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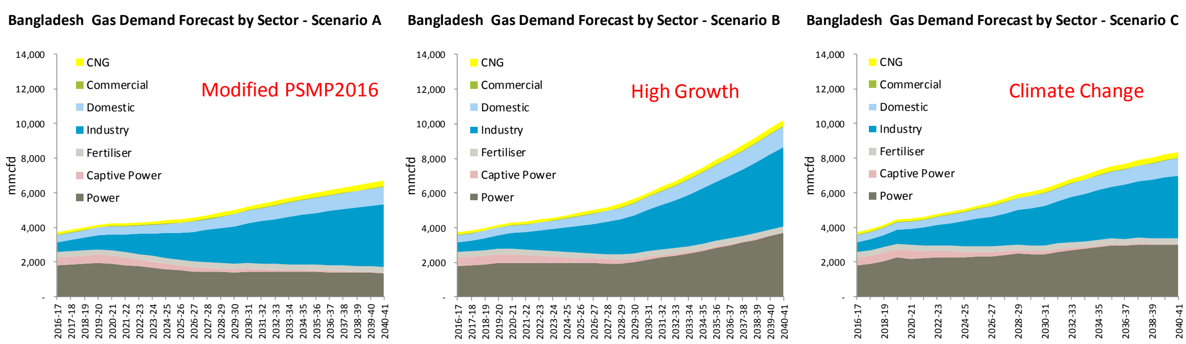
1. EXECUTIVE SUMMARY

This executive summary follows the outline of the report by first outlining the demand projections and quantifying the unmet demand. Secondly, this executive summary summarises the findings from the domestic gas supply/production analysis, which shows that any significant increase in domestic production is not likely to materialise within the next 6-8 years. In conclusion, and not surprisingly, in each and every scenario there is a need for importing gas to Bangladesh both through LNG and pipeline. Due to the geography of Bangladesh however, the locational options for importing LNG are restricted to the south-eastern part of the country at Moheshkhali. Bringing gas from the south to the north, instead of the other way around, requires new investments in the gas transmission system. The executive summary presents main features and conclusions from the analysis of the performance of the transmission system resulting from the derived future demand and supply situation. Finally, the summary presents suggestions to the legal and regulatory framework, changes which would support a positive development in domestic gas production, facilitation of LNG imports, and a sustainable development of the transmission system.

Demand for gas in Bangladesh – large unmet demand

During the last decade, the gas production and consumption has doubled to 2,750 MMCFD. The demand is even higher as there is a large unmet demand and need for curtailment of supply. Our analyses in the GSMP 2017 show that it is likely that demand will continue to grow, depending on scenarios and use of other fuels like coal and renewable. In the GSMP 2017, we have analysed three scenarios; A: base scenario (similar to PSMP2016) with focus on self-sufficiency and hereby introduction of coal on large scale, B: a high growth, international oriented scenario with focus on gas, and C: climate scenario, where climate change renewable energy supplement use of gas on large scale. In order to maintain the flexibility and based on comments received during and after the stakeholder workshop, we use Scenario C as our basis for the further analysis.

Figure 1: Gas demand per sector and per scenario

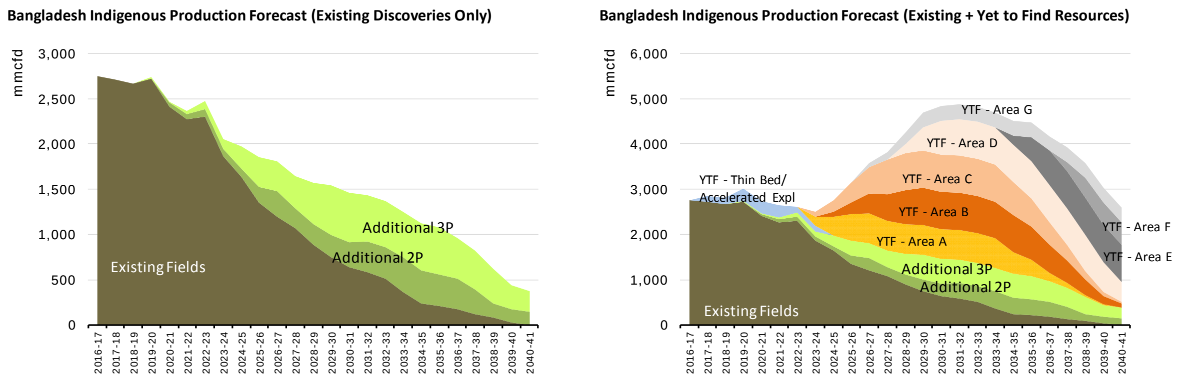


Source: Ramboll

Supply of gas – indigenous resources, LNG and pipeline gas imports

The current indigenous gas production in Bangladesh is 2,754 MMCFD. The production level from existing discoveries is expected to start declining quickly in the next few years. However, the majority of geological areas in the country is still unexplored. The Gas Sector Master Plan Consultants (hereafter the Consultants) believe that there are still large upsides in the indigenous production in Bangladesh if further exploration successes can be achieved. See charts below.

Figure 2: Future potential gas production

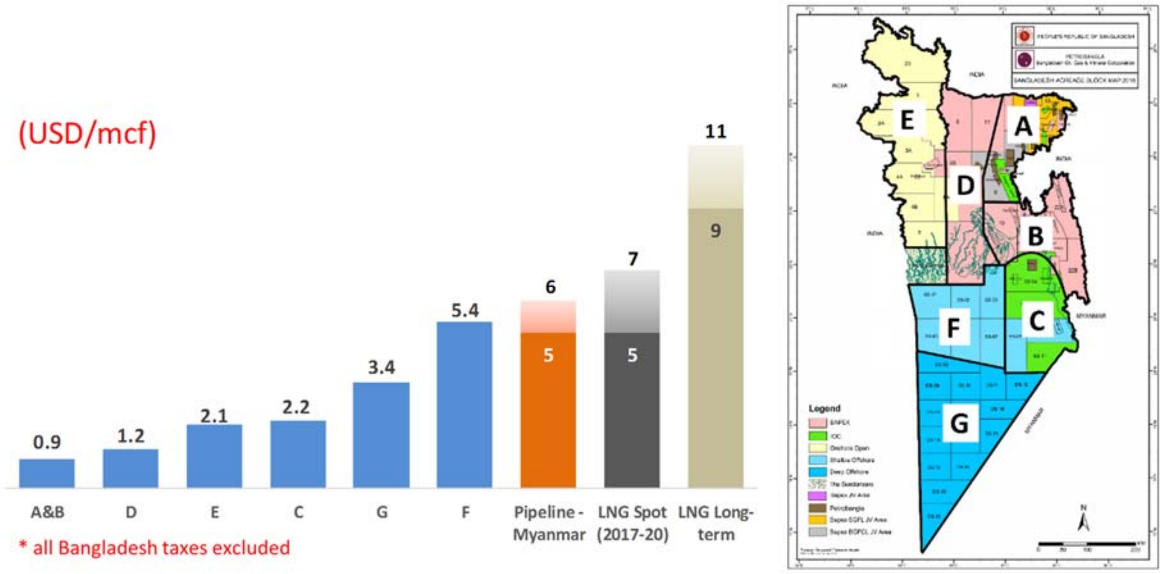


Source: GEUS, Ramboll

The Consultants believe that, even at P90 level, the Yet-to-Find (YTF) resources in Bangladesh is as large as 34 tcf – a significant volume that could almost double Bangladesh's current production level if all geological areas are to be explored and developed properly. This in turn will reduce the total cost of gas to Bangladesh, hence the financial burden for the country would be significantly reduced comparing to paying higher prices for imported gas.

For example, we estimate that, in a USD 60/bbl global long-term oil price environment, the net cost of indigenous gas production in Bangladesh ranges from USD0.9 to USD5.4/mcf. This is lower than potential imported gas from Myanmar USD 5 to USD 6/mcf, LNG from the spot market (in the next few years only) USD 5 to USD 7/mcf, and long-term contracted LNG USD 9 to USD 10/mcf, see Figure 3 below.

Figure 3: Net cost of supply by geological area at USD 60 / bbl environment



Source: Ramboll

In order to capture this significant production potential in Bangladesh, rigorous exploration and development programmes as well as adequate resources and time are required.

Firstly, additional gas can be extracted from thin-bed resources as well as deeper prospects so that gas can easily be tied-in to existing infrastructure for early production.

BAPEX has already planned to drill a large number of exploration wells within the next few years. The Consultants understand the urgency of such exploration programme in order to make quick discoveries and sustain current production level. However, we recommend Bangladesh to allow itself more time for in-depth and structured G&G preparatory work, as this will improve both the likelihood and the size of the discoveries.

As large geological areas in Bangladesh remain unexplored, we recommend a systematic and risk based approach for Bangladesh's exploration and development programmes in order to best utilise its resources. Priorities should be given to better known areas (eastern Bangladesh) and then gradually move to more frontier areas (western Bangladesh).

As the future E&P of indigenous gas becomes increasingly larger and challenging, it requires systematic capacity building and the strengthening of human resources in Petrobangla and its subsidiaries. We recommend relevant authorities to give adequate managerial and financial support for such development.

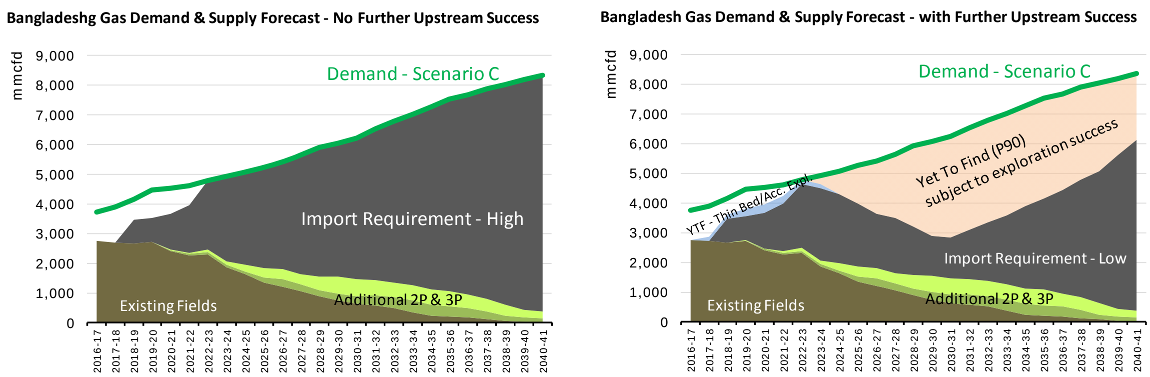
We also recommend Bangladesh to invest in multi-client and open seismic surveys in preparation for future bidding rounds. Gas prospects in Bangladesh can be made more attractive to international applicants when processed and open data packages are made available.

We understand that Petrobangla and relevant authorities have been adjusting its upstream fiscal regimes in order to attract IOCs for Bangladesh's offshore blocks. We support such adjustments and believe further engagements with IOCs are a key to unlock these technically challenging resources in offshore areas.

From a financial prospective, it could still be rewarding for Bangladesh to invest more in its indigenous gas potentials, if there are not enough IOC investments. Looking at this in context, if long-term contracted LNG costs Bangladesh around USD10/mmbtu at ex-regasification terminal, the purchase of LNG at 800mmcf/d (0.3tcf/yr) will cost over USD3 billion for a single year. Such amount of money could be used to finance large exploration and development programmes both onshore and offshore, where significant yet-to-find potentials are expected.

In short, we believe that there is still significant potential in Bangladesh's indigenous gas production, and it should be given high importance and explored properly. The scale of future E&P success will determine the level of gas required from foreign sources, through LNG and pipeline gas.

Figure 4: Examples of import requirements as a function of upstream successes



Source: Ramboll

Bangladesh has already taken some very encouraging steps in increasing gas supply through LNG imports. Two FSRUs namely Excelerate and Summit are scheduled to be in operation in mid-2018 and end 2018 respectively, while future LNG receiving terminals are under consideration. At the time of writing, Bangladesh is in an advanced stage of negotiating an LNG contract with Qatar.

The GSMP Consultant supports Bangladesh's decision in purchasing significant volumes of LNG, and recommends further import capacity through both connections to existing India LNG terminals and a third LNG terminal in Bangladesh within the next few years in order to satisfy the unmet demand for gas in the country.

Often, long-term LNG contracts to Asia are linked to oil price, while the spot LNG price is likely to be kept low up to 2020 due to the oversupply situation in the global market; hence, spot LNG is likely to offer more competitive prices during this period. Therefore, the Consultants recommend

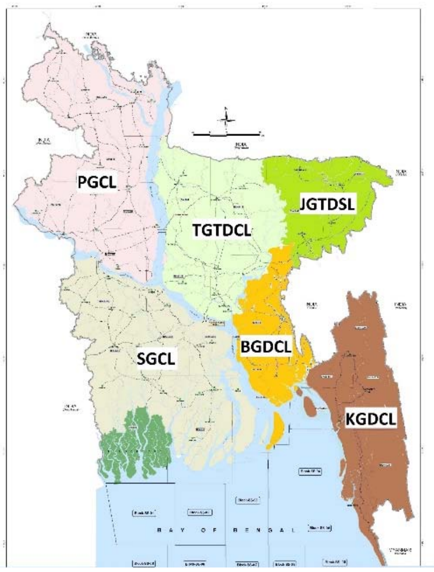
Bangladesh to import maximum quantity of LNG as its infrastructure allows, with majority of the LNG to be purchased from the spot market while small quantity from long-term contracts, creating a price and risk adjusted portfolio.

However, the oversupply situation in the global LNG market may start to change after 2020, which in turn affects the price differentials in spot LNG and long-term contracted LNG. The Consultants therefore recommend Bangladesh to keep fine tuning the balance of its LNG portfolio to minimise its spending. Bangladesh can also consider entering joint LNG purchase contracts with its neighbour countries (e.g. India) in order to strengthen its negotiation power on LNG prices.

Meanwhile, the need for LNG in the longer term is inherently uncertain, and the scale of LNG requirement will largely depend on the outcome of the exploration of indigenous gas resources in Bangladesh as well as the availability of pipeline gas from foreign countries, e.g. Myanmar, Turkmenistan and Iran. Therefore, the Consultants recommend that Bangladesh's gas supply mix strategy and consequently infrastructure plan to be reviewed and adjusted periodically in response to the evolving conditions.

Albeit a challenging task, the Consultants strongly recommend Petrobangla and relevant Bangladesh authorities to pursuit pipeline gas from foreign countries mentioned above. The success of such pursuit will not only enhance the security of supply for Bangladesh, but also bring down the overall cost of gas imports and strengthen Bangladesh's negotiation power in the international market. It also needs to be mentioned that there are strong competitions for the said pipeline gas, especially gas from Myanmar. Petrobangla and relevant Bangladesh authorities are therefore strongly recommended to (re)start the dialogs swiftly.

Bangladesh can also consider acquiring interests in projects from where it imports its gas as favourable acquisition costs can be achieved under the current oil price. This could also help to hedge against possible high oil and LNG prices in the future, as Bangladesh would be buying gas from its own oversea assets.



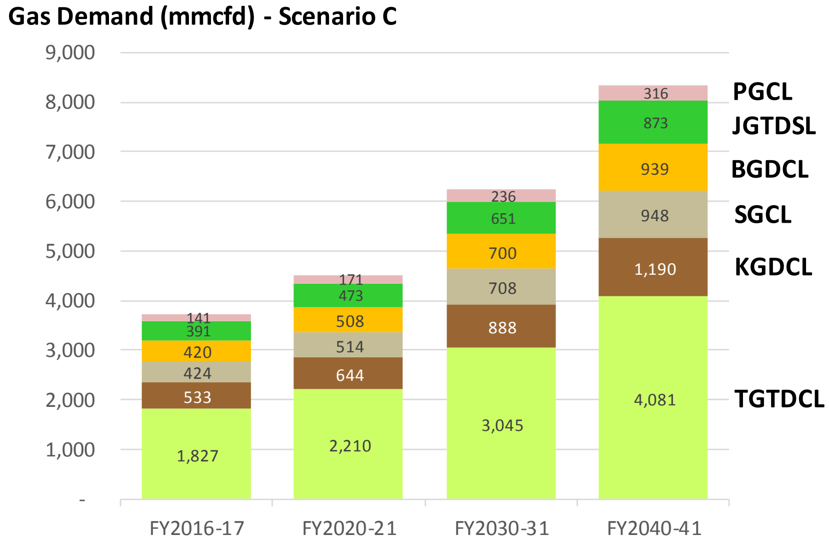
Transmission infrastructure – investments in large diameter pipelines needed flow gas from south to north.

The gas transmission system in Bangladesh will need to change to accommodate the increase in demand and the need for imports. Specifically, the flow direction which is currently from the North to the South will need to change as most of the new supplies, LNG, offshore production; connection with Myanmar will be brought in from the south.

The current gas transmission system[1] has been modelled in Pipeline Studio investigating the ability to deliver gas to the 6 franchise areas of the country. The modelling was done for the years 2021 (short term) and 2031 (medium term).

In the short term, the demand for gas is expected to increase moderately in all franchise areas. In the medium term, 14 years from today (2017), a large increase in gas demand is expected. The developments in the franchise areas are presented below in Figure 5.

Figure 5: Demand in franchise areas in scenario C



Source: Ramboll

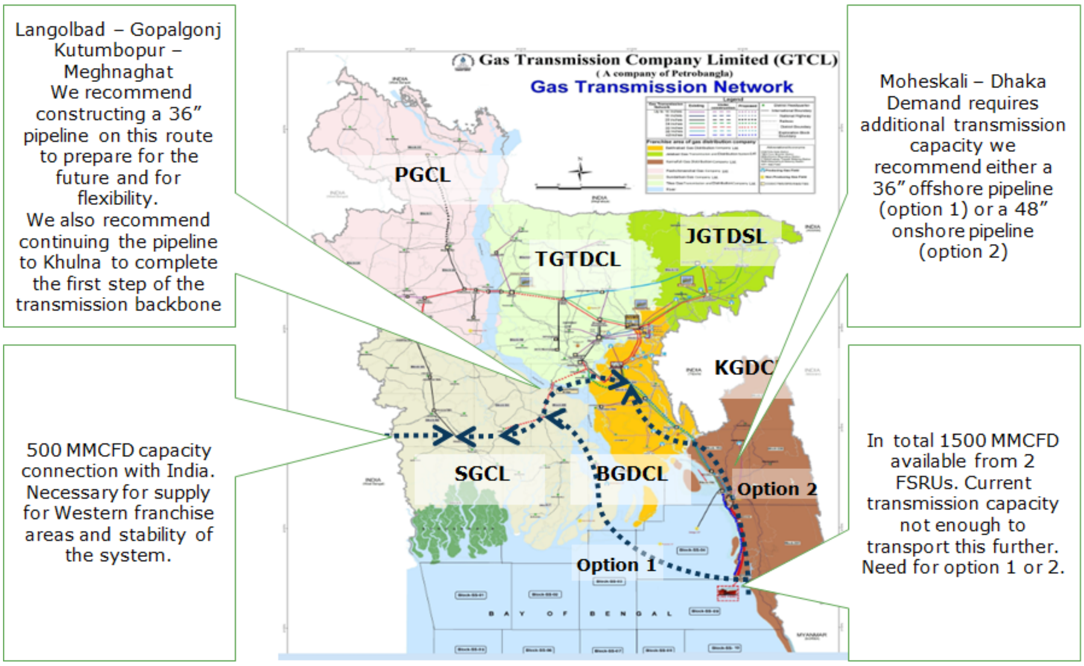
SHORT TERM (2021) TRANSMISSION SYSTEM DEVELOPMENTS – FOCUS ON CONNECTION TO INDIA

The first key finding in the short term is that with the transmission system as 2021 there will be challenges in meeting demand with a potential short fall of around 500 MMCFD. Theoretically, this shortfall could be spread out over the entire country; however, realistically, the shortfall in gas will be felt mostly at the end of the transmission system specifically in Khulna in the Sundarban region, as gas either from the south east or from the north east would have to be transported across the country to reach the west. If this area is prioritised at the expense of another area, the Elenga compressor station would have to be turned on. The best solution for resolving the potential shortfall in volumes and corresponding transmission capacity has been identified and comprises of a pipeline from India (connection at Khulna), an additional 3rd LNG terminal in south east at Moheshkhali and a large onshore pipeline connection Moheshkhali to the west of the country via a system loop with pipelines from Langlband to Khulna.

[1] Current system defined as current system (2017)+all ongoing projects + all proposed investments by GTCL until 2021 – Table 24 and Table 25

The GSMP Consultant recommends the pipeline from India to Khulna as this connection will increase system stability, security of supply, and strengthen the bargaining position of Bangladesh towards external suppliers. Given the supply and demand situation in 2021, we recommend a third LNG terminal at Moheshkhali which will trigger a need for additional transmission capacity from Moheshkhali. It can be argued whether this should be an offshore or onshore pipeline solution. Ideally, from a technical perspective, we would recommend the offshore pipeline; however, this will take more time to plan and execute. It is also most likely that the onshore pipeline can be completed in the short term, and therefore given the urgency required for meeting the short-term demand capacity, it is recommended to pursue the onshore solution first. The onshore solution also has the advantage that it can be built in sections and that investment money largely stays within the country. However, the offshore pipeline is still to be required in the mid/long term strategy, hence it is recommended to start feasibility studies immediately for this.

Figure 6: Short-term additional investments



Source: Ramboll

The second key finding of the short-term modelling is that if the India connection is not built, more volumes and capacity are needed, which will need to come from the south east at Moheshkhali with a 4th LNG terminal (triggered by the additional volumes). With the current plans for LNG the 4th terminal is likely to be a land based terminal – in that case reaching completion by 2021 will be difficult. Alternatively, the volumes could be secured by connecting the transmission system with Myanmar (also from the south east); however, we also doubt this can realistically be achieved by 2021. In any case, (Myanmar or a 4th LNG) the transmission capacity would need to be expanded.

System optimisation and usage of existing compressor stations

Finally, depending on the exact delivery demands and supply locations, it may be beneficial to lower the pressure at Ashuganj/Muchai compressor station in order to help the gas flow from the south east of the country to the west. A more detailed study is required to definitively determine this.

Prepare the system for future growth – exploit economies of scale

It will be essential for the supply of gas to the west that the 30" x 45 km pipeline Kutumbopur – Meghnaghat and the 30" x 140 km Langolbad – Gopalgonj pipelines are constructed. We recommend a higher capacity of the pipelines (36") to accommodate future growth in gas demand. We would also recommend connecting Gopalgonj and Khulna to complete the first step of the transmission backbone also creating a system loop. The connection would serve as an important part of the major transmission backbone of the country and facilitate further expansions and connections of power plants. Without these investments, the ELENGA compressor must be turned on to supply the west of the country with 500 MMCFD.

Looking at demand post 2021, it quickly becomes evident that the pipelines suggested by GTCL are undersized to carry the volume further in the system. Thus, at this stage, we recommend installing larger dimensions pipelines to accommodate future demand. Of course, for pipelines where materials have already been purchased or even installed this might prove to be a challenge. In these cases, we suggest to carry on as is.

Short term gas transmission network development – 2021

Based on the pipeline studio modelling combined with the need for gas transmission in the long term, the Consultants' recommendations for the short-term network development will be the following pipelines and compressor stations in addition to the projects already under construction.

Table 1: Gas transmission projects – short term up to 2021

		Type	Length	Diameter GTCL	Diameter Ramboll	CAPEX Cost	Finished
			km	Inch	inch	USD Million	
1	Moheshkhali-Anowara	Parallel	79	42	42	140	2018
2	Kutumbopur-Meghnaghat	Parallel	45	30	36	175	2021
3	Bangobandhu (Railway) Bridge Section	Parallel	12	36		20	2021
4	Langolband-Maowa		45	30		60	2021
5	Gopalgonj to Khulna	New East-West	90	30	42	200	2021
6	Bogra-Rangpur-Nilphamari	Parallel	160	20	30	160	2021

7	Moheshkhali – Dhaka Region		320	48	480	2021
8	India- Khulna	New	70	36	150	2021
	Various smaller pipelines for connection of power plants 5@ 30 km	New and parallel	150	30	180	2017-2021
	Compressor				50	2021
	Meter station India				30	2021
	SCADA				40	
	Total				1685	

Source: GTCL, Ramboll

MEDIUM TERM (2031) TRANSMISSION SYSTEM MODELLING – SURGE IN DEMAND REQUIRES COMPLETION OF THE MAJOR TRANSMISSION SYSTEM BACKBONE

The medium term (2031) has been modelled building upon the infrastructure included in the short term and the connection to India at Khulna. In between 2021 and 2031, we project an increase in demand from approximately 4500 MMCFD to just above 6500 MMCFD. On the domestic supply side, we would expect that some E&P results have been achieved between 2021 and 2031 increasing the domestic production from 3000 MMCFD to 4800 MMCFD; however, these are uncertain figures and do of course rely on following the recommendations on the E&P. The import capacity has been set to allow up to 500 MMCFD from India (connection at Khulna). From the south east, we allow up to 2000 MMCFD. We do, however, on purpose not specify the source of the volumes from the south east as these can be achieved from either additional LNG, from Myanmar or from offshore domestic production. Time will show how these sources develop in feasibility and we find that keeping the flexibility to adjust is important and prudent.

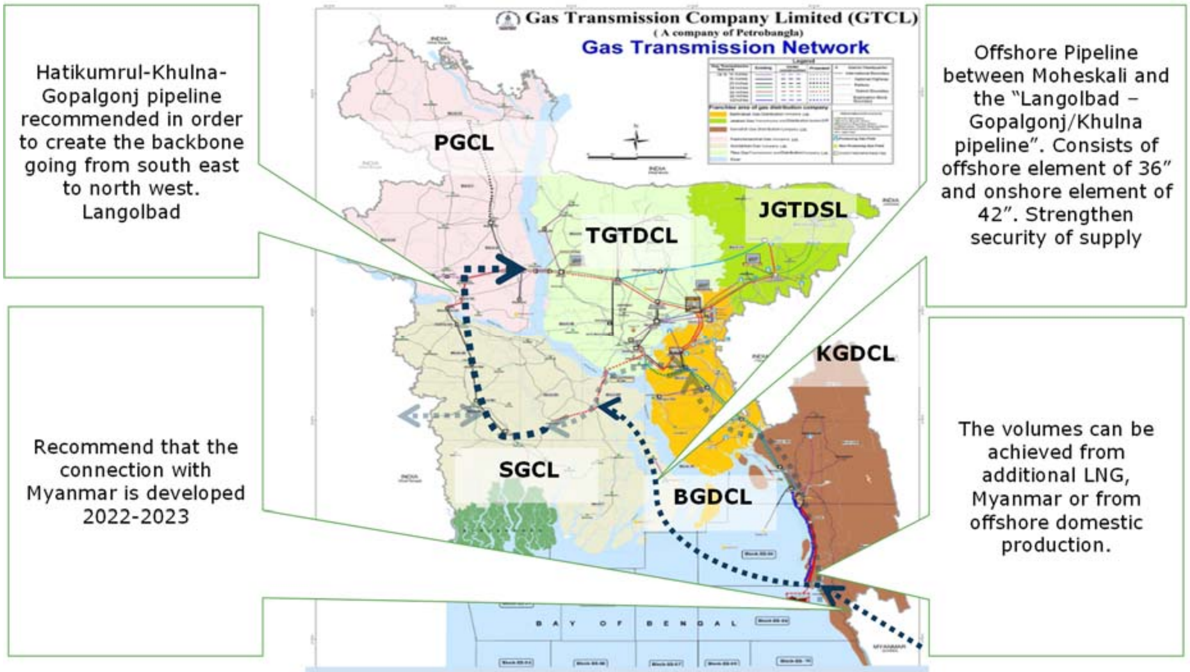
Large scale transmission capacity from Moheshkhali onshore and offshore required to facilitate import

Regardless of the source of the gas volumes from the south east, we find that in order to meet the gas demand in the Titas, Pashchimanchal and Sundarban regions, the following projects must be completed:

Offshore Pipeline between Moheshkhali and the “Langolbad – Gopalgonj/Khulna pipeline”

We recommend a 36” x 150 km offshore pipeline and a 42” x 150 onshore between Moheshkhali and the Langolbad – Gopalgonj/Khulna pipeline. The actual routing of the pipeline will have to be adjusted to connection points to power plants and other large consumers as well as to right-of-way and environmental constraints. The connection will apart from evacuating the gas form south east at Moheshkhali, strengthen security of supply not only in the western part of the country but in fact help the entire country as dependence on the narrow onshore corridor is reduced. To facilitate the transport further in the system, it is necessary that the diameter of the connecting *Langolbad – Gopalgonj/Khulna pipeline* is 36”.

Figure 7: Medium term additional investments



Source: Ramboll

Hatikumrul - Langolbad – Gopalgonj/Khulna pipelines

As part of the backbone from south east to north west, we recommend that the offshore pipeline is continued (36" x 120 km) further to Hatikumrul in the north-western part of the country. The routing should preferably follow the existing transmission system. Finally, one intermediate compressor station is potentially required between Moheshkhali and Dhaka. A detailed study is required to definitively determine this.

Medium term gas transmission network development

The investments in the medium term will depend on the actual development of the indigenous gas production. However, in all cases, we foresee the need to strengthen the gas supply from the LNG import facilities and/or Myanmar, which is the nearest country with surplus gas production.

Based on the pipeline studio modelling combined with the view of long term use of the gas transmission, the following investments are proposed. The actual of implementation will need to be adjusted as the market develops. Also, we have an underground gas storage in the period to allow for market integration and system balance. This can facilitate import of gas but also ensure security of gas supply, a better utilisation of LNG terminals and possible transit of gas from Myanmar to India.

Table 2 : Transmission projects in the medium term to 2031

		Type	Length	Diameter GTCL	Diameter Ramboll	Cost	Finished
1	Myanmar	Inter	50		36		2022
2	Moheshkhali – West Bangladesh offshore pipeline		150		36	300	2026
3	Maheshkhali – West Bangladesh onshore pipeline		150		42	250	2026
4	Hatikumrul - [Langolbad – Gopalgonj/Khulna pipelines]		120		36	180	2026
5	Compressor					50	2026
6	Underground gas storage					200	2026-2028
	Various smaller pipelines for connection of power plants 5@ 30 km	New and parallel	150		30	180	2022-2031
	Total investment from 2022 to 2031					960	

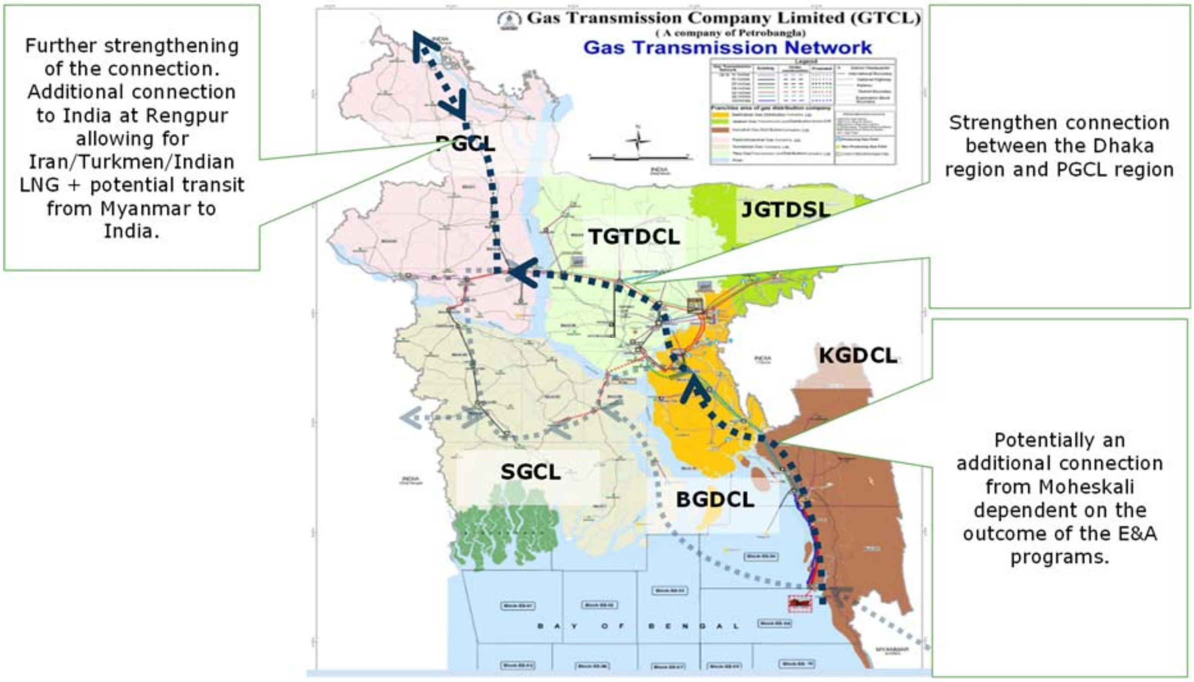
Source: Ramboll

LONG TERM (2041) TRANSMISSION SYSTEM MODELLING – UNCERTAINTY AHEAD FOCUS ON FLEXIBILITY AND KEEPING OPTIONS OPEN

The situation in 2041 has so much uncertainty about the actual gas production, import via LNG and pipelines, as well as the actual location of gas consumption. Therefore, the GSMP Consultant has decided not to further attempt to get the model to converge for this year but instead envisions the design of a flexible system, which will be able to adapt to most of the uncertainty by creating a strong backbone of the gas transmission system from the LNG import terminals, south of Dhaka and further to the Western part of the country.

As the import of gas supply increases, the indigenous gas production will increasingly be used close to the gas production or cease to exist in 2041. This situation may result in an operation where the pressure in the system close to production can be some lowered and perhaps even the flows reversed. Further to the gas transportation, a system with large diameter pipelines will also be able to provide additional line pack flexibility to ensure gas demand variations during the day. To further increase flexibility and as back up for LNG supply in case of severe weather conditions, the Consultants also recommend converting an existing gas field to underground gas storage.

Figure 8: High level Long Term Gas Transmission Plan[2]



Source: Ramboll

Post 2031, the GSMP Consultant estimates that there could be possibilities to get Turkmen/Iranian gas if the TAPI pipeline is constructed. Thus, an additional connection to India at Rangpur in the north is envisaged. The connection should also enable bidirectional flow allowing potential excess production from Myanmar to transit through Bangladesh to India. The length of the backbone from the Myanmar to the Indian border is approx. 500 km. It is recommended to develop this as a large diameter pipeline, even if such diameter is only required in the longer term to avoid investing in small diameter pipelines.

In general, the system in Bangladesh has so short pipelines that intermediate compression is only necessary in few cases to ensure sufficient flow.

- One intermediate compressor station between Moheshkhali and Dhaka – location suggested at Feni
- Compressor station could be combined with offshore underground gas storage Sangu field – the feasibility of this should of course be investigated before any decision, to date we are not aware of any relevant studies.
- Border station Myanmar
- Border station India (Khulna)
- Gas field compression – in particular when fields are being depleted

In addition to line compressor stations, there may be need for field compressor stations when the production pressure becomes lower than the needed pipeline pressure. By using increased

[2] The map shows the general envisioned back bone required for the long term plan of the network. Exact sizes and routings should be studied further in feasibility studies but it is recommended at least one 42” pipeline connects the south east to the north west of the country and as large as possible pipelines should be implemented.

volumes close to the gas fields, it may be possible to lower the operational pressure of the pipelines closed to production.

Long term gas transmission investments

The long-term investments from 2032 to 2041 are difficult to break down into actual projects. However, some of the investments will include at least one large diameter pipeline extra from the LNG import point to Dhaka and further to the west as shown in Figure 8.

Table 3: Long term pipeline investments

	Type	Length	Diameter GTCL	Diameter Ramboll	Cost	Finished
1	Moheshkhali – Dhaka Region	250		56	560	2034
2	Dhaka region – Rangpur	300		48	580	2036
3	India (Rengpur)					
4	Various smaller pipelines to power plants – 10 @40 km	400		30	480	2032 to 2041
5	Compressor				50	2036
6	New SCADA				50	
	Total investment from 2032 to 2041	950			1720	

Source: Ramboll

The actual routing of the large diameter pipeline will have to be adjusted to connection points to power plants and other large consumers as well as to right-of-way and environmental constraints.

LEGAL AND REGULATORY FRAMEWORK – LOOKING AHEAD PRICING OF LNG IMPORTS NEEDS TO BE ADDRESSED.

The demand and supply balance and the corresponding transmission plan clearly highlight the need for import from neighbouring countries by pipeline and LNG. Thus, Bangladesh is becoming connected to the world market and world market gas prices. The costs of imports will be higher than the current cost of indigenous gas production. The legal and regulatory part of this project focuses in particular on how Bangladesh may handle this situation.

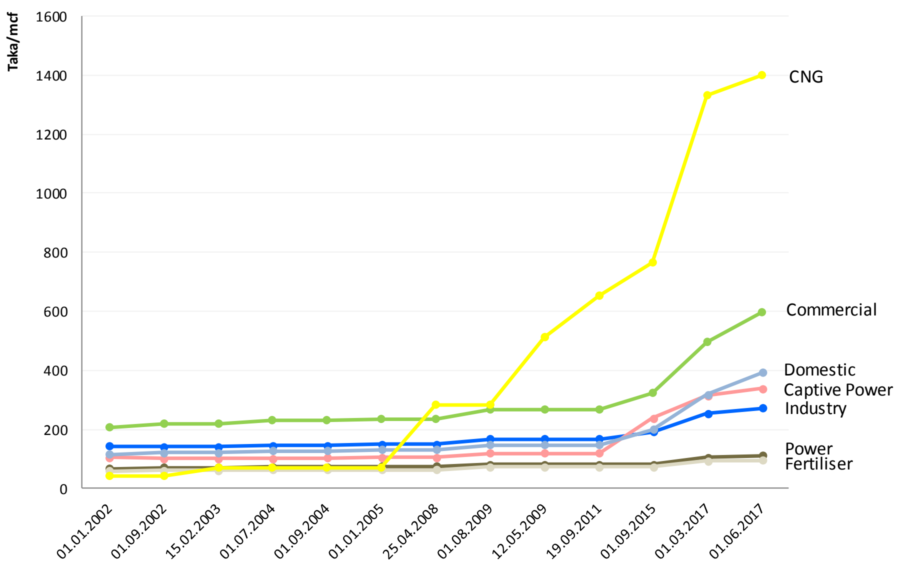
Current practice

Today's gas market structure can be characterised as a single-buyer model with a complex system of administered internal transfer prices. Petrobangla acquires gas from IOCs at PSC contract prices, mixes it with its own gas from subsidiaries, then other subsidiaries transmit and distribute it to their customers. In other words, the Government is allocating gas to consumers and administering a bundled gas price set by BERC. Bundled prices, which do not differentiate between the price of gas as a commodity and the cost of transmission and distribution, have some undesirable implications, such as:

- lead to inefficient pricing,
- do not show financial viability of the various segments production, transmission, and distribution, and
- result in cross-subsidies

However, since 2014, Bangladesh's gas price has gone up by almost USD 1/MMBTU. There has been a sharp increase in the price paid by CNG users, commercial, captive power and domestic metered gas consumption. We suggest a 3-step approach in introducing LNG.

Figure 9: Gas Price reviews – consumer groups



Source: Petrobangla Annual reports, BERC Public Notice for Gas Tariff, 2017

STEP 1: MAINTAIN BUNDLED PRICES IN THE SHORT TERM

From 2018, LNG will be imported at higher costs than the current gas purchases from PSCs and Petrobangla subsidiaries, at current oil prices this would be 6-7 USD/MMBTU. This will necessitate an increase in the gas tariff in the short term. Despite the undesirable effects of the single buyer model, our recommendation is to keep this current model[3] in the short term up to 2021 while import volumes are not very significant. In the medium term (post 2021), it is not recommended to keep this model, as it would continue cross-subsidies, inefficient allocation of resources and distorted pricing and potentially reduce the economic growth rate in the medium and long term.

STEP 2: FROM 2022 INTRODUCE DUAL MARKETS FOR GAS TO PROTECT THE DOMESTIC MARKET WHILE INTRODUCING MARKET BASED PRICES FOR THE MOST EFFICIENT AND CREDITWORTHY USERS

Several countries, Egypt and Pakistan amongst others, have introduced LNG into their markets at world market prices while protecting key customers not able to pay the full price. It is recommended to learn from the experiences made in particular with respect to how world market LNG was phased in. In that respect, the key learning is that the establishment of two markets for gas seems to be the most viable approach to introduce higher priced LNG. A dual market in Bangladesh is characterised by: 1) the current low priced gas supplied by Petrobangla subsidiaries to their customers at regulated prices, and 2) a market for new gas supply at (higher) market prices to customers willing to pay the higher price to get gas supply. LNG importers could be government–owned companies (Petrobangla, Power Cell) or private, selling gas at unregulated prices to customers willing to pay the price. A key issue is to determine the customers willing and able to pay a higher price to get gas supplied by new LNG imports.

STEP 3: THE END GOAL IS A COMPETITIVE MARKET WITH GAS TO GAS COMPETITION – REGULATED AND UNREGULATED MARKETS TO MERGE IN THE MEDIUM TO LONG TERM

It must be noted that dual markets as described and recommended above should not be seen as permanent solutions. In time, with the pipeline connections to India and Myanmar, the conditions for gas to gas competition will be present and the market should be allowed to move towards one price. The dual market solution does indeed allow for such a gradual transition to a more competitive gas market. As domestic gas production from existing fields continue to fall over time and higher cost supply from new fields increase over time, domestic regulated prices and unregulated prices will converge.

