Table 10-1 are shown by a graph in Figure 9-1. The reasons that lowered amount of production of PSMP2016 in comparison with PSMP2010 are following the fact that an argument of Coal Policy was prosperous in PSMP2010 and domestic coal development was expected. However, the situation changes and reaches it at the present in PSMP2016.

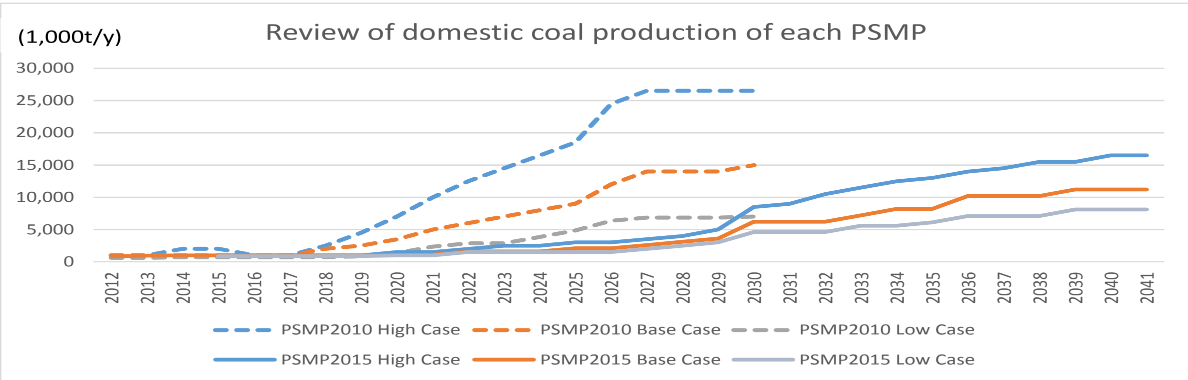
Table 10-1 Comparison of Forecasted Domestic Coal Production between PSMP2010 and This Investigation

Year	Domestic Coal Production in PSMP2010 (1,000t)			Domestic Coal Production in PSMP2016 (1,000t)		
	(Note: From 2005 to 2008 shows actual production)			(Note: From 2012 to 2013 shows actual production)		
	High Case	Base Case	Low Case	High Case	Base Case	Low Case
2012	1,000	1,000	600		855	
2013	1,000	1,000	600		947	
2014	2,000	1,000	700		1,000	
2015	2,000	1,000	700	1,000	1,000	850
2016	1,000	1,000	700	1,000	1,000	850
2017	1,000	1,000	700	1,000	1,000	850
2018	2,500	2,000	750	1,000	1,000	900
2019	4,500	2,500	850	1,000	1,000	900
2020	7,000	3,500	1,350	1,500	1,100	1,000
2021	10,000	5,000	2,350	1,500	1,100	1,000
2022	12,500	6,000	2,850	2,000	1,600	1,500
2023	14,500	7,000	2,850	2,500	1,600	1,500
2024	16,500	8,000	3,850	2,500	1,600	1,500
2025	18,500	9,000	4,850	3,000	2,100	1,500
2026	24,500	12,000	6,350	3,000	2,100	1,500
2027	26,500	14,000	6,850	3,500	2,600	2,000
2028	26,500	14,000	6,850	4,000	3,100	2,500
2029	26,500	14,000	6,850	5,000	3,600	3,000
2030	26,500	15,000	7,000	8,500	6,200	4,600

Year	Domestic Coal Production in PSMP2010 (1,000t) (Note: From 2005 to 2008 shows actual production)			Domestic Coal Production in PSMP2016 (1,000t) (Note: From 2012 to 2013 shows actual production)		
	High Case	Base Case	Low Case	High Case	Base Case	Low Case
2031				9,000	6,200	4,600
2032				10,500	6,200	4,600
2033				11,500	7,200	5,600
2034				12,500	8,200	5,600
2035				13,000	8,200	6,100
2036				14,000	10,200	7,100
2037				14,500	10,200	7,100
2038				15,500	10,200	7,100
2039				15,500	11,200	8,100
2040				16,500	11,200	8,100
2041				16,500	11,200	8,100

Remarks: YEAR shows the fiscal year in the table. The fiscal year Bangladesh is from July to June. For example, 2012 show from July, 2012 to June, 2013 in 2012

Source: PSMP Study Team



Source: PSMP Study Team

Figure 10-1 Comparison with PS2010

10.2 Current Situations and Issues of Supply and Demand of Domestic Coal

10.2.1 Coal reserve of each coal field and estimated minable coal reserve

It is well known that the bituminous coal, which is called "Godwin coal" of the Permian Period as well as sub-bituminous coal to lignite of the Tertiary Era occur in Bangladesh. According to the present development data, there are five coal fields in Bangladesh, all of which situated in between the Jamuna river and the Padma river in the northwestern part of Bangladesh. The measured and probable coal reserves total 3.3 billion tons. According to the Draft Coal Policy (June 2007), the measured coal reserve that can be mined for the time being is estimated to be 1,168 million tons, except in Jamalgonj where coal seams are located relatively deep underground. Though there were no additional information in the study of PSMP2016, as developments continue, probable coal reserves are likely to increase. Figure 10-2 indicates the location of coal fields.

Coal in Bangladesh is generally characterized as having low ash content and low sulfur content that are in favor of the environment. It is bituminous coal with properties similar to the coal being used by power stations in Japan. Another grade of coal, which is classified into coking coal for iron production whose commodity value is very high in the market, is also available.

Meanwhile, the problem lies in its mining method. For underground coal mines, the thick coal seams (30 to 40m) pose a problem for the mining method and miming rate. For open-cast coal mines, the mining method which includes dewatering technology to prevent inundation and protect the environment has become an issue, because coal deposits accumulate in the relatively deep underground (170 to 450m) and such a coal mine tends to have an aquifer, called "UDT (Upper Dupi Tila)," over the coal seams. The upper coal seam in particular is dotted with a rice field, the places of residence of inhabitants, and the move of inhabitants, social environmental consideration become the important issue.

Table 10-2 shows the details of six coal fields that were explored and the progress in their development. The Barapukuria Coal Mine is the only operating coal mine in Bangladesh and is undergoing completely mechanized underground mining, the details of which will be described later. An open-cast coal mine development in Phulbari came to a deadlock due to the oppositions by the local people, which will give directions to the coal mine development in Bangladesh. In other words, coal mine development in Bangladesh will depend on whether the Government of Bangladesh can successfully win, as a national policy, consent from people for an open-cast mining method, which is superior to underground mining in terms of stable coal production.

Table 10-3 shows estimated minable coal reserve depending on open-cast and underground mining method. As for the quantity of actual minable coal, 430 million tons in No .1 to No.4 is anticipated based on present mining technology.

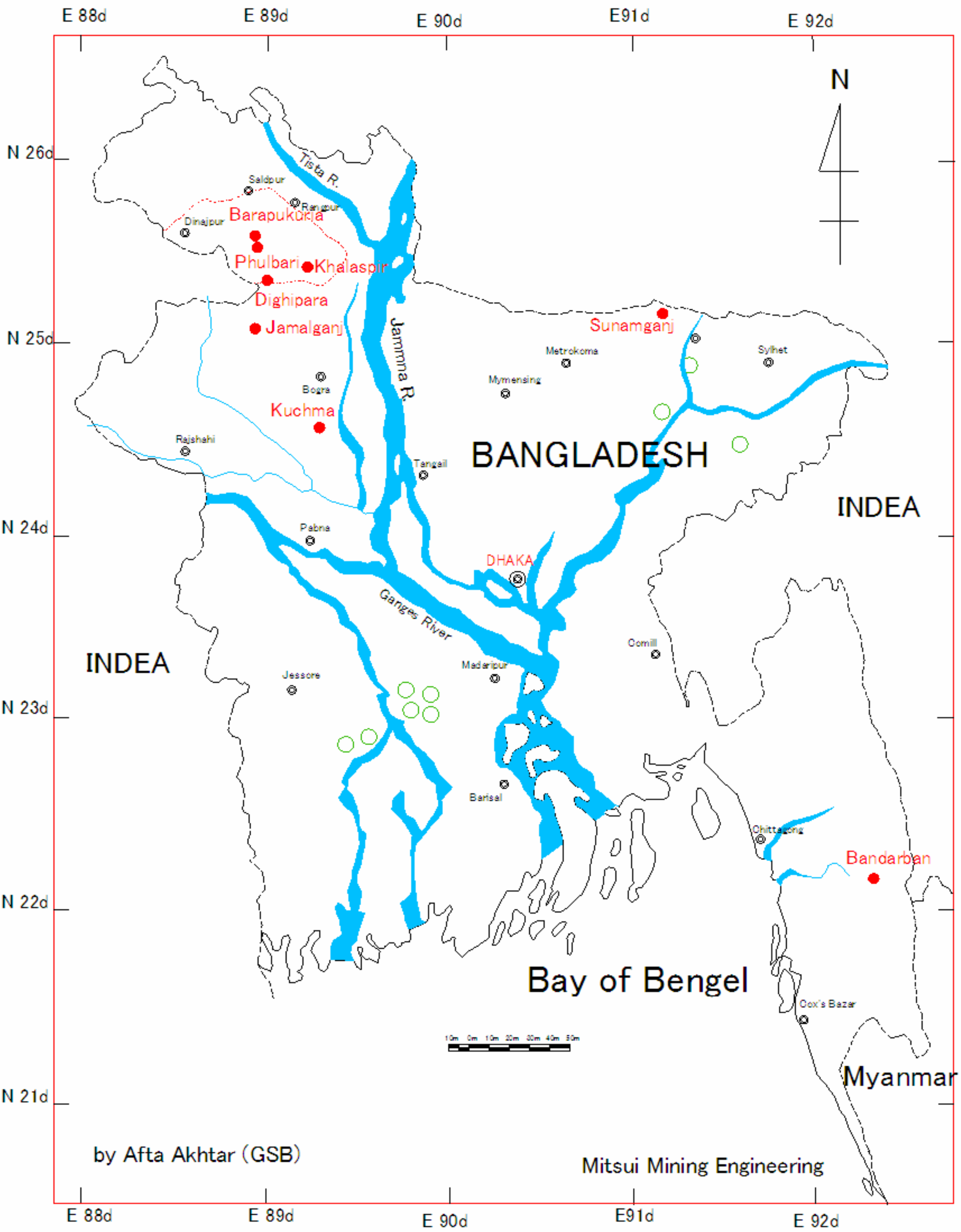


Figure 10-2 Locations of Coal Fields in Bangladesh[14]

14 Red points indicate coal fields.

Table 10-2 Coalfield Development Status in Bangladesh

	Coal field name	Develop-ment year	Exploring company (Number of borings)	Depth (m)	No. of coal seams	Av. thickness of composite coal seams (m)	Measured coal reserve (100 million tons)	Measured＋probable coal reserves (100 million tons)	Remarks
1	Barapukuria (Dinajpur)	1985 -87	GSB (31)	118 - 506	6	51	3.03 (Minable coal reserve by U/G: 64 million tons)	3.9	・Petrobangla and China National Machinery Import and Export Corporation (CMC) in China concluded an development agreement in 1994. BCMCL was founded in 1998. Capacity designed: One million ton /year. ・Enhancement of production is under planning. ・A small-scale open-cast mining project is feasible. For open cut mining technology introduction, Tata of the Indian company suggested open-air mining, but the government does not give a conclusion. ・A 250MW coal-fired thermal power station is in operation, and a study is on the table to build a new 125MW power station.
2	Phulbari, (Dinajipur)	1997	BHP (108)	150 - 240	2	15-70	5.72	5.72	・Asia Energy has completed a feasibility study. When the company was going to engage in a large-scale open-cast coal mine development, the development project was suspended in August 2006 due to oppositions by local people. ・It is a problem that the Phulbari open-cut mining plan submitted by Asian energy did not touch about groundwater behavior and a landfill plan after mined. The biggest problem is drinking water and irrigation water measures of inhabitants. ・Although Global Coal Management has succeeded to the development interest, progress made so far is unknown.
3	Khalaspir, (Rangpur)	1989 -90	GSB (14)	257 - 483	8	42.3	1.43	6.85	・The measured coal reserve is 143 million tons. ・F/S was completed by Chinese consultant of U/G mining in Shandon. But, the government was not satisfied the F/S report. The report included ten exploration drillings and good 3D seismic exploration. ・The annual coal production plan ranges from two million to four million tons.
4	Dighipara, (Dinajipur)	1994 -95	GSB (5)	328 - 407	5	62	1.5	6.0	・GSB made five borings in a 1.25 km2 area and found five coal seams. The initial probable coal reserve is 600 million tons. ・A Korean syndicate has approached Petrobangla for development and investment. ・BAPEX carried out an investigation into 2D seismic

									exploration in Dighipara. The report is under making at present.
5	Jamalgonj, (Bogra)	1962	GSB (10)	640-1,158	7	64	10.53	10.53	・Largest coal field in Bangladesh ・Targeting coal seam gas of CBM (coal bed methane) in deep underground ・There are three proposals to develop in Jamalgonj, which are Coal Bed Methane(CBM) for recover gas from coal seam, Underground Gasification(UCG) by Green Energy in Australia, U/G mining by Chinese company. But the government didn’t conclude to these proposals.
6	Kuchma, (Bogra)	1959	SVOC	2,380 -2,876	5	51.8			・Targeting coal seam gas of CBM (coal bed methane) in very deep coal seam

Source: GSB and edited PSMP Study Team

Table 10-3 Minable Coal Reserve depending on Mining Method

	Coal field name	Depth (m)	No. of coal seams	Av. thickness of composite coal seams (m)	Measured reserves (million tons)	Mining method	Minable coal reserve (million t)
1	Barapukuria (Dinajpur)	118 -506	6	51	303	U/G (15%)	45.5
2	Phulbari, (Dinajipur)	150 -240	2	15-70	572	O/C (60%)	343.2
3	Khalaspir, (Rangpur)	257 -483	8	42.3	143	U/G (15%)	21.5
4	Dighipara, (Dinajipur)	328 -407	5	62	150	U/G (15%)	22.5
5	Jamalgonj, (Bogra)	640-1,158	7	64	1,053	U/G (10%)	105.3
6	Kuchma, (Bogra)	2,380 -2,876	5	51.8			
Total					3,300		438

Source: Edited by PSMP Study Team

10.2.2 Current situation and issue of Barapukuria coal mine

(1) Overview
The Barapukuria Coal Mine was developed jointly by Petrobangla and XMC-CMC in China by an agreement of M&P (the Management, Production and Maintenance) concluded in 1994. According to the M&P Contract, CMC has transferred mechanized longwall mining method and achieved a certain degree in the stable production of coal. The first contract achieved of 3.65 million tons for target 4.75 million tons for 71 months from September, 2005. Furthermore, after an international bid aiming at 5.5 production million tons, XMC-CMC was entered again into as the second contract with MPM&P (Management, Production, Maintenance & provisioning Services). This was contracted on a premise to go back in August, 2011 in December, 2012. In this contract, the LTCC (Longwall Top Coal Caving) facilities of thick seam mining technology were introduced. It operated from May, 2013. The face conveyer carries mined coal of the 3m operating height and the rear conveyor installed rear of self advancing support carries collapse coal of about 2 m hight of coal.   Technical fixation and increased production in thick seam are expected.

All the underground facilities are from China. The vertical shaft is 300m long, and the skip capacity for coal hoisting is set to 3,300t/d. Coal productions have been stable in recent years. Coal is supplied for neighboring Barapukuria Thermal Power Stations (125kw x 2). The other remaining coal is primarily supplied for brick constructions and other purchasers in the general industry. At present, although the coal mine has an annual production capacity of approx. one million tons, the mine is studying to reinforce the production capacity to increase capacity of the power station. And the mine is also planning an annual production of 1.5 million tons in the future.

(2) Production results
The amount of production and sales of the Barapukuria coal mine are shown in Table 10-4. PDB in the table means the sales volume for the Barapukuria power station and the coal mine has always the coal stock of two months at the mine for the Barapukuria power station. LTCC face operated in 2013 and the production became stable and rising. Production decreased due to water burst and delay of withdrawal & installation of a face in 2014/2015. However, it is thought that it is near to achieve 1 million tons of production target of original existing facilities. In the other hand, the sales price of the coal for the power station for US$130/t (from May, 2015), the local buyer Tk 13,680[15]/t (from January, 2014, including VAT). As for this price, comparing with a mine mouth price of Australian coal of similar coal quality, these prices become considerably more expensive than present coal price of US $ 50-60 (March, 2015).

Table 10-4 Coal Production and Sales Records at Barapukuria Coal Mine

Year	Production (t)	Sale (t)	
		PDB	Others buyers
Till June, 2004	91,038		70,132
2004-2005	87,143		74,768
2005-2006	303,016	209,235	45,020
2006-2007	388,376	460,231	5,707
2007-2008	677,098	491,354	10,393
2008-2009	827,845	532,488	258,081
2009-2010	704,568	501,132	319,255
2010-2011	666,635	463,923	107,795
2011-2012	835,000	499,972	332,526
2012-2013	854,804	643,978	288,266

15 When ONE US$ is to be 78Tk (March 2014), Tk 9,200 is US$ 118.

2013-2014	947,125	524,143	338,618
2014-2015	6,75,776	5,222,129	313,405
Total	7,058,423	4,326,458	2,163,965

Souce : Annual Reportof 2-14-2015, Barapukuria Coal Mining Co. Ltd

Table 10-5 Change of the coal sales price to PDB (Barapucuria power station)

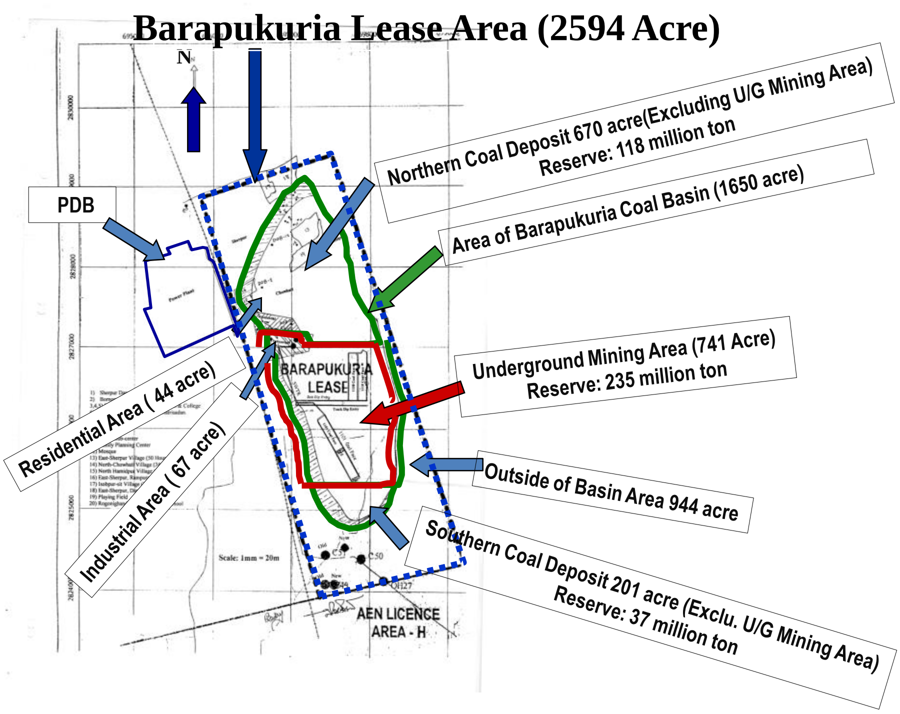
Sl No.	Date on which prices fixed	Price of coal/t (US$)
1	29 May 2001	61.50
2	July 2008	71.50
3	July 2010	85.50
4	01 Feburuary 2012	105.00
5	01 May 2015	130.00

(3) Expansion plan for the mine

An expansion program of the mine, there are the Southern part (reserves 37 million tons) and the Northern part (reserves 118 million tons). The area surrounded in a red line shows an existing mine and the area surrounded in a green line shows expansion plan in Figure 10-3. Figure 10-4 shows the details of Northern part and the Southern part. It can pay attention to the Northern part development to examine open cast mining method.

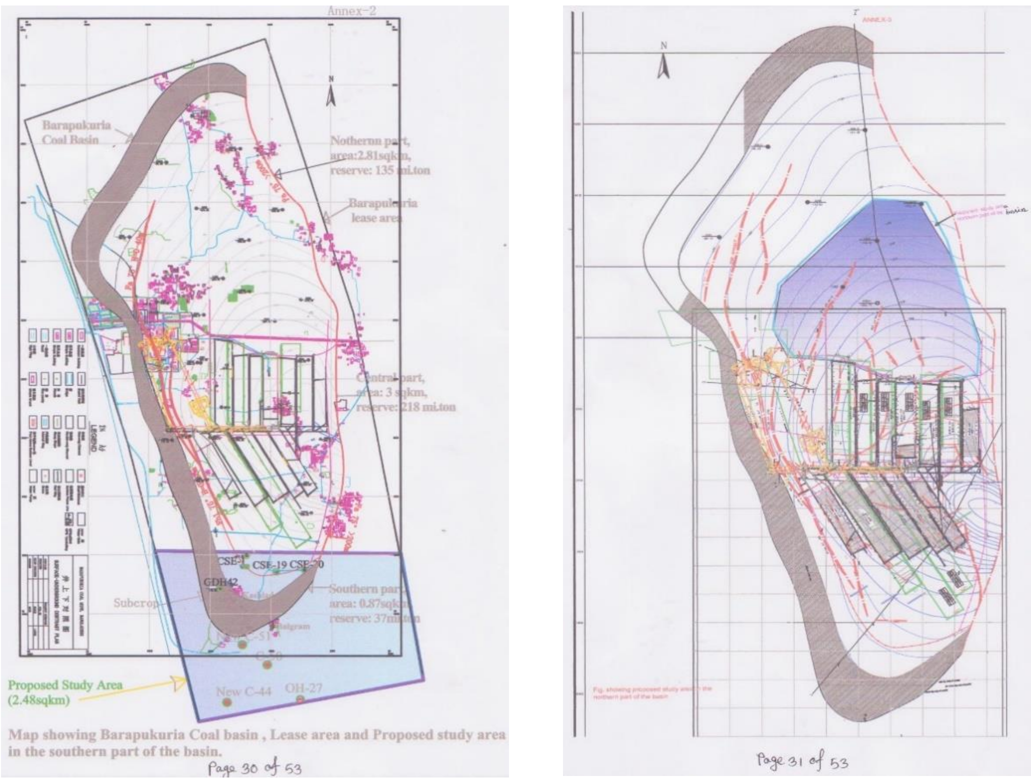
The plan will be along suggestion of PSPM2010 that opencast mining method in Bangladesh by a small pilot plan should be carried out and technique issues and social environmental problems should be examined at first through the pilot plan. The hydrological survey by six of the trial boring is already finished and a report is completed. The judgment of the Bangladesh government is waited now.