[3] Petrobangla acquires LNG imports, gas from IOCs at PSC contract prices, mixes it with its own gas from subsidiaries, then transmits the gas and distributes it to its customers through GTCL and distribution companies

2. ROAD MAP AND RECOMMENDATIONS

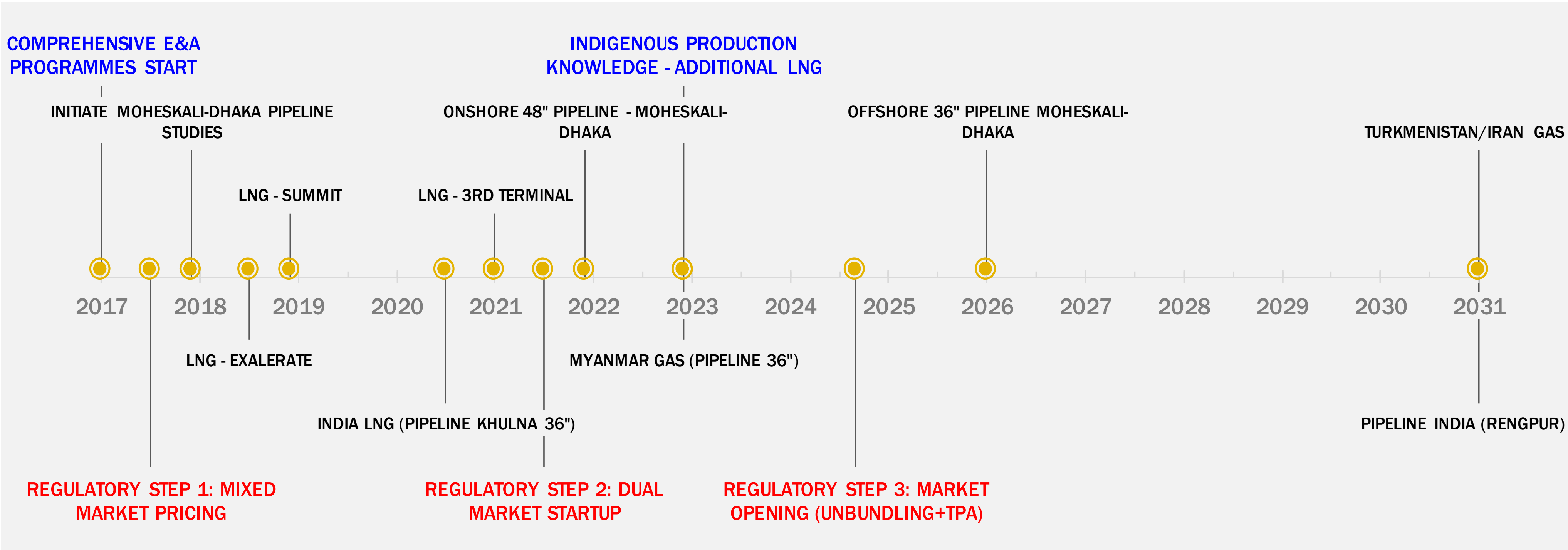
The road map for developing the gas sector into a direction where domestic production is maximised, infrastructure is developed and import is facilitated, consists of a number of decisions and uncertainties. Below in Figure 10 the main events, investments, and decisions are outlined for the following areas: domestic production, legal and regulatory and infrastructure.

Priority number 1 is to initiate the needed programs within E&P. Since the results and success of these programs will only be known 6-8 years from today, it is important to initiate this now. In 2023/2024, we expect that the industry and government will have a much deeper knowledge of how much additional production can be expected.

Priority number 2 is to initiate the technical and economic studies of the optimal solution for bringing additional gas from Moheshkhali to the Dhaka region. This will minimise the risk for bottlenecks in the system. We expect at least 3 LNG import terminals in the south east. The current transmission capacity is not enough to move this to the rest of the country.

Priority number 3 is the approach to LNG pricing and inclusion into the gas market. In the early years 2018-2021, we recommend bundling the price to allow for a gradual transition to dual markets where selected customers receive gas at higher prices and higher certainty. In these years, we recommend preparing key elements of the market opening. That means ensuring that third parties can access the transmission network and that the infrastructure ownership is separated from the trading activities on the distribution level. We estimate that if the vision of a competitive gas market should come true in 2024/2025, work needs to start 2017/2018 by updating and in some cases developing the sector legislation.

Figure 10: Overall roadmap



Source: Ramboll

INDIGENOUS GAS PRODUCTION

In order to capture the significant production potential in Bangladesh, rigorous exploration and development programmes as well as adequate resources and time are required.

Firstly, additional gas can be extracted from thin-bed resources as well as deeper prospects, such gas can then easily be tied-in to existing infrastructure for early production –first gas can be expected between Year 2018 and 2020. BAPEX has also planned to drill a large number of exploration wells within the next few years. The Consultants understand the urgency of such exploration programme in order to make quick discoveries and sustain current production level. However, we recommend Bangladesh to allow itself more time for in-depth and structured G&G preparatory work, as this will improve both the likelihood and the size of the discoveries.

As large geological areas in Bangladesh remain unexplored, we recommend a systematic and risk based approach for Bangladesh's exploration and development programmes to best utilise its resources. Priorities should be given to better known areas (eastern Bangladesh) and then gradually move to more frontier areas (western Bangladesh).

Key years will be 2023-2024 where the outcome of the seismic and E&P work will be known, if unsuccessful decisions on for example additional LNG will have to be taken in these years.

As the future E&P of indigenous gas becomes increasingly larger and challenging, it requires systematic capacity building and the strengthening of human resources in Petrobangla and its subsidiaries. We recommend relevant authorities to give adequate managerial and financial support for such development.

Table 4: Indigenous gas production

Geological Area	Bidding Round	Seismic & Geo Assessment	Exploration & Appraisal	Development	Production - 1st Gas	Ongoing Exploration & Development
	Year	*Year*	*Year*	*Year*	*Year*	*Year*
Area A - Thin Beds	-	2017	2018	2018	2018	-
Yet to Find - Area A (Accelerated E&P only)	-	2017	2018-2019	2019-2020	2020	-
Yet to Find - Area A (Remaining)	-	2017-2018	2019-2020	2021-2023	2024	2021 +
Yet to Find - Area B	-	2017-2019	2020-2021	2022-2024	2025	2022 +
Yet to Find - Area C (offshore)	Ongoing	2017-2018	2019-2020	2021-2023	2024	2021 +
Yet to Find - Area D	-	2020-2022	2023-2025	2026-2028	2029	2026 +
Yet to Find - Area E	-	2026-2028	2029-2031	2032-2034	2035	2032 +
Yet to Find - Area F (offshore)	Ongoing	2026-2028	2029-2031	2032-2037	2038	2032 +
Yet to Find - Area G (offshore)	Ongoing	2017-2018	2018-2019	2020-2026	2027	2021 +

Source: GEUS

INFRASTRUCTURE – ACTION PLAN

Infrastructure action plan is in the short to medium term focuses 3 areas 1) secure the necessary transmission capacity from Moheshkhali to the Dhaka region. 2) develop cross border connections with India and Myanmar in the short and medium term respectively. 3) develop the internal transmission system to avoid bottlenecks from east to west.

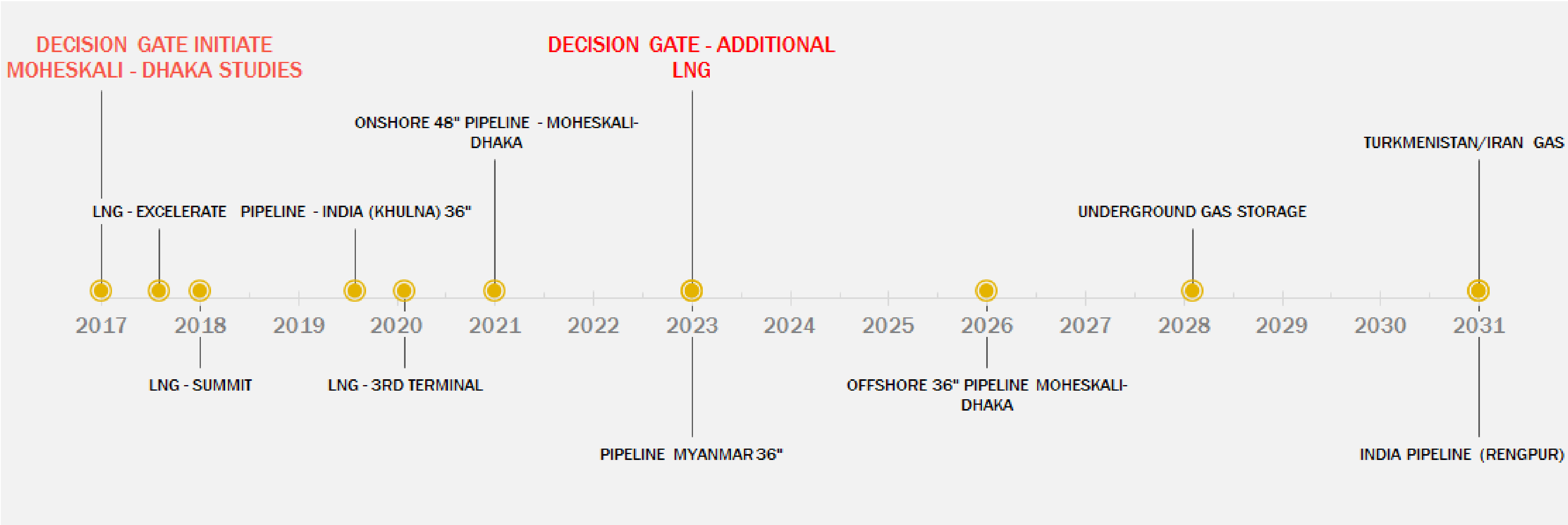
Further development of transmission capacity from the south east to the central and western part of the country can and should be done both onshore and offshore. Since there is a need for evacuating gas from the south east at Moheshkhali, we recommend starting with the onshore pipeline. It has been scheduled for 2021 – this ambitious completion would potentially stretch into 2022/2023 depending on the level of challenges and obstacles with key issues such as right of way. The offshore pipeline will require more time, and we estimate that it at the earliest can be operational by 2026. In both cases, the decision to undertake the necessary studies must be taken in 2017 in order not to lose time.

To increase system reliability, diversification, and bargaining power, we recommend connecting with India (Khulna) in 2021 and Myanmar in 2023. Failure to connect with India will imply a shortage of gas in the western part of Bangladesh. The connection with Myanmar we believe should be pursued regardless of the developments on indigenous gas production.

The transmission system will have to be upgraded in order to transport the volumes from the landing point in the south east to the rest of the system. We strongly recommend increasing diameter size whenever possible in order to prepare the system for future growth and to exploit economies of scale. Often this means installing 36” pipelines instead of 30”.

We estimate that the year of 2023 marks a decisive year for gas infrastructure investment. By then, it should be known whether the E&P programs described previously have been successful or not. Lack of success would necessitate further import most likely as LNG unless additional amounts and flexibility exists in India and Myanmar.

Figure 11: Infrastructure action plan



LEGAL AND REGULATORY ACTION PLAN

The action plan for the legal and regulatory analysis gives recommendations as to how to accommodate the higher LNG prices, open the market to competition and update the regulatory framework within the upstream sector. The key challenge is the treatment of LNG in the short run, establishing the infrastructure and ensuring the smooth flow of gas from the terminals is a challenge in itself and requires time and adaptation. Thus, we do not recommend implementing the dual markets overnight. A preparation period of 3-4 years is suggested to prepare the market, hereunder determining which customers should be eligible for higher prices. Meanwhile in the period 2018-2021, we recommend continuing the current practise of pooling/mixing the prices, although not optimal it may very well be the only option which is implementable in the short term. This implies that unless the State is covering the increased costs of purchasing gas, prices will increase for consumers. The distribution of these price increases is at the end of the day a political decision. Dual markets should also be seen as a transition. As domestic gas production from existing fields continue to fall over time and higher cost supply from new fields increase over time, domestic regulated prices and unregulated prices will converge.

Two preconditions for the above development exist, 1) changes to the current legal and regulatory environment and 2) development of infrastructure. The changes to the legal and regulatory framework must be focused on two separate areas:

- Provision of third party access to the network: third party access could in the future be beneficial to Bangladesh and could support on opening of the markets by allowing suppliers and producers to supply directly to consumers and retailers. This requires enhancement of the responsibilities of BERC regarding tariff determination and licensees for the various functions within the gas market. Finally, the network code for the transmission system must be developed. This will determine the rules and access conditions for third parties, the financial requirements, etc.

- Unbundling of distribution companies and transfers of ownership of all existing transmission infrastructure to GTCL; We recommend in the medium term to address the ownership of assets in Bangladesh. Currently, some transmission assets are owned by the distribution companies, we recommend transferring this to GTCL. Meanwhile, to avoid conflict of interest we recommend to legally unbundle the distribution companies into an infrastructure owner and a trading/supply company.

The development of infrastructure is outlined in the previous section. With respect to the impact on the regulatory changes, it is important to highlight that the opening of the market must go hand in hand with the infrastructure developments. In particular pipeline developments as this enables competition between different gas sources.

Table 5: Legal & regulatory action plan

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
LEGAL & REGULATORY														
Gas Rationing														
-Review gas utilization guidelines	Review	Decide												
-Allocate more gas to power and fertiliser sectors		Allocate												
Pricing														
-Mix higher priced LNG and lower priced domestic gas		Mix	Mix	Mix										
-Introduce dual markets for gas	Plan	Decide	Prepare	Prepare										
-Determine eligible customers to buy gas directly from suppliers	Plan	Plan	Plan	Identify	Dual market 2021-2023			Implementation of competitive gas markets 2023-2030						
-Increase the gas price to customers willing to pay a higher price	Plan	Decide	Prepare	Prepare										
Opening gas market														
-Update BERC Act for tariff methodology	Plan	Implement												
-Update BERC's License Regulations	Plan	Implement												
-Enhance BERC's regulatory capabilities on TPA	Decide	Draft	Implement											
-Develop Licenses for import of gas (LNG)	Draft	Implement												
-Develop Licenses for transmission, shipping and sale of gas	Decide	Draft	Draft	Agree	Award licenses									
-Develop Network code for transmission	Decide	Plan	Draft	Draft	Agree & Implement									
-Distribution Companies														
-Transfer all transmission assets to GTCL	Decide	Implement												
-Licenses for distribution, shipping and marketing of gas	Plan	Plan	Plan	Draft	Draft	Draft	Agree	Award licenses						
-Legally separate marketing and distribution of gas in Distribution Companies	Plan	Plan	Plan	Draft	Draft	Draft	Agree	Separate						
-Network code distribution	Plan	Plan	Plan	Draft	Draft	Draft	Agree	Implement						
Upstream														
-Establish Independent Upstream Regulator	Decide	Plan	Draft	Draft	Agree & Implement									
-Regulator to manage bidding rounds and granting PSCs					Decide	Plan	Implement							

Source: Ramboll

3. INTRODUCTION AND CONTEXT OF THE PROJECT

3.1 Background

This Gas Sector Master Plan 2017 is an update of the 2006 plan which was prepared for the time horizon up to the year 2025. The primary aim of the present GSMP 2017 is to update the GSMP2006 to align it with Bangladesh's current infrastructure development priorities and guide the development of the sector through 2041. In this context, coordination has been carried out with the Power Sector Master Plan 2016 and the team behind it. However, assumptions and scenarios are different than in the PSMP2016, not least due to the dramatic change in international gas prices, in wake of the decline in oil prices in late 2014.

Natural Gas is the principal source of commercial energy which accounts for about 79% primary commercial energy supply in the country. It is used for generation of electricity, manufacturing of urea fertiliser, industrial, commercial and domestic purposes and also for burning of bricks, tea processing and as fuel for CNG operated vehicles. In Fiscal Year 2015-2016, Share of gas based on installed generation capacity (MW) is 61.69% and share of gas based on net energy generation (MkWh) is 68.33%. The number of discovered gas fields in the country is 26. The total reserve of recoverable (Proven + Probable) gas is 27.12 TCF and a total of 14.38 TCF gas had been produced up to December 2016, net remaining reserve is 12.74 TCF on January 2017. Presently, 20 gas fields are in production producing in aggregate at a rate of about 2,750 MMCFD.

The Government of Bangladesh has a vision to become a middle-income country by 2021 and a developed country by 2041, and it is one of the fast-growing economies in the Asian region. Its GDP is growing at a rate higher than 6% per annum. Dependable supply of energy at affordable cost is a precondition for sustainable growth. With fast paced growth and uplift in the standard of living, demand for energy is growing rapidly in Bangladesh.

The purpose of the GSMP 2017 is to provide a strategic technical plan for the long-term development of the gas sector in Bangladesh. The sector faces a critical point as domestic production is projected to decline and additional supplies will require increased investment and an opening of the sector to import and world market prices of gas. The primary objective of the GSMP 2017 would be to identify a possible path for developing additional supply and to lay the foundations for informed policy making.

<u>The new GSMP 2017 focuses on:</u>

- Gas demand-supply projection, with the latter based on long-run marginal cost of supply;
- Assessment of Oil & Gas exploration possibilities and development of a road map to enhance Gas reserve;
- Gas field development to meet the growing demand;

- Considering the flow patterns from various gas fields to the demand centres using the existing infrastructure;
- LNG import facilities;
- Regional gas development and integration of Bangladesh gas system with neighbouring countries;
- Optimising expansion of gas supply and transmission infrastructure in the medium- and long-term;
- Recommendations on changes to the policy, legal, regulatory and institutional framework required to support long-term gas development.

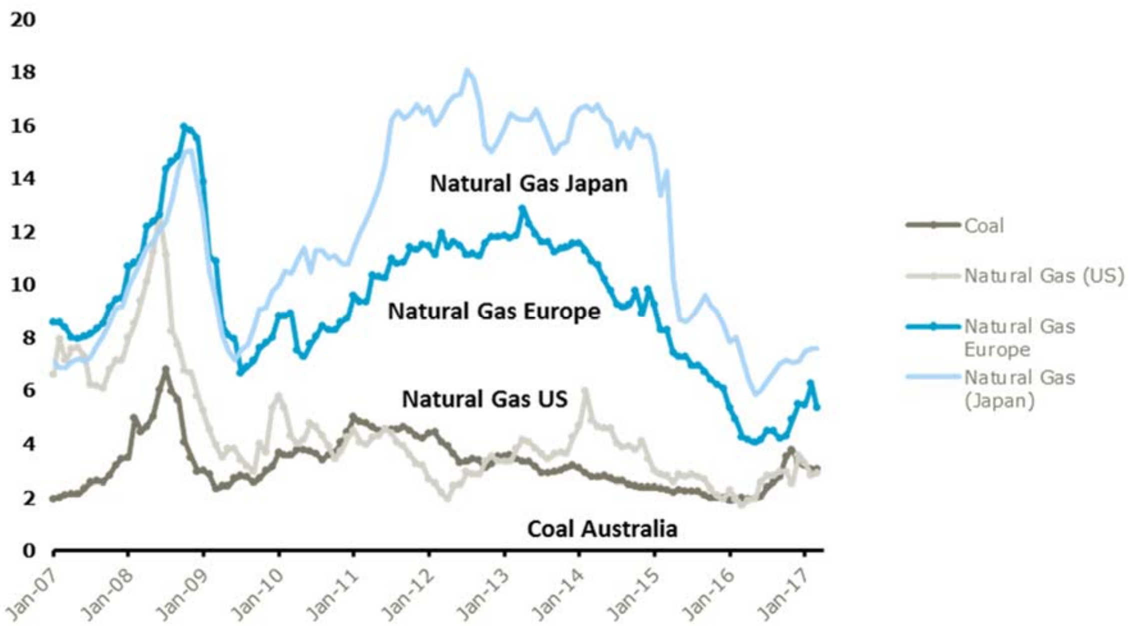
The expected results of the assignment are:

- The study is expected to constitute a medium-term plan for least-cost augmentation of supply and sustainable development of the gas sector in Bangladesh.

3.2 Problem statement

Since the GSMP2006, the oil & gas sector has undergone significant changes globally as well as locally in Bangladesh. Global energy prices were already in 2006 on the rise supported by rising demand and slumps in supply of oil and gas.

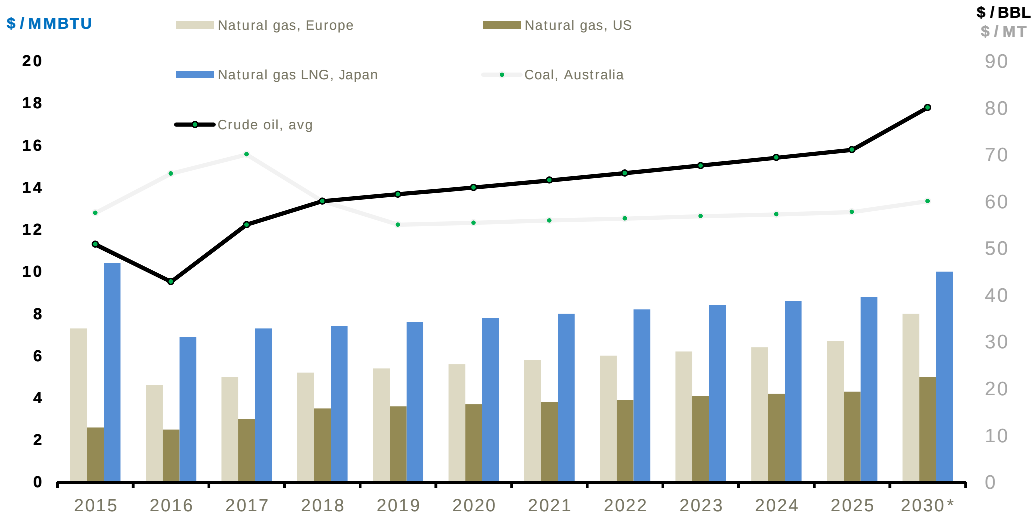
Figure 12: Historical Energy Prices, USD / mmbtu



Source: World Bank 2017

Today, prices of oil and gas have come down and have remained relatively stable at around 50 USD/bbl. The World Bank outlook for 2030 is presented below showing sustained low prices of gas compared to the past 10 years.

Figure 13: World Bank Commodities Price Forecast (in nominal USD)



Source: World Bank 2017

Several elements are in favour of a prolonged decline in commodity prices. First of all, there is an expectation that the world in the short to medium term will experience a supply glut of LNG caused by many of the mega projects initiated during the booming oil and gas years now being finished especially in Australia. Secondly, since the GSMP2006, the United States has undergone a revolution within its energy sector leading the United States to become an exporter of gas instead of importer, as was envisaged back in 2006. Thirdly, some of the high potential markets such as the European market are moving away from fossil fuels and will in the future use less gas than what was anticipated previously. Fourthly, recent events in the Middle East;

- sanctions being lifted on Iran;
- Qatar lifting its Moratorium on gas exports;
- and the coalition of Arab states imposing a ban on Qatar might push the LNG markets further downwards.

The changed price picture has implications for the choices of Bangladesh – especially now when the country is becoming an importer of LNG.

Locally in Bangladesh, GDP has been increasing significantly with year on year growth rates of minimum 6.0 % in local real value since 2006. Bangladesh, a self-sufficient country in gas since the 1950'ies has experienced difficulties in meeting the growing demand for energy, in particular gas. The shortfall in energy has in effect been limiting the economic growth in the society. The reasons for demand outpacing supply are many and should be found on both the supply and the demand side. On the demand side several factors have facilitated an exceptional growth in energy and gas demand, the most significant being:

- The average growth rate over the period 2002-2016 was 6.0%. The exponentially growing GDP has had a direct impact on energy demand.

- Population levels have been growing significantly and steady, on average 1.3% per annum. Bangladesh's population in 2016 was estimated to be at 162.9 million, which is a 19.6% change compared to 2002 where the population was 136.2 million.

- Domestic gas pricing: Offering gas well below economic prices has implied a high demand in some areas of society. The effects of energy subsidies are well-known and have been studied intensively by IMF and the World Bank; when natural gas prices are subsidised, it leads to a rapid growth in gas consumption and electricity consumption as gas is one of the main fuels for power generation. Low natural gas prices lead to underinvestment in the energy sector and even in countries where producers and transmission and distribution companies (often the National Oil and Gas Company) are compensated in the state's fiscal budget, the payment is often not large enough to invest in new production and infrastructure, resulting in fuel and electricity shortages. When international energy prices go up, energy subsidies lead to a rapidly rising fiscal burden in gas importing countries. Exporting countries also incur a cost, in the form of foregone revenues that could have been invested in new infrastructure or other government programs.

Supply has entirely been from domestic resources. However, the current domestic resources have not been adequate to supply the energy demands resulting from the growing population and GDP. Several of the major producing fields, originally discovered back in the 60'ies and 70'ies, are in decline. Efforts have been made to increase supply from domestic production during various licensing rounds; however, the interest from IOCs has been limited.

Thus, with GDP and population levels continuing to expand, the Government has been faced with a limited set of choices in the short term. Initiatives to curb gas demand through regulatory changes and demand side measures have been initiated, the most significant being increasing prices and reduction in subsidies and an immediate halt to expansions of the domestic consumption.

On the gas sourcing side, efforts to meet the demand for gas have been concentrated around development of LNG import to the country and maximising the output from the existing producing fields. LNG import is expected to commence in 2018.

Thus, Bangladesh faces a number of important choices with respect to the paths that the country can chose from. Continuing the present path with future declining production, increasing demand, and residual demand to be covered by imports could have a series of negative consequences to the country, the most significant are:

- Lack of gas and energy to meet domestic demand putting a ceiling on economic growth.
- Significant exposure to international gas and energy prices implying a high risk of an increased fiscal burden – which the country cannot afford in the long run.
- Poor bargaining position vis-à-vis suppliers of LNG.

- Lack of investments in gas sector infrastructure – increasing the pressure on the current system.
- Political and social instability as a result of the above.

This report outlines alternative paths and has concrete and specific recommendations which would support this formulated in a road map for the country.

3.3 Overview of this final report

The Final Report is divided into the following chapters: chapter 4 gas demand analysis, where energy and gas demand is investigated and developed for three different scenarios. In the following chapter 5, domestic gas supply is addressed. In chapter 6, the various supply possibilities coupled with demand developments are presented to present the least cost of supply in the short, medium, and long term. Chapter 7 presents the transmission system of Bangladesh bringing together the previous chapters in a simple framework that allows illustration and detection of bottlenecks in the system given the different development paths with Bangladesh starting to import gas. Chapter 8 presents the cross-border pipeline import solutions for Bangladesh – a topic which was not analysed in GSMP2006. Chapter 9 presents the LNG import options and plans. Chapter 10 addresses the legal and regulatory changes needed in order to achieve the least cost solution and support the development of the sector. Changes in the regulatory framework impact both the demand and the supply.

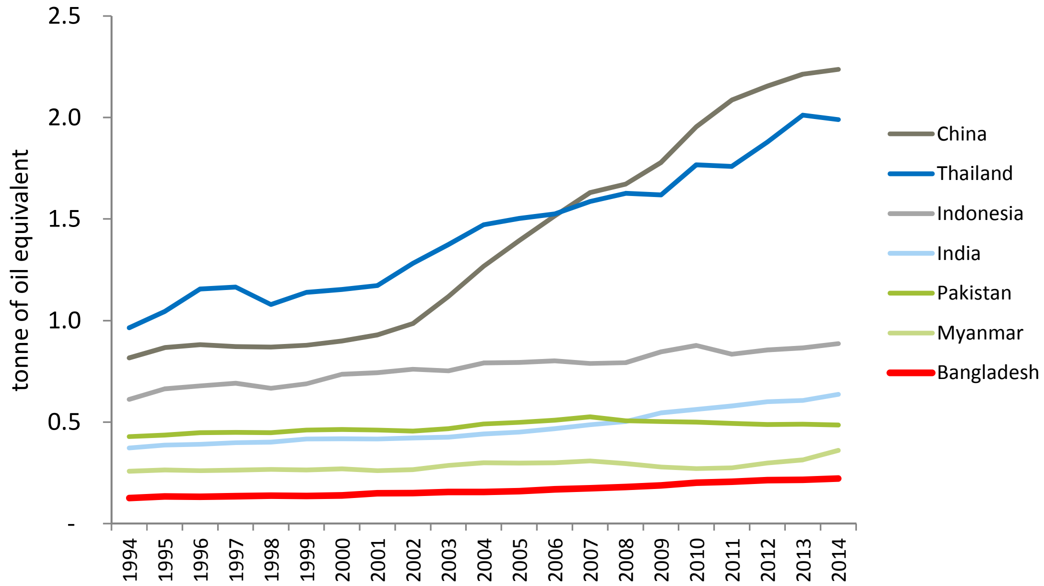
4. GAS DEMAND

4.1 Bangladesh energy sector current status – a burning challenge

4.1.1 Primary energy consumption compared to peer countries

Bangladesh has been facing a severe challenge of energy shortage. In 1994, the primary energy consumption per capita of Bangladesh was only 0.13 tonne of oil equivalent (toe). In 2014, this figure increased to 0.22 toe, still at a low level comparing to other Asian countries. For example, on a per capita basis, Thailand consumes 9 times as much primary energy consumption as Bangladesh, see Figure 14.

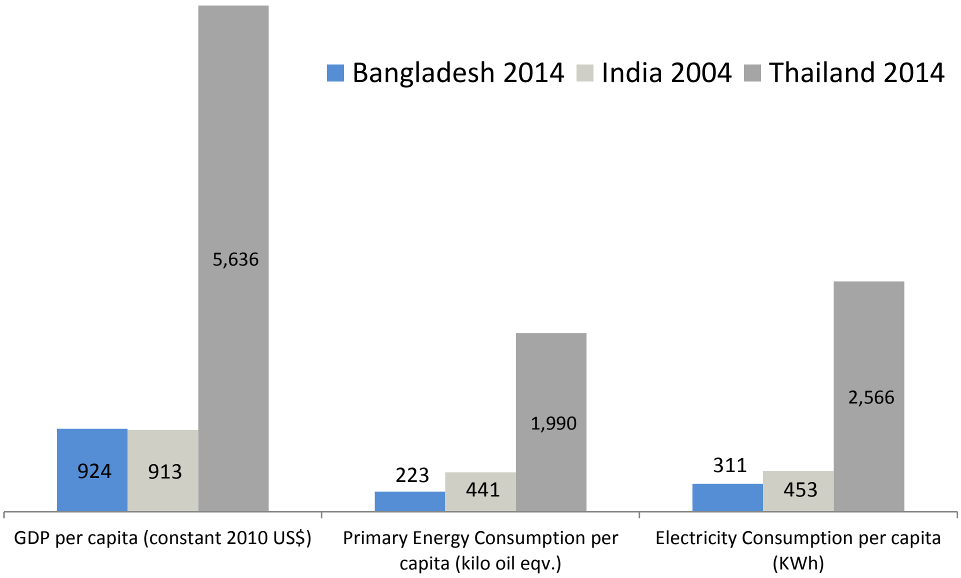
Figure 14: Primary Energy Consumption per Capita



Source: World Bank

Looking at this in context, Bangladesh's GDP per capita in 2014 was USD924 (measured at constant 2010 price), similar to that of India in 2004. However, the energy consumption stories of these two countries are very different. India's primary energy consumption per capita in 2004 was already twice as large as that of Bangladesh in 2014. It can be argued that India has had a high concentration of coal in its primary energy mix, less energy efficient than gas; therefore, the difference between Bangladesh and India may be overstated when looking at primary energy consumption. However, the difference in electricity consumption per capita was 46%, less dramatic yet still significant.

Figure 15: Energy Consumption Comparison - Bangladesh vs India vs Thailand

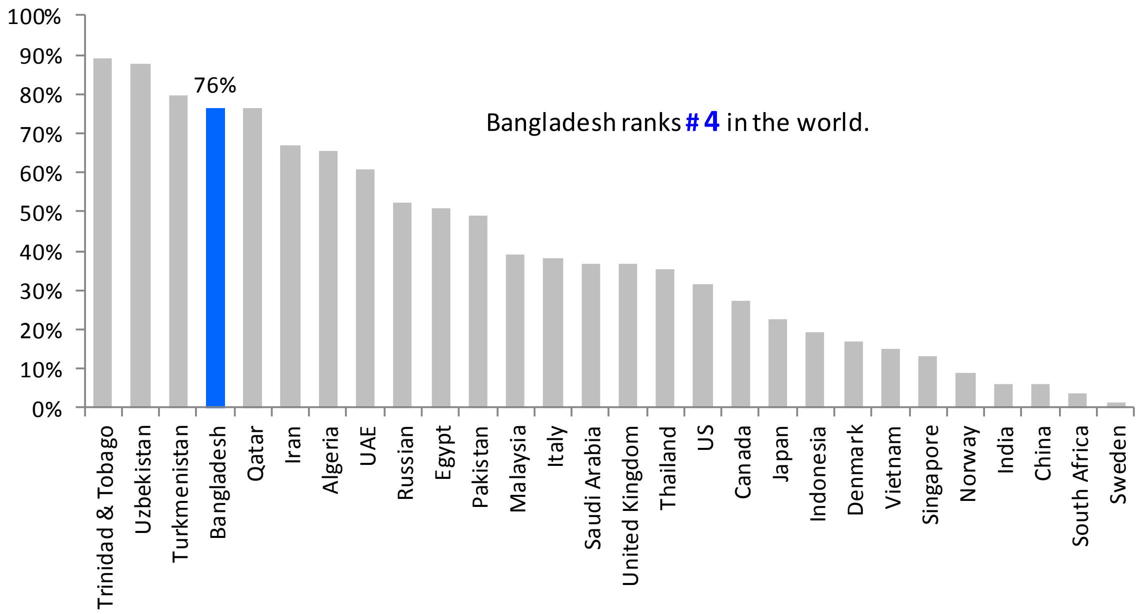


Source: World Bank

According to Bangladesh's 7th Five Year Plan, the government has the intention to pursuit an export-led economic growth model, a strategy that brought rapid GDP growth to China. China became a member of World Trade Organisation (WTO) in 2001, exporting predominately manufacturing products, and the primary energy consumption per capita in China has tripled since then. This highlights the need for Bangladesh to secure dramatically more energy in order to support its economic development plan.

Bangladesh also has a very high concentration of natural gas in its energy mix compared to other countries. In 2016, natural gas made up 76% of the total primary energy consumption of Bangladesh, ranking the country number 4 in the world for gas penetration. This is on the same level as that of Qatar (a major gas exporter) and twice as high as that of Italy (a gas importing country).

Figure 16: Gas Share in Primary Energy Consumption (excl. Biofuel & Waste), 2016



Source: BP Statistical Review 2017

Bangladesh's reliance on gas in its energy mix is a result of what is available from low cost domestic production, as well as the lack of development and import of other energy sources.

Natural gas has been vital in fuelling Bangladesh's economic growths over the past few decades, meanwhile, it is widely recognised that the overall energy supply for the country is now lagging far behind its economic development. The scale of the energy shortage requires Bangladesh to pursuit a substantial level of imports as well as diversifications of its energy mix.

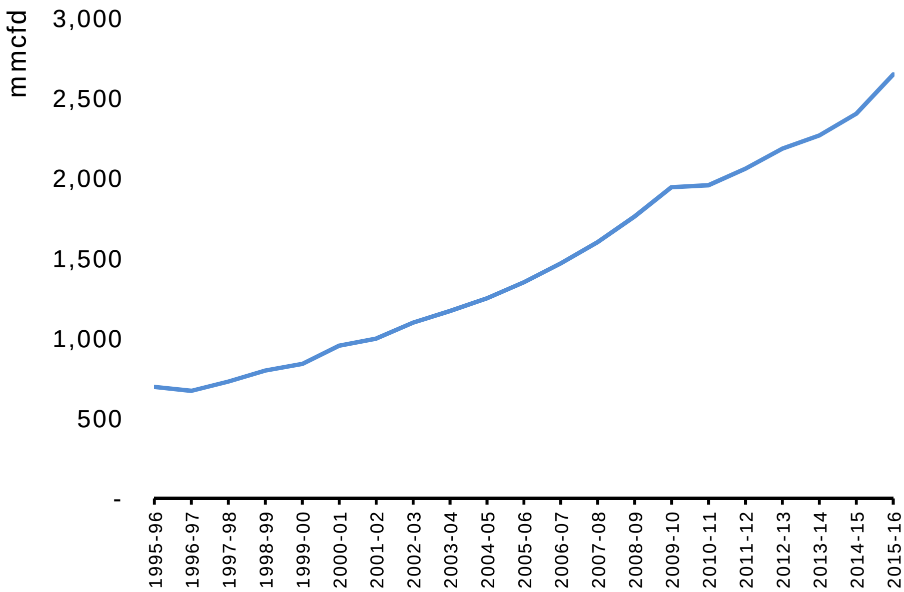
4.1.2 Developments in primary energy consumption components

In the following the various components of the energy mix are investigated.

Gas

According to Petrobangla, natural gas consumption in Bangladesh has increased dramatically from 698 mmcf/d in 1995/96 to 2,645 mmcf/d in 2015/16, almost 4 times increase over 20 years.

Figure 17: Bangladesh Historical Gas Consumption

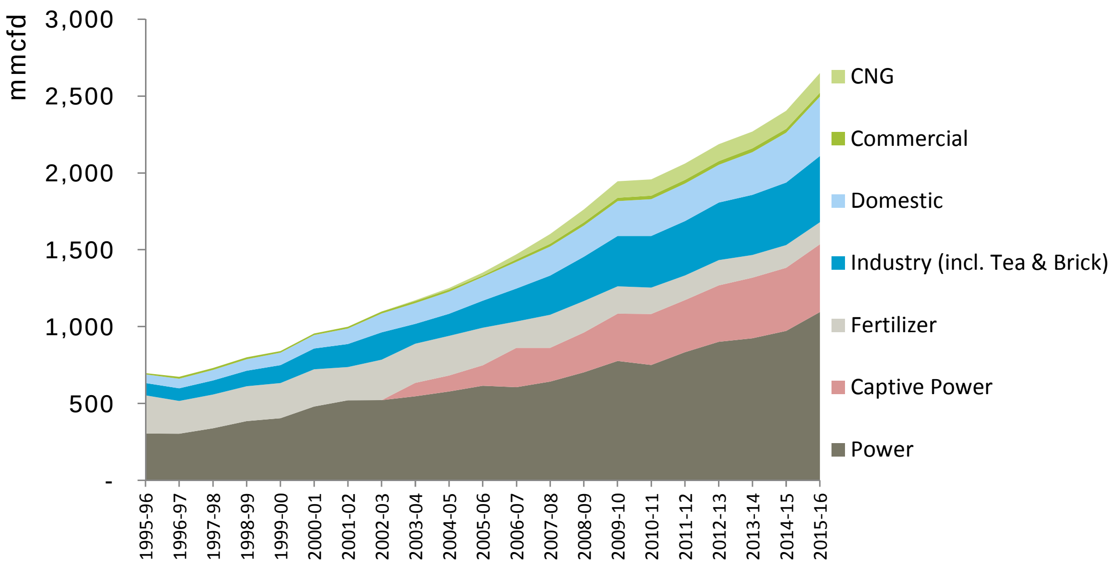


Source: Petrobangla, Annual report 2015

The power sector has been the biggest consumer of natural gas, accounting for 41% of total gas consumption in 2015. This is followed by captive power 17%, industry sector 17%, domestic sector 13%, fertiliser sector 6%, CNG sector 5%, and commercial sector 1%.

As shown in Figure 18, while power (grid power), captive power, industry and domestic sectors have increased their use of gas, the consumption from CNG sector has remained stable and that of fertiliser has in fact dropped in recent years. This is a direct result of the shortages in gas supply, creating a significant level of unmet demand as will be showed later on in this report.

Figure 18: Historical Gas Consumption by Sector



Source: Petrobangla Annual report

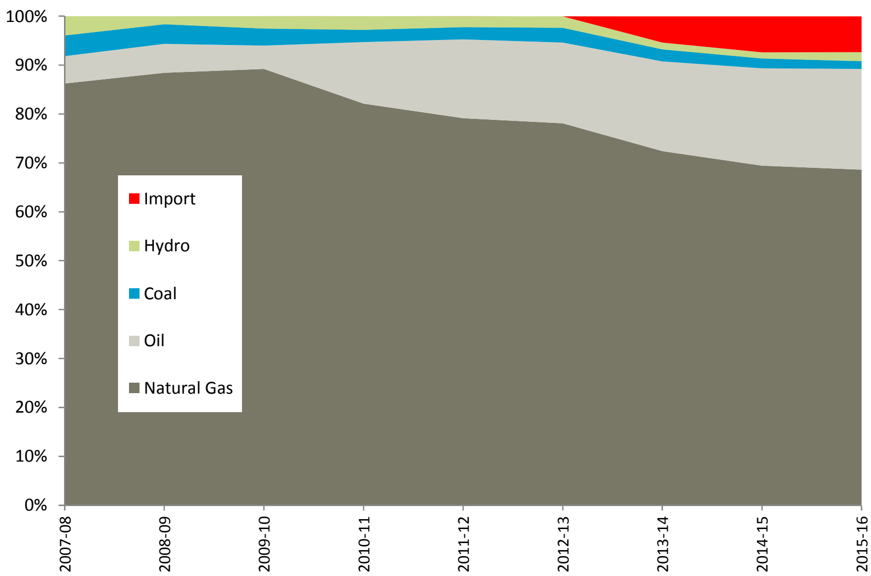
According to the Petrobangla estimates, the gas production capacity in 2016/17 was 2,754MMCFD while the demand is estimated to be 3,736MMCFD, about 1,000mmscf (27%) daily shortage in supply even if the maximum production is achieved. As a result of such shortage, there is now a severe rationing of gas. Even though priority has been given to the power sector, which has come at the expense of fertiliser production and growth in CNG gas consumption, the fast-growing demand for gas in power production has far outstripped gas supply.

Historically, natural gas has been the predominant source for power generation in Bangladesh. To meet its growing demand, Bangladesh began importing electricity from India in September 2013. In Fiscal year 2009/10, about 88.52% of grid power generation (net) was gas based, 5.08% was liquid fuel based, 3.75% was coal based, and the remaining 2.65% was hydro based. To meet its growing demand, Bangladesh began importing electricity from India in October 2013.

In FY 2015-16, with competing demands for gas and constrained supply, according to installed generation capacity, the share of gas based power to the grid fell to 62%. In contrast, the share of oil based power surged to 29% of the total. Meanwhile, hydro and coal based power both are same as the last year i.e. 2%. The remaining 5% of grid power supply was import based. The surge in the share of oil based power supply in recent years is a reflection of a major primary fuel constraint in Bangladesh. This has contributed to the rapid increase in the average cost of electricity generation.

There is currently neither nuclear nor renewable power supply to the grid. However, there is a substantial level of off-grid power generation from captive power and small amount from residential solar PV – the exact quantity from these sources are difficult to estimate, while some studies suggest that the off-grid power could currently account for around 20% of total Bangladesh power generation.

Figure 19: Bangladesh Historical Grid Power Net Energy (excl. Captive Power & Solar PV) Generation



Source: BPDB. NB: numbers are according to the net energy generation.

Coal

Bangladesh is endowed with rich bituminous coal deposit, with the measured and probable coal reserves total of 3,300 million tons. Out of five identified coal fields, namely Barapukuria, Phulbari, Khalaspir, Dighipara and Jamalganj, only Barapukuria is currently in production. Barapukuria's measured and probable reserve is 390 million tons. This mine has capacity to produce one million tonnes per year.

Coal produced from Barapukuria has good heating value, more than 6,072kcal/kg (25.68MJ/kg). This level of quality coal can be used for coking coal. Currently, the Barapukuria coal is fuelled for the mine-mouth Barapukuria Coal Power Generation (125 MW 2 units) and brick kilns. Additionally, another unit of 274 MW in Barapukuria is under construction stage. However, with such good heating value, Barapukuria coal could be used for higher energy efficient use, such as higher efficient coal-fired power plant (Super-critical or Ultra Super Critical) power plant, or for more energy-intensive industry use such as steel production (coking coal). Meanwhile, Coal Bed Methane (CBM) feasibility study project was undertaken to evaluate the methane gas reserve as well as to examine the commercial viability for extraction of CBM from Jamalganj coal field. The project was completed in December 2016; however, the result of the study was not satisfactory.

The Bangladeshi Government has a strong intention to diversify its power mix and rapidly develop coal-fired power plants. Given the present status of domestic coal, the implementation of these projects will require imported coal for fuel. This will require huge port, rail transport and coal stocking infrastructure. However, so far there is only one ongoing deep-sea port project in Matarbari Island which will be able to cater ships having 80,000 tonnes capacity. This is currently dedicated for Matarbari Ultra Super Critical Coal-fired Power Plant. In the near future, however, the Government intends to expand this deep-sea port and develop a coal Centre as “An Energy Hub” for the whole country.

According to PSMP2016, the construction of Dighipara coal mine and Khalashpir coal mines are to be commenced after 2022 and 2027, respectively. Coal shares 35% of total installed power capacity by 2041 as per the PSMP base case, and the annual imported coal to be expected as much as 60 million ton by the same year. This projection may be revised as the Bangladeshi government reconsiders its options in response to recent developments in the global energy sector.

Oil and petroleum products

Bangladesh's current oil annual demand is around 5 million tons, and the self-sufficiency rate is only 5%. The Bangladeshi Government expects continuous economic development. As a result, the industry sector and transport sector demand will lead drastic oil demand growth; 6 times higher in 2041 than in 2016 (average growth rate 7.4% p.a.).

In FY2014, Bangladesh Petroleum Corporation imported over 5 million tons of petroleum products, worth approximately USD3.5 billion. Out of this, power sector (public and private) consumed 1.364 million tons which accounts for 25.7% of the total consumption, communication (transport) sector 2.472 million tons i.e. 46.5%, and agriculture 0.929 million i.e. 17.5%. Bangladesh has several plans to extend or newly develop oil refineries; however, if the oil demand grows as projected, oil imports will be mandatory to meet the demand and keep increasing.

LPG

In many countries, LPG is a precursor fuel in new areas. The introduction of LPG allows the market for gas to develop, substituting for other fuels, such as biomass. By increasing demand for gas prior to the introduction of a network, the market is developed at a lower cost and at a lower risk than if a distribution network is installed upfront and the market developed afterwards.

In Bangladesh, the situation is different; natural gas supply is declining, and LPG can serve as a substitute for natural gas in new residential areas and for CNG in transportation. The market for LPG is already created, the main issue seems to be the pricing of LPG. At present, the price of LPG is much higher than that of the pipelined gas, and may not be affordable for average households in Bangladesh. While Bangladesh rural households spend 4-7 % of their monthly income on traditional solid biomass, LPG at the market price would be 25%.

A survey identified the key challenges with LPG in Bangladesh. Gas cylinder is not available on regular basis, and there is a transportation problem for gas cylinders from dealers to the households, often they need to purchase it far from the household. Also, the price of LPG is not stable.

Renewables

According to the 7th FYP, there is already some significant success in the area of solar energy that has delivered 150MW equivalent of power primarily through a highly successful Solar Home System (SHS) programme. Some 4 million SHS units have been delivered. While the delivered cost of electricity is high (about BDT76/kWh, i.e. USD0.95/kWh assuming 1USD=80BDT), they provide basic lighting and other services in areas where the grid is unlikely to reach for a long time.

Rooftop solar PV systems are also being introduced in the country with the current installed capacity estimated at 32 MW. There is also 180 MW of wind potential that has been identified through a USAID project. Mini-grids and grid-connected MW-scale solar PV plants are also being explored.

Large scale PV is being planned with the first 100 MW plant. It has been argued that lack of space is a hindrance for PV development. However, this argument is more anecdotic and based on local conditions.

The Bangladeshi Government had previously planned to generate 800MW of power through renewable energy by FY2017 with a target of 10% of the total electricity to be met from renewable resources by FY2020. However, this now appears to be overly challenging and delays are expected.

Wind energy is a possibility, but due to low and very fluctuating wind conditions, only a low utilisation rate of wind turbines can be expected. This may make wind expensive. However, the technological development of wind turbines is now towards low wind turbines which can be suitable for Bangladesh.

Waste to Energy could be developed, but need to be adapted to local waste quality.

Biogas is potentially a large source of energy, but is presently hold back of the small size of farms.

Nuclear

There is currently no nuclear power in Bangladesh. However, an agreement with Rosatom was signed in February 2011 for two 1200 MWe-class reactors to be built at Rooppur for the Bangladesh Atomic Energy Commission. Rooppur is close to a HVDC link with India and on the route of a planned 600 kV HVDC link running up the western side of the country.

Table 6: Planned nuclear power reactors

	Type	Capacity	Construction start	Commercial operation
Rooppur 1	AES-2006/V-523	1,200 MWe	Aug 2017	2024
Rooppur 2	AES-2006/V-523	1,200 MWe	2018	2025

Source: BPDB; PSMP2016

Hydropower

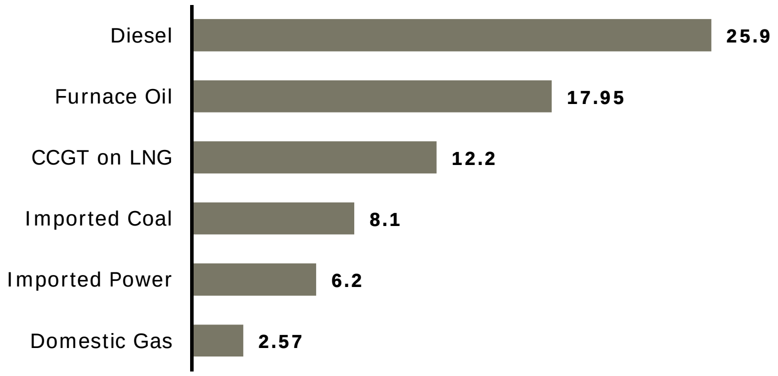
Currently, Bangladesh has a hydropower plant of 230MW at Kaptai (Chittagong), while further hydropower development has been planned and the first unit of a Pumped Storage Power Plant (100 MW) is expected to be commissioned by 2030.

Bangladesh also has a strong interest to import hydropower from neighbouring countries, as well as to invest in hydro projects abroad. For example, Bangladesh and Nepal have signed an agreement to build two hydroelectric plants (1,110MW Sunkoshi II and 536MW Sunkoshi III) capable of generating over 1,600 megawatts of electricity in Nepal.

4.1.3 Budgetary impacts and subsidies – the age of cheap energy is over

The reliance on liquid fuel based power plants and the growing share of fuel oil in power generation have progressively increased the average supply cost of power and have strained power sector finances. The average bulk supply cost of power surged from BDT 2.65/kWh in FY2010 to BDT 6.10/kWh in FY2015, which equates to a staggering 26% increase per year. The BERC responded by increasing bulk average tariff at a regular interval. Even so, the average bulk supply tariff of electricity is less than the average cost of production. The resulting financial losses have created pressure on the national budget.

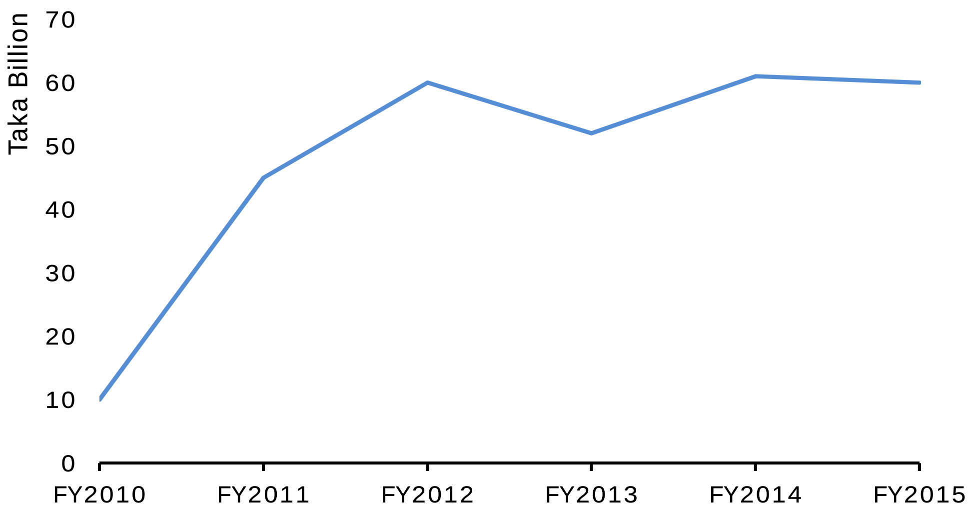
Figure 20: Unit Cost of Electricity Generation (BDT per KWh)



Source: Bangladesh 7th Five Year Plan, 2015

BPDB has received budgetary support from Government due to loss between bulk supply cost and bulk supply tariff, see Figure 21. The electricity budgetary support increased from BDT 10 billion in FY2010 to BDT 60 billion in FY2012. The budgetary support stayed around BDT 60 billion in the last few years thanks to the relatively low international fuel oil prices.

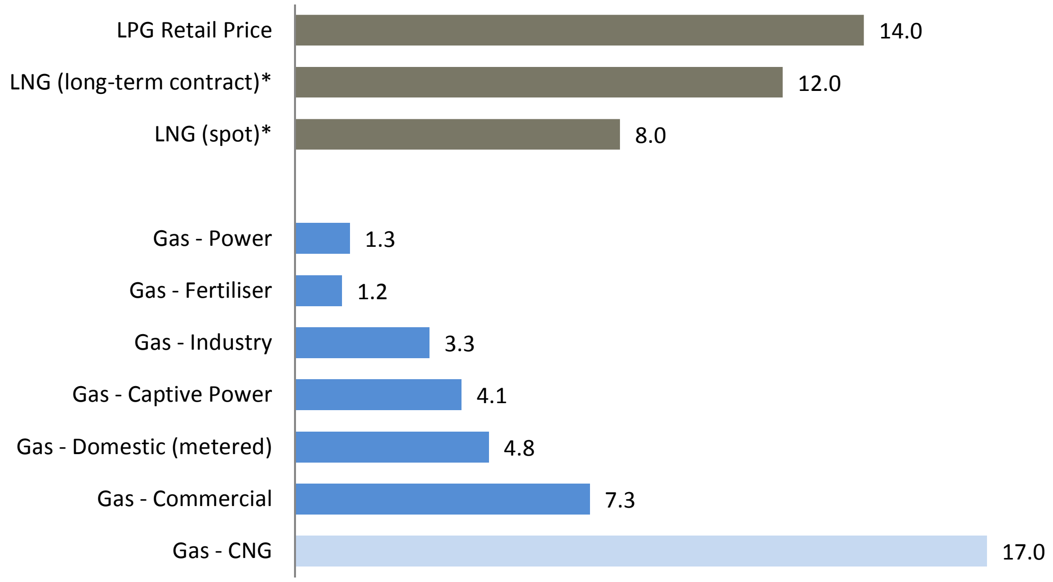
Figure 21: Electricity Budgetary Support



Source: Bangladesh 7th Five Year Plan, 2015

Until more recently, the gas prices have been very low in Bangladesh. The adjustments by BERC in 2016 and 2017 have increased the end user prices, although they (except for CNG) are still below the economic cost of gas.

Figure 22: End User Price Comparison (USD / mmBtu)

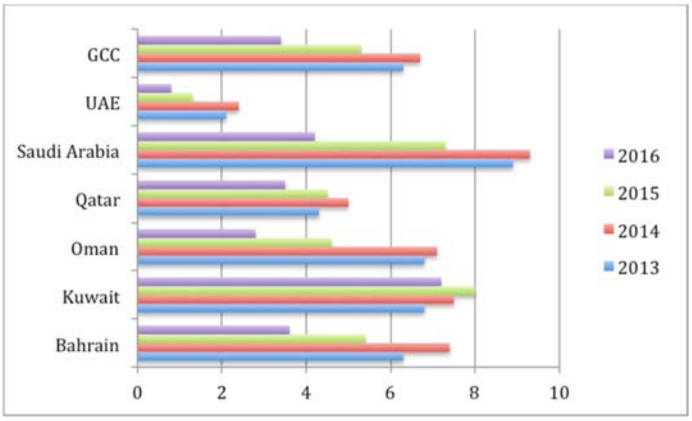


*LNG price (excl. taxes) @ $60/bbl oil; LNG DES + USD3/mmBtu regas and T&D tariff

Source: BERC 2017, PSMP2016, Ramboll

If economical gas price is considered, the cost of electricity per kWh would be even higher. Even without accounting for the economic price of gas, total energy subsidies amounted to BDT 204 billion in FY13, which is almost 2% of GDP, close to the average of the GCC countries.

Figure 23: Gas subsidies as % of GDP GCC countries



Source: IEA

This subsidy excludes capital investments financed entirely from the national budget which amounted to BDT 100 billion in FY13. The total gap in energy sector finances was therefore BDT 304 billion (USD 3.8bn) which is about 3.0% of GDP. Furthermore, in view of uncertainties of international oil/LNG prices, and increasing shortage in domestic gas supply, the total energy subsidy requirement may become too large and pose serious fiscal challenges to the Bangladeshi Government. In addition, research shows that much of the energy subsidies benefit households that are not poor.

4.1.4 Energy plans and policies

In recognition of the energy challenges faced by the country, the Bangladeshi Government set out a National Energy Policy (NEP) in 2005. A revision was issued in 2008 adding a particular focus on renewable energy. Currently, there are no further updates on the NEP.

However, in committing to the Paris Agreement, Bangladesh submitted its Intended Nationally Determined Contribution (INDC) in September 2015, outlining its mitigation contributions for climate change. It is also recognised in the 7th Five Year Plan that specific gas sector policies are required. These issues are discussed in the texts below.

Energy Sector Policy

Key objectives of the NEP (2008):

- To provide energy for sustainable economic growth so that the economic development activities of different sectors are not constrained due to the shortage of energy.
- To meet the energy needs of different zones of the country and socio-economic groups.
- To ensure optimum development of all the indigenous energy sources.
- To ensure sustainable operation of the energy utilities.
- To ensure rational use of total energy sources.
- To ensure environmentally sound sustainable energy development programmes causing minimum damage to environment.
- To encourage public and private sector participation in the development and management of the energy sector.

Gas Sector Policy

There is currently no clearly defined gas sector policy in Bangladesh; however, it is recognised in the 7th Five Year Plan that specific policies need to be developed for the following:

(i) Gas Allocation Policy

Since Bangladesh will be facing extraordinary challenge for gas supply in near future, it is critical for Bangladesh to establish clear gas allocation policy to best utilise the limited domestic reserve. Even after domestic reserve is depleted, an expensive LNG cannot be used as freely as domestic gas was in the past. Therefore, regardless of domestic or import, policy on gas allocation is required. “Gas Allocation Policy” may not need to direct cross-sector allocation; rather it should direct allocation for more energy efficient users within one sector. For example, within the power sector, higher energy-efficient combined cycle power plant should enjoy higher priority of gas supply over efficiency-deteriorated aged gas power plants, because lower efficiency means more gas consumption to produce one unit of electricity.

In addition, as part of Gas Allocation Policy, policy on how to disseminate gas prepaid meter and LPG should also be defined. Some of the current natural gas demand should be curbed by prepaid meter, and be replaced with LPG. A policy should define replacement of existing pipelined gas by LPG followed by price adjustment.

Furthermore, in order to promote the use of LPG, the price policy needs to be adjusted to minimise the difference between LPG and pipelined gas tariffs. Currently, LPG users are facing a more than 9 times higher tariff (at per calorific value) than that of pipelined domestic gas, where one 12.5 kg cylinder costs at 1200BDT

In addition to LPG, biogas can also be considered as the alternative of pipeline natural gas. Similar to the LPG utilisation policy, biogas utilisation policy may also define how primary energy, namely pipeline gas, LPG and biogas can be best mixed.

(ii) Indigenous Gas Exploration & LNG Import Policy

Bangladesh still has untapped gas resources. The cost of exploration and development of untapped resource is likely to be lower than the cost of LNG import. Therefore, Bangladesh will need to focus on investment for exploration and development. Subsequently, LNG import should be considered to ensure smooth supply of natural gas. Two LNG FSRU terminals (Excelerate and Summit) are scheduled to be constructed and in operation by mid-2018 and end 2018, with a nameplate capacity of 500MMCFD for each terminal.

Furthermore, in order to implement exploration and development of undiscovered resources, external resources may be required. The untapped resource is likely to lie in coastal/transitional areas, hill tract areas or in the offshore areas where seismic survey and drilling is difficult. Especially, deep offshore oil and gas exploration requires high technology and huge capital. To address such technical and financial issues, Joint Venture or “Strategic Partnership” between BAPEX and foreign companies may be sought or Production Sharing Agreement with IOCs who are experienced in such areas can be signed. After delineation of maritime boundaries with Myanmar and India, a new opportunity has opened up for offshore exploration. Therefore, both onshore and offshore oil and gas options could be pursued.

Power Sector Policy

The Bangladesh Power Division has a vision and mission statement for the universal access to quality electricity in a cost-effective and affordable manner, and ensuring reliable electricity for all by 2021 through integrated development of power generation, transmission and distribution system. In order to seek a practical and short-term solution toward this vision, Power Division enacted “Power and Energy Fast Supply Enhancement (Special Provision) Act 2010” is to expedite the introduction of highly expensive quick rental power plants. Meanwhile, PSMP2016 projects Bangladesh to rapidly develop its grid power and start reducing low efficient/high cost captive power from around 2020.

Renewable Energy Policy

In response to the revision of the National Energy Policy (NEP) 2005, the Renewable Energy Policy was prepared in 2008. It defines the renewable energy targets; by 2015 Bangladesh will introduce renewable energy 5% of all generation, and by 2020, 10%.

In December 2012, the Sustainable Renewable Energy Development Authority (SREDA) Act was approved by the Parliament and SREDA was established. The purpose of this authority is to ensure the energy security, by promoting renewable energy and energy efficiency and conservation. In 2013, the Bangladeshi Government announced “500MW Solar Program” to accelerate the renewable/PV solution Deployment.

As discussed in the earlier section, the total installed capacity of SHS is projected to be 220MW by 2017. There are also a small number of biogas-based power generations and a wind power plant in Bangladesh, adding another 20MW capacity. The total renewable capacity by 2017 is therefore only 240MW, less than the 800MW target set by the Government.

Energy Efficiency and Conservation Policy

In the 7th Five Year Plan, energy efficiency and conservation is recognised as an urgent policy priority. The policy effort involves substitution of low thermal efficient gas-fired power plants with more energy efficient plants; incentives for adoption of improved fuel use efficiency and energy conservation technology in industry; and conserving gas consumption by households through proper metering and pricing based on volume of gas consumed rather than a monthly flat rate per stove. The potential for conserving gas through these steps is enormous and the value of gas saved much exceeds the financial cost of implementing these policies.

Pricing Policy

In NEP 2005, it points out that “all forms of non-renewable energy are to be priced at their economic cost of supply”. The Consultants understand that such policy has yet to be fully implemented due to practical challenges; however, such pricing policy demonstrates that the Bangladeshi Government recognises the need for further price adjustments, and there have been significant increases in end user prices in 2016 and 2017. Further discussions on this topic can be found in the Legal and Regulatory chapter of this GSMP report.

Paris Agreement

Bangladesh is a highly climate vulnerable country and has already been affected by the impacts of climate change. For example, extreme temperatures, erratic rainfall, floods, drought, tropical cyclones, rising sea levels, tidal surges, salinity intrusion and ocean acidification are causing serious negative impacts on the lives and livelihoods of millions of people in Bangladesh.

Moreover, the impacts of climate change are gradually offsetting the remarkable socio-economic development which Bangladesh has gained over the past 30 years, which is also likely to jeopardise the country’s future economic growth. However, at the same time, Bangladesh is also working to achieve lower carbon as well as more resilient development.

In its commitments to the Paris Agreement, Bangladesh submitted its Intended Nationally Determined Contribution (INDC) in September 2015, and it consists of the following mitigation contributions:

- An unconditional contribution to reduce GHG emissions by 5% from Business as Usual (BAU) levels by 2030 in the power, transport and industry sectors, based on existing resources.
- A conditional 15% reduction in GHG emissions from BAU levels by 2030 in the power, transport, and industry sectors, subject to appropriate international support in the form of finance, investment, technology development and transfer, and capacity building.
- A number of further mitigation actions in other sectors which Bangladesh intends to achieve subject to the provision of additional international resources.

Bangladesh already has a number of activities and targets that are driving action to reduce GHG emissions and help the country to meet its unconditional contribution, including:

- A target to reduce energy intensity (per GDP) by 20% by 2030 compared to 2013 levels (EE&C Master Plan)
- An Energy Management Programme, including establishment of Energy Management Systems and energy audits for industry by accredited energy auditors
- An Energy Efficiency labelling programme to promote sales of high efficiency products in the market Energy Efficiency measures for buildings, such as heat insulation and cooling measures, and a revised code on energy efficiency of new buildings
  The Solar Homes Programme, providing off-grid electricity access to rural areas
- The country has set aggressive target to scale up the potentials of Solar Irrigation Pumps, Solar mini and nano grids to address the energy access issue of off-grid population
- Improving kiln efficiency in the brick making industry, composting of organic waste and waste biomass-based thermal energy generation
- Construction of Combined Cycle Power Plant (CCPP) by the Government of Bangladesh and utilities companies

Bangladesh will also need to implement additional mitigation actions in order to meet the conditional contribution. Examples of these are set out in the table below:

Sector	Description	Objectives by 2030
Power	• Ensure all new coal generation uses super-critical technology • Increased penetration of wind power • Implement grid-connected solar plant to diversify the existing electricity generation mix	• 100% of new coal based power plants use super-critical technology • 400 MW of wind generating capacity • 1000 MW of utility-scale solar power plant

Industry (energy-related)	• Carry out energy audits to incentivise the uptake of energy efficiency and conservation measures in the main industrial sectors based on the Bangladesh Energy Efficiency and Conservation Master Plan	• 10% energy consumption reduction in the industry sector compared to the business as usual
Households	• Put in place policy mechanisms to incentivise the uptake of improved (more efficient) gas cookstoves • Support the replacement of biomass with LPG for cooking purposes • Promoting policies to induce greater level of energy efficiency and conservation in the household sector based on the Bangladesh Energy Efficiency and Conservation Masterplan	• 70% market share of improved biomass cookstoves, reaching 20 million households in 2030 • 40% market share of improved gas cookstoves • 10% market switch from biomass to LPG for cooking compared to the business as usual
Commercial buildings	• Promote policies to induce greater level of energy efficiency and conservation in the commercial sector based on the Bangladesh Energy Efficiency and Conservation Master plan • Incentivise rainwater harvesting in commercial buildings as a form of water and energy conservation	• 25% reduction of overall energy consumption of the commercial sector compared to the business as usual
Waste	• Promote landfill gas capture and power generation	• 70% of landfill gas captured and used for electricity generation

4.1.5 Conclusions on the energy sector review

The above findings illustrate the shortage of energy in Bangladesh with regard to absolute quantity as well as the range of options. Indigenously produced natural gas has played a key role in the nation's energy supply; however, as Bangladesh's economy continues to grow, indigenous gas production alone is unlikely to meet the nation's demand for energy. The shortage of energy supply in Bangladesh has arguably affected the nation's economic development, and a growing demand-supply gap in the future is in all likelihood to cut back Bangladesh's economic growth further.

As the current indigenous gas production starts to peak, LNG seems to be the only option in the short term to improve the energy shortage situation in Bangladesh. The introduction to LNG will expose Bangladesh to the risks of fluctuating energy and commodity prices with possibly heavier budgetary burdens.

There is a path out of this - a window of opportunity also realised by the Government of Bangladesh which has embarked on a journey to reform its gas and power sector. First of all, by launching the Power Sector Master Plan in 2016 followed by the completion of this update of the Gas Sector Master Plan in 2017, the ground has been laid for a more coordinated and structured approach for the future. Secondly, the timing for addressing gas pricing and subsidies might be right. With relatively low international energy prices, there is a window of opportunity for Bangladesh to initiate a coordinated phase out of subsidies in both the power and gas sector.

The key to the future energy requirement of Bangladesh lies in both the economic development of the country and the government's energy policies.

4.2 Scenarios Setting

As a country in the early take-off stage of its economic development, Bangladesh faces large uncertainties in its long-term GDP growth. At the same time, the country needs to move away from the over reliance on indigenous gas supply in order to overcome the growing energy shortage. Therefore, the Bangladeshi policymakers need to have various options in designing the country's energy sector policies, as well as enough flexibility to fine-tune and revise these policies when necessary.

The Consultants have developed three scenarios to capture a confined range of these uncertainties mentioned above, and our gas demand forecasts are then derived based on these assumptions. Each of the three scenarios is as described below:

Scenario A	Scenario B	Scenario C
Modified PSMP2016	High Growth	Climate Change

4.2.1 Scenario A - Modified PSMP2016

In order to provide some consistency across the energy sector, we have made Scenario A to reflect some key assumptions in the Base Scenario of Power Sector Master Plan 2016.

In particular, Scenario A assume the same GDP growth projections as that in PSMP2016 Base Scenario, where the 7th FYP targets are to be achieved and the GDP growth rates then decline gradually from 8% in 2020 to 4.3% by 2041. This makes the GDP in 2041 four times as large as current level (2016/17).

Scenario A also assumes the same demand forecast for overall power generation as that in PSMP2016. In the meantime, comparing to the original power development schedule in the PSMP2016, there have been delays in the commissioning of some coal-fired power plants in Bangladesh. Consequently, some inefficient gas-fired power plants are expected to be kept for the next few years and decommissioned only then. Therefore, Scenario A assumes that, in the short-term, gas demand from the power sector will increase modestly – rather than drop sharply as assumed in PSMP2016.

Nevertheless, the gas penetration in the power generation is assumed in Scenario A to decline gradually yet significantly over the forecast period. This is to reflect a policy where coal is seen as a more secure and favourable option to future gas import, a policy similar to the recent development in India for example.

Except for the power sector, the gas demand for all other sectors in Scenario A is forecasted independently to that in PSMP2016, reflecting the Consultants' own views of the gas sector development in Bangladesh.

4.2.2 Scenario B – High Growth

This scenario assumes that Bangladesh will be successful in pursuing an export-led economic growth model as indicated in the 7th five-year plan. In such case, Bangladesh will be able to continually increase its export and shift its growth driver from currently a high reliance on textile to a more diverse mix of manufacturing goods in the future. Currently, there are already a good number of foreign companies (particularly Chinese, Japanese, and Korean) investing in Bangladesh, while the Bangladeshi Government has the policy to develop around 100 special economic zones and attract further foreign direct investments.

As such, this scenario assumes that the 7th five-year plan's short-term growth targets will be achieved and that the GDP growth rates then maintain at 7% from 2021 to 2041. This makes the GDP in 2041 five times as large as current level (2016/17).

In the 7th five-year plan of Bangladesh, China is used as a reference for the export-led economic growth model. Until recent slowdown, the Chinese economy had often been growing at around 10% per annum for a long time although not without environmental and social costs. Therefore, albeit challenging, a 7% long-term GDP growth rate seems to be a reasonable assumption for the High Growth Scenario if the Bangladeshi Government's economic development plans can be delivered.

Scenario B also implies a strong international environment for trade, suggesting that Bangladesh is able to secure enough gas import through pipeline connections from Asian countries as well as LNG from even wider global sources. This scenario will therefore be tilted towards use of gas, similar to the recent development in the USA for example.

4.2.3 Scenario C – Climate Change

The Climate Change Scenario can develop if rapid change in climate, or understanding of the climatic development, takes place. As Bangladesh is one of the countries which are most exposed to rising sea level, increased precipitation and more severe storms, there will be a strong focus on the issue inside the country and understanding in the population that there is a need to act on climate globally as well as in Bangladesh. Bangladesh therefore decides to become frontrunner on cleaner energy and energy savings.

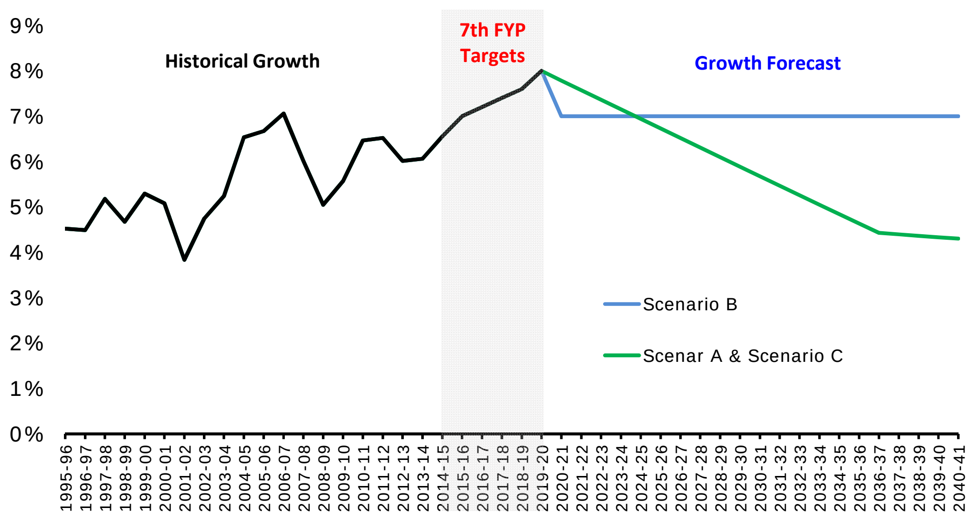
In this scenario, only a few coal fired power plants will be developed, while there will be strong developments in renewables, natural gas, nuclear, and hydropower imports. For example, although there has so far been lack of support for large solar power plants due to the high population density, this scenario assumes the development of a clean energy policy where sufficient space will be made available for solar power projects.

In the PSMP2016, it is found that the peak load will change from evening as at present to mid-day over the coming years. With more solar energy, it is assumed that the midday peak demand to a large degree will be supplied by solar energy, while the gas fired power plants will cover the evening peaks. It will hence still be necessary to develop further gas network and gas power plants in Bangladesh to cover the peak demand too.

This scenario also assumes that the cost of such a cleaner energy policy will have an impact on Bangladesh's economy, so that the GDP growth rates in the scenario coincide with that in Scenario A, making the GDP in 2041 four times as large as current level (2016/17).

The GDP growth rates for all three scenarios are as shown as below:

Figure 24: Bangladesh Real GDP Growth



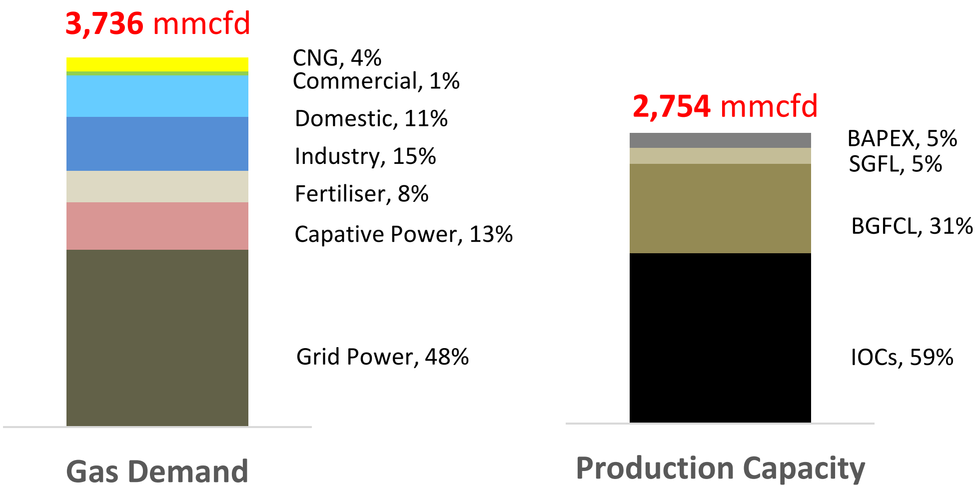
Source: World Bank, Bangladesh 7th FYP, Ramboll

4.3 Gas demand forecast methodology

4.3.1 Demand vs Consumption

To forecast the gas demand in Bangladesh, it is important at first to look at the current gas market status and make a distinction between demand and consumption of gas.

Figure 25: Gas demand and supply 2016/17



Source: Petrobangla

According to Petrobangla estimate, the gas demand in Bangladesh is 3,736 MMCFD (1.36 tcf/y) in 2016/17, made up by the following sectors: grid power 48%, captive power 13%, fertiliser 8%, industry 15%, domestic 11%, commercial 1%, and CNG 4%. On the other hand, there is no imported gas and the current production capacity from existing fields is only 2,754 MMCFD (1.01 tcf/y) of which IOCs account for 59%, BGFCL 31%, SGFL 5% and BAPEX 5%.

As a result, the consumption of gas in Bangladesh is currently capped by the indigenous production; around 1,000 MMCFD of demand for gas is not met. The Consultants have been advised by Petrobangla that the demand estimate is based on known customers, while there are likely to be some hidden demand, i.e. potential customers who have not expressed their need for gas due to the shortage of supply. It should be noted that the actual gas production is on average below the production capacity due to normal technical problems. Therefore, the actual demand-supply (demand-consumption) gap is even larger although the exact size cannot be quantified.

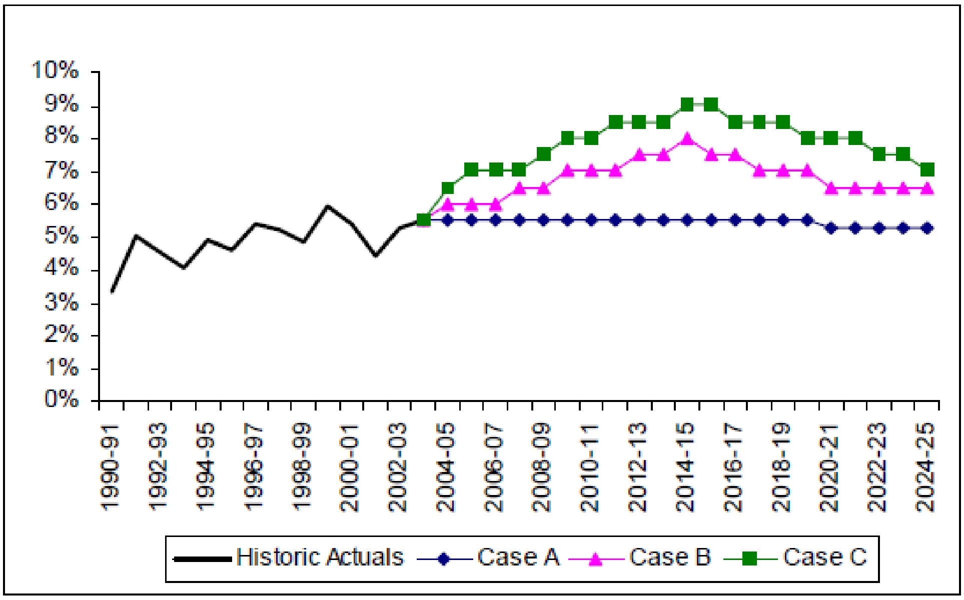
In order to take a practical approach for our forecast, we use the Petrobangla estimate of 3,736 MMCFD as the current demand for gas in Bangladesh.

4.3.2 GSMP2006 Review

The results and the approach for the 2006 master plan have been evaluated to determine whether the approach is still fit for purpose and complementary measures required in order to determine the demand for gas in Bangladesh.

In GSMP2006, a detailed statistical regression analysis was carried out to assess the historical (1995-2004) correlations between various gas demand (by sectors and regions) and GDP in Bangladesh. The result demonstrates strong correlations between these variables in most case, hence the GDP elasticity method was largely used to project future (2005-2025) gas demand under three GDP growth scenarios:

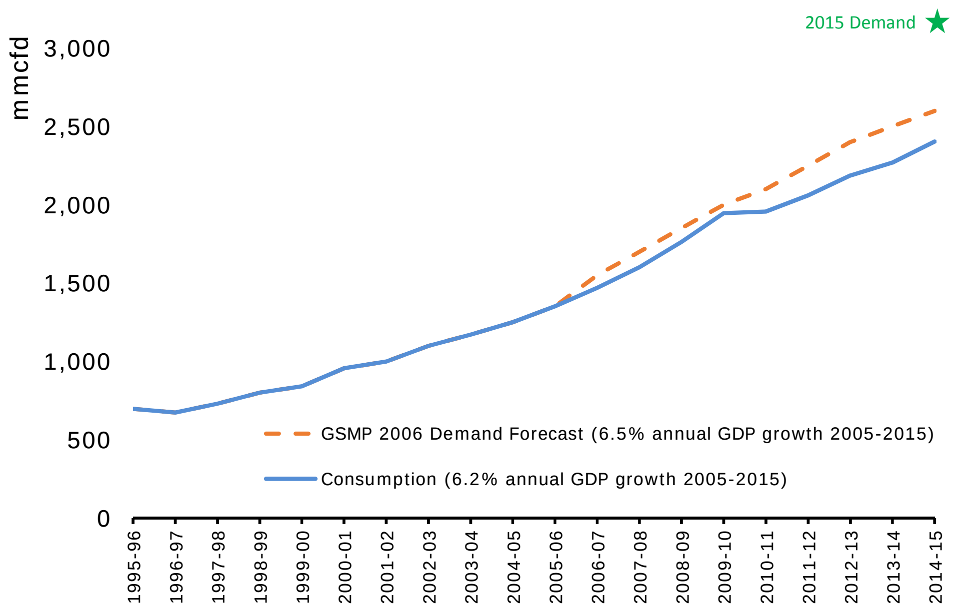
Figure 26: GSMP2006 – GDP Growth Scenarios



Source: Historic data: Bangladesh Bureau of Statistics; Forecasts: Wood Mackenzie and Petrobangla

In Case B, the Bangladesh GDP was forecasted to grow on average around 6.5% per year between 2005 and 2015, which is close to the 6.2% actual annual growth during this period. Therefore, we choose Case B to assess how the GSMP2006 gas demand forecast has performed against reality.

Figure 27: Bangladesh Gas Demand – Forecast vs Consumption



Source: Woodmac GSMP 2006, Ramboll

Figure 27 above shows that the GSMP2006 has produced a demand projection that is fairly close to the consumption of gas in Bangladesh over a 10-year period. It has an error margin of 8% in 2015, which reduces to less than 5% if we eliminate the difference in the forecasted and actual GDP growth rates. However, the actual demand estimated by Petrobangla was 3,200 MMCFD in

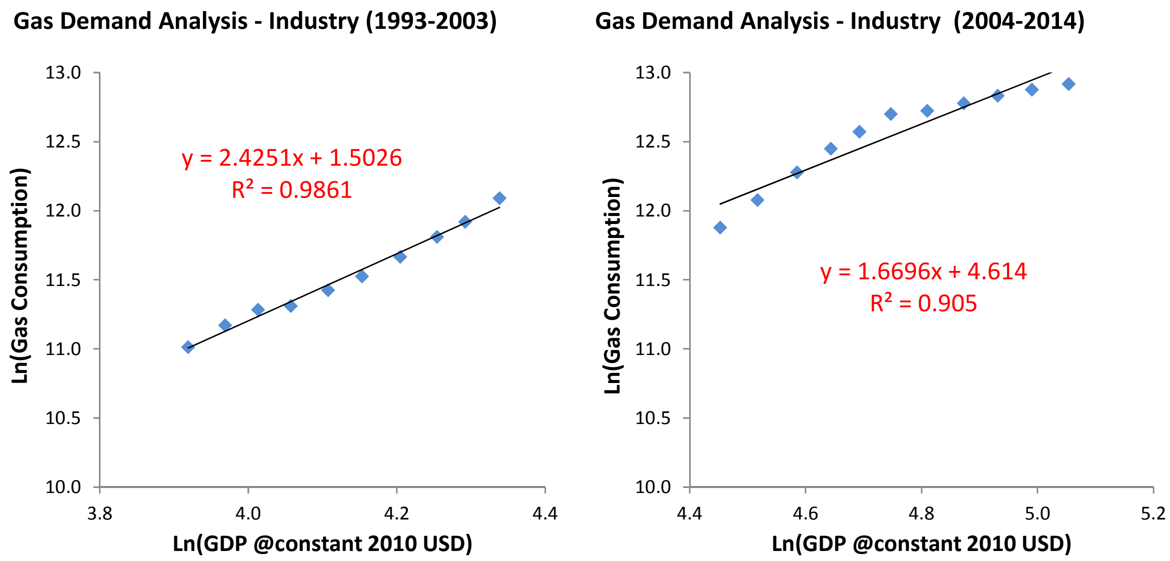
2015, over 20% higher than the GSMP2006 demand projection. It is therefore in our view important to modify the methodology in order to (A) recognise the consumption-demand gap and improvements in energy efficiency, (B) recognise sector structure changes, (C) consider impacts of power mix and overall energy mix policy changes.

(A) Demand-Consumption Gap and Improvements in Energy Efficiency

As already discussed, indigenous production has been the only source of gas supply in Bangladesh. Despite the significant increases in output over the past 20 years, the production level has not been able to catch up with the country's economic growth. In other words, the consumption of gas in Bangladesh has been held back by the shortage of supply, leaving a gap between demand and consumption. Turning this around, economic growth could have been higher if gas demand was fully met.

This large demand-consumption gap (unmet demand) creates an inaccurate illusion of the changes in demand, the correlations derived from GDP growth and gas consumption growth therefore need to be modified for demand projection. For example, the elasticity of gas consumption to GDP for the industry sector dropped from 2.58 between 1993 and 2003 to 1.68 between 2004 and 2014. This was a decline largely due to the shortage of gas supply rather than slower growth in demand.