Barapukuria coal mine has a pioneer role of the coal development of the Bangladesh, and the wave of the future will become some guide line for coal development of the future Bangladesh.



Source: Barapukuria Coal Mining Co. Ltd

Figure 10-3 Expansion Plan of Barapukuria



Source: Barapukuria Coal Mining Co. Ltd

Figure 10-4 Expansion Plan of South Area (at left) and North Area (at right)

(4) Issues

(a) The stabilization of production in the deeper place than 2nd Slice[16] by LTCC.
LTCC face operated from May, 2013, and Face 1210, Face 1206 were finished. The mining height was 3m in original at 1st Slice and the mining height of these LTCC faces was total 5m by mechanical mining height (3m) plus caving height (2m) and the caving height is planned to increase more. It is under examined now but the person in charge did not seem to have the particularly big problem.

(b) Increased production
The present transporting capacity of a shaft skip to carry out the mined coal to the surface is small with 8 tons now. It will be possible to increase it to around 1.2 million tons per year by extension of the operating time of skip and the reinforcement of an underground coal reserve pocket. When more than 1.5 million production is planed, new investment will be required to upgrade capacity of the skip or to make a new skip shaft.

(c) An aspect of technology transfer to Bangladesh engineer and worker
Technology transfer at Barapukuria Coal Mine is very important to predict the future development and production at underground coal mines in Bangladesh.

- Regarding the methods of the technology transfer, there is “On the Job Training” and “Classroom within MPm&P Contract” between China and BCMCL. Safety control items are exceptionally very important in technology transfer program.

- The production technology and safety technology are particularly important in various kinds of technical acquisition. The safety technology is the most important in that. In Japan, the coal mine corporate strategy of “Safety First, The Production Second” has been demanded from old days.

10.2.3 An aspect of un-developing coal field

Obvious progress was not found and refer to REMARKS in the Table 10-2 for the present situation of each coal field.

10.2.4 Forecast of domestic coal production

Table 10-6 shows forecast of domestic coal production until 2014 including future coal mine development program.

[16] When thick seam is mined by longwall mining method in underground, thick coal seam is divided into some thicknesses of coal seam because all seam can’t be mined at a time. 2nd slice is called coal seam mined secondly.

Table 10-6 Performance and Forecast of Domestic Coal Production

Year	Total coal production (High Case) (1,000t/y)	Total coal production (Base Case) (1,000t/y)	Total coal production (Low Case) (1,000t/y)	Production of Domestic Coal Mine (1,000t/y)														
				Existing Coal Mine & New O/C					New Coal Mine (U/G & O/C)									
				Barapukuria U/G & new O/C					Kalaspir(U/G)			Dighipara(U/G)			Phulbari(O/C)			
				Under Ground mining (U/G)			Open Cast mining(O/C)		U/G			U/G			O/C			
				(HC)	(BC)	(LC)	(HC)	(BC)	(HC)	(BC)	(LC)	(HC)	(BC)	(LC)	(HC)	(BC)	(LC)
2005-6		303			303												
2006-7		388			388												
2007-8		677			677												
2008-9		828			828												
2009-10		705			705												
2010-11		667			667												
2011-12		835			835		F/S & Const-ruction Term										
2012-13		855			855												
2013-14		947			947												
2014-15		676			676												
2015-16	1,000	1,000	850	1,000	1,000	850											
2016-17	1,000	1,000	850	1,000	1,000	850											
2017-18	1,000	1,000	900	1,000	1,000	900			F/S & Const-ruction Term						F/S & Const-ruction Term		
2018-19	1,000	1,000	900	1,000	1,000	900											
2019-20	1,000	1,000	900	1,000	1,000	900						F/S & Const-ruction Term					
2020-21	1,500	1,100	1,000	1,500	1,100	1,000											
2021-22	1,500	1,100	1,000	1,500	1,100	1,000											
2022-23	2,000	1,600	1,000	1,500	1,100	1,000	500	500									
2023-24	2,500	1,600	1,000	1,500	1,100	1,000	1,000	500									
2024-25	2,500	1,600	1,000	1,500	1,100	1,000	1,000	500									
2025-26	3,000	2,100	1,000	1,500	1,100	1,000	1,500	1,000									
2026-27	3,000	2,100	1,000	1,500	1,100	1,000	1,500	1,000									
2027-28	3,500	2,600	1,500	1,500	1,100	1,000	1,500	1,000	500	500	500						
2028-29	4,000	3,100	2,000	1,500	1,100	1,000	1,500	1,000	1,000	1,000	1,000						
2029-30	5,000	3,600	2,500	1,500	1,100	1,000	1,500	1,000	1,500	1,000	1,000	500	500	500			
2030-31	8,000	5,700	3,600	1,500	1,200	1,100	3,000	2,000	2,000	1,000	1,000	1,000	1,000	1,000	500	500	500
2031-32	9,000	6,200	4,100	1,500	1,200	1,100	3,000	2,000	2,000	1,000	1,000	1,500	1,000	1,000	1,000	1,000	1,000
2032-33	10,500	6,200	4,100	1,500	1,200	1,100	3,000	2,000	2,000	1,000	1,000	2,000	1,000	1,000	2,000	1,000	1,000
2033-34	11,500	7,200	4,600	1,500	1,200	1,100	4,000	2,000	2,000	1,000	1,500	2,000	1,000	1,000	2,000	2,000	1,000
2034-35	12,500	8,200	4,600	1,500	1,200	1,100	4,000	2,000	2,000	2,000	1,500	2,000	1,000	1,000	3,000	2,000	1,000
2035-36	13,000	8,200	5,100	1,500	1,200	1,100	4,000	2,000	2,500	2,000	1,500	2,000	1,000	1,500	3,000	2,000	1,000
2036-37	14,000	10,200	5,100	1,500	1,200	1,100	4,000	2,000	2,500	2,000	1,500	2,000	2,000	1,500	4,000	3,000	1,000
2037-38	14,500	10,200	6,100	1,500	1,200	1,100	4,000	2,000	2,500	2,000	1,500	2,500	2,000	1,500	4,000	3,000	2,000
2038-39	15,500	10,200	6,100	1,500	1,200	1,100	4,000	2,000	2,500	2,000	1,500	2,500	2,000	1,500	5,000	3,000	2,000
2039-40	15,500	11,200	6,100	1,500	1,200	1,100	4,000	2,000	2,500	2,000	1,500	2,500	2,000	1,500	5,000	4,000	2,000
2040-41	16,500	11,200	6,100	1,500	1,200	1,100	4,000	2,000	2,500	2,000	1,500	2,500	2,000	1,500	6,000	4,000	2,000
2041-42	16,500	11,200	6,100	1,500	1,200	1,100	4,000	2,000	2,500	2,000	1,500	2,500	2,000	1,500	6,000	4,000	2,000

Remarks: The arrow in the Table shows a run-up term including authorization for the coal mine development, construction.

Source：PSMP Study Team

10.3 The Present Aspect and Issues of the Import coal

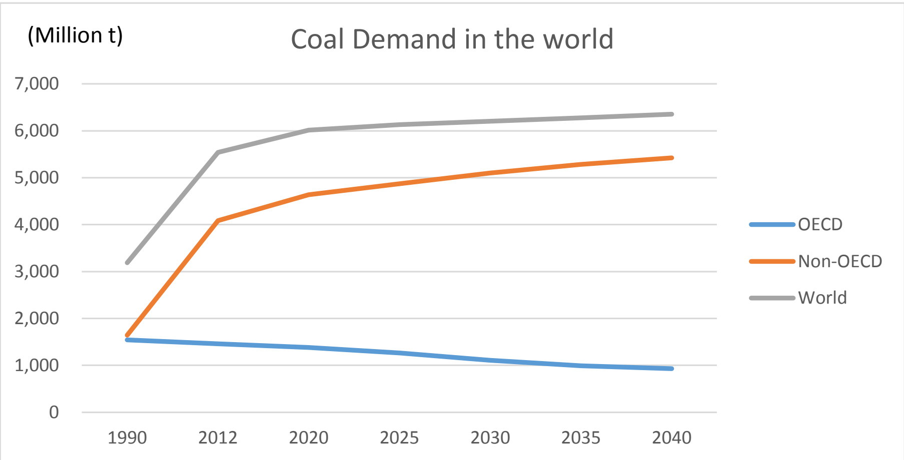
10.3.1 General view

Figure 10-5 shows the quantity of world coal demand until 2040 in New Policies Scenario[17] of World Energy Outlook of IEA. Coal demand for Non-OECD countries increases rapidly from the Figure. The quantity of demand for Non-OECD countries is expected to increase five-fold of the demand of current OECD countries. China and India occupy this main increase to show it in Figure 10-6.

On the other hand, it is a coal import of Southeast countries trend in Figure 10-6 to be important to Bangladeshi. Figure 10-7 shows the coal import trend of other Southeast countries to begin Malaysia, Thailand, Philippine which is the advance country of the coal consumer. It is in particular a trend of these past five years to attract attention. Table 10-7 shows the import quantity of each countries.

It is obvious that the coal import of each country suddenly increases from the Table. In addition, the result of our investigation found that Bangladeshi, actually, imports coal of approximately 4 times bigger than the number of the Table. It will be a difference of how to handle statistics amount. Therefore the figures in Figure 10-7 and Table 10-7 should be treated as for a reference figures.

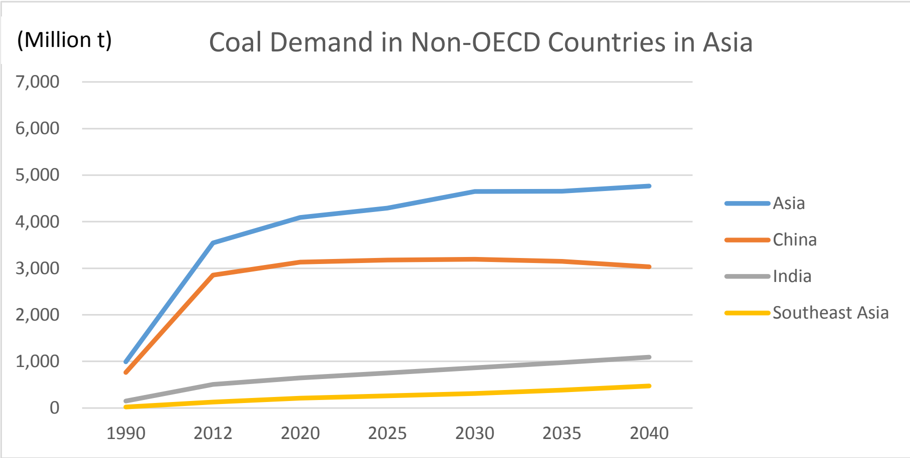
It will be difficult to predict exactly how much coal Bangladesi can import sustainably and economically depending on coal quality, price, concession, but it seems that Bangladesi will have a tough time to procure coal considering coal demand in Southeast in the near future. Therefore, when Bangladesi lowers the specifications of the coal quality than circulating coal now, 20-30 million tons of coal will be ensured in stable import and economic situation from India, Indonesia, Australia, the African supply system at a stage in 2030. In addition, as for the quantity of import coal demand for Bangladeshu country, 60 million tons are expected in 2040 in Table 10-12, but it is thought that there will be many problems.



Source: Table 5.3 in Coal market outlook by World Energy Outlook 2014

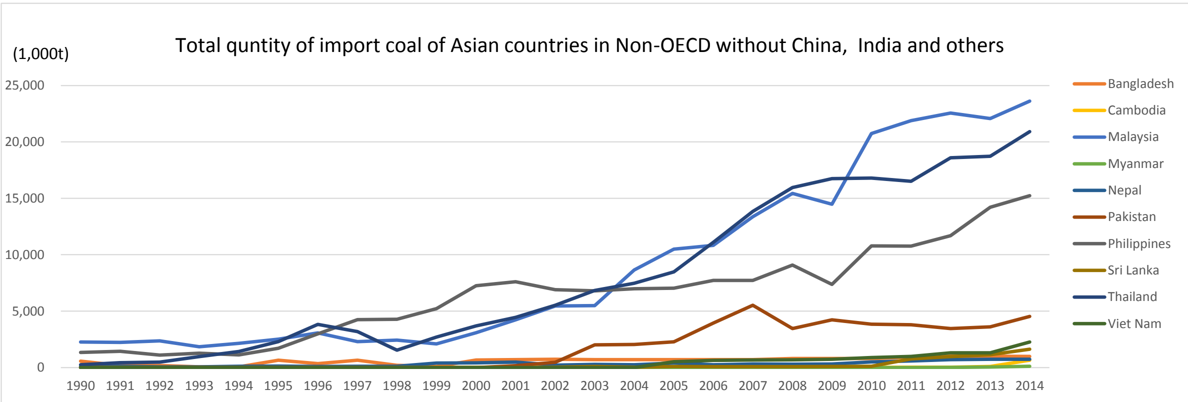
Figure 10-5 Forecast of Coal Demand in the World

[17] The World Energy Outlook 2014(WEO-2014) present projections for three scenarios. The Current Policies Scenario is based on those government policies and implementing measures that had been formally adopted as of mid-2014. The New Policies Scenario, which is WEO's central scenario, takes into account the policies and implementing measures affecting energy markets. The 450 Scenario is projection considering control global warming until 450ppm.
As for the prediction of EIA (Energy Information Administration, United States Department of Energy), it may be said that New Policies Scenario watches a predictive number modestly because Current Policies Scenario of IEA is near.



Source: Table 5.3 in Coal market outlook by World Energy Outlook 2014

Figure 10-6 Forecast of Coal Demand in Non-OECD Countries in Asia



Source: Coal Information, IEA

Figure 10-7 The Quantity of Import Coal of Southeast Asian Countries in Non-OECD without China, India and Others

Table 10-7 The Quantity of Import Coal of Asian Countries in Non-OECD without China, India and Others for the Past 5 Years

(1,000t)

	2009	2010	2011	2012	2013	2014
Malaysia	14,477	20,737	21,881	22,558	22,064	23,611
Thailand	16,740	16,802	16,510	18,586	18,726	20,909
Philippines	7,367	10,772	10,755	11,681	14,199	15,224
Pakistan	4,227	3,838	3,782	3,446	3,598	4,524
Viet Nam	724	884	978	1,295	1,308	2,260
Sri Lanka	100	108	760	962	1,131	1,617
Bangladesh	800	800	924	1,000	1,000	988
Nepal	307	489	583	698	724	724
Cambodia	16	17	19	21	96	642
Myanmar	0	0	0	8	47	113
Totl of Asia in Non-OECD without China, India and others	44,758	54,447	56,192	60,255	62,893	70,612

Source: Coal Information, IEA

10.3.2 Import coal price

Present coal price has a tendency to fall by global oversupply. Figure 10-8 shows the change of the number that exchanging the FOB price of coal of 6,700kcal/kg in the Newcastle Port from 2002 through 2015 to in price of coal (¢) per 1,000kcal/kg. A price of coal gradually declines from 2011 and is still progressing now. There is the prediction that the price will increase in about 2020, but the percentage of rise is unidentified.

The prediction of coal price until 2040 is difficult under present situation, but Figure 10-9 shows prediction of coal price starting from coal price at October, 2015 using the same degree of leaning of the approximation straight line except the price at the time when the remarkable rise of the price.

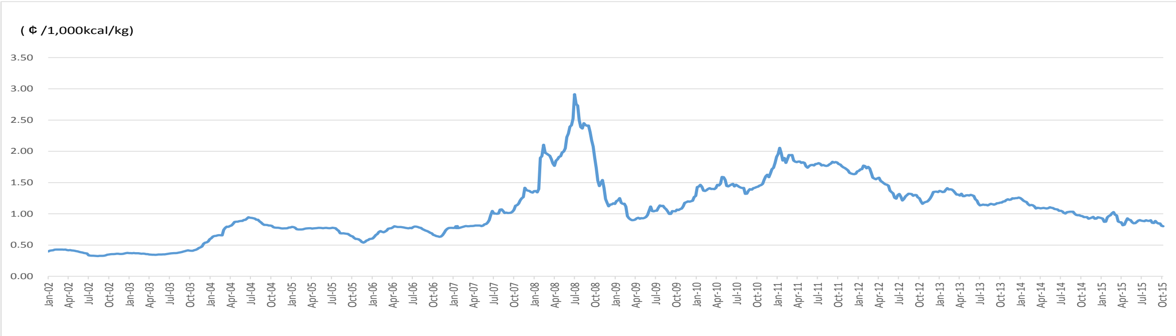
In addition, there is a some difference in price of coal (¢) per 1,000kcal/kg by the calorific value of the coal. Table 10-8 shows the mean weight of the price of coal of each calorific value when 6,500kcal/kg is assumed as 1 in Indonesian Coal Index (ICI)[18] which Argus announces for the past 2 years 1.

Using this weight, a price of coal prediction until 2040 of 6,300kcal/kg and 4,700kcl/kg in Table 10-9. In this case it is assumed that 6,300kcal/kg will be approximately equal to 6,500kcal/kg and is adopted Weight 1 and 4,700kcl/kg will be equal to 5,000kcal/kg and is adopted Weight 0.919.

As for Table 10-10, the coal of 6,300kcal/kg settles a CIF price and an unloading expense in Chittagong on a premise to import from Australia. In addition, as for Table 10-11, the coal of 4,700kcl/kg settles a CIF price and an unloading expense in Chittagong on a premise to import from Indonesia.

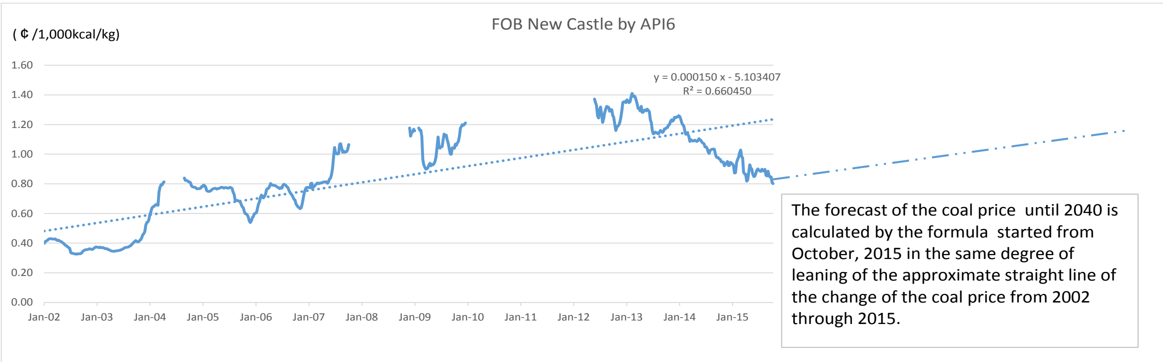
As a result, coal cost becomes about 1/2 generally comparing with the forecast of coal cost in PSMP2010.

[18] Indonesian Coal Index / ICI (Coal) The ICI (Indonesian Coal Index) reflects the spot price of five key grades of Indonesian coal — 6,500 (ICI 1), 5,800 (ICI 2), 5,000 (ICI 3), 4,200 (ICI 4) and 3,400 (ICI 5) kcal/kg GAR. It is published weekly and is the average of the Argus fob Indonesia price as reported in the Argus Coal Daily International report and the PT Coalindo Energy weekly panel system. The full database of time series data is available from 2006.