Figure 28: Gas Demand Analysis – Industry Sector



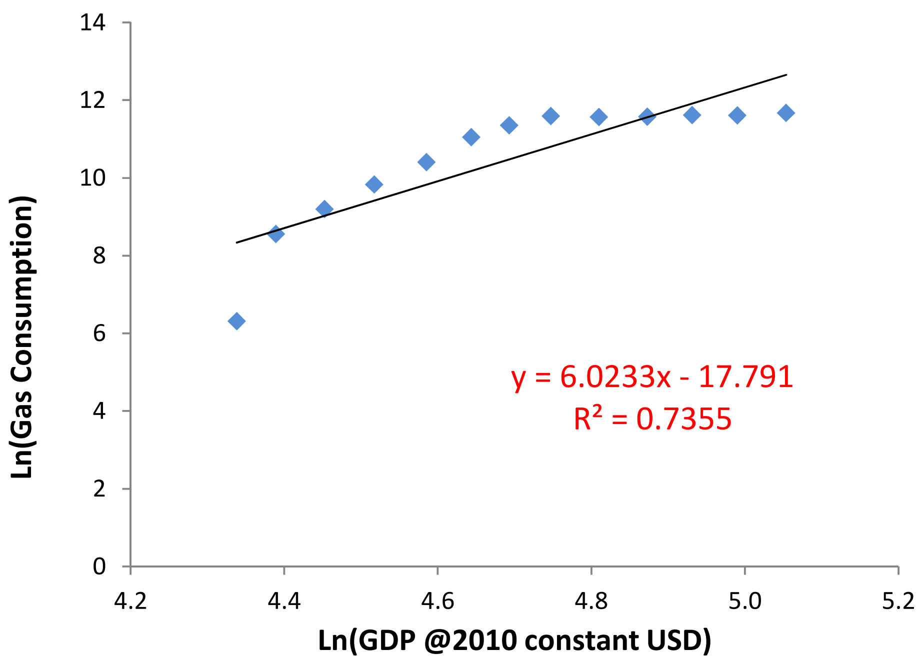
Source: Ramboll

In addition, improvements in energy efficiency will reduce the energy intensity for every unit of GDP, this in turn reduces the elasticity of gas demand to GDP.

(B) Sector Structure Changes

As one sector undergoes structure changes, the demand for energy is also likely to change. It will therefore be difficult to identify the relationship between GDP growth and energy consumption. Consider Bangladesh's CNG sector for example: the sector demand for gas increased 20 times from merely 1.9 MMCFD in 2003 to 39.3 MMCFD in 2009, reflecting the very early development stage of this sector. However, the gas consumption then only reached 46.5 MMCFD in 2015, largely due to the shortage of gas supply as well as the fact that the sector was now more stable. As a result, the correlation between CNG sector gas demand and GDP during this period was relatively weak (with an R-square of 0.74), and the corresponding elasticity of 6.02 is obviously not a good fit for future demand forecast.

Figure 29: Gas Demand Analysis – CNG Sector 2002-2014

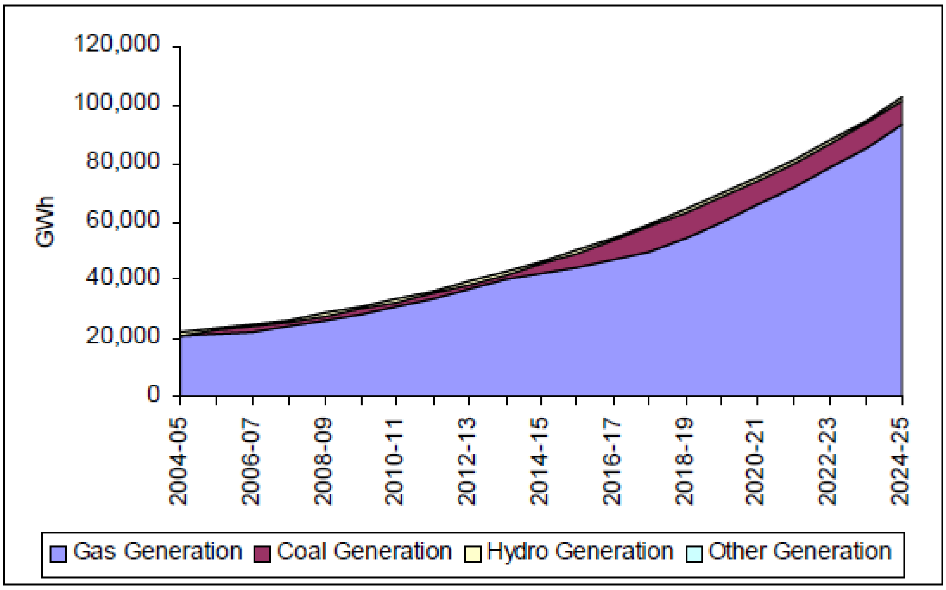


Source: Ramboll

(C) Power Mix & Overall Energy Mix

In GSMP2006, gas was forecasted to retain its overarching dominance in the Bangladesh power mix, which would only start to give ground to coal from 2015, but still account for around 90% of total power generation dispatch thereafter, see Figure 30. This assumption may no longer fit well with the Government's policy nor with the reality of future; therefore, different scenarios for power mix need to be considered.

Figure 30: GSMP2006 – National Power Generation Dispatch Forecast – Case A



Source: Wood Mackenzie

Source Wood Mackenzie GSMP2006

In awake of shortage of natural gas, the Bangladeshi Government has also started developing alternative energy such as LPG. A continued trend like this will gradually reduce the gas penetration in the overall energy mix. Consequently, the elasticity of gas demand to GDP growth will be weakened over time. Nevertheless, it needs to be recognised that it is very challenging to quantify such effect and any projections are subject to significant uncertainties.

4.3.3 Approach to projecting demand

For reasons mentioned above, we will conduct our gas demand forecast based on the specific characteristics of each sector, namely power, captive power, fertiliser, industry, commercial, domestic, and CNG. In the meantime, we use Petrobangla's demand estimates as our base for Financial Year 2016/2017.

The power sector projections in this study are derived from PSMP2016. In addition to the base case scenario in PSMP2016, this study also considers different GDP growth rates as well as gas shares of total power generation. Modifications are also made on the short-term outlook to reflect a more updated and realistic picture of the development status power plants in Bangladesh.

We use GDP elasticity method for industry and domestic sectors' demand forecasts. In the absence of relevant data, we use the elasticity of gas consumption to GDP as a proxy for demand analysis. Meanwhile, we make modifications to these elasticities in recognition of the historical consumption-demand gaps as well as higher gas prices and future improvements in energy efficiencies.

Finally, we assume constant gas demand from fertiliser and commercial sectors due to food security and government energy policy respectively, and a constant rate of demand growth from

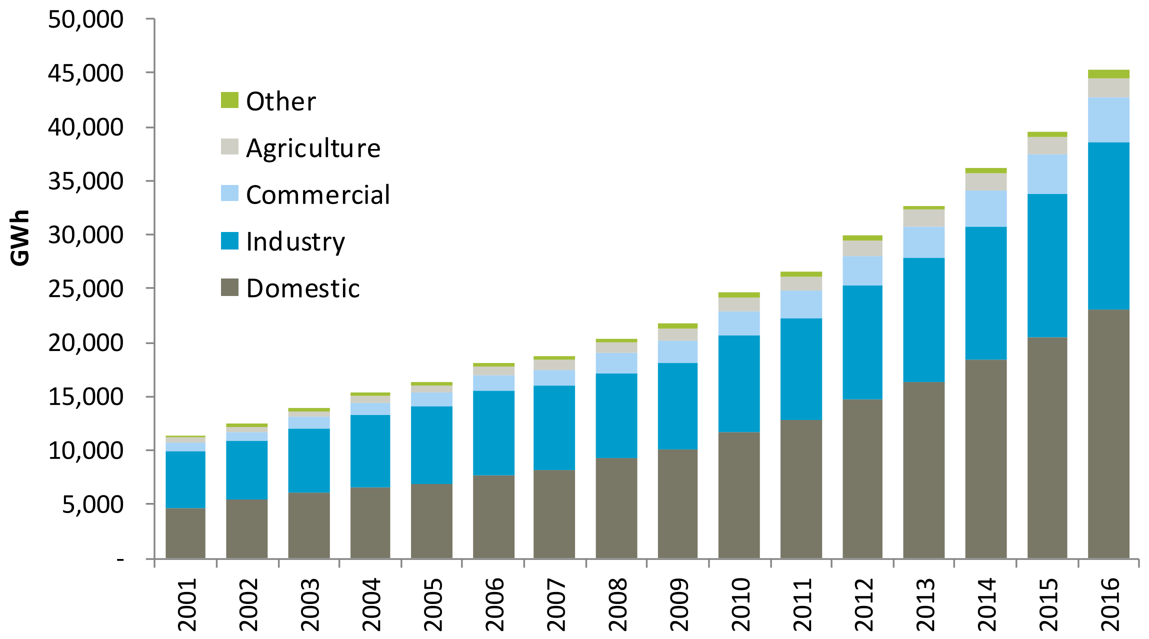
CNG sector post 2020. In contrast, we assume the gas demand from the captive power sector to gradually decline over time due to the development of grid power.

4.4 Power sector gas demand forecast

4.4.1 Historical trend of power consumption

As shown in Figure 31, the total power consumption of Bangladesh increased by 4 times from 11,409GWh in 2001 to 45,299GWh in 2016. The domestic (residential) sector is the largest consumer and accounted for 51% of the total power consumption in 2016, followed by industry sector consuming 34% of the total.

Figure 31: Bangladesh historical electricity consumption



Source: BPDB

4.4.2 Power Plants

According to PSMP2016, the total power generation capacity in Bangladesh was 10.9GW in 2015 where gas-fired power plants accounted for 62%. The total installed capacity of gas-fired power has increased since then, and lists of existing gas-fired power plants and planned new gas-fired power plants are included in Appendix 2.

4.4.3 Methodology

In order to provide a reference to the Bangladeshi policy makers, this GSMP adopts the PSM2016 methodology in forecasting the power demand and subsequently the associated gas demand in the power sector. Additional scenarios with different GDP and gas share of total power generation have also been included to reflect our views on future possibilities – this in turn leads to different power and gas demand forecasts.

However, some key assumptions in PSMP2016 are no longer up to date. Therefore, modifications are required to give more realistic projections.

For example, PSMP2016 base case forecasts that the gas share of total power generation declines rapidly from 69% in 2018 to 62% in 2019 and then to 36% in 2020 – a result of a number of new built coal-fired power plants. However, the Consultants understand that practical challenges and constraints have already delayed some of the proposed new power plants in the original Power Development Plan set out in PSMP2016. Meanwhile, the Bangladeshi Government is open to adjust its power mix policy in response to recent significant changes in global energy environment, e.g. low international prices for oil and gas. Hence, gas-fired power plants will need to maintain a high share of power generation in the short-term.

PSMP2016 base case forecast also assumes a number of old gas-fired power plants to be retired over the next few years, while many new gas-fired power plants are to be commissioned during the same period – thereby improving the average operational efficiency of gas-fired power plants from around 25% in 2019 to around 40% in 2020. This also seems to be unlikely due to practical challenges and constraints. It is our view that many old gas-fired power plants will continue to operate for a longer period of time until new replacements are gradually in place – hence only gradual improvements in the average operational plant efficiency.

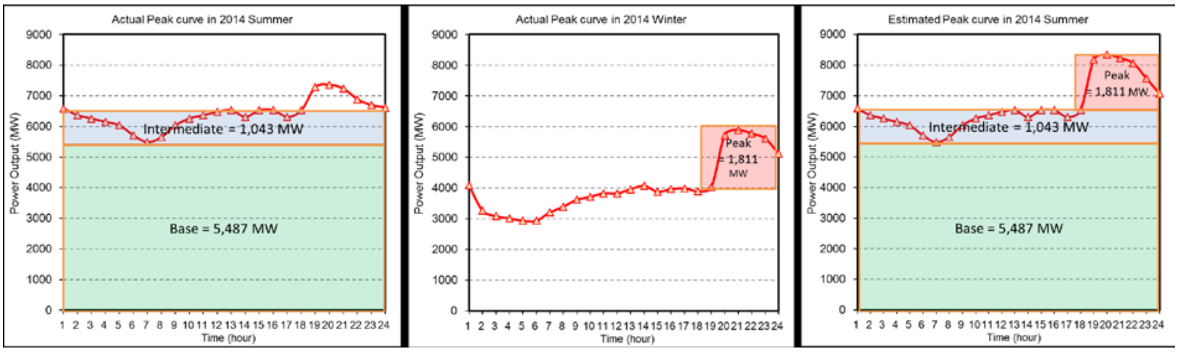
4.4.4 Peak demand projection

PSMP2016 adopted the GDP elasticity method for peak demand projection, we will therefore use the same approach in this study.

Deciding the level at which the baseline is to be set is an important factor in peak power demand forecasting. Because of the particular situation in Bangladesh whereby rolling blackouts have been used as a measure to circumvent power shortages at the peak hours, the recorded maximum power consumption does not include such potential power demand. Therefore, an accurate forecast of the maximum demand including the potential demand requires a theoretical estimation of load curves from the daily operational data with particular attention on the characteristics of the seasonal changes in the daily load curve and the frequency and durations of rolling blackouts. Because rolling blackouts have been relatively rare on weekends and holidays in the winter (between November and January), a daily load curve gives an actual peak load (at the hours of the peak power consumption for lighting) that is quite accurate. A daily load curve in the summer gives estimates of the base and intermediate loads close to the recorded values.

Therefore, a composite daily load curve representing the peak power demand was created from the daily load curve in the summer with part of the peak hours replaced by the same part of the daily load curve in the winter as shown in the figure below. The peak power demand in FY2014, which was used as the baseline for the peak demand forecast, was set at 8,039 MW by adding the base and intermediate load in the summer (5,487 MW and 1,043 MW, respectively) and the peak load in the winter (1,811 MW) recorded in FY2015. The peak power demand in FY2015 was estimated at 8,921 MW in the same way and this value was used as the reference value in the peak power demand forecast.

Figure 32: Peak power curves



Source: PSMP2016

Table 7 below shows the results of the maximum load analysis. The maximum load recorded in FY 2015 was 7,500 MW, while a maximum load of approximately 8,921 MW was estimated from the estimated base load of 6,170 MW, the potential intermediate and peak-hour loads and the actual net/gross ratio. Therefore, the 8,291 MW obtained in this analysis is used as the reference value in the long-term demand forecast up to 2041.

Table 7: Peak load estimation 2005-2015

Fiscal Year	Estimated Base Load (MW)	Estimated Intermediate Load (MW)	Estimated Base Over Peak Load (MW)	Estimated Peak Load (MW)	Actual Net/Gross	Estimated Net Peak Load (MW)	Growth (%)	Actual Net Peak Load (MW)	Growth (%)
2005	3,097	-	1,379	4,476	0.95	4,230		3,900	
2006	3,600	-	1,413	5,013	0.95	4,737	12.0%	4,200	7.7%
2007	4,050	-	1,063	5,113	0.95	4,832	2.0%	4,500	7.1%
2008	4,190	-	1,484	5,674	0.95	5,362	11.0%	4,600	2.2%
2009	4,150	-	1,500	5,650	0.95	5,339	-0.4%	5,050	9.8%
2010	4,300	817	1,462	6,579	0.95	6,258	16.4%	5,550	9.9%
2011	4,400	836	1,496	6,732	0.95	6,411	2.3%	5,550	0.0%
2012	5,000	950	1,700	7,650	0.96	7,326	13.6%	6,600	18.9%
2013	5,300	1,007	1,802	8,109	0.96	7,764	6.0%	6,600	0.0%
2014	5,487	1,043	1,811	8,341	0.96	8,039	2.9%	7,356	11.5%
2015	6,170	1,111	1,974	9,255	0.96	8,921	11.0%	7,500	2.0%

Source: PSMP2016

Table 8 below shows the historical trend for GDP elasticity of power demand in Bangladesh for the last 10 years, and the average was 1.27. Considering that the elasticity in some other ASEAN countries (Thailand, Indonesia, Malaysia) also fell in the range between 1.1 and 1.3, see Table 9, this study assumes that this 1.27 will continue in the BAU (business-as-usual) case.

Table 8: Historical Trend of GDP Elasticity of Power Demand in Bangladesh

Year	GDP at Constant Market Price (Million Taka)	GDP Growth Rate (%)	Actual Net Energy Generation (GWH)	Energy Not served	Forecasted Net Generation (GWH)		GWH Growth	Elasticity
2005	2,669,740		21,408	260	21,668	21,798		
2006	2,846,726	6.6%	22,978	843	23,821	24,243	7.3%	1.1
2007	3,029,709	6.4%	23,268	2,264	25,532	26,664	1.3%	0.2
2008	3,217,855	6.2%	24,946	1,107	26,053	26,606	7.2%	1.2
2009	3,406,524	5.9%	26,533	1,363	27,896	28,577	6.4%	1.1
2010	3,608,450	5.9%	29,247	1,829	31,076	31,991	10.2%	1.7
2011	3,850,500	6.7%	31,355	1,899	33,254	34,204	7.2%	1.1
2012	4,090,530	6.2%	35,118	1,647	36,765	37,588	12.0%	1.9
2013	4,337,200	6.0%	38,229	1,070	39,299	39,834	8.9%	1.5
2014	4,601,770	6.1%	42,195	515	42,710	42,968	10.4%	1.7
								1.27

Source: PSMP2016

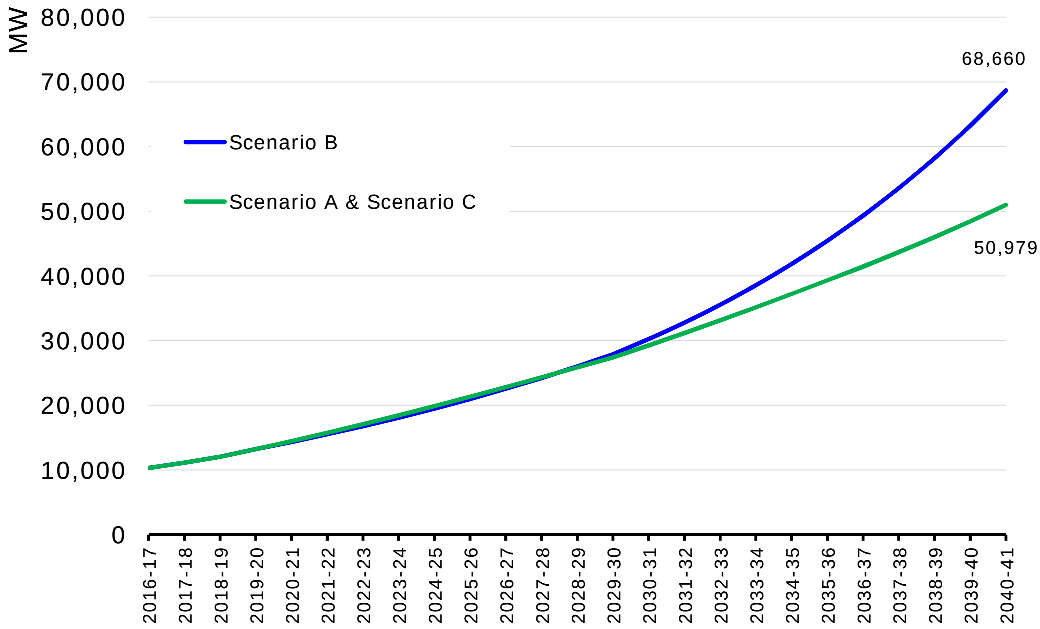
Table 9: Actual Energy-GDP Elasticity in ASEAN Countries

Thailand	items	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	
	GDP (constant 2005 US$)	170,956,863,507	181,708,833,946	189,318,499,954	198,723,685,564	209,524,501,833	213,140,198,921	211,566,627,910	227,448,322,637	229,344,519,381	246,139,191,582	
	Electricity consumption (GWh)	106,959	115,044	121,229	127,811	133,178	135,450	135,209	149,320	148,700	161,749	
	(A) GDP growth	7.2%	6.3%	4.2%	5.0%	5.4%	1.7%	-0.7%	7.5%	0.8%	7.3%	
	(B)Electricity growth	6.8%	7.6%	5.4%	5.4%	4.2%	1.7%	-0.2%	10.4%	-0.4%	8.8%	
	(A)/(B)	0.94	1.20	1.28	1.09	0.77	0.99	0.24	1.39	-0.50	1.20	
	(A') 5-year average GDP	5.2%	5.5%	5.4%	5.8%	5.6%	4.5%	3.1%	3.7%	2.9%	3.3%	
	(B') 5-year average Electricity	5.9%	7.2%	6.6%	6.7%	5.9%	4.8%	3.3%	4.3%	3.1%	4.0%	
	(A')/(B')	1.1	1.3	1.2	1.2	1.0	1.1	1.1	1.1	1.1	1.2	1.1
Indonesia	items	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	
	GDP (constant 2005 US$)	257,516,488,195	270,471,818,103	285,868,619,206	301,594,114,117	320,730,327,692	340,018,098,955	355,757,098,753	377,898,901,817	401,214,448,583	425,407,883,059	
	Electricity consumption (GWh)	90,441	100,097	107,705	113,415	121,614	128,810	136,053	147,972	159,867	175,329	
	(A) GDP growth	4.8%	5.0%	5.7%	5.5%	6.3%	6.0%	4.6%	6.2%	6.2%	6.0%	
	(B)Electricity growth	3.9%	10.7%	7.6%	5.3%	7.2%	5.9%	5.6%	8.8%	8.0%	9.7%	
	(A)/(B)	0.81	2.12	1.34	0.96	1.14	0.98	1.21	1.41	1.30	1.60	
	(A') 5-year average GDP	3.7%	4.6%	4.7%	5.1%	5.5%	5.7%	5.6%	5.7%	5.9%	5.8%	
	(B') 5-year average Electricity	6.7%	7.0%	6.4%	6.1%	6.9%	7.3%	6.3%	6.6%	7.1%	7.6%	
	(A')/(B')	1.8	1.5	1.3	1.2	1.3	1.3	1.1	1.1	1.2	1.3	1.3
Malaysia	items	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	
	GDP (constant 2005 US$)	127,611,641,758	136,268,098,017	143,534,102,611	151,550,262,734	161,096,089,356	168,879,881,704	166,323,572,126	178,674,711,521	188,133,365,986	198,430,759,593	
	Electricity consumption (GWh)	73,420	77,252	80,755	84,573	89,358	92,881	102,920	110,853	111,852	120,637	
	(A) GDP growth	5.8%	6.8%	5.3%	5.6%	6.3%	4.8%	-1.5%	7.4%	5.3%	5.5%	
	(B)Electricity growth	6.6%	5.2%	4.5%	4.7%	5.7%	3.9%	10.8%	7.7%	0.9%	7.9%	
	(A)/(B)	1.14	0.77	0.85	0.85	0.90	0.82	-7.14	1.04	0.17	1.43	
	(A') 5-year average GDP	5.3%	5.4%	4.7%	5.8%	6.0%	5.8%	4.1%	4.5%	4.4%	4.3%	
	(B') 5-year average Electricity	6.6%	6.6%	5.7%	5.4%	5.3%	4.8%	5.9%	6.5%	5.8%	6.2%	
	(A')/(B')	1.3	1.2	1.2	0.9	0.9	0.8	1.5	1.5	1.3	1.5	1.2

Source: PSMP2016

Based on the GDP elasticity method, the Bangladesh peak power demand is projected to grow to 51GW by 2041 in Scenario A and Scenario C, and 69GW in Scenario B, as illustrated in figure below.

Figure 33: Bangladesh Peak Power Demand Forecast



Source: Ramboll

4.4.5 Power demand and gas share of total power generation projection

According to PSMP2016, the plant factor remains stable in between 69-70% between 2017 and 2030, then gradually declines to 63% by 2041. We have therefore used this set of plant factors for power demand (GWh) forecast. In the 5 scenarios of PSMP2016, for each year from 2017 to 2041, power generation requirement forecast is the same but fuel mix generation is not equal.

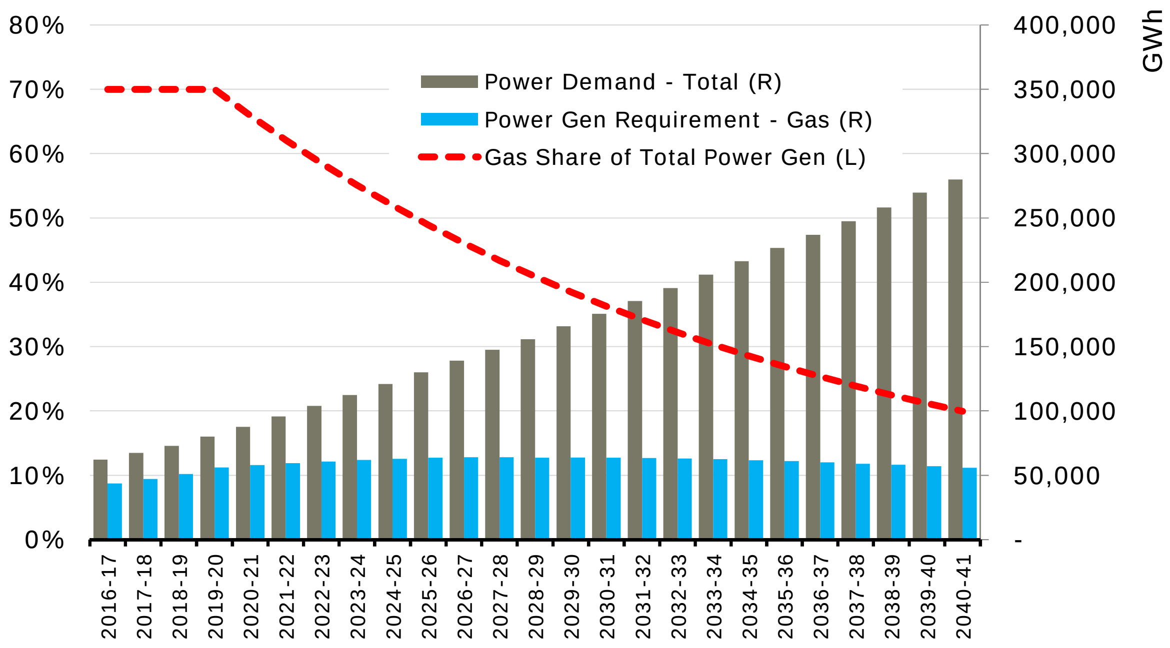
In Scenario A, we assume that Bangladesh significantly changes its power sector mix by aggressively pursuing alternative energy sources, especially coal. The gas share of total power generation requirement in this scenario stays at 70% of total between 2017 and 2020, then decreases significantly to merely 20% by 2041.

In Scenario B, we assume gas to have a greater share in power mix, and the gas share of total power generation requirement stays at 70% of total between 2017 and 2020, then gradually decreases to 40% by 2041.

In Scenario C, the total power generation is the same as that in Scenario A; however, the gas penetration is different. The Consultants have incorporated the latest power sector gas demand forecast agreed between Petrobangla and BPDP.

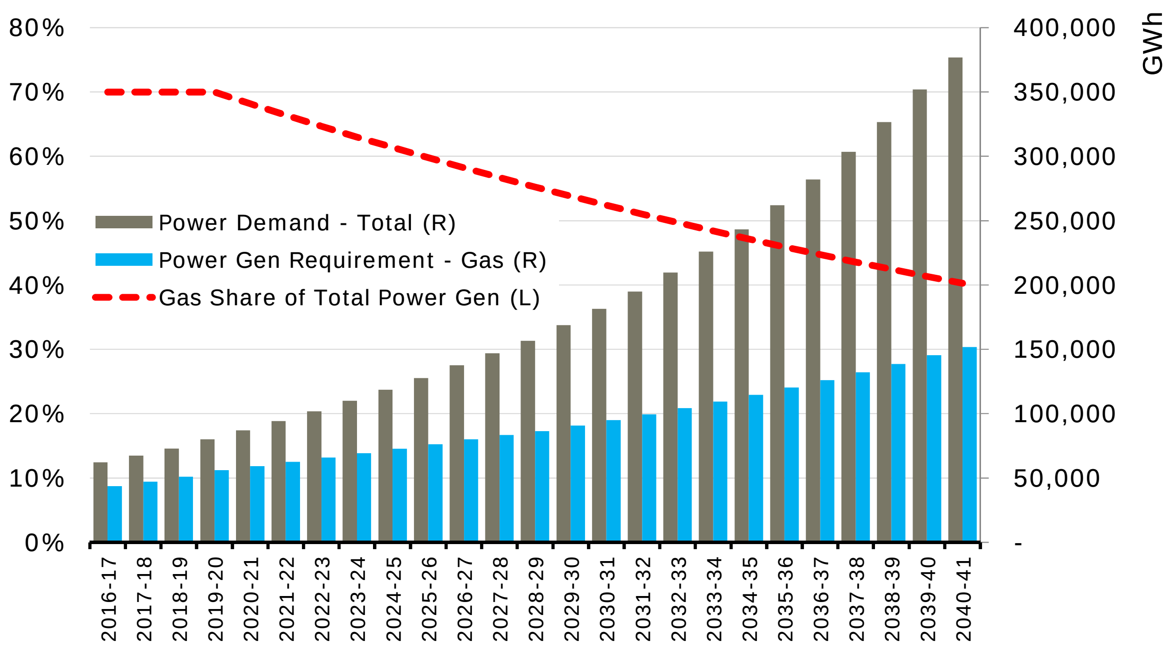
The resultant power demand and generation requirement forecasts are as shown below in Figure 34 and Figure 35.

Figure 34: Power demand / generation requirement forecast – Scenario A



Source: PSMP2016, Ramboll

Figure 35: Power demand / generation forecast – Scenario B



Source: PSMP2016, Ramboll

4.4.6 Gas demand forecast

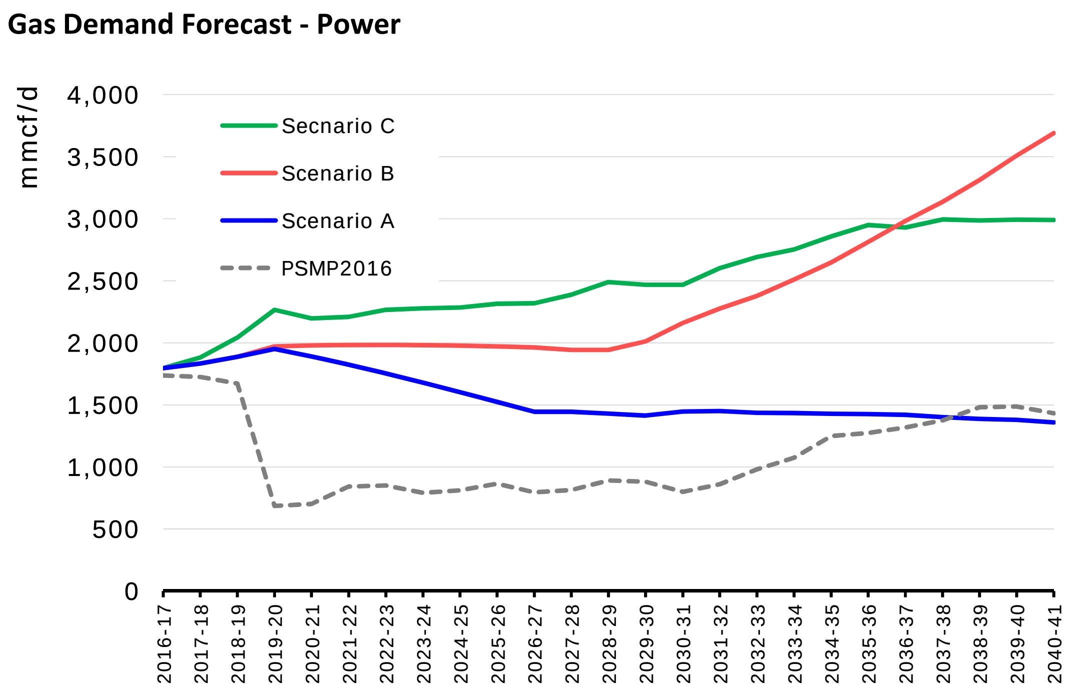
The gas demand forecasts in this study are derived from the PSMP2016 base case forecast. The difference between Scenario A and PSMP base case is the result of modified timing for various power plants, as discussed in the methodology section above. While the difference between Scenario B and Scenario A is due to different GDP growth assumptions and policies for gas concentration in power mix.

In Scenario A, the demand for gas from the power sector increases from 1,792MMCFD in 2016/17 to just below 2,000MMCFD in 2019/20, reflecting a modest number of new gas-fired power plants to become operational during this period. However, the gas demand then gradually drops to around 1,358MMCFD by 2041, reflecting a scenario where existing gas-fired power plants to be replaced by new and more efficient gas-fired power plants and even more so by new coal-fired power plants. The demand forecast of 1,358MMCFD in 2041 is similar to the base case scenario presented in PSMP2016.

In Scenario B, the gas demand increases to just below 2,000MMCFD in 2019/20, then stays at this level until 2030. Such stabilised demand level between Year 2020 and Year 2030 is to reflect a situation where new and more efficient gas-fired power plants replace those existing inefficient plants, hence more total gas-fired power generation from the same amount of gas inputs. The gas demand then increases rigorously before reaching 3,690MMCFD by 2041, reflecting additions of further gas-fired power plants while there are no further decommissioning of existing plants during this period.

In Scenario C, the gas demand increases rapidly by a quarter from 1796MMCFD in 2016/17 to below 2,266MMCFD in 2019/20, then steadily reaches almost 3,000MMCFD by 2041. The significant gas demand in this scenario reflects a situation where gas is continually to be seen as a predominant source of power generation over the next 15 years or so, contributing to a clean energy policy before large quantity of renewable energy to be established in Bangladesh.

Figure 36: Gas demand forecast – power sector



Source: PSMP2016, Ramboll adjustments according to Petrobangla's updated information

4.5 Captive power sector gas demand forecast

4.5.1 Status of captive power demand for each industrial subsector

There is a lack of statistical data on captive power demand from each relevant industrial subsector; however, below are insightful findings from PSMP2016.

Textile and Garment

In the textile and garment industry, both electricity and thermal energy are used in the process of manufacturing. Almost every factory is connected to the grid of distribution companies. However, it is generally observed that electricity generation from on-site generators is utilised for sustaining factory production.

According to existing literature, 80% of factories have their own captive power plant. The textile sector alone has a captive generation capacity of 1,100 MW, while the country as a whole has a total generation capacity of about 8,525 MW as of December 2012.

There is a commonly observed practice in many factories that the electricity demand mainly relies on captive generation from natural gas whereas the power supply from grid is used as back-up. This is due to the fact that the tariff of gas supply for captive power is set lower than electricity tariff, i.e. electricity supplied by distribution companies to factories is at the rate of 6.95 BDT/kWh while the cost of electricity generation from captive power is about 3 BDT/kWh, even without utilising waste heat recovery. This is why most industrial facilities prefer using captive power generation.

Steel-making and Re-rolling

Most of the iron and steel factories are connected to the grid; however, many of them also generate electricity through gas-fired captive power generation for sustaining factory production. The captive generation is said to be cheaper than electricity supply from distribution companies by up to 30%.

Cement

Cement factories usually have grid connections. Though many factories prefer to have their own gas connection and generate electricity from natural gas, only 20% of the units have their own captive power plant.

Glass, Sanitary and Tiles

Almost every factory has a connection to the grid. However, electricity supply mainly relies on captive power generation, and grid connection is used mainly as backup power when gas supply is interrupted or is of low pressure.

New gas connections have been suspended since March 2009, causing the stagnation of establishing new factories. Because of the restrictions in new connections of gas supply, some new companies use CNG or HSD (High Speed Diesel) as substitute. HSD is also used as the fuel for back-up power generation for lighting.

The ceramics industry is characterised by the fact that its manufacturing process is vulnerable to low voltage electricity and low gas pressure, and this is said to be the main reason for the recent trend of lowered quality and the slump in export. Ceramic tableware processes require uninterrupted power and gas supply so that the 360°C temperature is maintained constantly for 24 hours, and drops in temperature need to take at least 12 hours for recovery which causes a huge loss in production. Stable supply of electricity and gas is indispensable.

Chemical, Plastic & Paper

Many factories in chemical, plastics and pulp & paper industries rely on electricity generation through captive power generators for sustaining factory production. About 55% of factories are said to have their own captive power plant. Factories that have both electricity and gas connections use grid electricity as backup power when gas supply is interrupted or of low pressure.

Electricity supply quality is poor and the factories frequently suffer five to six hours of load shedding in summer in Dhaka area, where SMEs in the plastics sector are located. Productivity is badly affected by shortage or fluctuations in electricity supply. Firms that have gas connections for captive power generation enjoy relatively better conditions of power supply, but after early

2009, when the government stopped new gas supply connections, firms have experienced difficulties with their planned expansion projects.

Agro Processing

Agro processing plants usually use captive power generation as the energy source for sustaining factory production. 50% of the factories have their own captive power plant, and use gas or diesel as fuel sources.

4.5.2 Balance between grid power and captive power (gas-fired)

As seen in the previous section, a common issue in the captive power generation in Bangladesh is that the price of natural gas for captive power generation is set at a low level. Thus, the cost of captive power generation is less expensive than the cost of power purchase from the grid. According to the existing literature, there are many factories that use the electricity from the grid not because it's economically rational, but because the gas suppliers reject new connection requests.

Currently, the grid power capacity is insufficient to meet the power demand in Bangladesh. Hence, it will take years for the grid power supply to cover the total power demand including the part that is currently fed by captive power.

At the same time, there are also many manufacturers who require captive power generation to guarantee high quality power supply for their production process, as the power supply from the grid is not reliable enough. Such situation will start to change when the grid power becomes developed and secure enough.

4.5.3 Gas demand forecast

We expect captive power generation to gradually decline after 2020s when the capacity and quality of grid power supply becomes more strengthened. Petrobangla estimates the gas demand from the captive power sector to be 480MMCFD in 2016/17. We therefore forecast the gas demand to stay at this level until 2020, which then declines 10% per year before reaching 58MMCFD in 2041.

Figure 37: Gas demand forecast – captive power sector

Source: Ramboll

4.6 Fertiliser sector gas demand forecast

There are seven Ammonia-Urea Fertiliser plants in Bangladesh listed in Table 10. Six of these are BCIC enterprises and one, Karnaphuli (KAFCO), is a joint venture between BCIC and private sector interests from Japan, Denmark and the Netherlands.

Table 10: Bangladesh fertiliser plants

Factory	Capacity (KMT/year)	Gas Demand (MMCFD)
Jamuna	561	45
Chittagong	561	52
Polash	95	14
Ashuganj	528	52
Ghorashal	470	45
Shahjalal	580	45
Total for BCIC Plants	***2,795***	***243***
Karnaphuli	Urea – 570 Amm – 150	63
Grand Total	***3,515***	***316***

Source: TCIL Report 2015,

Petrobangla Daily Gas & Condensate Production and Distribution Report

However, over the past several years, both the BCIC plants and KAFCO have suffered from reduced gas supply even though the KAFCO plant has a contractual arrangement for guaranteed gas supply with its gas distribution company.

The gas consumption from the fertiliser sector has declined from its peak of 263 MMCFD in 2004/05 to only 144 MMCFD in 2015/16. This is largely due to the government's policy in rationing the country's gas consumption due to supply shortages, especially during summer when the country experiences peak demand in power.

As shown in Table 11, Bangladesh has been importing more than half of its urea in recent years, while demands for fertilisers have not been fully met.

Table 11: Demand, production, import & consumption of Urea, TSP, DAP & MOP fertiliser in Bangladesh

Demand, Production, Import & Consumption situation of Urea, TSP, DAP & MOP Fertilizer for last six years in Bangladesh

1 Lac=100,000 MT

	Year	Demand (Lac M. Ton)	Production(BCIC) (Lac M. Ton)	Import (Lac. M Ton)	Consumption (Lac M. Ton)
Urea	2007-08	28.14	14.00	11.62	**26.85**
	2008-09	28.50	12.50	14.16	**25.00**
	2009-10	29.51	11.30	14.91	**24.40**
	2010-11	28.31	7.00	15.08	**25.80**
	2011-12	30.00	9.34	12.82	**22.964**
	2012-13	25.00	10.00	16.00	**22.47**
	2013-14	24.50	10.00(Target)	14.50(Target)	
TSP	2007-08	4.75	0.30	PS-2.37 BADC-1.68740	**3.80**
	2008-09	5.00	0.25	PS-1.50 BADC-0.75	**1.50**
	2009-10	6.70	0.70	PS-2.0 BADC-2.0	**4.70**
	2010-11	5.73	0.60	PS-3.11 BADC-1.55	**4.91**
	2011-12	7.00	0.50	PS-3.82 BADC- 2.25	**5.00**
	2012-13	7.00	0.50	PS-2.53 BADC- 2.00	**6.54**
	2013-14	6.75	0.60	PS-2.55 BADC- 2.25	
DAP	2007-08	2.5	1.0	PS- 0.10	**2.40**
	2008-09	2.00	0.45	PS - 0.068	**0.17**
	2009-10	2.63	0.40	PS -1.0 BADC-1.0	**2.40**
	2010-11	3.43	0.35	PS-2.11 BADC-1.25	**2.73**
	2011-12	6.50	0.50	PS-3.80 BADC-2.60	**4.49**
	2012-13	6.00	0.50	PS-1.99 BADC-1.00	**4.34**
	2013-14	6.50	0.50	PS-4.00 BADC-1.00	
MOP	2007-08	4.00	-	PS - 2.90 BADC- 0.696	**3.80**
	2008-09	4.00	-	PS - 1.45 BADC – 0.775	**0.75**
	2009-10	4.97	-	PS – 2.0 BADC -2.0	**2.55**
	2010-11	4.92	-	PS – 2.14 BADC- 1.25	**4.36**
	2011-12	7.40	-	PS – 3.87 BADC- 1.00	**4.50**
	2012-13	8.70		PS – 3.66 BADC- 3.90	**5.71**
	2013-14	8.00		BADC- 4.50	

PS = Private sector & BCIC & BADC = GOB

Source: Fertilizer Association of Bangladesh

Source: Fertilizer Association of Bangladesh

We expect the demand for fertilisers to be largely dictated by the total plant capacity rather than GDP or population growth in Bangladesh. Without clear information on future plans on fertiliser sector development, we assume that the total plant capacity remains the same. Hence, the demand for gas stays at current level of 316 MMCFD which echoes Petrobangla's own projection.