Source: API6, by Argus

Figure 10-8 The Coal Price of 1,000kcal/kg Movement at Newcastle Port in Australia



Source: API6, by Argus

Figure 10-9 The Forecast of Coal Price of 1,000kcal/kg

Table 10-8 The Weight of Coal Price by Calorific Value by ICI, Indonesia

6,500 Kcal/kg	5,800 Kcal/kg	5,000 Kcal/kg	4,200 Kcal/kg	3,400 Kca/kg
1.000	0.977	0.919	0.769	0.638

Source: Indonesian Coal Index

Table 10-9 The Forecast of Coal Price of 1,000kcal/kg to High Grade Coal and Low Grade Coal

Year	₵/1,000kcal/kg for High grade coal	₵/1,000kcal/kg for Low grade coal	Coal Price(US$)	
			6,300kcal/kg	4,700kcal/kg
2015	0.80	0.74	50.5	34.6
2020	1.07	0.99	67.7	46.4
2030	1.35	1.24	85.0	58.3
2040	1.62	1.49	102.2	70.1
2050	1.90	1.74	119.5	81.9
2060	2.17	1.99	136.8	93.8

Source: PSMP Study Team

Table 10-10 Total Cost including FOB, Freight, Insurance and Handling Cost from Australia

Year	FOB Price of 6,300kcal/kg (US$)	Freight & Insurance (80,000t class) (US$)	Case A		Case B	
			Handling Cost(US$)	G. Total of Coal Price at Chittagong CFTPP(US$)	Handling Cost(US$)	G. Total of Coal Price at Chittagong CFTPP(US$)
2015	50.5	15.0	16.0	81.5	0	65.5
2020	67.7	17.8	17.8	103.3	0	85.5
2025	85.0	20.5	19.7	125.1	0	105.5
2030	102.2	23.2	21.5	147.0	0	125.5
2035	119.5	26.0	23.4	168.9	0	145.5
2040	136.8	28.7	25.2	190.7	0	165.5

Source: PSMP Study Team

Table 10-11 Total Cost including FOB, Freight, Insurance and Handling Cost from Indonesia

Year	FOB Price of 4,700kcal/kg (US$)	Freight & Insurance (80,000t class) (US$)	Case A		Case B	
			Handling Cost (US$)	G. Total of Coal Price at Chittagong CFTPP(US$)	Handling Cost(US$)	G. Total of Coal Price at Chittagong CFTPP(US$)
2015	34.61	9.1	16.0	59.7	0	43.7
2020	46.43	10.7	17.8	75.0	0	57.2
2025	58.26	12.4	19.7	90.3	0	70.7
2030	70.09	14.1	21.5	105.7	0	84.1
2035	81.92	15.7	23.4	121.0	0	97.6
2040	93.76	17.4	25.2	136.4	0	111.1

Source: PSMP Study Team

10.4 Prediction of Coal Demand & Supply

10.4.1 Prediction of Coal Demand & Supply

Table 10-12 shows domestic supply and demand of the coal until 2041. Figure 8 10 shows the coal supply and demand by a graph. As the major figures became the coal for power generation, demand quantity was predicted based on a new coal-fired station construction plan.

Table 10-12 Prediction of Coal Demand & Supply

			2014	2015	2020	2025	2030	2035	2040	2041
Demand	Power Sttion	New Coal fired Power Station				14,129	24,917	38,837	62,904	68,704
		Barapukuria PS(125MW x 2)	433	433	433	433	433	433	433	433
		Barapukuria PS(125MW x 1)			217	217	217	217	217	217
	Industry	Forcast following IEA Import figures	1,000	1,023	1,136	1,249	1,362	1,475	1,588	1,610
		Present Local user at BCMCL	300	300	300	300	300	300	300	300
		Total Demand	1,733	1,755	2,085	16,327	27,228	41,261	65,441	71,263
Supply	Domestic	BCMCL & Other new mine	1,000	1,000	1,100	2,100	6,200	8,200	11,200	11,200
	Import	Balance Between Total Demand And Domestic Production	733	755	985	14,227	21,028	33,061	54,241	60,063
		Total Supply	1,733	1,755	2,085	16,327	27,228	41,261	65,441	71,263

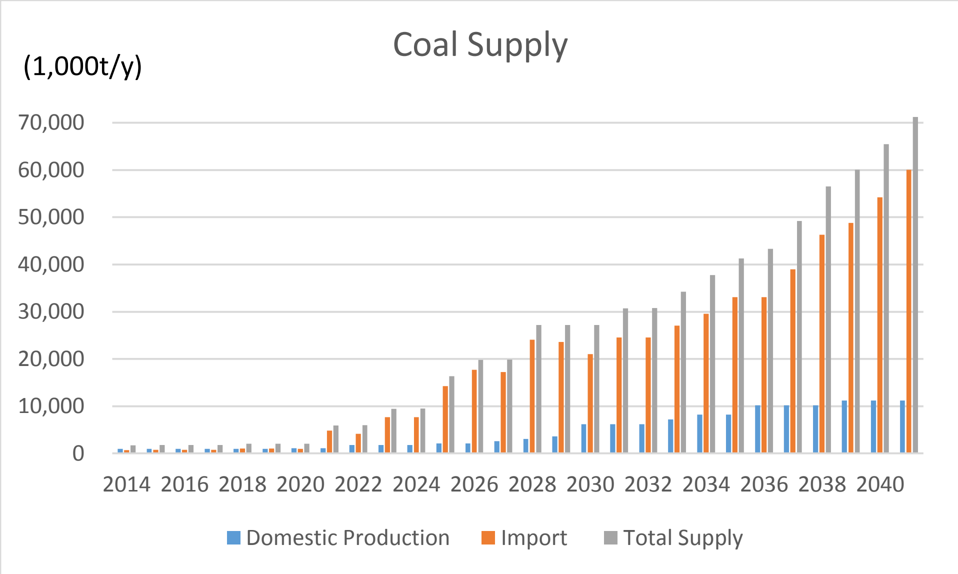


Figure 10-10 Coal Supply

10.4.2 Coal demand of industry

The quantity of coal demand for domestic industry in Table 10-12 is predicted based on a growth rate of Table 10-9 for the past 5 years. It is difficult to grasp a real coal consumption. Table 10-13 is data from an annual report in the Bangladesh Statistics Bureau, but the real import amount is seemed to be enormous, and it is a fact that statistics number does not show. This number seems to be the import from the sea route mainly. The import with the land route from India is unidentified.

The industry of the main coal consumption in Bangladesh is a brick factory and there are small a rolling mil factory (foundry) although, in addition, being small. As for the coal consumption of a brick factory, the quantity of brick production of 34/unit x 3500unit=119,000 units by operation for six months requires 700t. Generally, typical production quantity of the brick per one factory is 1lakh (100 thousand units). Therefore, 1,000 places of brick factories consumpt 700,000tons of coal per year.

Table 10-13 The Data of Quantity of Import Coal by Bangladesh Bureau of Statistics

Year	Cord No.	Item	Import amount (t)	Import price (BDT)	@ BDT/t
2019/2011	2701	Coal & Briquette	59,778	476,813,100	7,976
	2704	Coke and Semicoke of coal	4,464	104,318,000	23,316
2011/2012	2701	Coal & Briquette	56,636	411,608,100	7,268
	2704	Coke and Semicoke of coal	3,903	103,100,000	26,416
2012/2013	2701	Coal & Briquette	82,228	495,411,576	6,025
	2704	Coke and Semicoke of coal	3,359	90,888,657	27,058
2013/2014	2701	Coal & Briquette	NA	NA	NA
	2704	Coke and Semicoke of coal	2,645	65,094,975	24,616

Source: Bangladesh Bureau of Statistics (BBS)

10.4.3 The quality of import coal for industry

As a field work, a coal seller around Fatulla Station of the river mouth of Madaripur of Dhaka City was investigated. They sold Indonesia, India, Chinese coal and Indonesan coal was major at the investigation. The calorific value was three kinds of 5,000, 6,500 and 7,500kcal/kg and annual volume of trade was 20,000t - 30,000t. The coal was shipped by a boat from Chittagong. Table 10-14 shows the analysis contents of the coal which the coal seller sold. The quality such as the calorific value is good, but it is a problem that sulfur is high. The coal imported by land by the northeast Indian side of the Bangladeh has also a high sulfur content and the Bangladesh goverment prohibits import for high sulfur coal, but management will be difficult.

Table 10-14 Coal Quality for a Brick Factory

Item	Unit	Base	Coal sample	
			Indonesia A	Indonesia B
Total moisture	wt%	AR	11.0	4.8
GCV (HHV)	kcal/kg	AR	6,360	7,100
	MJ/kg		26.7	29.7
NCV (LHV)	kcal/kg	AR	6,140	6,880
	MJ/kg		25.7	28.8
[Proximity analysis]				
Moisture	wt%	AD	5.7	3.4
Ash			6.9	8.8
Volatile Matter			44.0	43.8
Fixed Carbon			43.4	44.0
Total Sulphur	wt%	Dry	2.71	0.86

10.5 Environmental and social aspects of coal development

10.5.1 Environmental Impact Assessment

Basic rules of Environmental Impact Assessment are given by Environment Conservation Act 1995. The clause 12 of the Act “No industrial unit or project shall be established or undertaken without obtaining, in the manner prescribed by rules, an Environmental Clearance Certificate from the Director General”. Environment Conservation Rules 1997 (subsequent amendments in 2002 and 2003) stipulate the procedures and required documents by categories (see Table 10-15).

Table 10-15 EIA Categories and Required Clearance and Documents

Category	Required clearance	Required documents
Red	Location clearance, Environmental Clearance	Feasibility Study report (FS report), IEE or EIA, Resettlement Action Plan (RAP), No Objection Certificate of the local authority (NOC), Emergency and pollution minimization Plan
Orange B	Location clearance, Environmental Clearance	FS report, IEE, NOC, Emergency and pollution minimization Plan, RAP
Orange A	Location clearance, Environmental Clearance	General Info, Raw materials and the manufactured product, NOC, Process flow, Layout, Effluent discharge arrangement, RAP
Green	Environmental Clearance	General Info, Raw materials and the manufactured product, NOC

Source: Environment Conservation Rules 1997

MOE has prepared various guidelines of EIA such as Guidelines for Industries in 1997, EIA Guideline for Coal Mining, Guideline for Gender Responsive Environmental Management. All the coal and gas development projects have to apply Environmental Clearance to DOE of Dhaka, Chittagong, Khulna, or Rajshahi Division. It is not clear that which categories should be applied to various kinds of Gas and coal projects (see Table 10-16).

Table 10-16 EIA Guidelines for Gas and Coal Sector

Activities	Category	Guidelines to be referred
Coal exploration	?	EIA Guideline for Coal Mining
Coal mining	Red	EIA Guideline for Coal Mining
Coal storage	?	EIA Guidelines for Industries in 1997
Coal Power Plant	Red	EIA Guidelines for Industries in 1997

10.5.2 Experienced Environmental and Social impact of Coal development

Currently there is only one coal mine is operating. Information is gathered from Barapukuria Coal Mining Co. Ltd (BCMCL) and literatures.

(1) Environmental and Social Impact of Barapukuria Coal Mine

EIA report and Environmental monitoring reports were prepared for the Barapukuria Coal Mine project. But both of them are not disclosed by BCMCL. BCMCL does not submit the monitoring reports to DOE periodically. There are many reports and articles which suggest various Environmental and Social impact caused by the project. Based on the hearing, articles and reports 320HH are resettled and 622 acers of land are acquired at the construction stage. After the subsidence happen, fish farming has started, wildlife use the pond as their habitat. But 2,500 people are additionally resettled by the subsidence, and 15 villages are affected by lowered underground water (see Table 10-17). Compensation measures are taken but some conflicts caused by the people thought it is not enough (see Table 10-18). It seems that Environmental and Social impacts are not fully controlled.

Table 10-17 Reported Environmental and Social impact by Barapukuria Coal Mine

Items	Impact	Source
Tremor	Tremor is experienced by local people.	Hearing to BCMCL
Subsidence	Subsidence area is 627 acre(2.5 km2). Compensation to the affected land, houses and others was finished and issues are solved.	Hearing to BCMCL
	Subsidence started in 2008 and lowered around 1m. 2,500 people in seven villages are affected. Eight to ten “tin sheds” are proposed by BCMCL. Government is planning to establish Coal City for 10,000 families.	Hoshour (2011)
Underground water degradation	Underground water level was lowered and 15 villages lost their access to water.	Hoshour (2011)
Water pollution	2200m3/h treated water is discharged into river. People are using the treated water for irrigation. People are raising fishes at the pond of the subsidence area and many wildlife using the pond.	Hearing to BCMCL
	30ton/hr waste water is drained that is mainly acidic in nature and rest of water is recycling. AMD, classified as hard water, contains harmful heavy metals and metalloids like HCO3-, Na+, Ca2+ which have a tendency to leach out over a period of time.	Akter et al. (2015)
	The chemical properties of surrounding water such as concentration of Calcium, Magnesium, Lead, Iron, Copper, Zinc etc are greatly increased by the mixing of coal water and greatly impacts on the farmer’s field soil.	Hasan (2013)
Soil contamination	By releasing of heavy metals which are associated with coal such as aluminium (Al^{3+}), zinc (Zn^{2+}) and manganese (Mn^{2+}), AMD is affecting directly and indirectly on the Environment and	Mohanta (2015)

	Ecosystem.	
	The chemical properties of surrounding soil of coal mine, such as concentration of Ca, Mg, Pb, Fe, Cu, Zn etc is greatly increased by the farmer's field soil.	Rashid (2014)
Land acquisition	622.28 Acre of land is acquired.	Hearing to BCMCL
Resettlement	320 HH were resettled during construction stage.	Hearing to BCMCL

Table 10-18 Reported Social Conflict of Barapukuria Coal Mine

Year	Social conflicts	Source
2011	The national committee to protect oil, gas, mineral resources, ports and power on Monday enforced a six-hour road and rail blockade at Phulbari in Dinajpur, demanding implementation of its seven-point demands including compensation for Aman crops near Barapukuria coal mine area.	New Age (March 29, 2011)
2011	Local peoples blocked railways and a highway protesting the government's plan for open pit mining. Thousands of people demanded compensation for loss of aman crops and postponement of the ongoing land survey. Hundreds of people from Chowhaati, Durgapur, Shahgram, Rambhadrapur, Yousufpur and Bagra villages attacked the 'National Committee' members. At least five people were injured during the ten-minute-long clash.	The Daily Star, (May 5, 2011)
2011	Barapukuria coal miners and staffers stopped production at the mine, demanding regularisation of their jobs.	The Daily Star, (Aug. 24, 2011)
2012	At least 20 people, including three policemen, were injured as thousands of villagers protested and clashed with police. The protestors were demanding disbursement of money granted under the authorities' compensation package; the affected people have been agitating since 2009 after at least 627 acres of land subsided at 10 villages.	The Daily Star, (July 9, 2012)

(2) Accident at Barapukuria Coal Mine

Two serious accidents have been reported by Hoshour (2011) so far. One of it is a fatal accident of a British mining expert by a gas leakage happened in 2005. Second one is a roof cave in caused one person dead and 19 wounded in 2010.

10.5.3 Environmental and social risk of Coal development

There are several potential coal mine areas in Bangladesh. Among them only one project, Phulbari, has prepared the EIA report which is fully opened on the web. Based on the EIA reports of the Phulbari Coal mine various impacts are expected as shown in Table 10-19. The impacts are larger than Barapukuria because the mining style is open cut.

Table 10-19 Main Environmental and social impact described in the EIA report of Phulbari Coal Mine

Items	Impact
Soil	Topsoil removal would be 4,300 hectares.
Air	The maximum predicted PM10 (24-hour) concentrations deriving exclusively from Project emissions exceed the residential area standard of the Government only at two locations during year 5 assessment stage.
Surface water	The net result of this land settlement is that some small areas, especially the area immediately north of the mine site, could be inundated during a 100-year flood to depths of around 0.2–0.5 m. As it is anticipated that much of this low flow release will be extracted by irrigators, it can be concluded that the mine dewatering flows are unlikely to cause any hydrologic or hydraulic problems in the Little Jamuna River. The Khari Pul creek (which is actually more of a drainage channel, with water flows of 0.3 m3/sec to 12 m3/sec during extreme rainfall) carries the untreated wastewater from Barapukuria Coal Mine (just north of the Project area).
Ground water	Dewatering activities will have potential impacts on the local and regional hydrogeological regime, with predicted groundwater drawdown of approximately 25 m at a distance of 4 km from the mine pit, and 15 m at a distance 6 km. This may result in (i) reduction in groundwater availability to the local farming community, Phulbari township, and nearby villages; (ii) reduced baseline flow into watercourses and Ashoorar Beel during the dry season; (iii) land settlement; and (iv) a general reduction in groundwater quality.
Subsidence	Land subsidence in the order of 2 meters (m) at the mine crest, reducing to 0.02 to 0.4 m at a distance of about 5 km from the mine.
Biological Environment	The Project could potentially result in the direct loss of some common habitats. No Sal forests or major Beels will be directly affected by mining activities, but indirect effects may occur as a result of watercourse diversion, discharge of excess mine site-treated “dirty” water, increased sediment load resulting from land clearing and earthworks, mine dewatering activities, and groundwater discharge to watercourses. Other impacts may include weed invasion and elevated noise levels.
Land acquisition	Approximately 5,933 ha of land will be required. Most of them is for the Mine Footprint (85.5%). Other activities are new areas for town and village resettlement sites and the realignment of transport (rail and road) infrastructure.
Sociocultural Environment	Current estimates are that about 9,000 households (some 40,000 people), including some residents at the extreme eastern end of the Phulbari township, will have to be relocated. Population displacement will occur in all four upazilas, with Phulbari being the most affected. In addition, up to 160 households may have to be relocated for the realignment of rail and road corridors.

It is not clear that how much environmental impacts will be anticipated for the other four mines. But the impact items would be similar as Phulbari because the locations are ‘Irrigated croplands’ same as Phulbari coal mine (See Figure 10-12). The direct impact on the protected areas will be avoided as the locations are outside of the protected areas. Phulbari, Khalaspir, and Dighipara are in the distribution areas of Dhole (Cuon Alpinus) (See Figure 10-11). Then the impact on bushes and forest area should be minimized and offset mitigation should be considered. Even if underground mining method is selected, some amount of resettlement and land acquisitions will not be avoided. And there is a possibility of people's protest. Then detail social survey and compensation planning in participatory style is recommended.

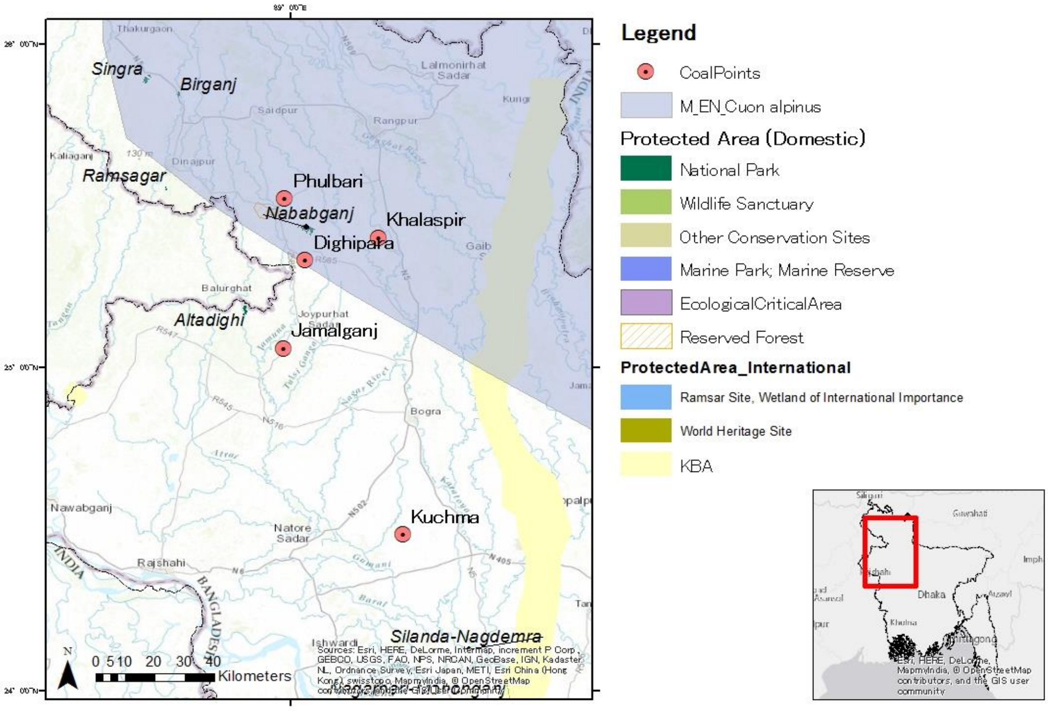


Figure 10-11 Possible Coal Mines and Protected Areas

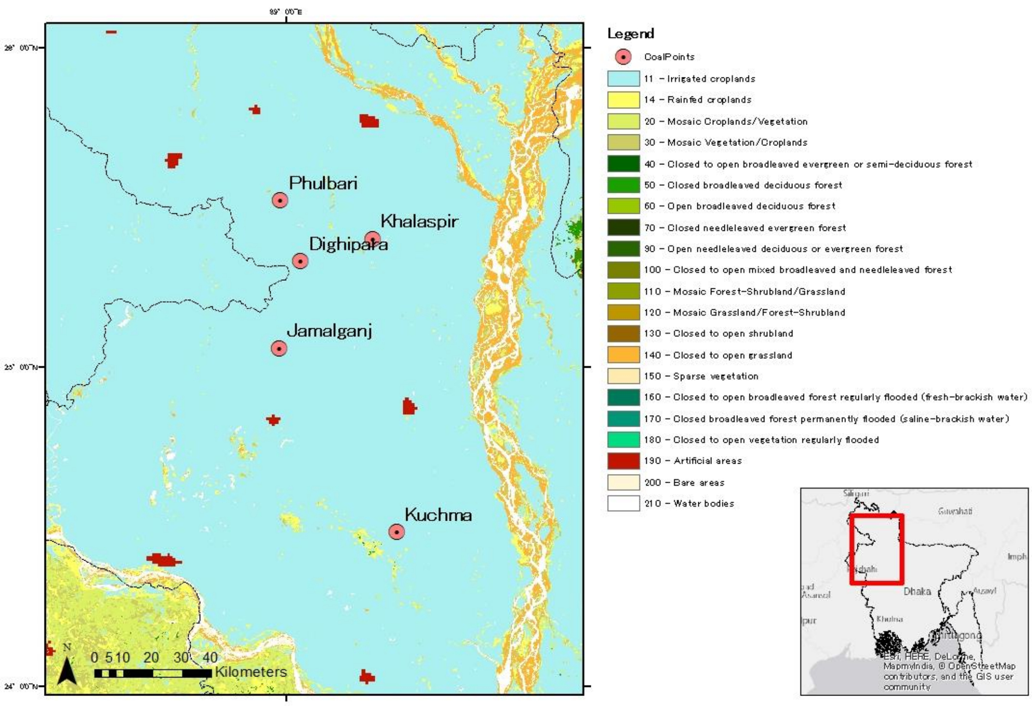


Figure 10-12 Possible Coal Mines and Land Use

Source:
Akter et al. (February 2015) “Degradation of the Surface and Subsurface Water Quality on the Adjacent Area of Barapukuria Coal Mine due to the Improper Effluent Treatment of Mine Waste Water”, International Journal of Emerging Technology and Advanced Engineering Volume 5, Issue 2
Hasan et al. (2013) “Environmental Impact of Coal Mining: A case study on Barapukuria Coal Mining Industry, Dinajpur, Bangladesh” J. Environ. Sci. & Natural Resources, 6(2): 207 - 212 , 2013
Kate Hoshour, (March 4, 2011) "Massive protest against Phulbari & Barapukuria coal mines in Bangladesh" International Accountability Project.
Rashid et al. (2014) “Environmental Impact of Coal Mining: A Case Study on the Barapukuria Coal Mining Industry, Dinajpur, Bangladesh” Middle-East Journal of Scientific Research 21 (1): 268-274, 2014
The Daily Star, (May 5, 2011) "Siege protesting open pit mining to continue today"
The Daily Star, (Aug. 24, 2011) "Miners strike halts Barapukuria coal production for 2nd day"
The Daily Star, (July 9, 2012) ”20 injured as Dinajpur land subsidence victims, cops clash,"
Tusher Mohanta et al. (July 2015) “Case study on surrounding area of Barapukuria coal mine impeding soil fertility” International Journal of Scientific & Engineering Research, Volume 6, Issue 7