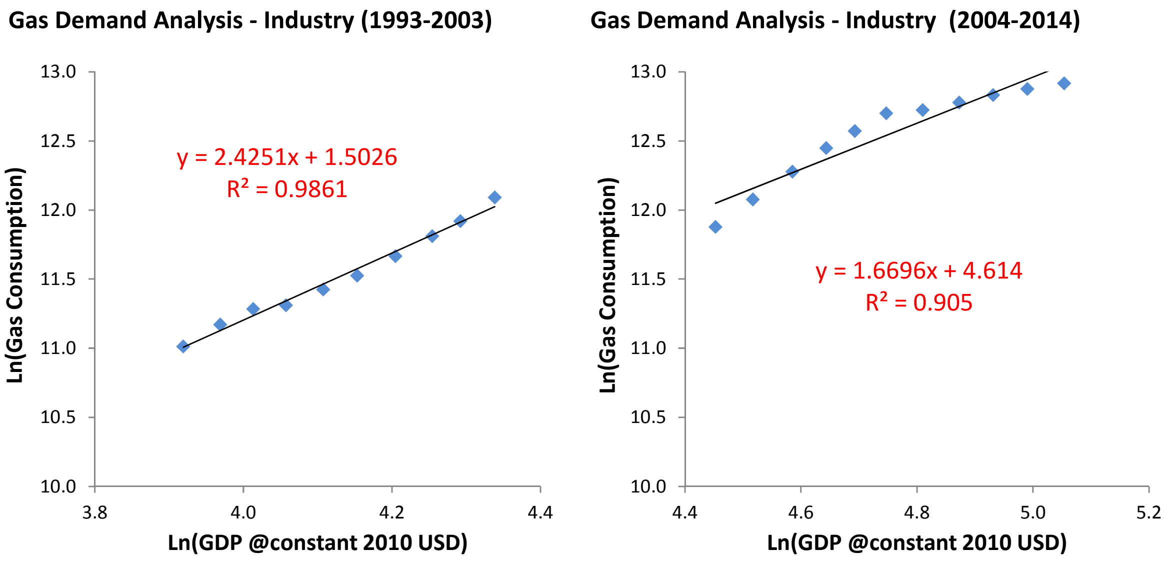
However, it needs to be pointed out that the 316 MMCFD demand forecast is also largely based on the need to protect Bangladesh's fertiliser sector and consequently protect the food security for the nation. The actual supply and consumption of gas in the fertiliser sector can be varied based on the availability of gas as well as the commerciality of indigenous fertiliser production versus imports.

For example, the average efficiency of the fertiliser plants in Bangladesh is low. 44mcf is required to produce 1 ton of urea which is significantly less efficient than the world standard of 25mcf/ton. Therefore, it may be more economic for Bangladesh to import fertilisers rather than producing them domestically. This also implies that fertiliser plants in Bangladesh may not all need to be running at full capacity, and incremental demands for fertiliser due to population growth in the future can be satisfied either by utilising more indigenous capacity or by higher levels of imports.

4.7 Industry sector gas demand forecast

The gas consumption from industry sector was just over 405 MMCFD in FY2014, a relatively small increase from 389 MMCFD in FY2013. In the meantime, Petrobangla estimates a demand of 542 MMCFD in FY2016, suggesting an unmet demand of over 100 MMCFD. This explains why the gas consumption from the industry sector has experienced rapidly slowdowns in its growth. As shown in Figure 38 below, the elasticity of industry consumption for gas to GDP has dropped from 2.43 between 1993 and 2003 to 1.67 between 2004 and 2014.

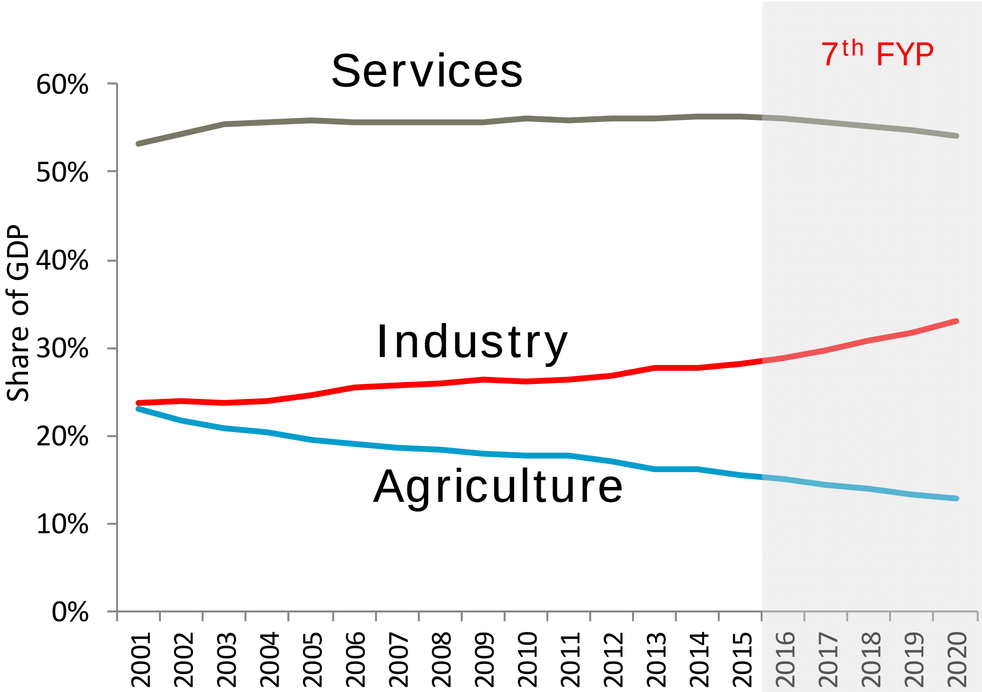
Figure 38: Gas demand analysis - industry



Source: Ramboll

At its take-off stage of economic development, Bangladesh has an underdeveloped industry sector. Nevertheless, the success in textile exports has been a key drive for Bangladesh's economic growth in the past decades; this has also increased the industry sector's share in GDP to 28% in 2015. It is in the government's 7th FYP to accelerate the development of the industry sector.

Figure 39: Bangladesh GDP by sector



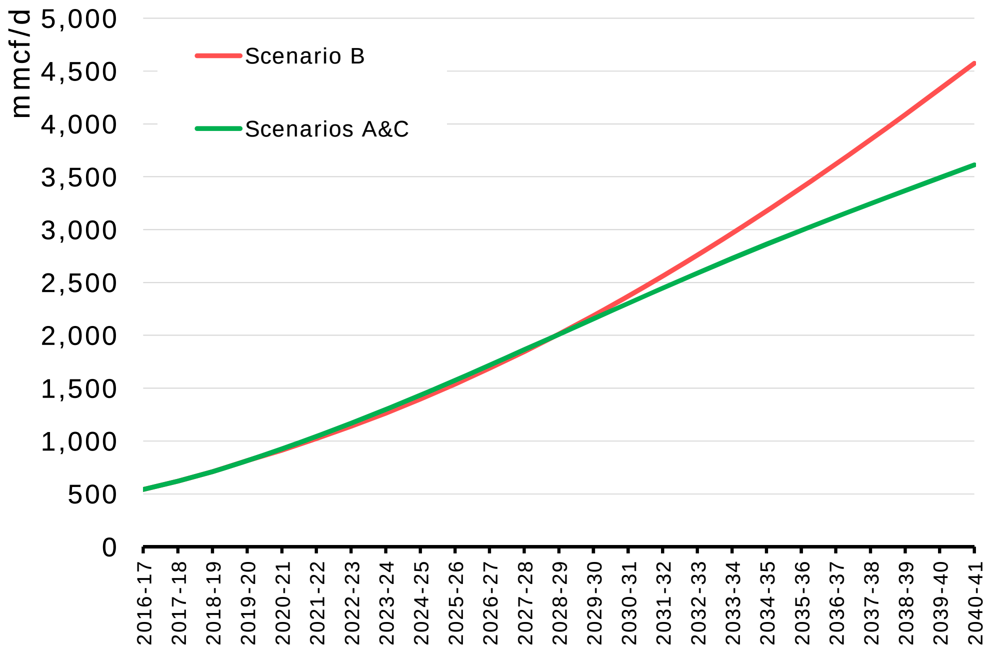
Source: World Bank, Bangladesh 7th FYP

As a result of this pro-industry policy of the Bangladeshi Government, we expect the gas demand from industry sector to grow strongly. Given the shortage of gas supply in recent years, the elasticity of industry consumption for gas to GDP between 2004 and 2014 understates the actual demand growth. Therefore, we choose the average elasticity (i.e. 2.05) of gas consumption to GDP between 1994 and 2014 as a proxy for gas demand projection. We also assume that, as a result of higher gas prices, energy efficiency improvements and availability of alternative fuels, this elasticity declines gradually by 60% by 2041.

It needs to be recognised that there are large uncertainties in the assumptions mentioned above. These uncertainties are inherently unavoidable because (1) historical trend in Bangladesh will no longer be a good indicator for the future, and (2) there are large uncertainties in the overall energy sector both within Bangladesh and internationally.

Figure 40 shows the gas demand forecast for the industry sector. In Scenario A, gas demand reaches just over 3,600MMCFD in 2041, while in Scenario B, the figure rises to just under 4,600MMCFD.

Figure 40: Gas demand forecast – industry

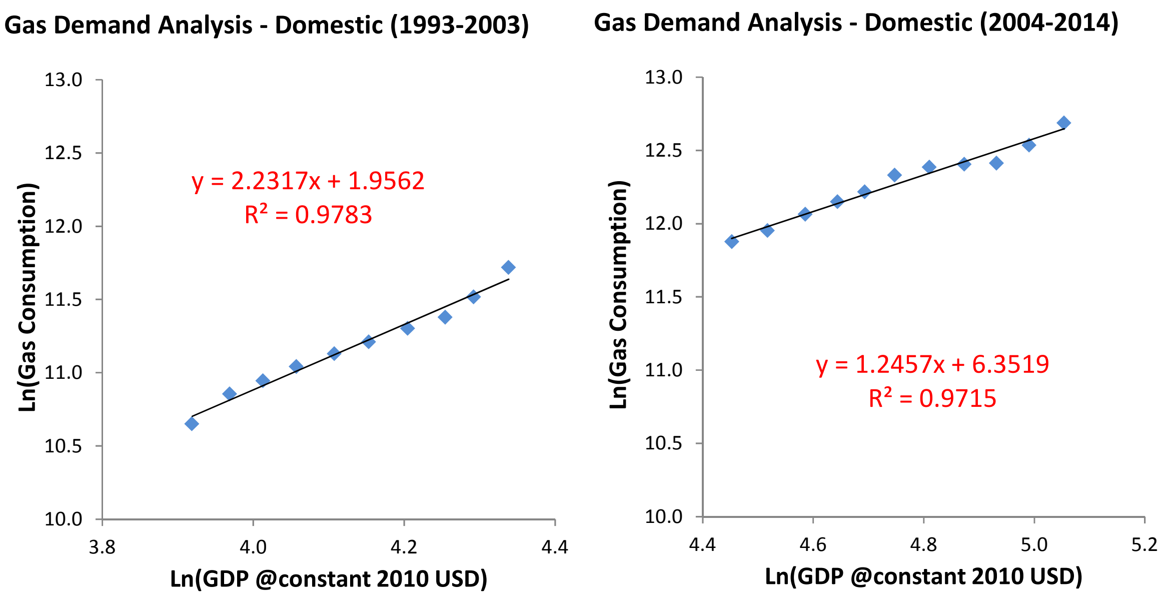


Source: Ramboll

4.8 Domestic sector gas demand forecast

The historical gas consumption from domestic sector has been strongly correlated with GDP growth, see Figure 41.

Figure 41: Gas demand analysis - domestic



Source: Ramboll

Currently, there are just under 3 million households connected to natural gas, many of these domestic users are charged on fixed monthly fees for their stoves, i.e. same monthly bill regardless of the actual use of gas. This has supposedly resulted in significant losses due to wasteful use of gas. Initiatives are being taken by the Bangladeshi Government and local distributors to improve this wasteful use situation. For example, TGTDCL has been implementing the Installation of Pre-paid Gas Meter Project.

In response to the shortage of natural gas, the Bangladeshi Government has a policy to cap the gas supply to domestic users, and promote LPG as an alternative to satisfy the future growth in this sector.

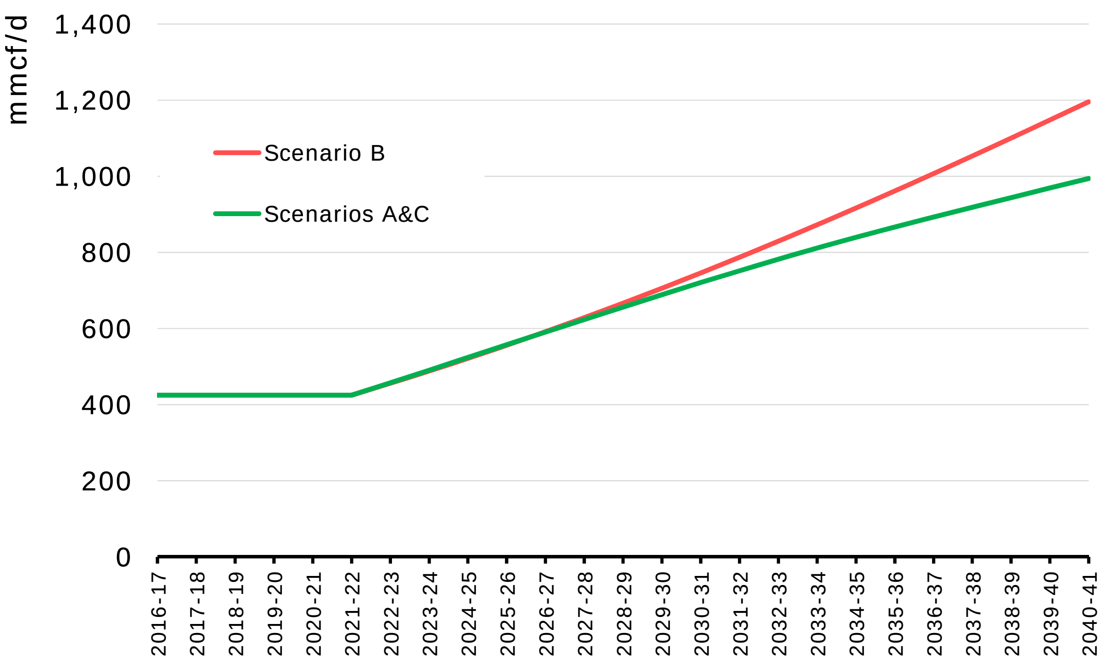
As a result of the Consultants' site visits in Bangladesh and interviews with some locals, we recognise that domestic users' demand for LPG is growing fast, although LPG is still seen to be an expensive source of energy for many low and mid income families. We also believe that it can be practically difficult and economically inefficient to make new customer connections in the suburb areas of Dhaka, as it is our view that many of these suburb areas will be restructured and redeveloped in the foreseeable future as Bangladesh's economy continues to grow.

In consideration of the government policy and economic development factors as mentioned above, we project that the gas demand from the domestic sector will remain constant for the next five years, i.e. until 2022.

However, the majority of the population in Bangladesh are still using biomass (e.g. wood) for their domestic fuel usage. This is most likely an impractical option as the population becomes wealthier and move into new built residential buildings. The Consultants are of the view that indigenous LPG production alone is unlikely to be sufficient for the nation's growing demand, while natural gas is still likely to be required as an important supplement. As such, we use the elasticity of gas consumption to GDP between 2004 and 2014 as a proxy for gas demand projection. Meanwhile, we recognise the effect of LPG development, weakened gas demand growth due to higher gas prices, as well as the expectation that the wasteful use of gas in the domestic sector will improve over time. Therefore, we project that elasticity of gas demand to GDP gradually declines by around 50% over the forecast period.

Figure 42 shows the gas demand forecast for the domestic sector. In Scenarios A and C, gas demand reaches 994MMCFD in 2041, while in Scenario B, the figure rises to around 1,196 MMCFD, both are significant increases from the estimated current demand of 425MMCFD.

Figure 42: Gas demand forecast – domestic

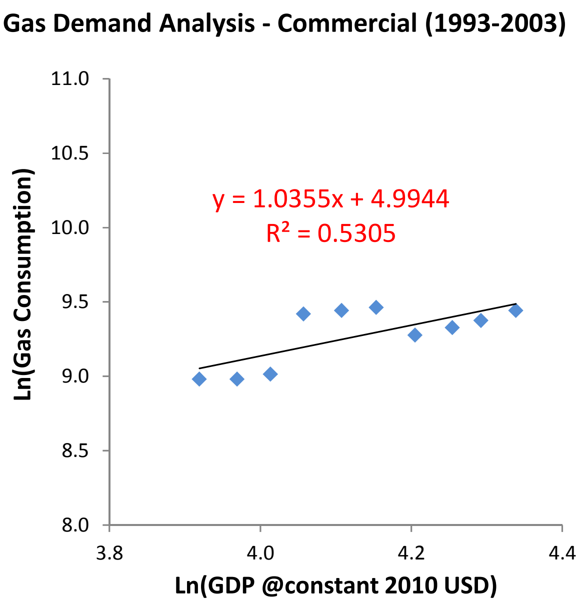


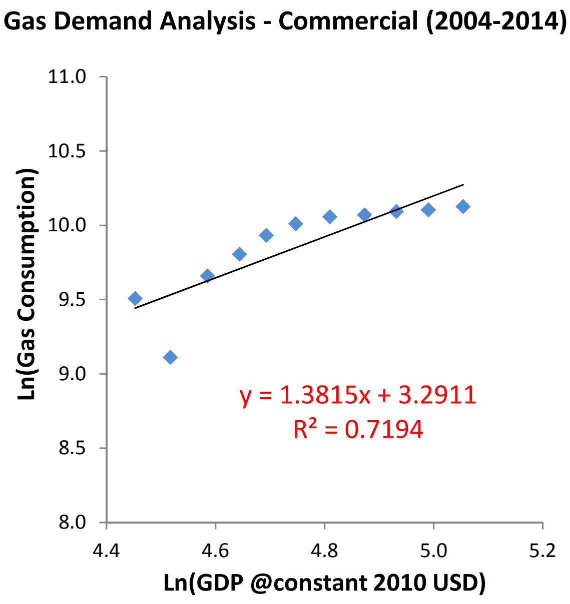
Source: Ramboll

4.9 Commercial sector gas demand forecast

The historical correlations between gas consumption from commercial sector and GDP has been somewhat weak, as the regression results in Figure 43 show R-squares of only 0.53 and 0.72 for the periods 1993-2003 and 2004-2014, respectively. Therefore, the GDP elasticity method will not be adequate for the future gas demand forecast for the commercial sector.

Figure 43: Gas demand analysis - commercial

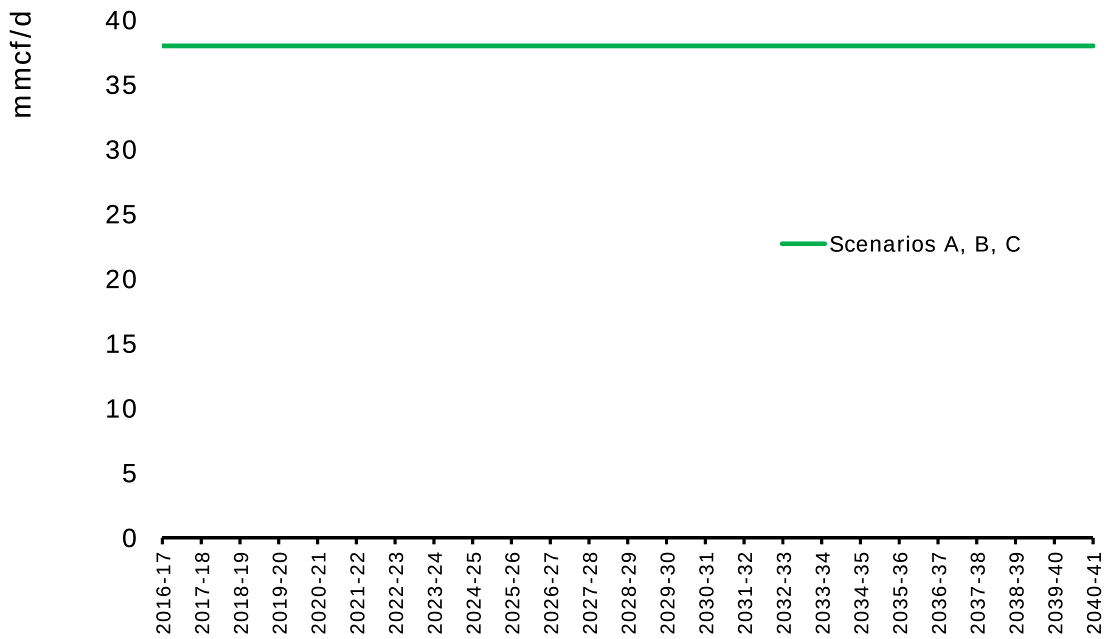




Source: Ramboll

Currently, the Bangladeshi Government has a policy to promote LPG to replace natural gas for additional demand from the commercial sector. Given the small quantity requirement, we assume that LPG will be sufficient to satisfy all incremental demand from the commercial sector, while the gas demand in the sector will remain at current level, i.e. 38 MMCFD (incl. 8 MMCFD from Tea) throughout the forecast period, as shown in Figure 44. This echoes with Petrobangla's own projection.

Figure 44: Gas demand forecast – commercial

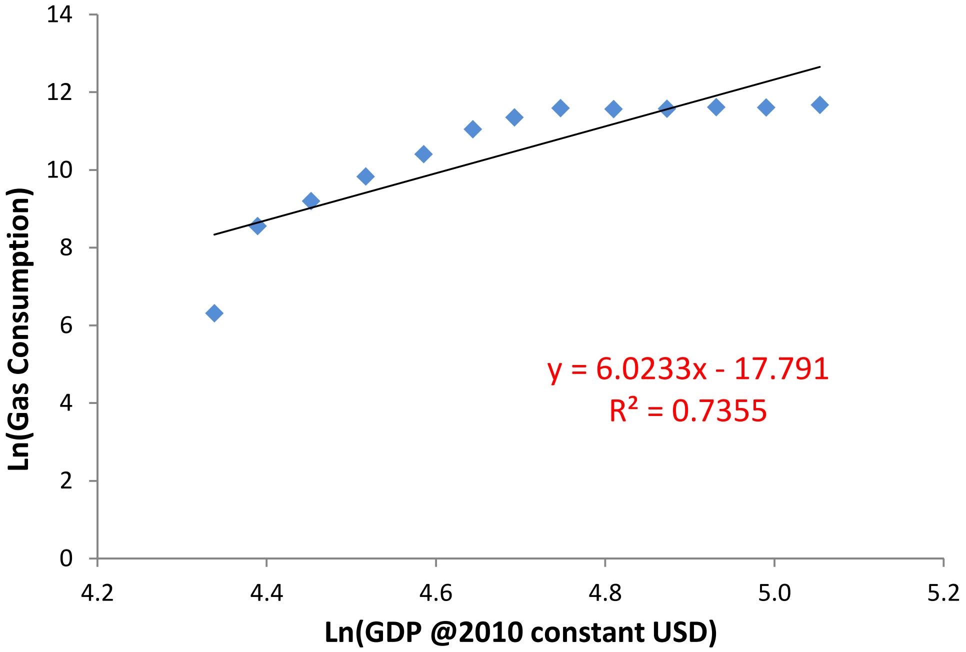


Source: Ramboll

4.10 CNG sector gas demand forecast

Started from 2002/2003, the CNG sector in Bangladesh has yet to reach an established/stabilised stage of its development. Due to supply shortage, the CNG price is being increased to discourage consumption, while the quantity of supply has also more or less been capped. For these reasons, there is no strong correlation between historical CNG consumption for gas and GDP growth as seen in Figure 45. Therefore, GDP elasticity method will not be used for CNG demand forecast.

Figure 45: Gas demand analysis - CNG



Source: Ramboll

As of 2017, there are 596 approved CNG refuelling stations for almost half million running vehicles. See table below for details:

Table 12: Bangladesh CNG Sector Overview

FY	Approved CNG Refuelling Stations (#)	Approved CNG Workshop (#)	CNG Converted Vehicles (#)	CNG Running Vehicles (#)	Monitoring Activities (#)
Prior June 2015	590	180	220,920	259,050	60
2015-2016	1	-	32,289	34,542	100
2016-2017	5	-	10,916	204,158	86
Total	**596**	**180**	**264,125**	**497,750**	**246**

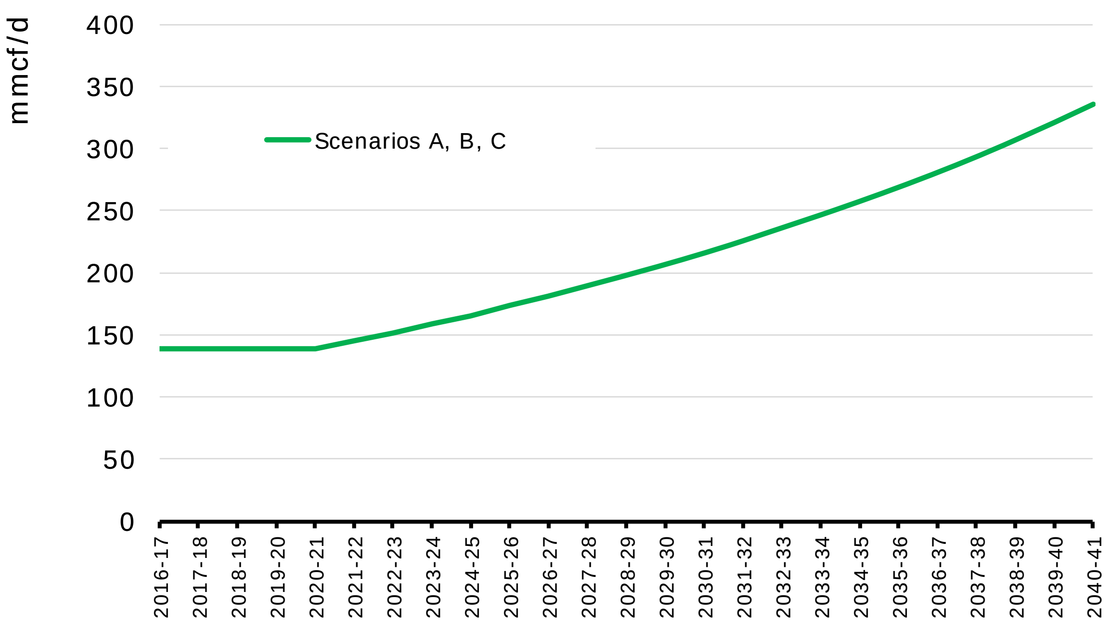
Source: RPGCL 2017

At the time of writing, the Bangladeshi Government has a policy to encourage LPG to fill the growth of automobiles because of the current shortages of natural gas. However, the Consultants are of the view that such policy can be revised as Bangladesh starts importing gas and becoming less and less constrained by indigenous production. Furthermore, to support Bangladesh's goals in its economic development, large quantity of additional energy will be required. Therefore, the development of LPG alone may not be enough to satisfy the nation's demand, while the need for natural gas will continue to grow albeit at a slower pace.

ExxonMobil projects the global demand for gas in transport sector to increase 3 folds between 2014 and 2040, an equivalent of 4.5% average annual growth rate. We assume the CNG demand of Bangladesh to hold at the current level up to 2020 and then grow at the rate as the global average - a rate lower than the nation's GDP growth forecast. Given that the CNG sector is already facing a high retail price of 17.4 USD/mcf as of 2017, the need for further price increases is limited. Consequently, very little impact of price on demand should be included for the gas demand forecast for the CNG sector.

As shown in Figure 46, the gas demand from CNG sector is projected to grow from 139MMCFD in 2016/17 to 335MMCFD by 2041.

Figure 46: Gas demand forecast – CNG



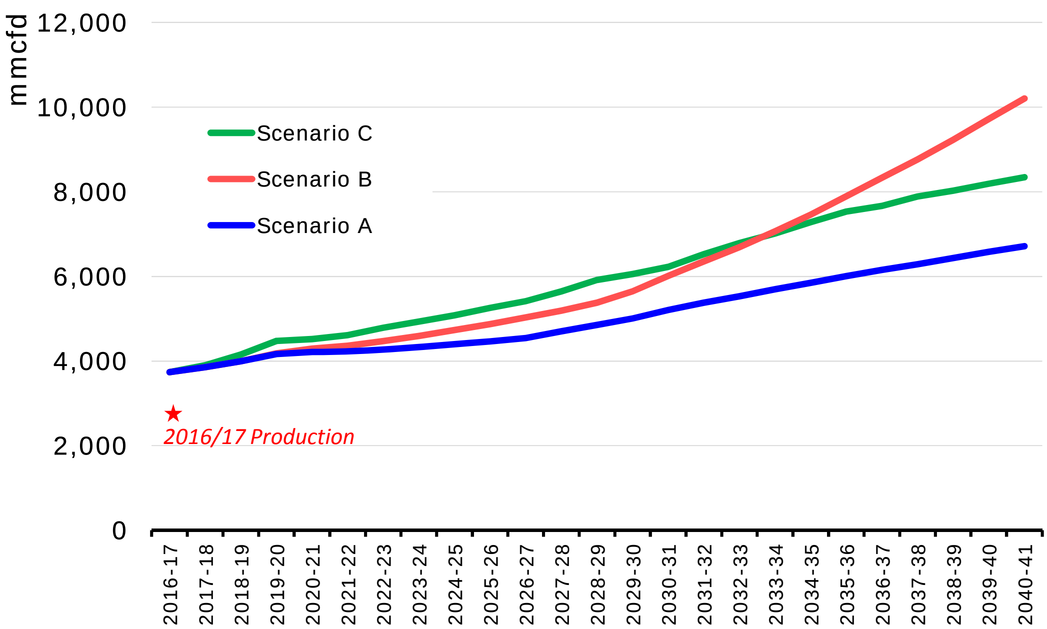
Source: Ramboll

4.11 Total Gas Demand Forecast

Using Petrobangla's estimation as our base year demand reference, we have derived the total gas demand in Bangladesh to be 3,740MMCFD (eqv. 1.4tcf/year) in Financial Year 2016/17. As shown in Figure 47, the total gas demand is projected to reach 6,713MMCFD (eqv. 2.5tcf/year) by 2041 in Scenario A, 10,208MMCFD (eqv. 3.7tcf/year) in Scenario B, and 8,346MMCFD (eqv. 3.0tcf/year) in Scenario C.

The indigenous production is estimated to be 2,750MMCFD in 2016/17, as much as 1,000MMCFD less than the estimated demand. We consequently see a continuous increase in consumption when new supply sources are made available.

Figure 47: Gas demand forecast – total



Source: Ramboll

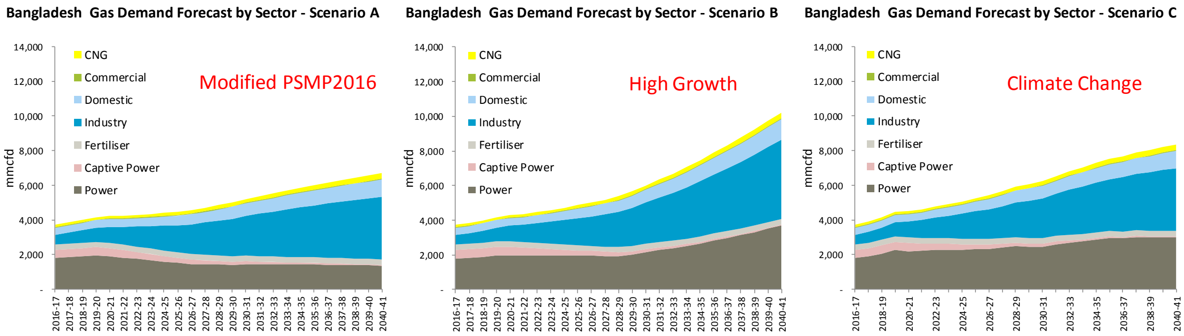
In Scenario A, the gas demand from power sector is projected to fall if the gas share in power generation is to be reduced from current level of around 70% to only 20% by 2041, which is less than IEA World Energy Outlook 2016 global average of 23%. The share of power in total gas demand drops from 48% in 2016/17 to only 20% in 2041, while captive power to fade away during the same period. In contrast, the demand from both industry and domestic sectors is forecasted to grow strongly, together accounting for 69% of total gas demand by 2041.

In Scenario B, the gas share in power generation is to be declining from current level of around 70% to 40% by 2041, much less aggressively than that in Scenario A. By 2041, the absolute gas demand from the power sector doubles from current level, although the share of power in total gas demand drops from 48% in 2016/17 to 36% in 2041. Similar to Scenario A, captive power is projected to fade away whilst the demand from both industry and domestic sectors are forecasted to grow strongly throughout the period.

Scenario C projects the same gas demand as Scenario A in all sectors except in Power, where the gas demand in this sector reaches around 3,000 MMCFD in 2041, accounting for 36% of total gas demand of Bangladesh.

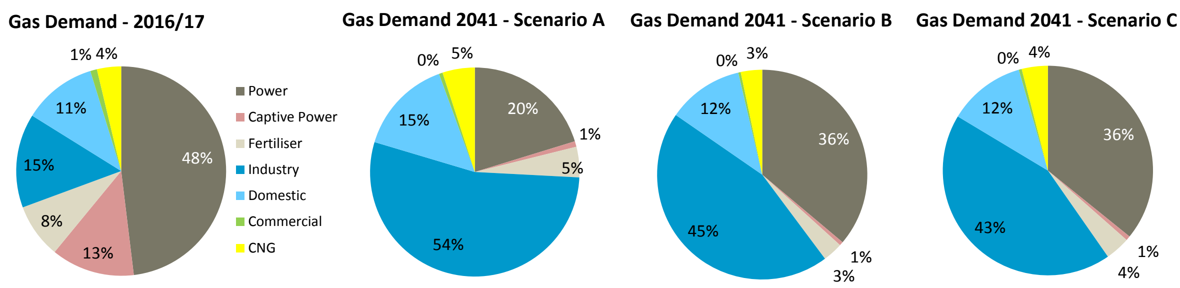
In all scenarios, the gas demand from CNG sector is projected to grow after 2020 at 4.5%. Meanwhile, the demand from fertiliser and commercial sector is projected to stay at a constant level.

Figure 48: Gas demand by sector Scenarios A, B, C



Source: Ramboll

Figure 49: Gas demand forecast by sector share

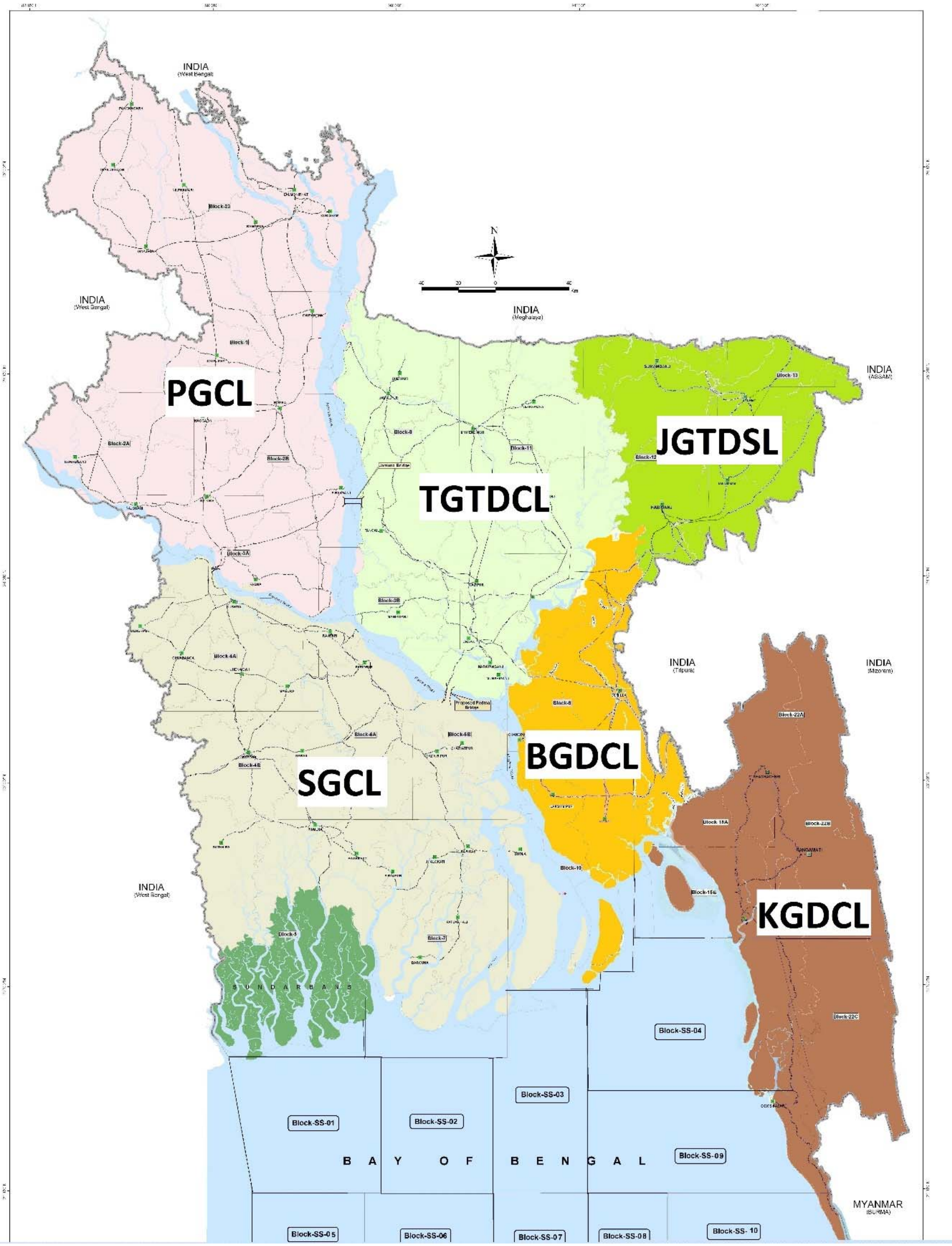


Source: Ramboll

4.12 Regional Gas Demand Forecast

There are six companies covering the gas distribution in Bangladesh, namely TGTDCL, BGDCL, JGTDSL, PGCL, KGDCL, and SGCL. Brief overviews for each of these companies are presented below.

Figure 50: Bangladesh gas distribution by franchise area



Source: GTCL, Ramboll

4.12.1 Titas Gas Transmission and Distribution Company Limited (TGTDCL)

The discovery of a huge gas field on the bank of the Titas River in Bhramanbaria in 1962 created a new horizon for the utilisation of natural gas. Titas Gas Transmission and Distribution Company Limited (TGTDCL) was established on 20 November 1964. The company began its commercial operation with the commissioning of gas supply to Siddhirganj Thermal Power Station on 28 April 1968 after construction of 14" x 93 km Titas-Demra gas transmission pipeline by the then East Pakistan Industrial Development Corporation. In October 1968, the first domestic natural gas connection was provided to the residence of renowned litterateur Shawkat Osman.

In the beginning, 90% of its shares belonged to the then Pakistan Government, and Pakistan Shell Oil Company owned the rest. Under the Nationalisation Order of 1972, all the Government-owned shares of the company were invested in the Government of Bangladesh (GoB). In accordance with an agreement signed between Shell Oil Company and GoB on 9 August 1975, the ownership of the remaining 10% shares was transferred to the GoB through Petrobangla. After the independence of Bangladesh in 1971, the company started its journey as a company of Petrobangla with an authorised and paid up capital of BDT 17.8 million. At present, the authorised and the paid up capitals of the company are BDT 20,000.0 and BDT 9,892.2 million, respectively. Presently, Petrobangla holds 75% shares of this company while private shareholders hold 25% of shares.

The main objective of the company is to supply natural gas to customers of different categories under its franchise area and thereby reduce dependency on imported liquid fuel. Towards this end, the company has to construct, operate and maintain pipelines, stations and associated facilities.

Currently, the company distributes gas in the districts of Dhaka, Narayanganj, Narsingdi, Munshiganj, Manikganj, Gazipur, Tangail, Mymensingh, Jamalpur, Sherpur, Netrokona and Kishoreganj.

Presently, total length of pipeline owned by the company is 12,889.03 km including 383.53 km built during the FY 2014-15. The total number of customers of the company was 1,897,316 as on 30 June 2015 which rose to 1,996,801 in December 2015. Bulk customers of the company include 3 fertiliser plants, 7 government and 28 private power stations.

4.12.2 Bakhrabad Gas Distribution Company Limited (BGDCL)

Bakhrabad Gas Distribution Company Limited (BGDCL), previously named as Bakhrabad Gas Systems Limited (BGSL), was established on 7 June 1980, initially with the three-fold responsibilities of production, transmission and distribution.

Gas supply was commenced on 20 May 1984. Subsequently, Bakhrabad Gas Field was handed over to BGFCL putting an end to its production wing. Further, the 2 main transmission pipe lines of the company, 24" X 110 km Bakhrabad-Chittagong and 20" X 69 km Bakhrabad-Demra gas transmission pipe lines were handed over to GTCL leaving only the responsibility for marketing gas in the Chittagong Division excluding Brahmanbaria district and Kashba and Bancharampur Upazilas (outside its franchise area). As per Government decision, the company has again been reconstituted keeping greater Comilla and greater Noakhali Districts under its franchise area and adding Brahmanbaria to its operational area.

The cumulative gas pipeline of different categories constructed by the company up to 30 June 2015 is 3,869 km. During the FY 2014-15, a total of 81,103 domestic gas connections (burner) were given. The cumulative gas connection stood at 399,540 as on 30 June 2015 which includes 15 power, 1 fertiliser, 157 industrial, 74 captive power, 2,140 commercial, 88 CNG and 397,067 domestic (Burner) connections. In order to enhance the gas supply to the greater Noakhali region, a project was undertaken to supply gas to Maijdee Lateral Line from Begumganj Gas Field with a cost of BDT 59.9 million. As per approval 10 bar 8" X 5.378 km pipeline from Begumganj Gas Field to Maijdee Lateral Line at Setubhanga Point and 30 bar 6" X 207 metre pipeline in the premises of Begumganj Gas Field were constructed. One RMS of 20 MMSCFD capacity was also installed in the Begumganj Gas Field.

4.12.3 Jalalabad Gas Transmission and Distribution System Limited (JGTDSL)

Jalalabad Gas Transmission and Distribution System Limited (JGTDSL) was formed under the Companies Act on 1 December 1986 with an authorised capital of BDT 1,500 million after infrastructural development of gas transmission and distribution system under the management of Petrobangla for supplying gas to different categories of customers in Sylhet Division.

During the FY 2014-15, the Company possessed a gas network comprising of 465.08 km transmission, 1,336.29 km distribution, 1,205.42 km feeder mains and service lines and 777.34 km other (customer financing) pipelines. During the year, the company provided 16,546 new gas connections - 1 power station, 11 captive power, 7 industrial, 4 CNG, 115 commercial and 16,408 domestic connections - which was 10.55% higher than the previous year.

4.12.4 Pashchimanchal Gas Company Limited (PGCL)

This is the 4th gas marketing company under Petrobangla set-up with the objective of distributing gas in the north-west region of the country. The Company commenced its business on 23 April 2000. By the end of June 2015, the Company encompassed a network of 1,626.21 km pipeline. At the end of FY 2014-15, the company provided gas connection to 1,19,483 customers.

4.12.5 Karnaphuli Gas Distribution Company Limited (KGDCL)

Karnaphuli Gas Distribution Company Limited (KGDCL) was formed on 8 February 2010, with greater Chittagong and Chittagong Hill tracts area under erstwhile BGSL franchise, pursuant to a government decision to rationalise and improve the services of the companies under Petrobangla. The commercial activities of the company commenced on 1 July 2010.

At the end of the FY 2014-15, KGDCL had a customer base of 533,273 of which 60,671 (CNG 2, Industry 5, Captive Power 1 and Domestic 60,663) were new customers. During FY 2014-15, 124.83 km distribution pipelines with diameters ranging from ¾" to 8" were constructed.

Following Steps have been taken to prevent misuse and to ensure the accuracy of metering system:

Tele-metering system has been introduced initially in the RMS of 5 bulk industrial customers (KAFCO, Shikolbaha Power Station, 210MW CTPS, KPM and CUFL) for monitoring the quantum of gas supplied to them. Meters with Electronic Volume Correctors (EVCs) are being installed in the RMS of load intensive customers. By now, meters with EVCs have been set up in the premises of 164 customers including 62 CNG, 64 captive power and 38 industrial customers, and they are billed on the basis of EVC data. With the finance of Japan International Co-operation Agency (JICA), a project for installation of 60,000 pre-paid gas meters for the domestic users in the Chittagong city area is in progress to prevent the misuse of gas. Rest of the domestic customers will be brought under this system in phases.

Development of customised software by IICT, BUET to bring all the activities of KGDCL under ERP software is in progress. Installation of online gas bill system by IICT, BUET is in process to ensure easy and fast bill payment by all categories of customer of KGDCL. The company has undertaken the work of mapping its network of gas pipelines and gas installation through the Center for Environment and Geographic Information Services (CEGIS).

4.12.6 Sundarban Gas Company Limited (SGCL)

The Sundarban Gas Company Limited (SGCL) was formed on 23 November 2009 with the objective of supplying natural gas to the south-western region of the country which includes Khulna Division, Barisal Division and 5 districts of Dhaka division.

In the initial stage, the Company has been implementing gas distribution network in 5 districts, namely Kushtia, Jhenaidah, Jessore, Khulna and Bagerhat under “South West Region Gas Distribution Network Project" since February 2011. The project is being implemented through joint financing by the Government of Bangladesh and Asian Development Bank (ADB). To implement the project, the necessary procurement of pipeline materials and other items have been completed. On the other hand, the Rupsha river crossing work for laying 20" diameter line pipe through HDD is in progress. Land acquisition for company’s head office building in Khulna and regional offices of other 3 districts have been completed. A MOU has been signed with House Building Research Institute as consultant for performing the work of design, drawing, estimating and preparing tender document. It is to be mentioned here that “South-West Region Gas Distribution Network Project” was closed in 2016 - despite SGCL taking new projects for connecting gas to Power and Industrial customers.

Presently, Sundarban Gas Company Limited is supplying gas to the island district Bhola and Bheramara under kushtia district. In Bhola one 34.5 MW rental power plant of venture Resources

Ltd, 225 MW power plant of PDB and 3,000 domestic customers and in Bheramara one 360 MW power plant are connected with the gas distribution network of this company. Extension of gas distribution network in Bhola town and new network at Borhanuddin have already been completed.

There have been 3 more MOU signed between SGCL and concerned authority to supply gas to:

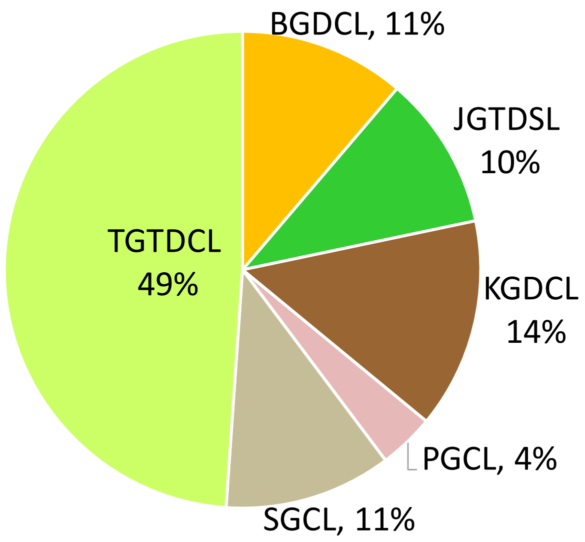
- Khulna 225 MW power plant (required gas load 35 MMCFD)
- Khulna 800 MW power plant (required gas load 125 MMCFD)
- Bhola 225 MW power plant (required gas load 23 MMCFD)

The relevant implementation works are in progress.

4.12.7 Gas Demand Forecast by Franchise Area

Figure 51 below shows the gas demand estimations for each franchise area in 2016/17. Titas franchise area has the largest gas demand which accounts for almost half of the nation's total, Karnaphuli franchise area is the second largest with 14% of the total, Bakharbad, Jalalabad and Sundarban franchise areas have similar level of gas demand and each accounts for 10%-11% of the Bangladesh total, meanwhile Pashchimanchal francise area has the least demand with 4% of the nation's total.

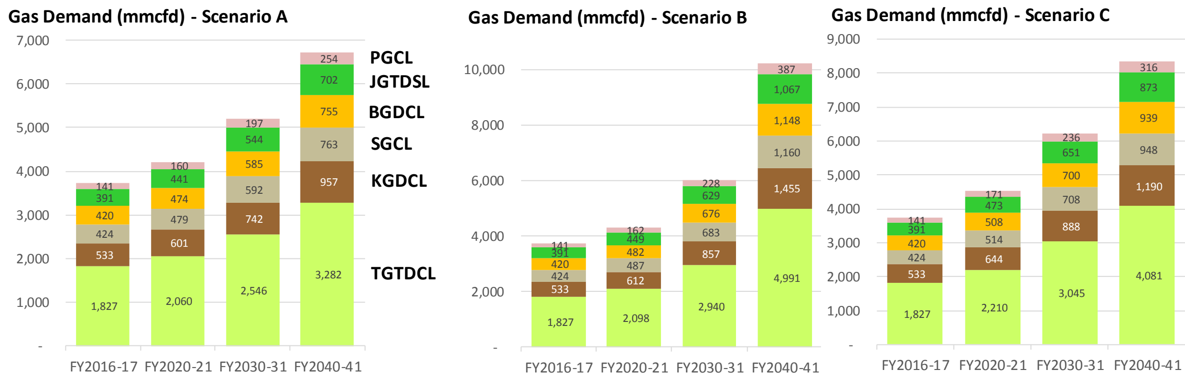
Figure 51: Gas Demand – Franchise Areas Share of Total Bangladesh Demand



Source: BGDCL, JGTDSL, KGDCL, PGCL, SGCL, TGTDCL, Ramboll

As Bangladesh is going through the take-off stage of its economic development, there are large uncertainties in how each sector and region in the country will develop economically, which in turn creates large uncertainties in regional gas demand. Therefore, for simplicity, we assume each of the franchise area mentioned above will maintain its share of total Bangladesh gas demand, and the demand forecasts are as shown in graphs below:

Figure 52: Gas Demand Forecast by Franchise Areas



Source: Ramboll

5. GAS SUPPLY

This chapter presents the work carried out on the supply elements of the Updated Gas Sector Master Plan and Strategy for Bangladesh. The overall structure of the chapter is based on the GSMP (2006); however, updated with relevant new topics.

The chapter is structured into seven sections:

- Review of the upstream supply sector
- Gas reserve position for Bangladesh
- Country supply – production forecasts
- Review of GSMP 2006
- Analysis of the exploration program by public sector
- Analysis of the exploration program by private sector
- Key recommendations for gas supply augmentation

5.1 Review of the upstream supply sector

This review is based on relevant annual reports provided by Petrobangla and its subsidiaries, as well as other relevant documents provided by Petrobangla for this study.

5.1.1 Industry structure

Upstream, midstream and downstream activities for Oil & Gas in Bangladesh are carried out by both the public sector represented by Petrobangla and by the private sector represented by the International Oil Companies (IOCs) currently operating in the country.

The public participation in the oil and gas industry in Bangladesh is organised into four distinct segments with individual companies, which are subsidiaries of Petrobangla, responsible for exploration, production, transmission and distribution of natural gas.

Following Bangladesh's achievement of independence from Pakistan in 1971, a new State oil Company, Bangladesh Oil and Gas Corporation (Petrobangla), was established in 1972 to promote and regulate petroleum activities in Bangladesh either on its own or in joint ventures with foreign parties.

In 1985, Petrobangla was re-organised and formally renamed the Bangladesh Oil, Gas and Minerals Corporation (BOGMC) as a public sector holding corporation with eleven subsidiary companies. BOGMC coordinates, supervises and controls its subsidiaries in exploration, production and distribution and are under the direct control of the Ministry of Energy and Natural Resources. The organisational setup of BOGMC (Petrobangla) is illustrated in the organisation chart, see Figure 53.

Figure 53: Petrobangla Organisational Structure.

Source: Petrobangla Annual Report 2016

5.1.2 State Upstream Companies

BAPEX

BAPEX was formed in 1989, by abolishing the Exploration Directorate of Petrobangla with purpose of accelerating the exploration of oil and gas within the country and to undertake drilling operations. In 2000, BAPEX was turned into an exploration and production company and given permission to go into production alongside with its exploration activities. Against this backdrop BAPEX was registered as an exploration and production company in 2002.

BAPEX currently employs around 720 (2016) but has in its organisation structure room for 1800 employees. BAPEX owns three drilling rigs and two workover rigs and offers geophysical, geological and laboratory services.

BAPEX produces nearly 130 MMCFD from Shaldanadi, Shahbazpur, Fenchuganj, Semutang, Begumganj, Shahzadpur-Sundulpur and Srikail gas Fields. Since its start, BAPEX has successfully completed work-over operations of 27 wells, drilling of 8 exploration wells and 21 development wells. Out of the 8 exploration wells, 5 gas fields have been discovered.

Under Bangladesh Offshore Bidding Round in 2012, two production sharing contracts (PSCs) have been concluded with ONGC Videsh Ltd. (OVL) and Oil India Ltd. (OIL) for shallow-sea blocks SS-4 and SS-9 (Figure 54), and one PSC with Santos Sangu Field Ltd. and KrisEnergy Bangladesh Ltd. for shallow-sea block SS-11. The Government of Bangladesh has nominated BAPEX as stakeholder carrying 10 percent interests for these blocks. A joint operating agreement was signed with Santos Sangu Field Ltd and KrisEnergy Bangladesh Ltd on 18 June 2016. Signing of a joint operating agreement with ONGC Videsh Ltd. (OVL) and Oil India Ltd. (OIL) is in the offing.

Participating in an international open tender, BAPEX obtained a contract for drilling Bangora 6 and 7 development wells which fall under KrisEnergy, the operator of PSC block 9.

Bangladesh Gas Fields Company (BGFCL)

The Bangladesh Gas Fields Co. Ltd. (BGFCL) was registered in 1956 and was owned by Shell until the mid-seventies, when Shell sold it to the Government of Bangladesh. BGFCL became a public limited company in 1996. The company owns six gas fields - Titas, Habiganj, Bakhrabad, Narsingdi, Meghna and Kamta. During 2014-15, approx. 300 bcf of gas and 180,000 barrels of condensate, extracted as by-product from the gas, were produced by the Company, which amounts to around 35% of Bangladesh’s total gas production.

As per latest report of Petrobangla, total recoverable gas reserve of 6 fields under the company is about 12.3 tcf, out of which 7.1 tcf or about 58 % was recovered till 30 June 2015.

The Titas gas field represents 65% of BGCFL’s total production and is the most important field in Bangladesh. Gas is produced from 26 wells and due to the requirement to meet the domestic gas demand, the field is kept running flat out at almost full capacity. This has led to little reservoir data being gathered over the field life of some 35 years. Water production has risen in line with gas production.

Completed recent projects include appraisal of gas fields with 3D seismic data. The objective of the project was to determine the gas reserve, delineate the overall geological features as well as the structural extent of Titas, Bakhrabad, Sylhet, Kailashtila and Rashidpur gas fields by conducting 3D seismic survey. Under BGFCL part of the project, 335 km^2 field level 3D seismic survey over Titas structure was completed. Based on this, drilling of 11 new wells has been proposed at Titas gas field in 2013. Among the proposed 11 wells, drilling of Titas 18, 23, 24, 25, 26, 27 has been completed.

210 km^2 field level 3-D seismic surveys over Bakhrabad structure were completed and upon completion of data processing and data interpretation, final survey report was submitted on 18 March 2014. In the report, drilling of 3 new wells at Bakhrabad gas field has been recommended. Among these, 1 well (BKB#10) has been drilled.

Sylhet Gas Fields Limited

Sylhet Gas Fields Limited (SGFL), a company of Bangladesh Oil, Gas and Mineral Corporation (PETROBANGLA) under the Ministry of Power, Energy and Mineral Resources is the pioneer in the discovery and production of natural gas and mineral oil in the country. Though this Company was incorporated on 8th May 1982 under companies Act 1913, its history of production and sale of natural gas dates back to 1960 under the umbrella of its predecessor, erstwhile Pakistan Petroleum Limited (PPL) which discovered gas at Sylhet Well No. 1 at Haripur in Sylhet District in 1955. It was the first hydrocarbon discovery in the Country.

At present, the Company has under its umbrella 5 gas fields, namely Sylhet (Haripur), Kailashtilla, Rashidpur, Beanibazar and Chhatak with 12 producing gas wells (1 at Sylhet, 4 at Kailashtilla, 5 at Rashidpur and 2 at Beanibazar) which produce an average of 140 mmsfd of gas. SGFL shares about 6% of country’s total gas production. In the FY 2014-15, SGFL produced 54 bcf of gas and 225696 barrels of condensate and 173730 barrels of NGL. The company also produced 980130 barrels of finished petroleum products – petrol, diesel and kerosene – by fractionating natural gas-condensate from its own fields and Bibiyana Gas Field operated by Chevron Bangladesh.

The company has been implementing various development projects with the objective of diversifying its activities and enhancing gas production capacity. The ongoing projects are: (i) Installation of 4000 BPD capacity Condensate Fractionation Plant at Rashidpur, (ii) Installation of 3000 BPD capacity Catalytic Reforming Unit (CRU) at Rashidpur to convert Petrol into Octane, (iii) Drilling of well no. Kailashtilla-9 (Appraisal/ Development Well), (iv) Drilling of well no. Sylhet -9 (Appraisal/ Development Well), (v) Reviewing of 3D Seismic Survey data and reports of Sylhet (Haripur), Kailashtila & Rashidpur Structures of SGFL & (vi) Workover of 3 wells (KTL-1, RP-2 & 6) under SGFL.

5.1.3 International Oil Companies currently operating (IOC)

Chevron

Chevron has the capacity to supply 50% of the natural gas produced in Bangladesh. Chevron merged with the American company Unocal in 2005 and thus acquired its gas fields from Unocal. All the natural gas and condensate that Chevron produces in Bangladesh is sold to Petrobangla, the national oil company. Through Chevron subsidiaries, the company operates three fields; Bibiyana, Jalalabad and Moulavi Bazar, under production-sharing contracts signed with the Government of Bangladesh, represented by the Ministry of Energy & Mineral Resources and Petrobangla. In 2015, net daily production averaged 1,400 MMCFD of natural gas and 3,000 barrels of condensate produced with the natural gas.

Chevron operates the Bibiyana Field in Block 12 (Figure 54). In late 2014, the company announced the start of production at the Bibiyana Expansion Project. The project includes two gas processing trains, additional development wells and an enhanced liquids recovery facility and has a capacity of 300 MMCFD of natural gas and 4,000 barrels of condensate per day. The liquid recovery facility started up in the first quarter of 2015.

Chevron operates the Jalalabad gas field in Block 13 which is currently the third highest gas producer in Bangladesh. Discovered in 1989, it went into production in 1999. Chevron produces natural gas from the Moulavi Bazar gas field in Block 14. It was discovered in 1999 and came on-line in 2005.

In April 2012, Chevron launched the Muchai compression project which supports additional production from the Bibiyana, Jalalabad and Moulavi Bazar natural gas fields.

In 2017, it was announced that Chevron intents to sell its interests to Himalaya Energy. Himalaya Energy is owned by a consortium comprising state-owned China ZhenHua Oil and the investment firm CNIC Corp. The deal is currently under the consideration of the Bangladeshi Government and awaits its approval.

Santos Sangu Fields Limited

In 2010, Australia’s Santos acquired the interest of Carin and has the operatorship of the offshore Sangu field wherefrom production since 1 October 2013 has been suspended. Santos has launched an exploration targeting the offshore Magnama structure under a joint venture with BAPEX. Magnama is situated close to Sangu in offshore Block 16 (Figure 54) and may hold 1.5 tcf of gas in place. A recent exploration well on the structure reportedly was dry suggesting that no significant resource is present in the structure. The Consultants have not seen details on the assessment nor the drill data. Santos holds a 51% operated interest at Sangu, with Bapex owning the remaining 49% stake.

In March 2014, Santos was awarded a 45% interest and operatorship in Block SS-11 PSC (in joint operation with KrisEnergy [45%] and BAPEX [10%]). The majority of the block lies in shallow waters up to 200 metres with the furthest southwest portion extending into water depths up to 1 500 metres. Block SS-11 is adjacent to the Bangladesh/Myanmar maritime boundary and is north of the about 9 tcf Shwe large gas field situated in Myanmar. The Shwe field was discovered in 2004 and began production in 2013.

KrisEnergy

KrisEnergy Asia Holdings BV acquired Tullow Oil in 2013 and has a production capacity of 110 MMCFD in 2015 from 5 wells from the Bangura gas field in Block 9, Ref. Figure 54, onshore Bangladesh.

ONGC Videsh

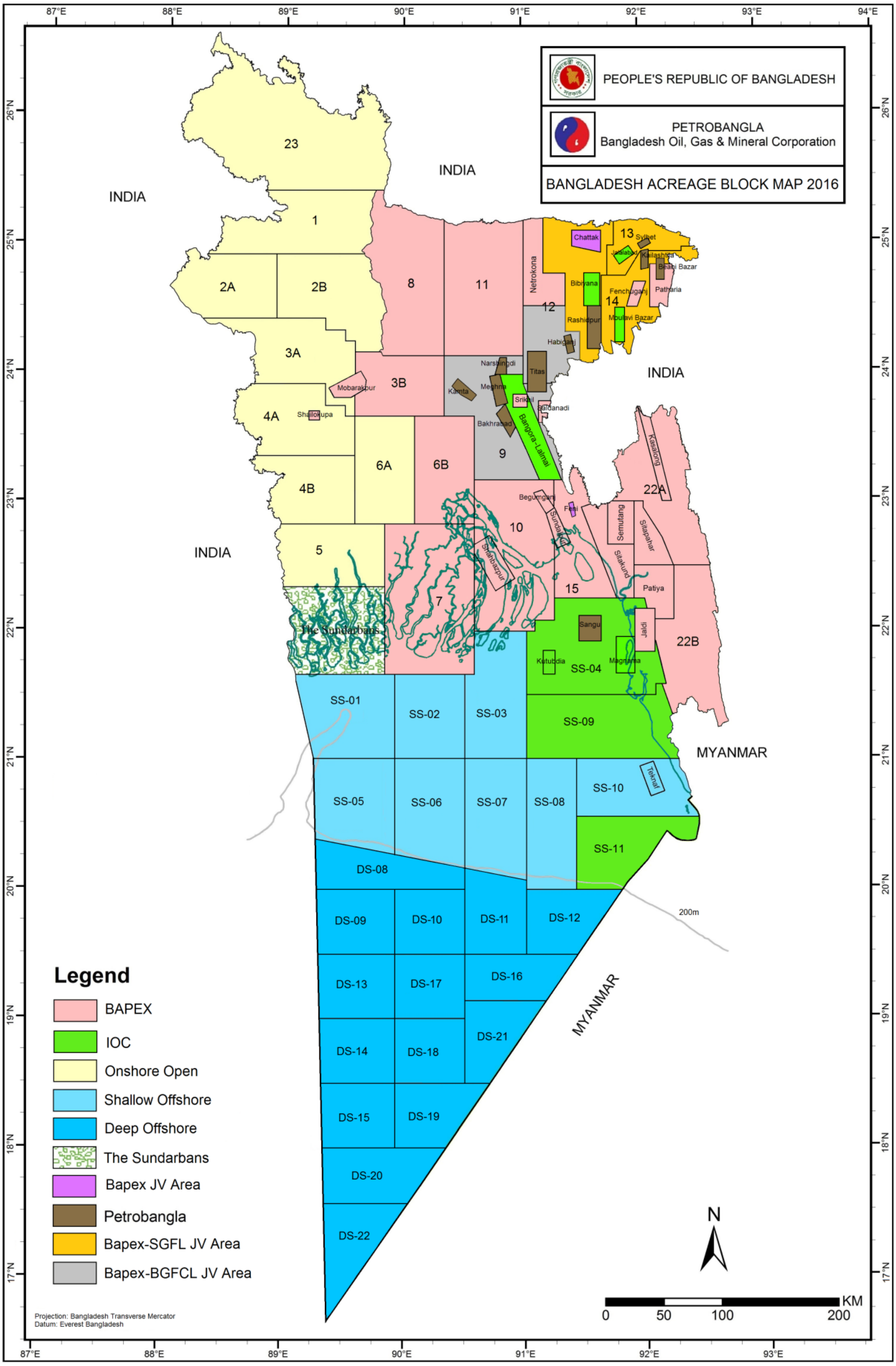
ONGC Videsh is a wholly owned subsidiary of Oil and Natural Gas Corporation Limited, the national oil company of India, and is India's largest international oil and gas E&P Company. ONGC Videsh operates Blocks SS-09 and SS-04 and holds a 45% interest in the production-sharing contract. Partners are Oil India Ltd. 45% and BAPEX 10%.

The company had completed a 2D seismic survey over two Bay of Bengal blocks last year (2016) and plans to drill the first of two commitment wells on Block SS-09 near Moheshkhali Island during 2017.

Posco Daewoo

Posco Daewoo is a fairly new player to the oil & gas business in Bangladesh. The company recently signed of PSC with a first entry into exploration phase 1 in March 2017 for Offshore Block DS-12 (100 % equity operator over Acreage of 3,560 square kilometres). As per the agreement, two-dimensional seismic survey would begin this year, and based on the outcomes of the survey, the real picture of gas availability could be known by 2019. According to public available information, the Korean company would spend $3-5 million for carrying out a two-dimensional survey, USD5-7 million for a three-dimensional survey, and USD50-100 million for drilling wells.

Figure 54: Licence Map.



Source: Petrobangla Annual Report 2015.

5.1.4 Exploration & Licensing

A comprehensive review of the exploration and licensing from 1950 and up to 2006 is presented in the GSMP (2006). The development since 2006 is presented in the report "Bangladesh Gas Sector Update" and relevant yearly reports from Petrobangla. Together, these reports provide the basis for the analysis of the exploration program laid out by both the Public and Private Sectors to enhance gas reserves. In addition, these reports together with data gathered from questionnaires provided to Petrobangla for completion form the basis for the recommendations to enhance efficiency and results.

Early Years

Petroleum exploration in Bangladesh, then part of India, started in 1914, with Burmah and IPPC drilling two wells each at Sitakund region, 30 km north-west of the district of Chittagong. Of the four, relatively shallow wells, three recorded gas shows. During the next 37 years, the only drilling activity was the spudding of two wells by Burmah in 1933. Patharia-1 and -2 were located in the very north-east of what is now Bangladesh, but again encountered only gas shows. At this time, exploration was based on surface geology and drilling near proven surface seeps.

<u>1950-1990s</u>

A spurt of activity occurred in the late 1950s and early 1960s when the Rashidpur, Kailashtilla, Titas, and Habiganj fields were discovered by Shell between 1960–1963. There was little drilling activity through the 1970s as the newly formed state of Bangladesh established a national oil company, Bangladesh Oil and Gas Corporation (Petrobangla), to oversee the country's petroleum sector. Petrobangla was later re-organised into Bangladesh Oil, Gas and Mineral Corporation, (BOGMC). Along with the formation of Petrobangla, the government passed the Bangladesh Petroleum Act 1974, to promote activity and six offshore production sharing contracts were signed that year. The companies who signed were: ARCO, Ashland, Canadian Superior Oil (CSO), Bengal ODC, INA, and Union Oil. All of these contracts were relinquished by 1978, following a combination of unsuccessful drilling, poor incentives and political uncertainty. The only success was the discovery of the offshore Kutubdia gas field by Union Oil (later named Unocal, now Chevron).

In the 1980s there was sporadic activity with only one or two wells being drilled each year. The 1980s saw the introduction of Production Sharing Contracts (PSC) with the first being signed by Shell in 1981 and the second by Scimitar in 1987. A new model of the PSC was introduced in 1988, which was followed by a licensing round later that year, in which the country was divided into twenty-three blocks. The round was unsuccessful, with only Texaco/Unocal JV expressing serious interest.

During the beginning of the 1990s, representatives from IOC started to show interest in exploration in Bangladesh. As a result, PSCs for eight blocks were signed with four companies (Occidental, Cairn, Okland/Rexwood and United Meridian).

Cairn was the first company to sign a PSC covering Block 16, including the rights to the offshore Kutubdia gas field. Three further PSCs were signed in 1995. Cairn signed a PSC for Block 15 including the development rights to the Semutang field, and two PSCs were signed by Occidental, the first covering Block 12 and the second covering Blocks 13 & 14, the latter including development rights to the Jalalabad field in Block 13.

A further six companies or joint ventures signed Memorandum of Understandig (MoU) with Petrobangla. These included: United Meridian, McKinzie Int'l. Co., Total, Stellar Oil and Okland/Rexwood. The MoUs were signed for a period of 6-9 months, in which the company could make a technical review of the block before committing to a contract. In 1997, PSCs for Blocks 17 and 18 were signed in by an Okland/Rexwood consortium and Block 22 by United Meridian.

Second Exploration Licensing Round: 1997 to 2006

After considerable delays during 1996, bidding on Bangladesh's long-awaited second exploration licensing round was opened by the government in mid-March 1997. Although the bidding round officially closed on 15 July 1997, with final contract signings scheduled for 15 December 1997, it was not until late July 1998 that the first awards were confirmed.

All of Bangladesh's remaining open acreage had been open to bidding as a part of this round, although several existing fields, all located within blocks 9 and 10, were excluded from the bidding. These included Kamta, Bakharabad, Meghna and Salda Nadi in Block 9 and Begumganj and Shahbazpur in Block 10.

An analysis of the bidding process highlighted the demand for blocks 9 and 10, with these receiving seven and six bids, respectively. Overall, a total of 37 bids were submitted on 12 of the 15 blocks on offer. Bids were submitted by 21 companies (including Bangladesh state exploration company BAPEX). The greatest number of bids came from the Cairn/Shell joint venture with four applications for a total of six blocks.

Despite the lengthy delay, the government confirmed the award of only five blocks in its 26 July 1998 announcement. This was seen as a direct result of the Bangladeshi objective of sharing blocks amongst bidders, placing the greater emphasis on ensuring no company dominated the upstream sector, rather than awarding blocks based on the individual merits of each bid.

Successful bidders in the second round were Cairn Energy and Shell in Block 5 and Block 10; Triton, Unocal, and PTI Oil and Gas in Block 7. Blocks 1, 2 and 23 received no bids, while no licenses were awarded for blocks 3, 4, 6, 8 and 21.

BAPEX took part in the round as a carried partner (10%) with Unocal in Block 10 and with Petronas and Mobil in Block 9. Later, the government decided to hold a 10% carried interest for BAPEX in all the awarded blocks.

Third licensing Round: 2008-2012

The Offshore Bidding Round 2008 was limited to newly-formed deep water blocks and attracted some bids. However, the ensuing maritime boundary dispute in most of the blocks created a stalemate. In this backdrop, two blocks were negotiated with Conoco Phillips and a PSC for 2 blocks were signed in 2011. Conoco Phillips completed the initial seismic survey in the blocks. They relinquished these blocks in 2014 without drilling any exploratory well.

Fourth licensing Round: 2012-2016

Following the delimitation of the maritime boundary between Bangladesh and Myanmar by the International Tribunal for the Law of the Sea (ITLOS) in March 2012, Petrobangla realigned the blocks considering the new boundary and announced a bidding round in December 2012. Substantial initial response was received. Under this round, 3 PSCs for shallow sea blocks have been signed. ONGC Videsh, Oil India and BAPEX joint venture has signed 2 PSCs for blocks SS-04 and SS-09. On the other hand, Santos, KrisEnergy and BAPEX joint venture has been contracted for block SS-11. Seismic surveys of all these blocks are in progress.

Petrobangla has planned to conduct 2D Non-Exclusive Multi-Client Seismic Survey in the offshore area of Bangladesh to provide the oil and gas industry with 2D Non-Exclusive Multi-Client Seismic data of the offshore areas. Bids were invited in December 2015. However, signing of agreement with successful bidder is awaiting approval of the Government. Bidding for deep sea blocks DS-12, 16 and 21 has been initiated by the Government. After evaluation of EOIs, Request for Proposal (RFP) has been sent to 3 short-listed companies.

Since the signing of the PSCs, several changes in ownership and restructuring in the contracts have taken place. All of the onshore PSCs have matured from the exploration phase to the production phase and major areas of the blocks have been relinquished. As of December 2015, PSCs are active in production areas of blocks 12, 13 and 14 with Bibiyana, Jalalabad and Moulavi Bazar gas fields operated by Chevron, and block 9 with Bangura Gas Field operated by Tullow.

Efforts to kick-start offshore exploration have generally been thwarted by PSC terms held to be unacceptable by its IOC partners. ConocoPhillips exited deep water licences DS-10 and 11 despite 2D seismic data reportedly indicating the acreage could hold 6-7 tcf (170-200 bcm) of reserves, according to Energy Bangla (this report has not been available to Contractors). A subsequent review of the PSC conditions led to formulating a new offer for 2016 exploration bidding round.

Table 13: Summary of PSC of past exploration bidding rounds.

Bid Round	Summary
1974	6 PSCs were signed for 6 blocks Block no: IOCs Offshore: Union Oil (Unocal) Offshore: Atlantic Richfield (ARCO) Offshore: BODC (Nippon Oil) Offshore: Ina Napthalin Offshore: Ashland Oil

	Offshore: Canadian Superior Oil Company (CSO)
	No bids received
1993	6 PSCs were signed for 8 Blocks Block no: IOCs 15 : Cairn Energy/ Holland Sea search 16 : Cairn Energy/ Holland Sea search 12 : Occidental 13&14 : Occidental 17&18 : Rexwood-Okland 22 : United Meridian Inc. Result: Discovery of Sangu, Moulovibazar, Jalalabad and Bibiyana gas field.
1997	4 PSCs were signed for 4 blocks Block no: IOCs 5 : Shell & Cairn 7 : Unocal 9 : Tullow & Chevron-Texaco 10 : Shell & Cairn Result: Discovery of Bangora gas field in Block 9.
2008 Bangladesh Offshore Bidding Round	1 PSC was signed for 2 blocks Block: DS-08-10 & DS-08-11 IOCs: ConocoPhillips Bangladesh Exploration 10/11 Ltd.
2012 Bangladesh Offshore Bidding round	3PSC were signed for 3 blocks Block no: IOCs SS-04 : ONGC Videsh-OIL-BAPEX SS-09 : ONGC Videsh-OIL-BAPEX SS-11 : Santos-KrisEnergy-BAPEX
1st Phase of 2016 (under special act)	1 PSC signed with POSCO Daewoo Corporation for block DS-12
2nd Phase of 2016 (Under special act)	3 EOIs from POSCO Daewoo, KrisEnergy & Statoil received for DS-10, DS-11 & SS-10. None of them submitted proposal.

Source: Petrobangla

5.1.5 Seismic data

A detailed review of the seismic data base is presented by Gustavson (2011) (Figure 55). According to this report, the Pakistan Petroleum Ltd. initiated seismic data acquisition in Bangladesh in 1955 primarily in the greater Sylhet district. SVOC and Shell's seismic campaign started in 1957. In 1963, OGDC started acquisition of seismic data. All these data were singlefold, analogue coverage. Approximately 7 000 kilometres of the pre-1971 seismic data are still available.

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

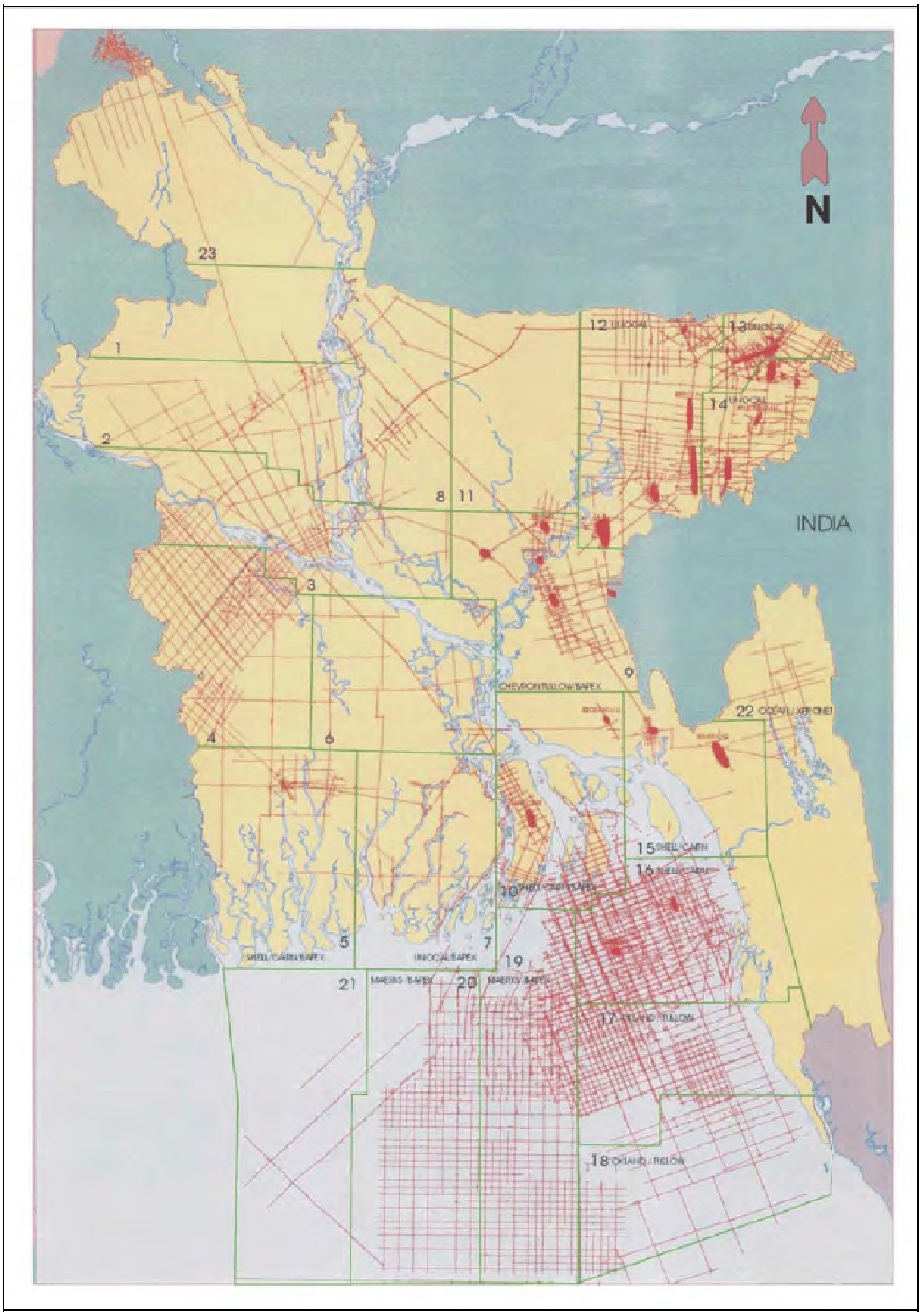
From the early nineties, there was an increase in seismic activity when Cairn Energy started acquiring data within Blocks 16 and 17 and Occidental in Blocks 12, 13, and 14. Occidental acquired 3-D surveys across both Bibiyana and Moulavi Bazar. Both Okland Oil and United Maridian Corporation (UMC) acquired seismic data. In 2003-2004, Tullow acquired 573 line-kilometres of 2-D data across the Bangora-Lalmai Anticline. They also acquired a 3-D survey of their PSC block in 2003.

Additional 3-D surveys have been acquired, are in the process of being acquired, or are proposed both onshore and offshore. NIKO, on behalf of their Joint Venture with BAPEX, acquired 3-D surveys across Feni and Chattak fields. Acquisition of 3-D surveys of 3320 Sq. Km has been completed over Sylhet, Kailashtilla, Rashidpur, Saldanadi, Sunetra, Shahbazpur, Begumganj-Sundalpur, Nassingdi and Mubarakpur structures, in order to seismically identify new pay sands and better delineate the areal distribution of existing pay sands.

Of newer projects (Table 14), BAPEX will conduct 3 000 km 2D seismic survey under proposed project named “Rupokalpo 9: 2D Seismic Project” from April 2017 to June 2019.

In early June 2017, BAPEX has called for Expressions of Interest (EoI) for the acquisition, processing and interpretation of a 3000 Line-km of 2D seismic survey over Exploration Blocks 3B, 6B and 7 (SI #11 in Table 14). The procurement of multirole survey vessel is therefore under process for the offshore exploration which will enhance the coverage as well as new prospect identification for future demands.

Figure 55: Seismic coverage of Bangladesh.



Source: Gustavson 2011.

5.1.6 Drilling data

According to the data available for analysis by the Consultants, 81 exploration wells were drilled between 1910 and 2014 (Ref. Figure 56). Of these exploration wells, a total of 21 wells were drilled offshore. This exploration well count, seen in comparison to the over 207 000 km^2 of sedimentary basins currently identified within Bangladeshi territory, represent an extremely low drilling density in comparison to many other countries. The wells have been typically drilled to approximately 3.3 km and have been targeting reservoirs of Miocene age. The Petrobangla Atgram-1 well is the deepest well in Bangladesh to date and it reached a TD of 4.9 km in 1982.

For the exploration wells, the average discovery rate is 36%, 12% contained shows and 52% of the wells were reported to be dry. In overall terms, the general average discovery rate means that a discovery is made for every third well drilled, and thus Bangladesh appears very favourable for the exploration of hydrocarbon accumulations based on the historical success rate. However, most of the discoveries are very small, and thus the discovery rate of significant and important fields in terms of gas volume is much lower.

The most extensive drilling period after a peak in the early 1990'ies was in the late 1990'ies to early 2000. After a peak in exploration drilling in 2004, the well count has been very low and almost stagnant. However, exploration activities got a momentum as in 2009. Since then, a number of new gas structures have been delineated, 8 exploration and 43 development wells have been drilled and workover of 18 wells have been completed.

However, Petrobangla's ambition towards 2021 is to increase their activities and a series of projects involving drilling of 53 exploratory wells, 35 development wells and workover/remedial of 20 wells by BAPEX is currently approved or in the process of approval (Ref. Table 14). Assuming that all exploration wells by BAPEX are to be drilled in the period 2016-2021, this means that the drill rate will be close to 9 exploration wells per year. Such high drill numbers have never been realised before in the oil and gas history of Bangladesh and will if fully implemented, raise the total exploration well numbers with 164%.

Data on the commitment by IOC on drilling are currently under questioning by the Consultants.

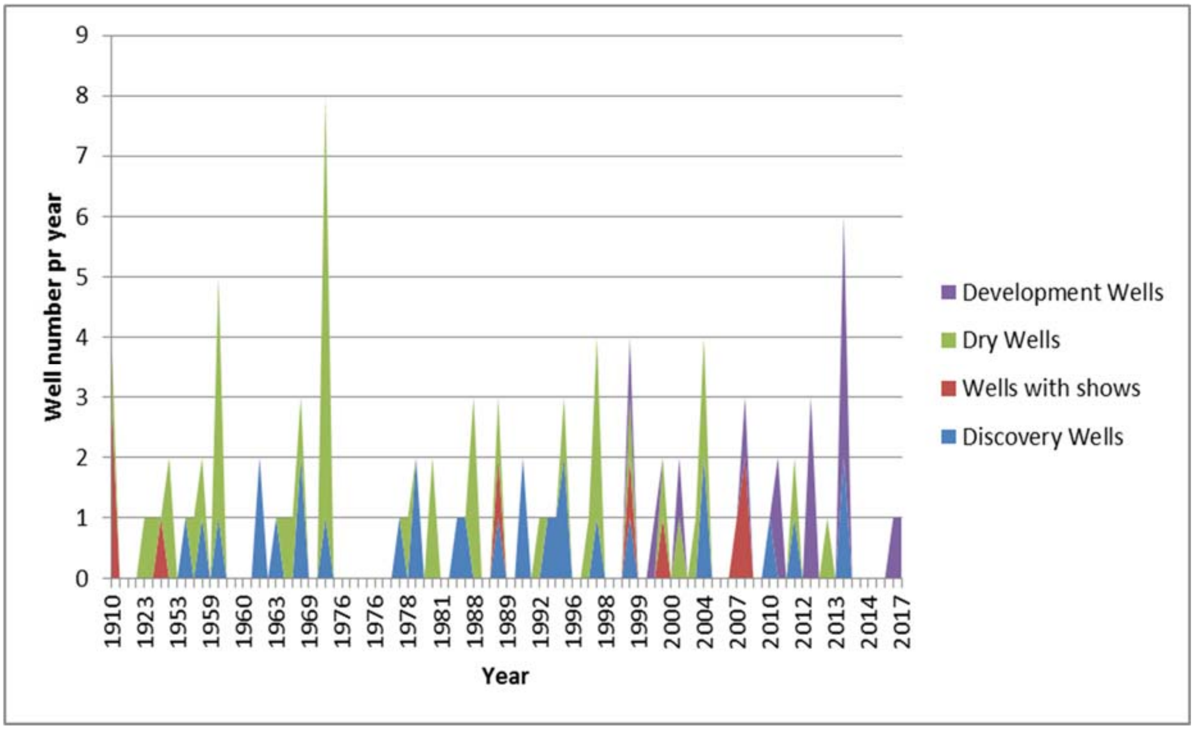
Table 14: Project and status of wells and their purpose.