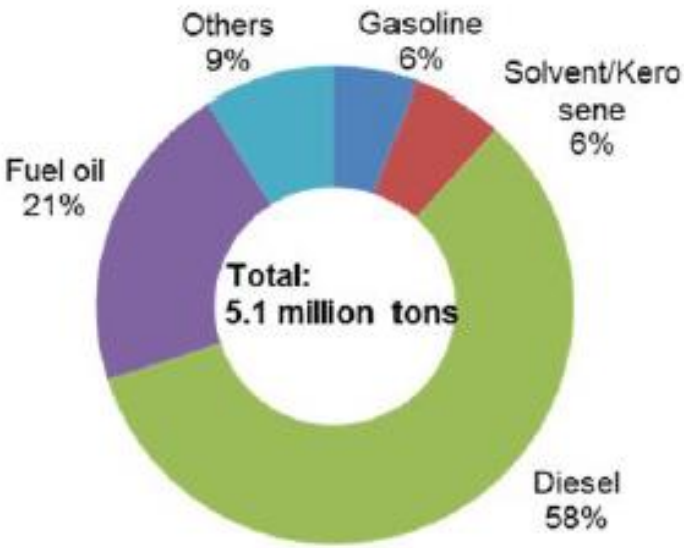
Chapter 11 Oil Products

This Chapter refers to the information collected and analyzed in the JICA-supported survey "Data Collection Survey on Integrated Development for Southern Chittagong Region," (hereafter referred as JICA “Southern Chittagong Survey”) Progress Report (January, 2016), especially on the supply plans. For the demand projection on oil products, this Chapter refers to Chapter 22.

11.1 Forecast of Oil Import

11.1.1 Oil Demand

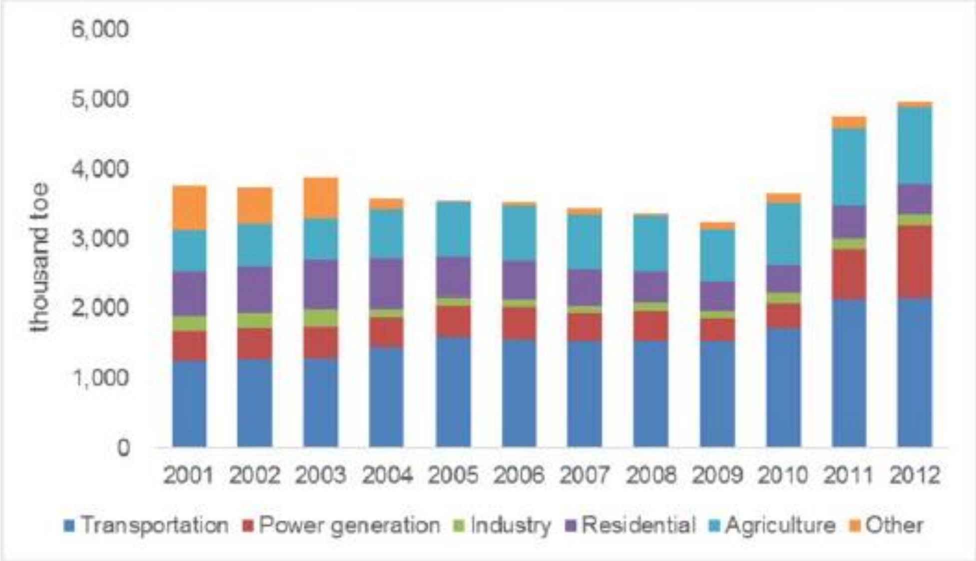
Bangladesh produces a small amount of condensates (about 7,800 barrels per day as of December 2014), from natural gas fields. Condensates are fractionated to petroleum products, such as liquefied petroleum gas (LPG) and motor gasoline and are marketed in the domestic oil market. The domestic condensate supplies only about 5% of the total domestic oil demand in Bangladesh, and the country’s most of the oil demand is met with import from abroad. The country’s annualized oil demand from 2012 to 2013 was 5.1 million tons (about 105,000 barrels per day) according to the obtained data from the Energy Division, Ministry of Power, Energy, and Mineral Resources. More than half of the demand was diesel oil because it is extensively used in various sectors from transportation to power generation, industry, and agricultural sector. The share of fuel oil is relatively high as it is still widely used in the industrial sector. The share of motor gasoline, on the other hand, is low as in Bangladesh motorization process is still at an early stage and the car ownership remains low.



Source: Energy Division, MoPEMR

Figure 11-1 Oil Demand by Products (2012-2013)

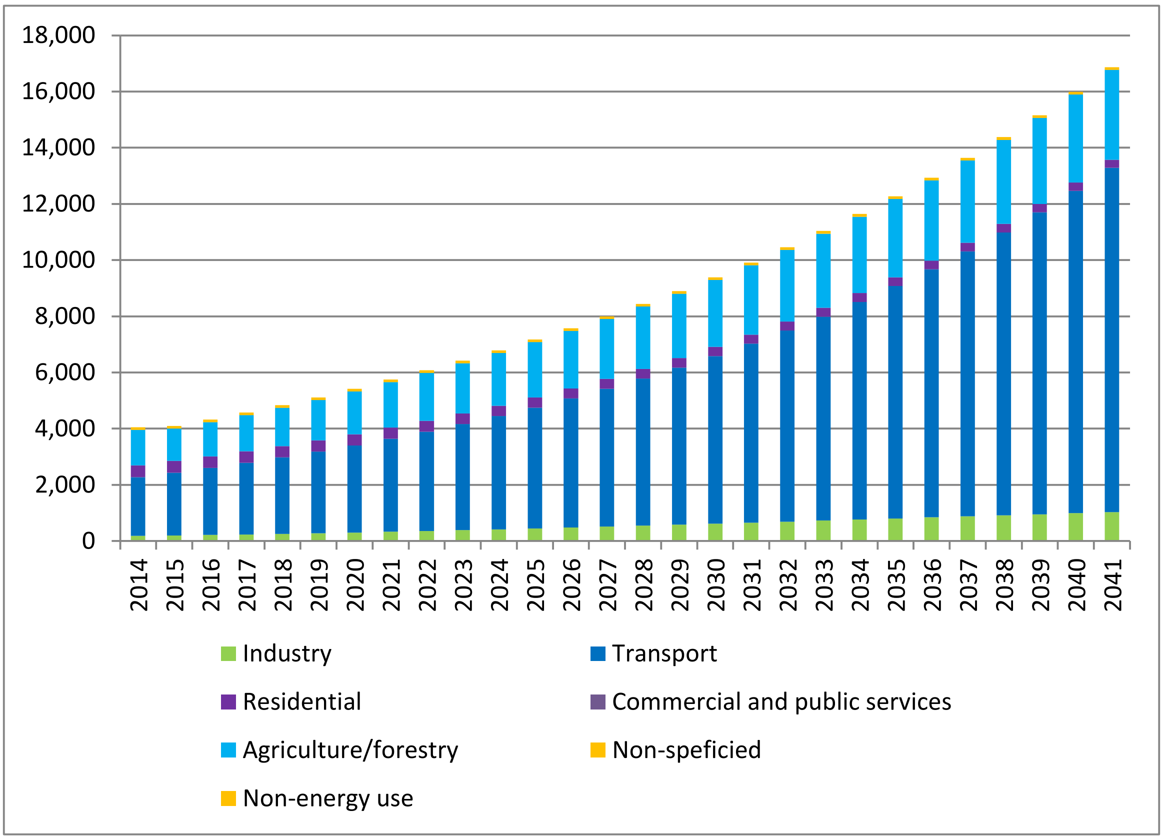
Bangladesh’s oil demand has rapidly grown in the last decade backed by the country’s high economic growth. The country’s oil demand has increased by 1.6 times from 2002 to 2012, and its annual average demand growth rate during the period reached 4.9%. While the demand growth is observed in all sectors, demand in the power generation sector in particular observed the highest growth rate (6.6%).



Source: IEA Energy Balance for non-OECD Countries, 2014 edition

Figure 11-2 Bangladesh's Historical Oil Demand by Sector

As shown in the below figure, JICA Survey Team forecasts that the country's total oil demand (power sector and non-power sectors) will increase four fold from 2014 to 2041, in average 5.2% p.a.. Oil demand for power sector will continue to grow until the mid 2020s with the increase of the country's power demand. The demand in power sector, however, will turn into a declining trend because most of the oil products in power sector are consumed by "rental", "quick rental" and captive power generations, and when a large scale power generation becomes online (e.g. an ultra super critical coal power generation) in the mid 2020s, these oil-fired power generations will be retired or kept for stand-by capacity.



Source: JICA Survey team

Figure 11-3 Oil Demand Projection for Non-Power Sectors, 2014 to 2041

Oil demand in other sectors, most notably in the Transportation sector, is likely to continue its high growth rate and become 11-times more in 2041 than in 2015. This is because the car ownership in Bangladesh is expected to increase as its per-capita income growth, and the country's economic expansion will be associated with high transportation demand of goods and passengers.

In general, oil demand growth is accelerated when the country's per-capita income approaches to USD 3,000. According to IMF World Economic Database as of April 2015, the country's per-capita GDP is USD 1,280, and as discussed in the previous Chapter, JICA Survey Team projects that Bangladesh's GDP per capita (real) as of 2041 will reach about 3,000 USD.