Sl No	Project Title	Approval Status
1	Rupkalpa-1 Drilling Project: three Exploratory well (Haraganj-1,Srikail East-1 & Salda North-1) Two Development Well (Srikail North-2 , Kashba-2)	Approved
2	Rupkalpa-2 Drilling Project: Four Exploratory well (Saldanadi South-1, Semutang South-1, Batiachar-1, Saldanadi East-1)	Approved

3	Rupkalpa-3 Drilling Project: Four Exploratory well (Kasba-1, Madarganj-1, Jamalpur-1, Shailkupa-1)	Approved
4	Rupkalpa-4 Drilling Project: Two Exploratory well (Shahbazpur East-1, Bhola North-1) Two Work-over Well (Shahbazpur-1,2)	Approved
5	Procurement of one Drilling and one Work over Rig with Supporting Equipment for BAPEX	Approved
6	Rupkalpa-5 Drilling Project: Two Exploratory well (Srikail North-1, Mubarakpur South East-1), One Appraisal cum Development well (Begumganj-4) and one Workover (Begumganj-3)	Approved
7	Rupkalpa-6 Drilling Project: 3 Exploratory Wells (Sariatpur-1, Madan-1 and Sunetra-2)	Approval Process
8	Rupkalpa-7 Drilling Project: 3 Exploratory Wells (Dupitila-1, Zakiganj-1 and Patharia West-1)	Approved
9	Rupkalpa-8: Equipment Procurement Project (Procurement of Exploration and Production Supporting Equipment for Bapex)	Approved
10	Rupkalpa-9: 2D Seismic Project	Approved
11	2D Seismic Survey Over Exploration Block 3B, 6B & 7. (Under Approval Process)	Approved
12	Rehabilitation of Gardner Denver E 1100 (IPS) RIG Project.	Approved
13	TAPP (Technical Assistance Project Proposal): “Engagement of Consultancy Firm for Procurement of Multi-Role Offshore Survey Vessel”.	Under Approval

Source: Petrobangla

Figure 56: Bangladesh exploration drilling history: 2010-2014. Development wells before 2010 are not shown.



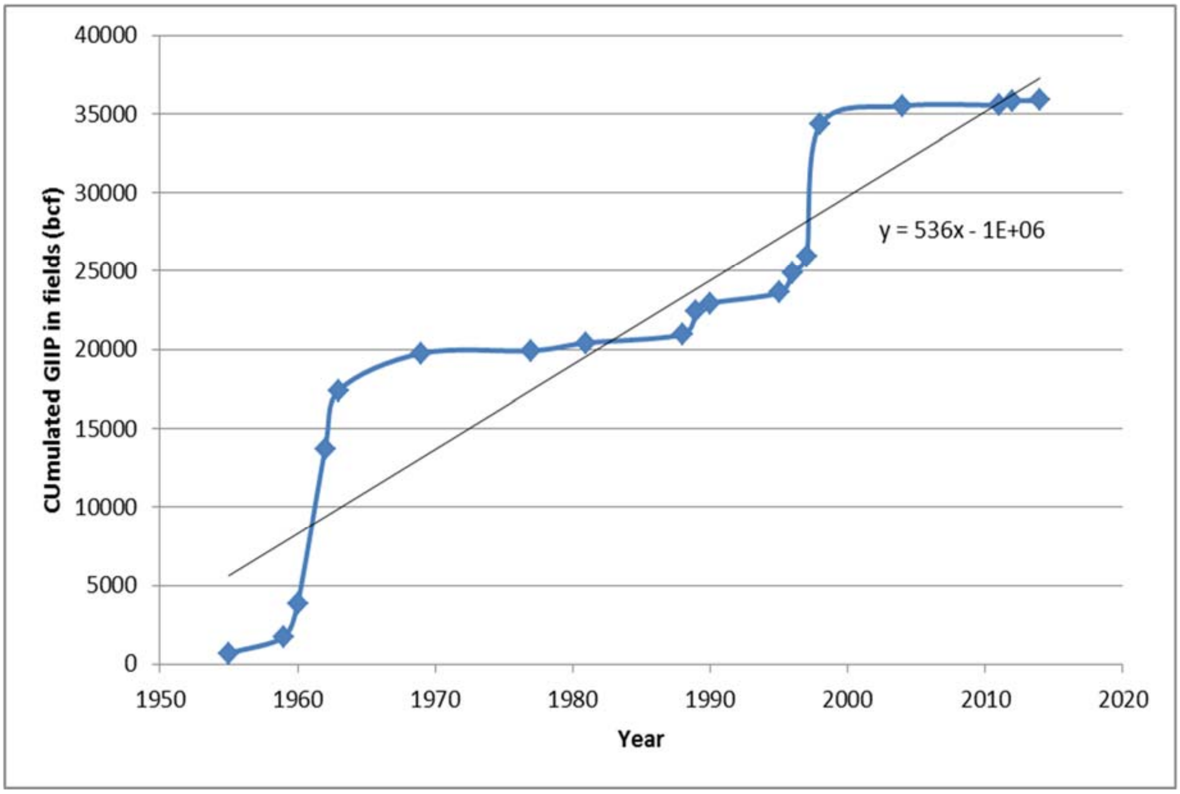
Source: Petrobangla, Gustavson 2011.

5.1.7 Growth trajectory of GIIP in fields

The growth of the volume of Gas Initially In Place (GIIP) versus time from all the discoveries show an increase from 0 tcf from the mid 1950'ies to more than 35 tcf in 2012 (Ref. Figure 57). The Consultants are aware that not all discoveries made in Bangladesh may have been available to The Consultants for the analysis presented in Figure 57. The data available show that the most recently discovered field contributing to the total GIIP estimate for Bangladesh is from 2011/2012.

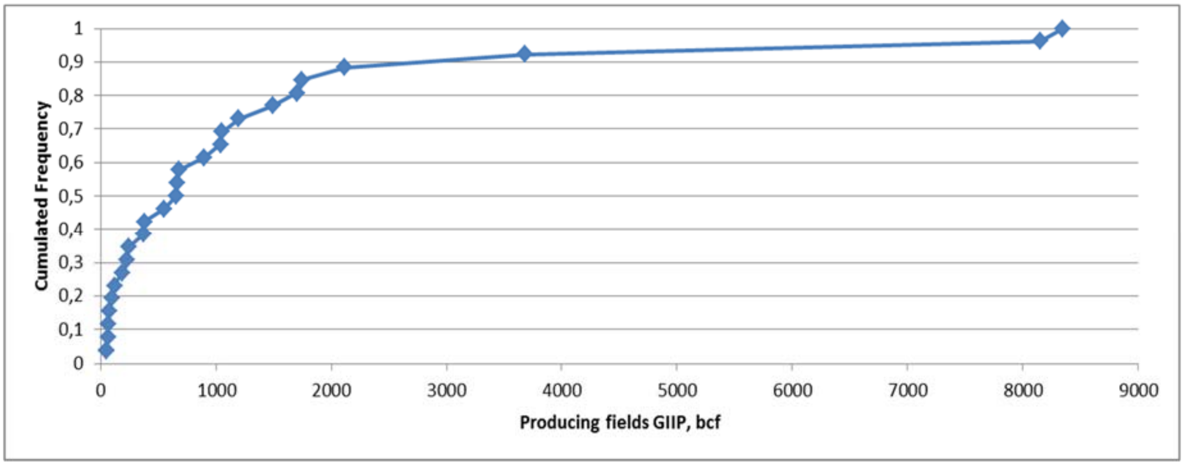
The growth curve is very irregular over the time period and notably two-time periods stand out. During the 1960'ies, the cumulated GIIP of discovered fields rose from 4 tcf to nearly 20 tcf with the discoveries of the Titas, Habiganj, Bakhrabad, Kailashtilla and Rashidpur fields. The second period of rapid growth in the cumulated GIIP was in 1998 with the discovery of the Bibiyana field. Since then, discoveries of new fields have not led to significant gas resources being added to the known GIIP.

Figure 57: Discovery ages and cumulated GIIP gas resource. Data from Table 16. The Average growth per year from 1960-2016 has been 500 bcf per year.



Source: Petrobangla

Figure 58: Size distribution of the Gas Initially In Place (GIIP) of the 26 discovered fields.



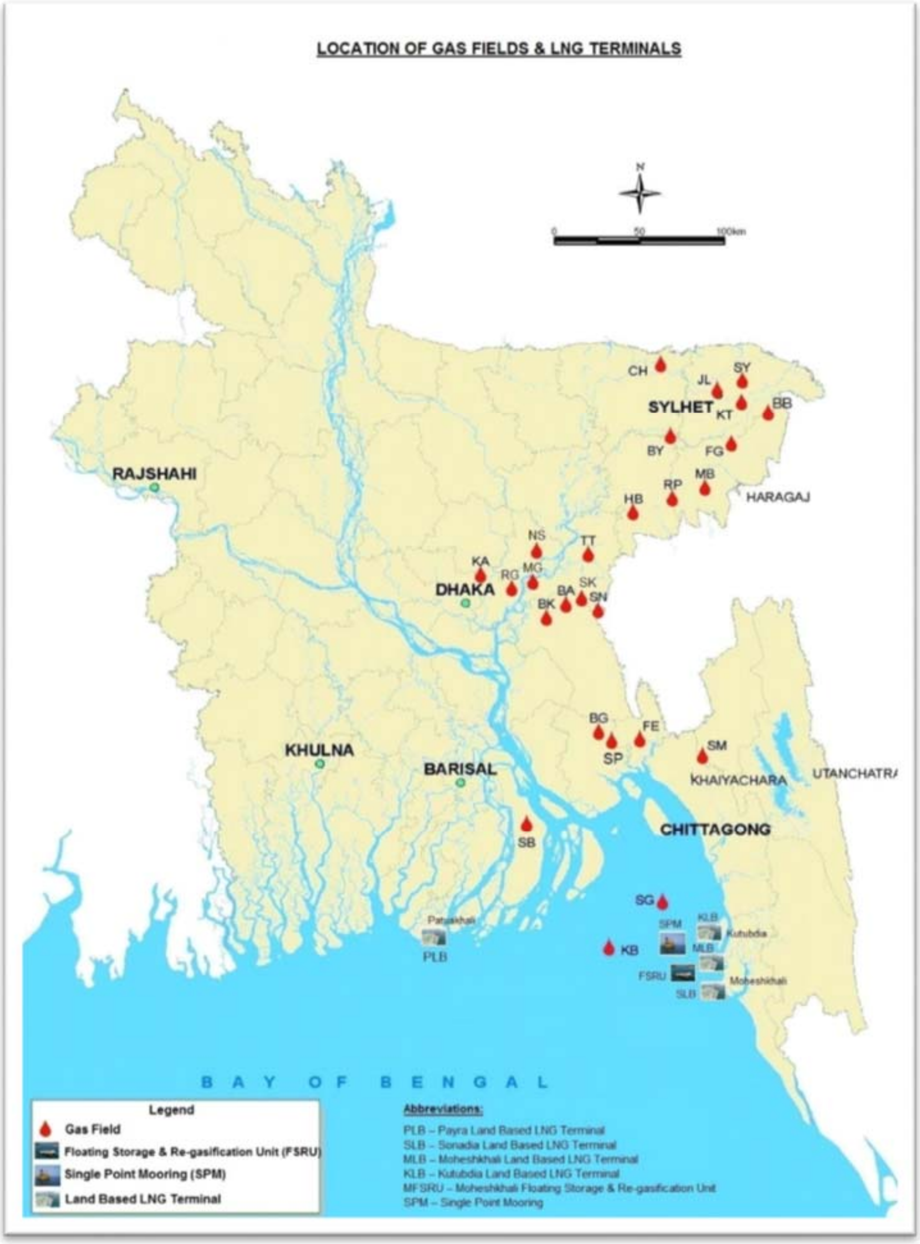
Source: Petrobangla

From the data available to the Consultants (Ref. Table 16), it is clear that most of the 26 fields in Bangladesh are small with respect to its GIIP value (Ref. Figure 58). The cumulated GIIP of the smallest 13 fields thus amounts to only 8% of the total GIIP for all 26 fields. On the other hand, the cumulated GIIP of the largest 10% of the fields amounts to 56% of the cumulated GIIP. In terms of probability - density relationships then the P90 of the fields is 65 bcf, the P50 is 654 bcf, the P30 is 1 000 bcf and the P10 is 2 800 bcf (Ref. Figure 58).

With respect to future exploration activities, it implies that given a discovery is made randomly [from a selection of prospects and leads], then there is a 50% chance that it will contribute with more than 654 bcf but also a 50% chance that is will contribute with less than 654 bcf. It will also be expected that there is a 30% probability that the prospect will contain at least 1 tcf. These calculations assume that the field sizes occur randomly and only serve to illustrate the nature of the field size distribution.

If on the other hand the selection of prospects and leads available are not randomly picked but sorted and ranked according to risked GIIP sizes, the likelihood of delivering higher GIIP field sizes increase. However, since all prospects and leads are related with a probability of success the risk of a dry well may or may not increase by aiming at more high GIIP fields.

Figure 59: Location of producing fields and LNG terminals.



Source: Petrobangla

5.2 Gas reserve position

5.2.1 Overview

A total of 26 fields are recognised in Bangladesh (Ref. Figure 59, Table 15 and Table 16). Since the GSMP (2006) study, a large number of reserve studies have been made on the Bangladesh fields either using a deterministic material balance approach or a probabilistic gas reserve approach such as the one followed by Gustavson (2011). The most comprehensive study of the latter approach available to the Consultants is presented by Gustavson (2011). This report also presents the geology of the fields, available data including maps and limited reservoir pressure data.

Since the Gustavson (2011) study, new seismic data have been gathered and better imaging of new and existing fields has been made, and as a consequence this has enabled better reserve models to be made. For this study, however, no detailed reports of these newer studies and reserve models have been made available to the Consultants with latest request for data. The Consultants provided Petrobangla with an integrated questionnaire (see Appendix 8) requesting this to be completed by its relevant Departments and Subsidiaries. Based on completed questionnaire-responses on the topic and to the best extend of available data and information, the Consultants have attempted to include the results from these studied in the current review for the revision of the Gas Section Master Plan.

5.2.2 Reserves Summary

It is not the purpose of the Consultants to perform another reserve study or reserve certification, but rather it is the purpose to review the available reports and prepare proved, probable, possible and Yet-to-Find (YTF) production forecasts for the three demand forecasts (Case A, B & C) in a similar manner as was done in the GSMP (2006) in order to evaluate whether there is likely to be enough gas to meet future demand.

A summary of the reserves developed since the GSMP (2006) updated to the most current estimates are presented in Table 15. In 2006, the latest reserve estimation performed by HCU in 2004 was used. At that time, the estimates of the GIIP of Bangladesh was 28.4 tcf distributed in 22 gas fields with a corresponding recoverable reserve estimated (2P) of 20.5 tcf (Ref. Table 15).

In the reserve studies summarised and presented in the yearly reports by Petrobangla, the GIIP from 26 fields (four additional to the GSMP 2006 study) in Bangladesh totals 35.8 tcf with a corresponding recoverable reserve (2P) estimated of 27.1 tcf (Ref. Table 15). In a study by SGFL from 2012, new reserves number are presented for the Kailashtilla, Rashidpur and Sylhet fields based on new 3D seismic mapping (Ref. Table 15). The updated reserve significantly reduces the mid-size Kailashtilla and Rashidpur fields from GIIP values around 3.6 tcf each to GIIP values of 1.7 tcf and 2.1 tcf, respectively. The reports for this new GIIP assessment are not available for the Consultants but nevertheless demonstrated the importance in acquiring new data in order to detail the estimation of the resources. The SGFL (2012) estimates are used as in the updated reserve position inventory, which form the basis for the forecasting (Ref. Table 16).

Compared to the GIIP estimates and the reserve position presented in Table 16, the reserve position of almost the same fields has risen by 7 tcf or with 25% compared to the values presented in the GSMP (2006) study (Ref. Table 15). Such reserve growth cannot be expected to continue since there is a finite gas resource in place but highlights the uncertainties that are involved and the need for applying best available data and models when strategic planning is to be made. However, for situations like this where uncertainties on all data aspects exist within the decision process, special care should be made in not making too confident predictions but instead remain as flexible as possible in order to accommodate newer and more accurate data and estimation in the decision process once they are available.

Similar to the recommendation in the GSMP (2006), the update Gas System Master Plan recommends that the Proven + Probable (2P) reserves are used for short and mid-term planning and that the Proven + Probable + Possible (3P) reserves together with undiscovered (Yet-to Find) resources are only used as a guideline for long term strategic planning.

Table 15: Summary of Gas Initially In Place (GIIP), Proved +Probable (2P Reserve) between the GSMP (2006) study and values used in the updated GSMP). Numbers are in bcf gas.

		As presenetd in GSMP 2006					As persented in BAPEX yearly reports					New 3D seimic mapping				
	Field	Reserve estimated company	Reserve estimated year	Gas Initially in Place (GIIP)	Recovery factor (2P/GIIP)	Proved + Probable (2P)	Reserve estimated company	Reserve estimated year	Gas Initially in Place (GIIP)	Recovery factor (2P/GIIP)	Proved + Probable (2P)	Reserve estimated company	Reserve estimated year	Gas Initially in Place (GIIP)	Proved + Probable (2P)	Recovery factor (2P/GIIP)
A. Producing (Dec. 2015)																
1	Titas	HCU	2004	7325	70%	5128	RPS Energy	2009	8149	78%	6367					
2	Habiganj	HCU	2004	5139	75%	3852	RPS Energy	2009	3684	71%	2633					
3	Bakhrabad	HCU	2004	1499	70%	1049	RPS Energy	2009	1701	72%	1232					
4	Kailashtilla	HCU	2004	2720	70%	1904	RPS Energy	2009	3610	76%	2760	SGFL	2012	1748	70%	1224
5	Rashidpur	HCU	2004	2002	70%	1401	RPS Energy	2009	3650	67%	2433	SGFL	2012	2116	70%	1481
6	Sylhet/Haripur	HCU	2004	684	70%	479	RPS Energy	2009	370	86%	319	SGFL	2012	666	70%	466
7	Meghna	HCU	2004	171	70%	120	RPS Energy	2009	122	57%	70					
8	Narsingdi	HCU	2004	307	70%	215	RPS Energy	2009	369	75%	277					
9	Beanibazar	HCU	2004	243	70%	170	RPS Energy	2009	231	88%	203					
10	Fenchuganj	HCU	2004	404	70%	283	RPS Energy	2009	553	69%	381					
11	Shaldanadi	HCU	2004	166	70%	116	RPS Energy	2009	380	73%	279					
12	Shahbazpur	HCU	2004	665	70%	466	Petrobangla	2011	677	58%	390					
13	Semutang	HCU	2004	227	66%	150	RPS Energy	2009	654	49%	318					
14	Sundulpur Shahzadpur				not included		BAPEX	2012	62	56%	35					
15	Srikail				not included		BAPEX	2012	240	67%	161					
16	Jalalabad	HCU	2004	1195	70%	837	D&M	1999	1491	79%	1184					
17	Moulavi Bazar	HCU	2004	449	80%	360	Unocal	2003	1053	41%	428					
18	Bibiyana	HCU	2004	3145	76%	2401	D&M	2008	8350	69%	5754					
19	Bangura				not included		Tullow	2011	1198	44%	522					
20	Begumganj	HCU	2004	47	70%	33	BAPEX	2014	100	70%	70					
	Sum A			**26388**		**18963**			**36644**		**25815**					
B. Non-producing (Dec. 2015)																
21	Kutubdia (Offshore)	HCU	2004	65	70%	46	HCU	2003	65	70%	46					
22	Rupganj				not included		BAPEX	2014	48	70%	34					
	Sum B			**65**		**46**			**113**		**79**					
C. Production suspended (Dec. 2015)																
23	Chattak	HCU	2004	677	70%	474	HCU	2000	1039	46%	474					
24	Kamta	HCU	2004	72	70%	50	Niko/BAPEX	2000	72	70%	50					
25	Feni	HCU	2004	185	70%	130	Niko/BAPEX	2000	185	67%	125					
26	Sangu (Offshore)	HCU	2004	1031	82%	848	Cairn/Shell	2010	900	64%	578					
	Sum C			**1965**		**1502**			**2196**		**1227**					
	Sum A+B+C			**28418**		**20510**			**38952**		**27121**					

Source: Petrobangla

Table 16: Summary of GIIP, Proven, Probable and Possible reserves, Cumulated production (per December 2015), remaining reserves (as per January 2016) and recovery factors 2P/GIIP and 3P/GIIP. Numbers are in bcf gas.

	Field	Year Discovery	Reserve estimated company	Reserve estimated year	Gas Initially in Place (GIIP)	Proved (1P)	Proved + Probable (2P)	Proved + Probable + Possible (3P)	Cum production (Dec. 2015)	Remaining reserve w.r.t. 2P (Jan 2016)	Recovery factor (2P/GIIP)	Recovery factor (3P/GIIP)	Operating Company
A. Producing (Dec. 2015)													
1	Titas	1962	RPS Energy	2009	8149	5384	6367	6517	4040	2327	78%	80%	BGFCL
2	Habiganj	1963	RPS Energy	2009	3684	2238	2633	3096	2191	442	71%	84%	BGFCL
3	Bakhrabad	1969	RPS Energy	2009	1701	1053	1232	1339	789	443	72%	79%	BGFCL
4	Kailashtilla	1962	SGFL	2012	1748	not avaiavle	1224	1398	623	601	70%	80%	SGFL
5	Rashidpur	1960	SGFL	2012	2116	not avaiavle	1481	1693	565	917	70%	80%	SGFL
6	Sylhet/Haripur	1955	SGFL	2012	666	not avaiavle	466	533	208	258	70%	80%	SGFL
7	Meghna	1990	RPS Energy	2009	122	53	70	101	59	11	57%	83%	BGFCL
8	Narsingdi	1990	RPS Energy	2009	369	218	277	299	171	106	75%	81%	BGFCL
9	Beanibazar	1981	RPS Energy	2009	231	150	203	203	91	112	88%	88%	SGFL
10	Fenchuganj	1988	RPS Energy	2009	553	229	381	498	138	243	69%	90%	BAPEX
11	Shaldanadi	1996	RPS Energy	2009	380	79	279	327	84	195	73%	86%	BAPEX
12	Shahbazpur	1995	Petrobangla	2011	677	322	390	488	19	371	58%	72%	
13	Semutang	1969	RPS Energy	2009	654	151	318	375	11	307	49%	57%	BAPEX
14	Sundulpur Shahzadp	2011	BAPEX	2012	62	25	35	44	9	26	56%	70%	BAPEX
15	Srikail	2012	BAPEX	2012	240	96	161	161	40	122	67%	67%	BAPEX
16	Jalalabad	1989	D&M	1999	1491	823	1184	1184	995	189	79%	79%	Chevron
17	Moulavi Bazar	1997	Unocal	2003	1053	405	428	812	282	146	41%	77%	Chevron
18	Bibiyana	1998	D&M	2008	8350	4415	5754	7084	2269	3485	69%	85%	Chevron
19	Bangura	2004	Tullow	2011	1198	379	522	941	323	199	44%	79%	Tullow
20	Begumganj	1977	BAPEX	2014	100	14	70	70	1	69	70%	70%	BAPEX
	Sum A				**33544**	**16033**	**23474**	**27163**	**12909**	**10565**			
B. Non-producing (Dec. 2015)													
21	Kutubdia (Offshore)	1977	HCU	2003	65	46	46	46	0	46	70%	70%	
22	Rupganj	2014	BAPEX	2014	48	-	34	34	0	34	70%	70%	BAPEX
	Sum B				**113**	**46**	**79**	**79**	**0**	**79**			
C. Production suspended (Dec. 2015)													
23	Chattak	1959	HCU	2000	1039	265	474	727	26	448	46%	70%	NIKO
24	Kamta	1981	Niko/BAPEX	2000	72	50	50	50	21	29	70%	70%	BGFCL
25	Feni	1981	Niko/BAPEX	2000	185	125	125	175	62	63	67%	94%	NIKO
26	Sangu (Offshore)	1996	Cairn/Shell	2010	900	544	578	639	498	80	64%	71%	Cairn
	Sum C				**2196**	**985**	**1227**	**1591**	**608**	**619**			
	Sum A+B+C				**35853**	**17064**	**24780**	**28833**	**13517**	**11263**			

Source: Petrobangla

In terms of the uncertainties connected with the reserves, it is appropriate to state the SPE definitions:

Proved Reserves

Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations.

Proved reserves can be categorised as developed or undeveloped. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

Probable Reserves

Probable reserves are those unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable. In this context, when probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves.

Possible Reserves

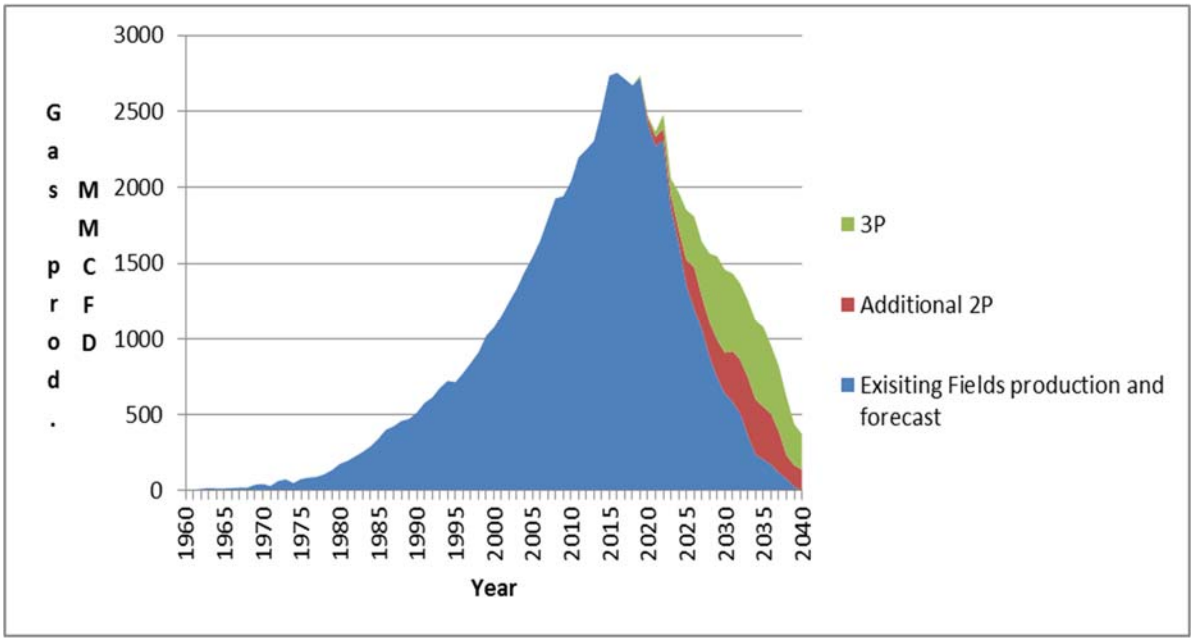
Possible reserves are those unproved reserves which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves. In this context, when probabilistic methods are used, there should be at least a 10% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable plus possible reserves.

The reserves estimates have been derived using a deterministic approach and therefore probability numbers do not strictly apply. However, for the sake of this discussion there is approximately a 10% chance that the proven reserve will be less than stated, a 50% chance that the probable reserve will be less than stated and a 90% chance that the possible reserve will be less than stated. For the purposes of near to medium planning (0-10 year), it is recommended that only the proved and probable reserve estimates be used, whereas for strategic (10-25 year) the 3P and YTF is used in addition.

5.2.3 Production history

A diagram showing the historical daily production data extending back to 1960 has been compiled from the draft report on the Five Year Gas supply Strategy (Petrobangla, 2015, draft) and is presented in Figure 60. The historical production data are the cumulated production of all fields at each year and thus does not show the development of one specific field but rather the development of the total gas field portfolio in Bangladesh. The production data show a steady increase from low numbers in 1960 to peak values above 2750 MMCFD reached in 2017 (Figure 60). From here, the forecasted production from existing fields is expected to decrease. The forecasted trend will be dealt with in Section 5.3.

Figure 60: Summary of actual average daily production (1960-2015) and forecasted production (2016-2041) from existing fields in Bangladesh.

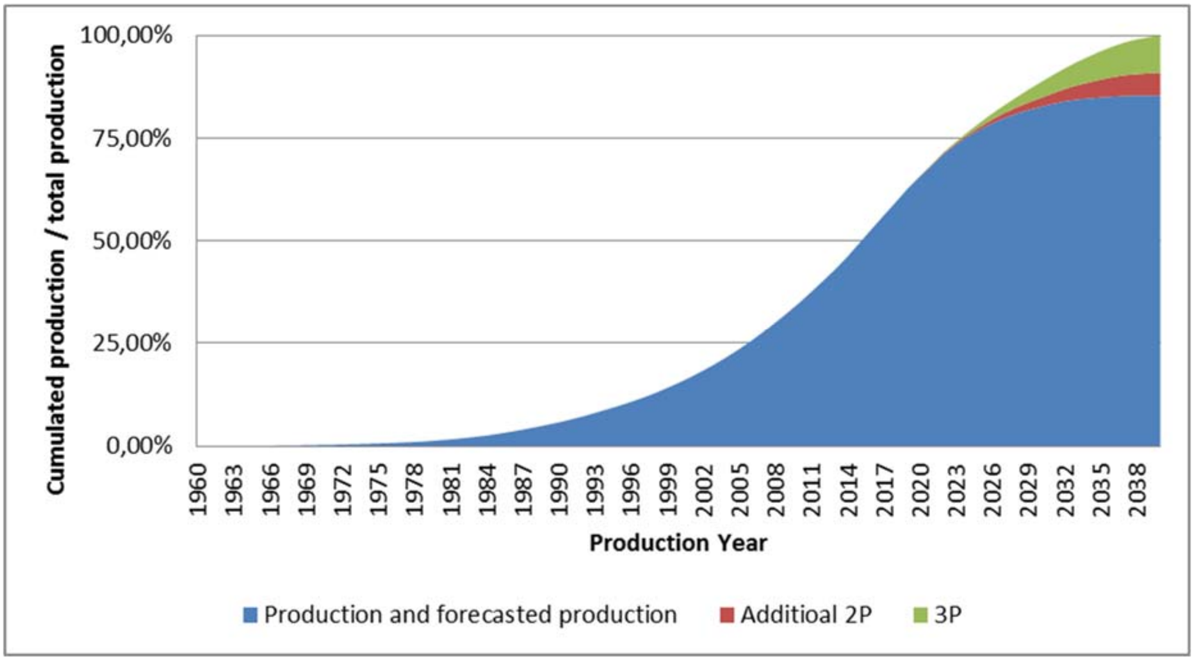


Source: Petrobangla

To show the rate of produced reserved versus time then the total production per year has been compared to the total recoverable (3P) reserve in all fields as recognised to day (Ref. Figure 61). This analysis shows that 25% of the expected ultimate production (3P) in the existing fields was produced in 2006 at the time of the first GSMP study, that 50% of the total production was reached nine years later in 2015 and that 75% of the gas resource in the current producing fields is expected to have been produced during 2023.

It thus took 45 years to produce the first 25% of the total production recognised today, but only 9 years for the next 25% to be used. This acceleration of the gas usage is an important understanding in why timely decisions are very important.

Figure 61: Cumulated annual production (1960-2015) and forecasted production (2016-2041) from existing fields in Bangladesh normalised to total present day expected production.



Source: Petrobangla

5.2.4 Recovery Factor

According to the literature the theoretical recovery factor for most volumetric depletion reservoirs with reasonable permeability is that these will produce 70 to 90 percent of the GIIP value (Petroleum Society 1994). However, as stated in the GSMP (2006) "during the depletion of gas reservoirs, production performance is affected by many factors. The basic characteristics and physical properties of the gas and its associated constituents or product, and its proximity and interrelationship to other fluids in the reservoir can either enhance or adversely affect recovery from the reservoir. Recovery factor for gas is related to the reservoir drive mechanism. In the case of a gas reservoir producing by expansion and without water drive, there is no physical reason why the gas may not be recovered down to near atmospheric pressure. In another way, it can be said that gas reservoirs under depletion drive can achieve near 100 percent recovery. However, when pressure approaches near atmospheric, production rate decreases rapidly and becomes uneconomic.

In the GSMP (2006) study, a recovery factor for the 2P resource varied between 66-82% with the norm of 70% of the GIIP (Ref. Table 16). In the Proven, Probable and Possible (3P) Reserves summary table (Ref. Table 17) the 2P to GIIP factor ranges between 41-88% with a mean of 66%. The 3P / GIIP ratio ranges between 76% and 90% with a mean of 78% of the producing fields.

In summary, the reported recovery factors are well with the theoretical expected ranges, however, the very low 2P recovery factors for some of the fields merit further work. Ultimately, the low recovery factors mean that the field is underdeveloped or that production is faced with difficulties as addressed below.

5.2.5 Producing Fields Summary

A comprehensive review of the 19 (2016) producing fields are presented in the work of Gustavson (2012) and for three key fields in the GSMP (2006). Study undertaken by Schlumberger (2011) for the HCU analysing individual well performance at individual fields is available for some of the fields for the Consultants.

Further, the Consultants have requested documentation for the summary report from RPS Energy on the reservoir simulation studies conducted for some of the fields (not received).

As started in the previous section, the Consultants find the individual field recovery factors within the industry standard for gas fields with good to medium reservoir properties. However, the Consultants agree with the findings in the GSMP (2006) that GIIP can be difficult to determine with respect to lack of field pressure data. The individual fields are operated to full capacity, which limits the possibility to obtain field pressure data for decline curve analysis or standard P/Z plots for the GIIP estimation. Most of the fields also have more than one gas bearing sands, which challenges the use of P/Z plots as pressure and fluid communication between individual sands can overestimate GIIP for the individual sands and then the aggregated value. Consequently, the reported recovery factors are subjected to relatively high uncertainties.

Overall, the Consultants assess that the Bangladesh gas field production suffers the general challenge with gas field development, *i.e.*;

i. Gas production is directly linked to the market demand which limits the possibility to take individual wells off stream for a longer period to determine reliable shut-in pressure.
ii. As production data acquisition and knowledge of the dynamics of the reservoir performance starts at day one of the gas-sale contracts, it is difficult to design an optimum development plan before production start. Especially in a rapidly growing gas market as in Bangladesh.
iii. When the supply-demand balance is tight, individual fields are often depleted with respect to demand and not to good reservoir management practice.

The Consultants acknowledge the work of Petrobangla to address the above challenges for future developments and re-developments. A draft of the “Five Year Gas Supply Strategy (Year 2015 – 2019), Petrobangla (2015) was issued to the Consultants.

The Consultants recommend taking the following actions for the future development of Bangladesh gas production:

1. Incorporate reservoir simulation studies early in project life to model field performance. Both the geological (static) model and the simulation (dynamic) model must be history matched regularly to constrain forecast modelling. (Start simple and update when practical feasible). It is imperative that the static modelling captures the contrasts in permeability rather than a very detailed geology; gas flow is not that sensitive to small scale heterogeneities but sensitive to large scale permeability contrasts. So initial flow models can be rather simple. The Consultants acknowledges that simulation works are already

ongoing at several fields, but at present time the documentation for the work is not available to The Consultants.

2. Simple reservoir simulation models can strengthen the interpretation of P/Z plots for gas in place evaluations.
3. As production at full capacity at all time limits the possibility for data acquisition for reservoir characterisation, evaluation of production performance, re-evaluation of GIIP and adjusted development design, it is imperative to gain excess capacity in the production line to take individual wells of-stream.
4. Insufficient structural knowledge makes well location uncertain and field depletion risk to be ineffective. Compartmentalisation on some fields is also an issue. Accelerated decision and sanction for 2D/3D seismic surveys for proper field delineation and detection of reservoir sands are imperative and worth the investment.
5. Water production challenges the production strategy/rates; water encroachment can maintain reservoir pressure but can also immobilise gas volumes as residual gas. The Habiganj field is an example; reservoir simulations can interpret the strong water drive in the Upper Sand to return a more reliable GIIP. Further, how fast can the gas be produced with minimum residual gas volume left behind.
6. Current production is based on technology which has matured and developed – introduce new technology such as horizontal drilling, hydraulic fracturing in tight reservoirs in order to maximise outputs from fields
7. Insufficient well dimensions and number of wells can challenge production rates and thereby the possibilities to take individual wells of-stream for a longer period for reservoir surveillance.
8. Proper reservoir management can increase field performance, i.e. plan for data acquisition and early development up-date, reservoir simulation, history matched on regularly basis, down hole gauge pressure monitoring, well shut-in for pressure build-up (reservoir pressure), PLT logging (identify non-producing zone, re-completion), water production monitoring - risk of well shut down due to liquid hold-up, regular well maintenance and workover.
9. Production augmentation; well tubing size and down-hole constrictions, well completion (shuts per inch, secure completion over all pay zones), fines – and water production surveillance, THB below transmission pressure i.e. installation of compressor.
10. Plan for final field blow-down.
11. Re-evaluate well design, tubing dimensions and flow constraints down-hole. Most IOCs tubing design is 5 inch, whereas Petrobangla design corresponds to 4 inch or even 3.5 inch. Moreover, monobore should be considered for shallower wells to reduce cost and increase production at the same time.

5.3 Country supply – production forecasts

Long-term gas production (2016-2041) scenarios have been provided to the Consultants from Petrobangla and its subsidiaries as response to questionnaires sent out in the beginning of the study. The forecast is based on material balance deterministic approach and the uncertainties involving in these estimates shall not be underestimated. The forecasts are all slightly different from each other but all predict a stable to slightly decreasing production from existing fields, and after approximately five years a rapid decline in production is expected to occur (Ref. Figure 60). The development in short-term production forecasts is not the main focus here, as it is also dealt with in reports such as the Five Year Gas supply Strategy Pertrobangla, 2015) and fields based production forecasts. Here the long term (+10 year) strategic planning is in focus.

The specific forecast used here for each producing field was provided as part of the data return on the questionnaires sent to operating companies. In addition to this, the Consultants have reviewed the available reserve data and have produced a number of forecasts based on the reserve data supplied by Petrobangla. (Note all forecasts are financial year forecasts):

- "Proved" remaining reserves of 4.9 tcf (Table 16, note this number is excluding the Kailashtilla, Rashidpur, Sylhet fields since these are not provided)
- "2P" remaining reserves of 11.3 tcf at end December 2015 (Ref. Table 16)
- "3P" remaining reserves of 14.3 tcf at end December 2015 (Ref. Table 16)[4]

As in the GSMP (2006) study, the objective of forecasting the gas supply here is to determine:

- whether Bangladesh is self-sufficient in meeting its gas demand
- when new discoveries will need to come on-stream
- and the required volreserves needed to fill any shortfall

In the following, three gas supply scenarios are presented and examined:

Case A – Proven, Probable and Possible (3P) Reserves

This scenario represents best utilisation of existing fields with no additional resources found.

Case B – Proven, Probable and Possible (3P) Reserves with YTF contribution

This scenario represents best utilisation of existing fields with a YTF contribution of 6.4 tcf. The YTF contribution has been provided to the Consultants as BAPEX new, Shallow offshore, Deep Offshore.

Case C – Proven, Probable and Possible (3P) Reserves with an additional YTF contribution

This scenario represents best utilisation of existing fields with an YTF contribution based on the report from Gustavson (2011), whereas it is anticipated that approximately 16-17 tcf can be produced until 2041 according to the Consultants investigation. The YTF contribution has been estimated by the Consultants from the available reports combined with an expectation from the upcoming and accelerated future exploration activities announced by Petrobangla and its subsidiaries. Reserve growth in this model is 1000 bcf per year reflecting twice the average historical rate seen in Bangladesh (Ref. Figure 57)

[4] We believe newer figures may exist.

The conclusion in all scenarios (A, B and C) is that the domestic gas production cannot meet the future gas demand as projected by the Consultants and thus LNG import in various amounts will be needed to fill the demand gap.

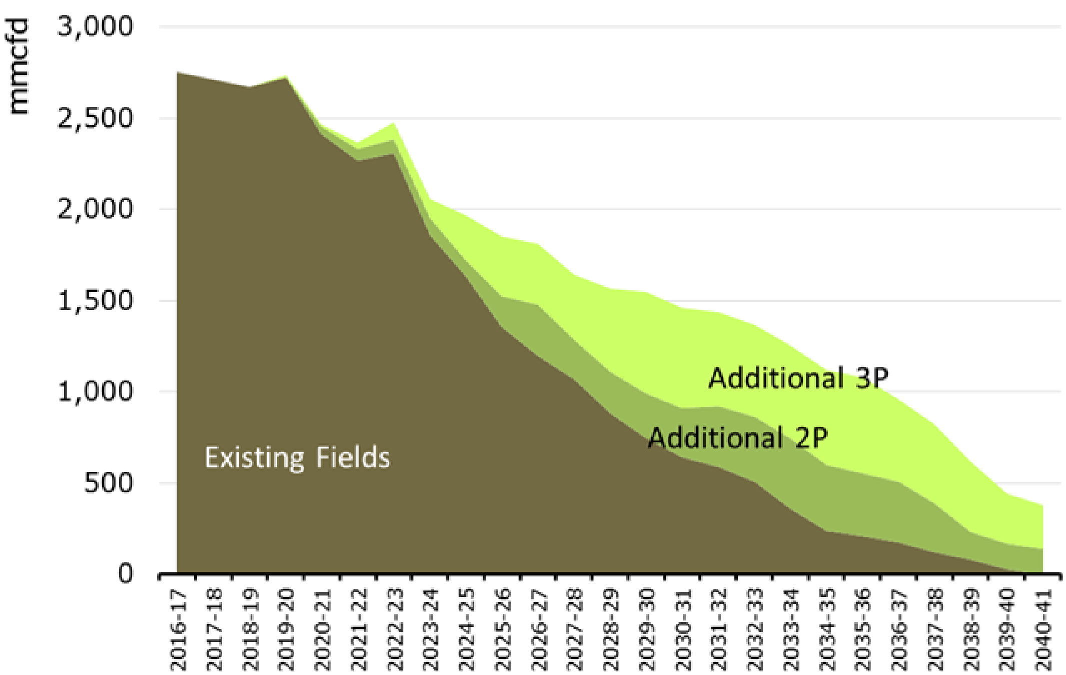
5.3.1 Case A – Proven, Probable and Possible (3P) Reserves

The production forecast for the period 2016-2041 as presented for the Consultants indicates that the gas production per day is 2500 mmcf until 2022 whereafter the production quickly diminishes (Ref. Figure 62). This production estimate reflects field development plans either approved or planned. The field development plans have not been available to the Consultants.