Though the actual demand growth rate in non-power sector of Bangladesh from 2004 to 2013 was approximately 4%, the PSMP2016 Survey team projects that the future demand growth will be higher than the historical level. Furthermore, Bangladesh used to heavily depend on the domestic natural gas for its transportation sector; however, as the domestic natural gas production declines and the demand in power sector is growing, the demand on natural gas for the Transportation sector is expected to decline, and this reduction will also contribute to oil demand growth in the Transportation sector. Given all these factors, the average growth rate of non-power oil demand is assessed at 7.2% until 2041, and becomes 8-times more than in 2015.

11.1.2 Oil Import Supply – Current Status

Because the domestic oil production in Bangladesh is very small, the country depends on import for most of the country's oil needs. The country has one refinery in Chittagong; but its refining capacity is not sufficient to meet the country's total oil demand, and the country imports oil products for the remaining demand. State-owned Eastern Refinery Limited (ERL), the country's only refinery, was built

in 1967, and its existing capacity is 1.5 million tons per year. Most of the crude oil processed at ERL is imported from Saudi Arabia and UAE.
Because the country's current oil demand is 5.1 million tons, the remaining 3.6 million tons are met by product imports. Oil products are imported mainly through foreign national oil companies, such as Kuwait Petroleum Corporation or Petronas of Malaysia.

11.1.3 Oil Import Supply – Future Projects

As the domestic refining capacity is smaller than the domestic demand, the demand growth automatically increases oil product imports. Bangladesh has several projects to meet the import growth. Domestic refining, to be elaborated in the later section has multiple advantages, such as lower freight cost and lower price volatility against product imports, and is a usually preferred option for an oil importer.

(1) Expansion of Eastern Refinery (ERL)

ERL has a plan to expand its existing capacity from 1.5 million tons to 4.5 million tons. The company plans to finance the expansion project by itself, but it may invite foreign investors by forming a joint venture[19].5 Even after the capacity expansion, however, the domestic refining capacity will be short to the domestic demand. The company, therefore, considers another expansion of the domestic refining capacity, when the expansion of Eastern Refinery is successfully done. The location and the size of the additional capacity expansion have yet been determined[20].

(2) Single Point Mooring (SPM) system project

Shallow draft along the coast of Chittagong has prohibited a direct access of larger-sized tankers, and thus caused a higher shipping cost of crude oil to refinery as lightering operation is required to deliver crude oil. Bangladesh plans to build a single point mooring system offshore Matarbari Island in order to approach this problem. It is reported that China Petroleum Pipeline Bureau (CPP) will undertake the construction of SPM system, and Chinese EXIM bank will provide financial support to the project[21]. Expected construction cost is USD 630 million and expected year of completion is 2018. The discharged pipeline will be built to the tank terminal that plans to be built in Maheshkhali Island. The tank terminal will have six crude oil and oil product tanks whose combined capacity will be 2.4 million tons. The discharge pipelines are of two types: one for crude oil and the other for oil product. Discharged crude oil and oil product will be shipped to Eastern Refinery in Chittagong through newly constructed crude oil and oil product pipelines..

(3) New refining and petrochemical complex by Kuwait

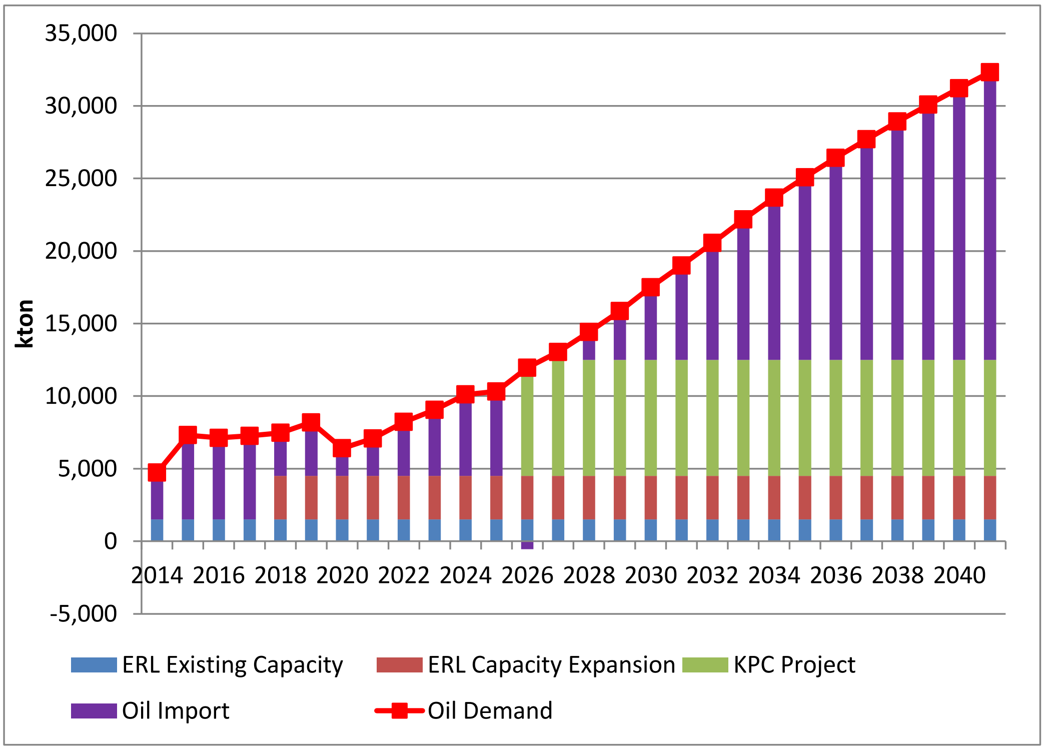
Kuwait Petroleum Corporation (KPC), the Kuwaiti national oil company, is considering investing a refining and petrochemical complex in Maheshkhali Island in Southern Chittagong. The project emerged in an agenda of the summit meeting when Prime Minister Hasina visited Kuwait in 2000. Although there had not been any progress since then, a delegation of KPC visited Dhaka in May 2015, and they requested to prepare for 1,000 acre (approximately 400 ha) land for the new refining and petrochemical complex in Maheshkhali Island[22]. The planned crude oil distillation capacity is 8.0 million tons and the expected construction cost is USD 6.0 billion. It is reported that the refinery will be built either through a joint venture between KPC and Bangladesh Petroleum Corporation (BPC), or with other international oil companies. KPC considers further expansion beyond 8.0 million tons at a later stage. The size of the refinery, however, could be too large for the domestic oil demand in Bangladesh if the demand would not grow as projected. If that is the case, the surplus capacity would be used for oil product export to

19 JICA "Southern Chittagong" Survey team interview with the Energy Division of MoPEMR, June 7, 2015.
20 JICA "Southern Chittagong" Survey team interview with the Energy Division of MoPEMR, June 7, 2015.
21 "Chinese firm gets SPM project Energy division to prepare commercial contract," New Age, 18 January 2015 (http://newagebd.net/87278/chinese-firm-gets-spm-project/#sthash.oIoMyYNT.dpuf)
22 "Kuwait to get Maheshkhali land for oil refinery," Financial Express, 25 May 2015 (http://www.thefinancialexpressbd.com/2015/05/25/93953)

neighboring countries. The project is still at a preliminary stage and the detailed project schedule has not been determined.

11.1.4 Oil Supply and Demand Balance

Oil demand supply balance in Bangladesh is estimated as shown in the below figure. Because the completion year of KPC refinery project has not been determined, its start-up year is tentatively set at 2025 in the following figure. As mentioned above, even with the expansion of Eastern Refinery (ERL), KPC's new refining project or any new refinery expansion by the government, the oil import will continue to increase, as far as the oil demand will sharply grow.



Source: JICA "Southern Chittagong" Survey Team and PSMP2016 Survey Team

Figure 11-4 Total Oil Demand & Supply Projection from 2015 to 2041

11.2 Development Scenario of Oil Refinery

11.2.1 Oil Refinery v.s. Oil Import

For a country that has a shortage of refining capacity against the domestic oil demand like Bangladesh, it is important to consider how the country will secure oil product supply, especially whether the country will build a refinery to meet the domestic demand or continue to depend on product import. Building a refinery will obviously bring multiple benefits to the country. Having a refinery will provide more options to secure oil products. If the country has a refinery, the country can import various kinds of crude oil from abroad and thus can diversify its oil supply sources as long as it can be processed at the refinery. Having a refinery also brings a freight cost-saving effect. Crude oil tanker is usually larger than oil product tanker because the size of cargo traded at crude oil market is usually larger than that at oil product market. Freight cost for a large tanker is obviously cheaper than that for a smaller tanker used for product imports. Importing oil in the form of crude oil can also ease negative impact of price volatility. Crude oil prices are notoriously volatile, but its price volatility is relatively lower than that of oil product prices. Furthermore, enforcing and monitoring quality specifications of oil product will be easier, if the country can refine its products by itself and does not need to monitor oil product imports from various refineries aboard.

Refinery construction option, on the other hand, certainly has disadvantages against oil product import option. The largest disadvantage is, of course, its need to secure large upfront investment money. Building a greenfield refinery with upgrading capacities often needs several billion dollars and this often becomes the largest obstacle to build a refinery for all countries. Even after the country can build a refinery, it still has a risk of underutilization and low refining margin. Refining industry, particularly in Asia market, has chronically harsh business environment due to excess capacity in the region. Investors in a new refinery have to bear in mind this business risk.

Table 11-1 Advantages of Constructing a Refinery against Product Import

Advantages	Disadvantages
- More oil product procurement option (diversification of oil product procurement) - Lower freight cost - Lower price volatility - Oil product control	- Large upfront capital expenditures - Risk of low utilization depending on domestic and export demand - Risk of low refining margin for a long period of time

Source: JICA South Chittagong Survey Team

In the case of refinery and petrochemical project in the southern Chittagong, the project is initiated by KPC and the challenge of large upfront capital investment may be addressed by KPC or other potential investors which KPC may invite. Securing a sufficient fund or finding a reliable operator will maximize the benefits of refinery building and operation.

11.2.2 Refinery Development Scenario

The development of refinery and petrochemical complex in the Southern Chittagong area will be undertaken by Kuwait Petroleum Corporation (KPC). The detailed development schedule is being evaluated by KPC and has not been proposed as of writing this progress report (January 2016). The planned starting year of operation is 2018; but given the status of project development, it is likely that the starting year will be deferred to 2025 or later[23]. Based on the assumption and the planned refining capacity expansion of Eastern Refinery Limited (ERL), the scenario of oil demand and supply of Bangladesh toward 2015 is provided as Table below. Because the refining capacity of the new refinery is large for the size of the domestic oil demand, the total refining capacity will exceed the domestic demand even as of 2035. We expect that the surplus capacity of the refinery will be used to produce oil product for export. The new refinery, therefore, has to be designed as an export refinery, if KPC maintains the planned capacity at 8 million tons.

[23] Because the progress of the refinery project is still at an early stage where FEED has not yet started, land acquisition and financing arrangement have not been completed, it is likely to take about 10 years to complete a green-field refinery project. In a similar refiner project in other emerging countries such as Vietnam, it has taken more than 10 years from the initial announcement of the project t commercial operation.