The Consultants has projected the addition 2P reserve not accounted for in the forecasted production schemes provided. For this “additional 2P” production no development plan exists for its production and thus depends on future development. Consequently, no short-term production increase is expected based on this additional 2P reserve although a mid to long terms additional production is expected to occur provided the needed development.

The total potential for the additional 2P reserve is 1.6 tcf. Fields with highest reserve within the additional 2P class and thus currently forecasted in the operator’s production forecast are the Rashidpur and Semutang fields (Ref. Table 17).

Figure 62: Case A – Proven, Probable and Possible (3P) reserves production forecast.



Source: Petrobangla

Table 17: Summary of GIIP, cumulated production (per December 2015), planned production in the forecast for 2016-2041 and the additional 2P and 3P reserves not included in the forecast for 2016-2041 but used in production forecast scenarios A, B & C.

	Field	Gas Initially in Place (GIIP)	Cum. production (Dec. 2015)	Cum. Gas production forecast (2016 - 2041)	Total past and planned production	Recovery factor (Past and Planned Produced / GIIP)	Recovery factor (2P/GIIP)	Recovery factor (3P/GIIP)	Addtional 2P	Addtional 3P
A. Producing (Dec. 2015)										
1	Titas	8149	4040	2325	6365	78%	78%	80%	2	152
2	Habiganj	3684	2191	564	2755	75%	71%	84%		342
3	Bakhrabad	1701	789	265	1054	62%	72%	79%	178	285
4	Kailashtilla	1748	623	675	1298	74%	70%	80%		100
5	Rashidpur	2116	565	419	984	46%	70%	80%	498	709
6	Sylhet/Haripur	666	208	90	299	45%	70%	80%	167	234
7	Meghna	122	59	11	69	57%	57%	83%	0	32
8	Narsingdi	369	171	95	266	72%	75%	81%	11	33
9	Beanibazar	231	91	34	126	54%	88%	88%	77	77
10	Fenchuganj	553	138	118	256	46%	69%	90%	125	242
11	Shaldanadi/salad	380	84	29	113	30%	73%	86%	166	214
12	Shahbazpur	677	19	336	355	52%	58%	72%	35	133
13	Semutang	654	11	13	24	4%	49%	57%	293	351
14	Sundulpur Shahzadpur	62	9	26	36	57%	56%	70%		8
15	Srikail	240	40	115	154	64%	67%	67%	7	7
16	Jalalabad	1491	995	580	1575	106%	79%	79%		
17	Moulavi Bazar	1053	282	56	338	32%	41%	77%	90	474
18	Bibiyana	8350	2269	4201	6471	77%	69%	85%		613
19	Bangura	1198	323	248	571	48%	44%	79%		370
20	Begumganj	100	1	36	37	37%	70%	70%	33	33
	Sum A	**33544**	**12909**	**10236**	**23145**				**1682**	**4409**
B. Non-producing (Dec. 2015)										
21	Kutubdia (Offshore)	65	0	0	0	0%	70%	70%	46	46
22	Rupganj	48	0	33	33	68%	70%	70%	1	1
	Sum B	**113**		**33**	**33**				**46**	**46**
C. Production suspended (Dec. 2015)										
23	Chattak	1039	26	449	475	46%	46%	70%		252
24	Kamta	72	21	0	21	29%	70%	70%	29	29
25	Feni	185	62	60	123	66%	67%	94%	2	52
26	Sangu (Offshore)	900	498	0	498	55%	64%	71%	80	141
	Sum C	**2196**	**608**	**509**	**1117**				**111**	**474**
	Sum A+B+C	**35853**	**13517**	**10778**	**24296**				**1840**	**4929**

Source: Petrobangla

For long term strategic planning 3P reserves from existing fields is an important asset to include. Based on the forecast for the period 2016-2041 including the additional 2P reserve the 3P reserve amounts to additional 4.4 tcf for all producing fields (Ref. Table 17). Fields with a large 3P reserves includes the Rashidpur and Bibiyana fields.

The 3P reserve may, if unlocked, extend the production period of the fields but it is not expected to contribute to the short term daily production. However, due to the significant volumes within this reserve class, production above 1000 MMCFD may be extended to 2036 (Figure 62). This reserve needs additional field development and may also be viewed as a "technological dependant" reserve.

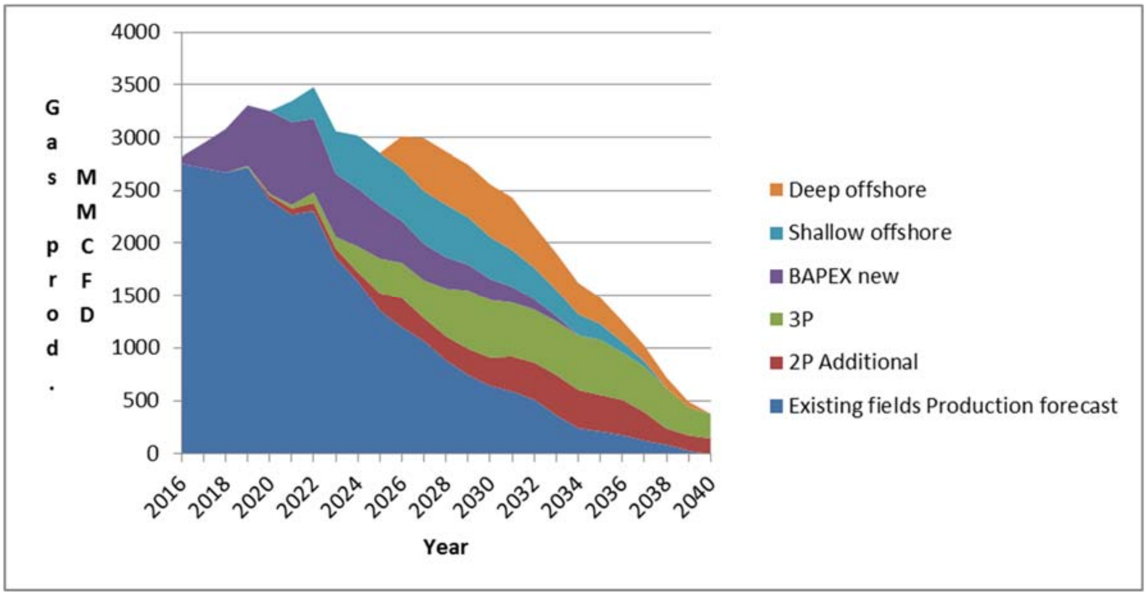
5.3.2 Case B – Proven, Probable and Possible (3P) Reserves with 6.4 tcf YTF contribution

In the "Gas Production Augmentation Plan (2016-2041)" provided to the Consultants, production from "yet-to-be-found" reserves from onshore and shallow offshore and deep offshore fields has been forecasted based on expectation in upcoming exploration. The contribution of the YTF is expected to provide 2.6 tcf from new onshore fields and 2.1 and 1.7 tcf, respectively for shallow offshore fields and for deep offshore fields.

The additional of the YTF resource is expected to impact production both on short, medium and long term. Addition of new production is in the forecast expected to kick-in already from 2017 and is expected to keep production above 3000 MMCFD until 2025 where also production from shallow offshore is expected. With the new YTF production rates above 2500 MMCFD is expected until 2031 (Ref. Figure 62). The details in these expected YTF by BAPEX and the assumptions behind the impact on the strategic reserve forecast are not available to the Consultants. Most important is to know the reserve status used and the risking that is attached to the estimates. Assuming, however, that it represents 2P reserves with a 70% recovery, the fields reflect GIIPs between 3.9-2.8 tcf.

The gas demand forecasted by the Consultants shows that gas demand will not be lower than 4000 MMCFD from 2017 and on. For this it is clear that the Scenario B will thus never meet the gas demand and that the supply gas will exceed 1000 MMCFD growing to more than 2000 MMCFD from 2019 (Ref. Figure 63, BAPEX Forecast).

Figure 63: Case B - Proven, Probable and Possible (3P) Reserves with YTF contribution to the production forecast.



Source: Petrobangla

5.3.3 Case C – Proven, Probable and Possible (3P) Reserves with 34 tcf YTF contribution

The YTF potential in Bangladesh is evaluated in Section 5.3.4. The analysis shows that there is a significant YTF resource available in the country. The resource is available both as conventional gas but also thin-bed resources at existing fields. As reviewed in Section 5.1, an ambitious exploration program has been approved by the Government of Bangladesh and is currently being implemented by Petrobangla and its subsidiaries. Based on these initiatives, the Consultants find that a scenario with a higher YTF contribution than presented in Scenario B is justified.

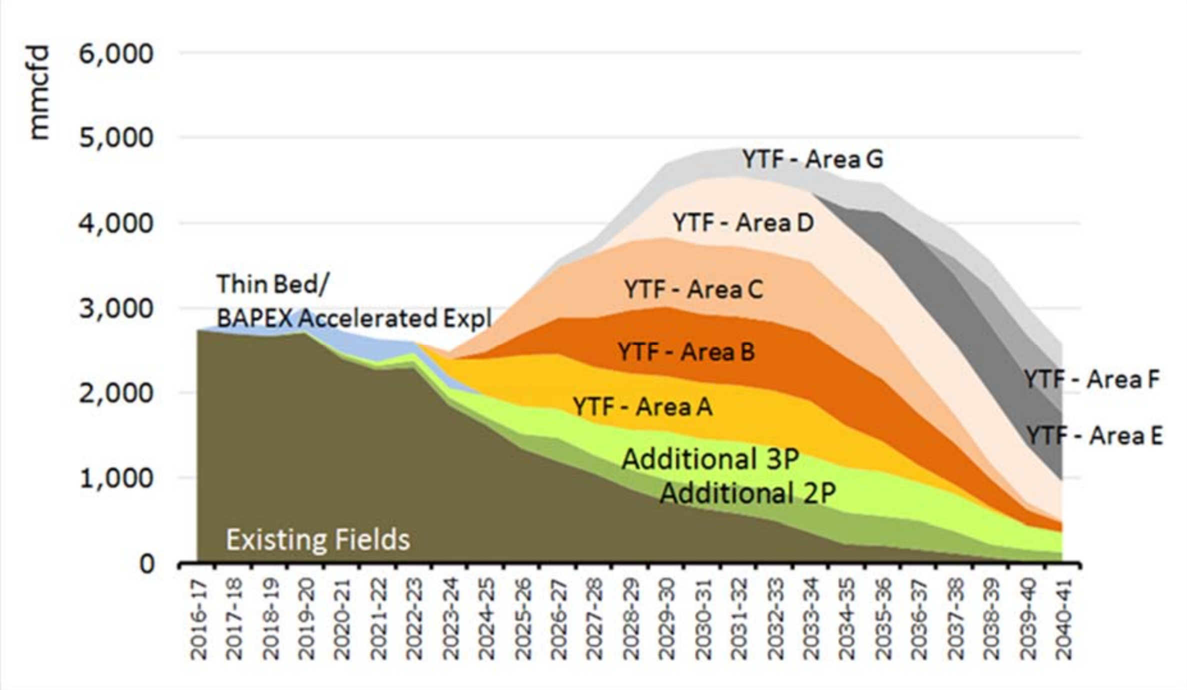
The historical data from Bangladesh demonstrate that with a drilling rate of 1-2 exploration wells per year an average GIIP growth rate of 500 bcf was achievable. This was obtained with an uneven yearly drilling rate. The exploration success was also unevenly distributed over the past 60 years (Ref. Figure 56 and Figure 57). The basic assumption in Scenario C is that a structured and well-planned exploration strategy can increase the average GIIP growth rate well above 500 bcf per year.

As LNG import has been sanctioned by the government, the demand for accelerated indigenous gas supply is to some extend relaxed. This can leave time for in-depth G&G work before seismic acquisition and drilling campaigns are executed. A beneficial balance between pace and preparatory work can be met.

On the short term, the Consultants acknowledge the announced 5 years exploration drilling campaign by BAPEX, but stress that the drilling operations must be prioritised based on a qualifying G&G work program.

the Consultants recommend starting with the low risk areas, i.e. areas with a proved petroleum system and then work around to more frontier areas. A constant evaluation on the volume of available drilling rigs and G&G staffs in general must be taken in order to avoid any bottle-neck issues. Further details and assumptions for the YTF potential are presented in Section 5.3.4. In Figure 64 the "BAPEX New" production is included in the different "YTF areas" and in to the "thin bed" production.

Figure 64: Case C - Proven, Probable and Possible (3P) Reserves with 34 tcf YTF contribution to the production forecast. Description for the assumptions for the individual YTF areas (A to G) is detailed in section 5.3.4 below



Source: GEUS

5.3.4 Yet to Find Resources (YTF)

The existence and advanced geological analysis of yet to find resources by two independent sources "USGS-Petrobangla Joint Study dated 2001" and "Final Updated Report on Bangladesh Petroleum Potential and Resource Assessment 2010" by Gustavson (2011) allow The Consultants to review the yet-to find resources. The Consultants also place emphasis on the discussion on the YTF presented in the report "Bangladesh Gas Sector Update".

The GSMP (2006) included a review of the various YTF Gas Resource methodologies and the reader is directed to this report and the report by Gustavson (2011) for further in-depth analysis of methodology. The USGS-Petrobangla (2001) study is a systematic and extensive study that represents the earliest and best study to assess the Bangladesh's undiscovered gas resource potential. This study determines that the undiscovered gas resources of Bangladesh range from 8 tcf (95% probability) to 66 tcf (5% probability) with a 50% probability of finding 29 tcf and a mean of 32 tcf.

The study by Gustavson (2011) provides the current most updated and best document study to evaluate the YTF resource for this report. The existing producing fields occur for the most parts within the Eastern Fold Belt but a potentially prospective area also exist in the Western Fold Belt in addition to shallow and deep offshore areas (Ref. Figure 65). In Gustavson study mapped leads and prospects are presented together with unmapped prospects. The risked resource is estimated to range between 34 tcf (90% probability) to 80 tcf (10% probability). In additionl to this estimate, conventional resource and unconventional resource is expected to be present in Bangladesh and is estimated to range between 4 tcf and 19 tcf (Table 18).

Table 18: Summary of Risked Gas Resource Estimates.

	Gas Resources Bcf		
Type of Resources	**P90**	**P50**	**P10**
Identified Prospects	12510	19295	28259
Identified Leads	21844	34057	49719
Unmapped	65	443	2548
Total Prospective Resources	**34419**	**53795**	**80526**
Shale Gas and Shale Oil	4007	9392	18931
Coalbed Methane	346	426	522
Total Contingent Resources	**4353**	**9818**	**19453**

Source: Gustavson (2011).

For the purpose of supply planning the recommendation in the GSMP (2006) study was that the P95 YTF resource estimate should be used. At that time this estimate amounted to 8.4 tcf.

In this updated GSMP, The Consultants recommend that the P90 YTF estimate of 34.5 tcf provided by Gustavson (2011) should be used given its more detailed nature of the study. Further, it is not the scope of the present update of the gas master plan to present a new and exhausting resource assessment for Bangladesh. The Consultants assess the volumetric probability resource estimate of Gustavson (2011) to be the present best update.

In order to unlock this potential, the prospect inventory compiled by Gustavson (2011) needs to be explored systematically in order to prove up the potential undiscovered volumes. This needs to be done on an ongoing basis to ensure that the potential resource is converted into proved reserves and developed in time to meet the supply shortfall, especially since the YTF resource has an even greater level of uncertainty than possible reserves (3P).

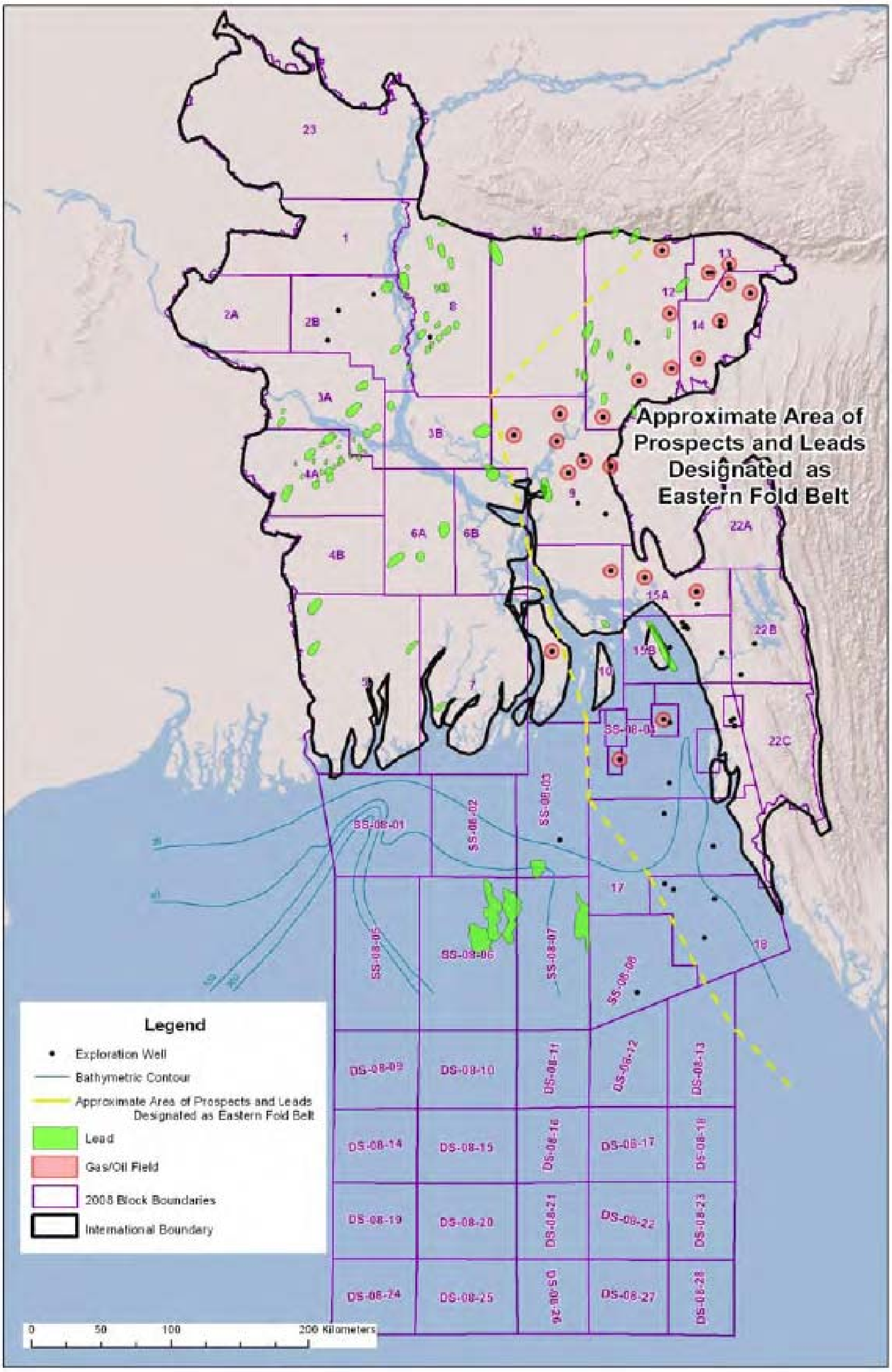
In addition to the Total Prospective Resources (Table 18), Gustavson (2011) also provides estimates on the Thin-Bed-Resources at existing fields (Ref. Table 19). This resource varies from 0 tcf (90% probability) to 27 tcf (10% probability). The resource is thus potentially significant but with much higher uncertainties than the prospective YTF resources. In the long term strategic planning, this resource should therefore not be considered. Nevertheless, it illustrates that additional potentials exist for future field developments and field tie-in. Exploration here will see if this resource can be un-locked and turned into proven resources.

Table 19: Summary of Thin Bed Resources (TBR) at existing fields.

	Gas Resources Bcf		
	P90	**P50**	**P10**
Bakhrabad	0	611	1521
Bangora	0	288	695
Beanibazar	0	61	159
Fenchuganj	0	123	339
Habiganj	0	1311	3195
Jalalabad	0	593	1531
Kailash	0	1220	3015
Moulavi	0	406	1064
Narshingdi	0	98	255
Rashidpur	0	1438	3676
Salda	0	118	322
Sangu	0	323	792
Shahbazpur	0	122	300
Sylhet	0	171	440
Titas	0	3516	8575
Chattak	0	204	591
Feni	0	44	163
Kamta	0	16	49
Meghna	0	25	75
Begumganj	0	14	74
Kutubdia	0	21	53
Semutang	0	149	368
Sum	**0**	**10872**	**27252**

Source: Gustavson (2011).

Figure 65: Mapped prospects, leads and discovered fields.



Source: Gustavson (2011).

In addition to conventional resources, unconventional shale gas and coal bed methane amounts to 4 tcf (P90) according to the studies by Gustavson (2011). These resources are currently not included in the strategic forecast but a study named “Feasibility study for the extraction of coal bed methane (CBM) at Jamalganj Coal field” showed that resource is not likely available at economic scale.

YTF resource and sectoring of Bangladesh

The YTF resource estimate provided by Gustavson (2011) did not allow for a geographical subdivision of the P90 estimate of 34 tcf. Such geographical breakdown of the YTF was provided by the USGS (2001) study. This study clearly shows that the most prospective areas are the geological stretches where the existing fields are located. Here, the geological structuring of the subsurface allows for well-defined relatively large four-way closures. In areas to the west of the country, the geological structuring is less pronounced leading to less distinct closures.

The current exploration activities are reflected in the licencing currently taken (Ref. Figure 54) and in the seismic data coverage (Ref. Figure 55). This shows that part of the country has had a long exploration history whereas other parts are almost virgin territories.

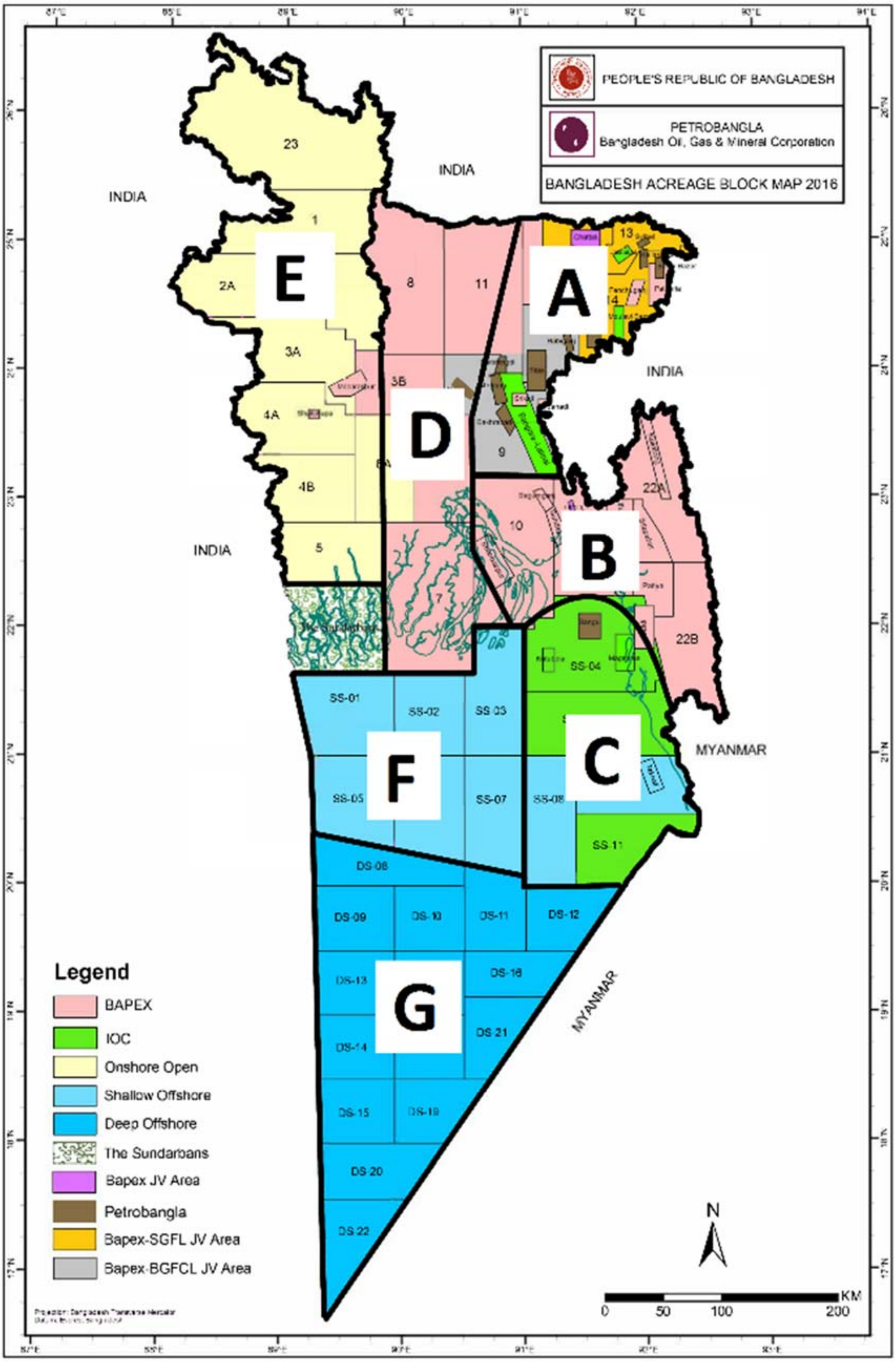
To reflect the two above characteristics of Bangladesh, the country has been divided into seven sectors (Ref. Figure 66). The definitions and basis characteristics are presented below and in Table 21.

Timing and planning of future exploration activities in Bangladesh are crucial for a successive indigenous gas reserve growth. The Consultants take a deterministic approach using the already gained exploration and development experiences. As the P90 estimate from Gustavson (2011) is risked resource estimate, the Consultants evaluated the probability of success (PoS) for the different areas and use the PoS to setup timing for exploration planning (Table 20).

Table 22 presents a recommended time-frame for exploration activities for the YTF areas in the short- and mid-term time interval. Prioritisation and timing are crucial for the success of discovering and developing new prospects and plays with respect to the limited resources available (number of drilling rigs etc.). The Consultants have prioritised the different areas A – G in Figure 66, rating the areas with the lowest exploration risk the highest priority.

The time-frame is developed knowing that the near future gas supply for Bangladesh involves import of LNG. This gives a unique opportunity for planning G&G work in a timely matter, so future seismic acquisition surveys and drilling campaigns can be done on a prioritised list of prospects.

Figure 66: Division of Bangladesh into seven areas (A-G) based on past and present exploration activities and seismic data availability.



Description of the YTF areas:

Area A:

Located onshore and includes most of the producing fields. Potential for rapid new resource to come on stream are thin-beds (1-3 tcf) and near field exploration (1-3 tcf) that may be tied-in within existing infrastructure. Furthermore, 3-5 tcf (P90) of additional YTF that may come relatively quick on stream (5-10 years). The PoS for the thin beds are 30% due to the risk of missing seals. For new explorations, Area A has a proven petroleum system and an assessed low risk for exploration (PoS = 33%). An overall recovery factor of 70% is projected, but thin beds will have a substantially lower expected recovery (20%).

Area B:

Located onshore and includes most of the remaining producing fields not in Area A. It has a proven petroleum system and low risk for exploration (PoS = 31%). It has expected 4-6 TCF (P90) of YTF that may come relatively quick on-stream (7-12 years). Potential for rapid new resource to come on stream are thin-beds (1-3 tcf) together with Area A and near field exploration that may be tied-in within existing infrastructure. A recovery factor of 70% is projected.

Area C:

Located shallow offshore and contains previous production fields. It has a proven petroleum system and low risk for exploration (PoS = 31%) and is currently under exploration by IOC. It has expected 4-6 TCF (P90) of YTF that may come relatively quick on-stream (5-10 years) if tie back to existing Sangu field is possible, otherwise a timeframe of 10-15 years. A recovery factor of 70% is projected.

Area D:

Located onshore. It has no producing fields and a medium risk for exploration. Currently under exploration by BAPEX (PoS = 23%). It has expected 4-6 TCF (P90) of YTF that may come on stream (10-20 years) from now. A recovery factor of 70% is projected.

Area E:

Located onshore. It has no producing fields and a high risk for exploration since a working petroleum system has not been proven (PoS = 13%. Currently the area is not under exploration. It has expected 4-6 TCF (P90) of YTF that may come on-stream (15-20 years) from now. A recovery factor of 70% is projected.

Area F:

Located shallow offshore. It has no producing fields and a high risk for exploration since a working petroleum system has not been proven (PoS = 13%. Currently the area is not under exploration. It has expected 2-3 TCF (P90) of YTF that may come on-stream (15-20 years) from now. A recovery factor of 70% is projected.

Area G:

Located deep offshore. It has no producing fields, but newly discovery in block DS-12 prove up a working petroleum system (PoS = 31%). Only limited information was available from this area to the Consultants. YTF may come on stream (15-25 years) from now. The long development period is due to the deep offshore configuration. A recovery factor of 70% is projected.

Production profile including the YTF areas is presented in Figure 64.

For Area A, B and C the main structure is already drilled and new play types and testing of other types of accumulation have to be made. It is recommended to perform semi-regional studies to also include exploration models from neighbouring India. Full utilisation of acquired 3D seismic data should be made.

For Area D and E there is relatively spars data coverage by 2D regional lines and need for collection of 3D seismic data of structures is urgently needed to be able to make a prioritised prospect list for drilling selection for this sector.

Table 20: Risk factors to assess Probability of Success (PoS) for the different areas and thin beds.

	Risk Factors [%]				Overall Probability of Success (PoS) [%]
Area	Source rock	Migration/timing	Reservoir rock	Seal/trap	
Thin bed	95	80	80	50	30
A	90	75	70	70	33
B	90	70	70	70	31
C	90	70	70	70	31
D	80	70	70	60	23
E	70	60	60	50	13
F	70	60	60	50	13
G	90	70	70	70	31

Source: GEUS.

Table 21: Characteristics of the seven areas in Bangladesh.

Area	Priority	location	Petroleum system risks	Exploration company	Expected Yet-To-Find (P90)	Expected time for production development	Exploration at existing fields	Expected time for production augmentation @existing fields	Challengers/possibilities
A	High	Onshore	Proven petroleum system low risk	IOC, BAPEX mixed	3 - 5 TCF (Thin-beds 1 - 3 TCF)	5 - 10 years	Development of Thin Beds	0 - 5 years	Analysis of thin beds and 3D seismic data possible now.
B	Medium	Onshore	Proven petroleum system low risk	BAPEX only	4 - 6 TCF (Thin-beds 1 - 3 TCF)	7 - 12 years		0 - 5 years	Main structures drilled. Play types from analogies to neighbouring countries
C	High	Offshore shallow	Proven petroleum system medium risk	IOC Licences	4 - 6 TCF	5 - 15 years		0 - 10 years	Main structures drilled. Play types from analogies to neighbouring countries
D	Medium	Onshore	Proven petroleum system medium risk	BAPEX only	4 - 6 TCF	10 - 20 years	No fields (New discoveries)		Geological development favours less structuring. Play types less distinct
E	Low	Onshore	Proven (partly) petroleum system medium risk	Very few Licences currently	4 - 6 TCF	15 - 25 years			
F	Low	Offshore, shallow	Not proven petroleum system high risk	No Licences currently	2 - 3 TCF	15 - 20 years			Seismic data very limited. Geological development favours less structuring
G	High	Offshore, deep	Discovery medium risk	IOC Licence	No information (4 - 6 TCF)	10 - 25 years			Seismic data very limited. New frontier area

Source: GEUS, Ramboll

Table 22: Recommendations and priority for the seven areas in Bangladesh.

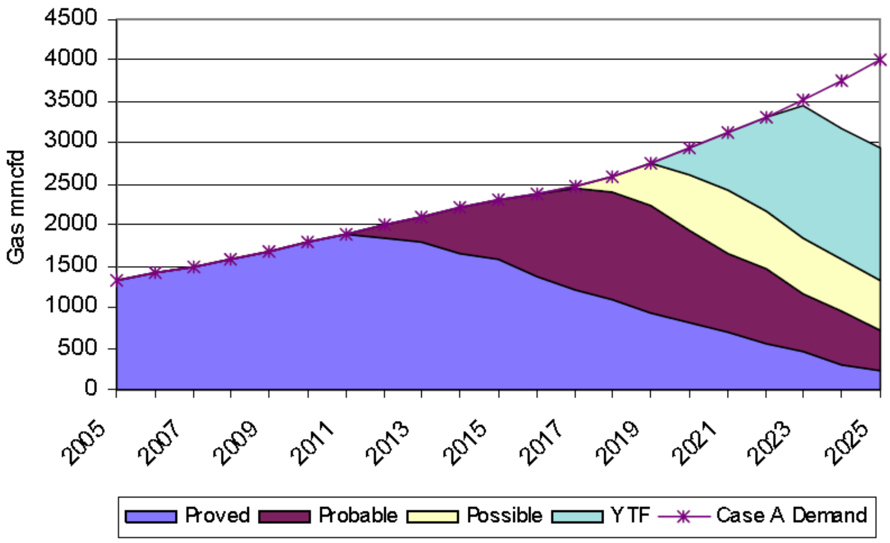
<table>
<tr><th></th><th colspan="5">Recommendations for year interval</th></tr>
<tr><th>Area</th><th>2017 - 2022</th><th>2022 - 2027</th><th>2027 - 2032</th><th>2032 - 2037</th><th>2037 - 2042</th></tr>
<tr><td>Thin beds, area A, B</td><td>Analysis of thin-beds; well log – and 3D seismic interpretation. Potential early production with tie-in to existing fields.</td><td></td><td></td><td></td><td></td></tr>
<tr><td>YTF Area A</td><td>G&G work. Update list of prospects. Exploration drilling based on prioritised list. Utilise existing seismic data to the best extend. and plan for new seismic surveys to enhance exploration success. Evaluate for deeper targets. Evaluate for HPHT drilling.</td><td colspan="2">Extend seismic coverage. Incorporate new play models into exploration model from neighbouring countries and from past exploration history.</td><td>New exploration campaign.</td><td></td></tr>
<tr><td>YTF Area B</td><td>As for area A (with 1 – 2 years delay depending on available resources).</td><td colspan="2">As for area A (with 1 – 2 years delay depending on available resources).</td><td>New exploration campaign.</td><td></td></tr>
<tr><td>YTF Area C</td><td>Obtain multi-client (open) seismic data and interpretation of play types and prospectivity. G&G work.</td><td>Prepare for - and assess bidding round.</td><td>G&G work. Exploration and appraisal drilling.</td><td></td><td></td></tr>
<tr><td>YTF Area D</td><td>G&G work on existing data.</td><td>Prepare for seismic surveys.</td><td colspan="2">G&G work. Exploration and appraisal drilling.</td><td></td></tr>
<tr><td>YTF Area E</td><td rowspan="2"></td><td rowspan="2">Preliminary G&G work.</td><td rowspan="2">Obtain seismic data and prepare multi-client study for prospectivity.</td><td rowspan="2">Evaluate play types/prospects.</td><td rowspan="2">G&G work. Exploration and appraisal drilling.</td></tr>
<tr><td>YTF Area F</td></tr>
<tr><td>YTF Area G</td><td>Obtain multi-client (open) seismic data and interpretation of play types and prospectivity. Prepare and asses bidding round.</td><td colspan="2">G&G work. Exploration and appraisal drilling.</td><td></td><td></td></tr>
</table>

Source: GEUS, Ramboll

5.4 Review of GSPM 2006

In 2006, the GSMP depicted a scenario in which peak gas production will occur 10 years ahead i.e. in 2015-2017 (Ref. Figure 67). According to their models, the peak gas would be followed by rapid production decline of the existing fields. According to the models and best judgments at that time, peak production was anticipated to be slightly above 2500 MMcfpd. This production level was not anticipated if the difficult 3P reserve of existing fields was converted to Proved reserves and if not a significant amount of new production from YTF fields was put on stream (Ref. Figure 67).

Figure 67: Demand Case A – Production Forecast, from GMSP (2006).



The analysis provided by the Consultants has shown that the models and expectations with regard to peak gas timing and level of production forecasted in 2006 was remarkably true. However, our analysis shows that the conversion of 3P reserves to Proved reserved and the additional of YTF field to be produced after depletion of existing fields will not be sufficient to meet the future demands in gas.

To maintain a high degree of domestic production requires a strong exploration commitment.
The Consultants can see that there is a strong awareness of the importance of showing due diligence with respect to finding new resources. The Bangladesh Government has made an action plan towards 2021 to raise the exploration activities since the lack of reserve growth is a consequence of reduced exploration activities - activities that were greatly reduced in the crucial time after 2002.

All evidence suggests that there is large YTF resources both offshore and onshore Bangladesh. As it takes about 7 years for a discovery to be turned on stream, these resources cannot help the current gas supply shortage and hence the need of LNG-terminal capacity will be important in securing that future demands in gas can be reached.

5.5 Analysis of the exploration program by public sector

Many recent discoveries have been made within the last decade but none of significant size. The historical high success rate for discoveries in Bangladesh may suggest that easy predictable field have been in focus. However, future exploration success will depend on unlocking more difficult settings and plays. The field size structure in Bangladesh favours many small fields and only few mid to large fields exist. The historical GIIP growth has been 500 bcf per year obtained from 1-2 exploration drilling per year. It is recommended that Petrobangla prioritises target structures that may have higher risked GIIP volumes preferentially in order to reserve growth to speed up. The ranking of to-be-drilled structures should be made based on a risking process that documents the uncertainties associated with the GIIP estimate.

The Consultants have not seen a list of risked GIIP structure aimed with the 53 exploration wells that are mentioned to be drilled within the years to come. Specifically, The Consultants recommend targeting a risked field size that lies within the P30 range of current fields. This may raise the ratio of unsuccessful drilling but will also lead to higher growth rate of GIIP vs time. Furthermore, this will also ensure a more restricted spending of development costs to fewer but perhaps larger fields that ultimately may provide higher resources per well successfully placed in the field.

The Consultants acknowledge the ambitious exploration program committed by the Government of Bangladesh but find based on the drilling history and on the fact that carefully geophysical and geological (G&G) work has to be made in planning and selection for each drill location that focus should not be on the drill number but rather on the quality of the prospect evaluation and section criteria.

<u>Seismic data</u>

To shoot non-exclusive seismic for the offshore area, it is very important to open up for activities. The Consultants urge for speeding up the process.

It is the Consultants' general understanding that 3D seismic data have been acquired over all major fields. The Consultants have, however, not seen the data or evaluation reports on the value gained from the studies. Apart from field optimisation, the evaluation of this data set is important for identification of near field exploration.

<u>Drilling</u>

The number of drill rigs onshore are now three with one planned to be acquired. These numbers of rigs may be too few to allow for the needed high number of exploration and development wells to be drilled. Petrobangla has ensured that drill rigs will be optimally operated but also that drill expertise from elsewhere is mobilised to ensure that the ambitious exploration is not halted.

However, it is important that exploration wells are drilled from a carefully prepared and prioritised list. Preparing the needed work and selecting drill site for a high degree of wells will demand very skilled work. Focus should be on reserve growth rather than well drilled. Time to prepare new prospect models inspired by recent successes as wells as successes in neighbouring countries is well spent. Preparing of semi-regional studied involving all stakeholders in Bangladesh is recommended to help in keeping a high level in the prospect-to-drill inventory.

5.6 Analysis of the exploration program by private sector

The YTF resource in Bangladesh is significant and most likely at least of similar size order of what is currently under production. Significant investments are, however, needed to develop these new assets. Given the expected decline in current production and expected dependence on LNG, energy related activities are needed in many parts of Bangladesh. As a consequence, the private sector exploration activities and its investment will be an increasingly important component in the future development of the gas sector in Bangladesh. Moreover, the activities and work-knowledge from this sector is likely to have a positive stimulation on the public-sector activities.

The results of the licence rounds clearly show that the interest in the areas is real and widely acknowledged by IOC. The efforts in acquiring non-exclusive 2D seismic coverage on a large part of the offshore area by Petrobangla are the first very important step to attract IOC and to enable local efforts to evaluate the area. It is the Consultants' judgment that better delineation of the structures and thus of the potential GIIP will help gaining a common understanding between the Bangladesh Government and IOC in signing for PSC for Block areas.

5.7 Key recommendations for gas supply augmentation

Based on the analysis of the existing producing fields in Bangladesh and the exploration - and development programmes for the country – the Consultants assess the potential for an increase in indigenous gas supply to be high and to be a valuable contribution to the overall gas demand/supply balance.

The Consultants find the following recommendations essential for the realisation of the future indigenous gas supply:

- Production augmentation from existing fields possible by increasing number of wells and well completions in producing zones. New well must have increased tubing size and deviated wells must be considered in low permeability formations.

- State of the art reservoir management, including both static and dynamic reservoir characterisation and modelling, is essential to optimize reservoir performance and securing high recovery.

- Field re-development should include an evaluation of thin-bed resources as well as deeper prospects to tie-in to existing infrastructure for early production.

- Exploration potential still huge in Bangladesh; majority of the country unexplored but assessed to be hydrocarbon bearing.

- To unlock exploration potential, a systematically and risk based approach is necessary to best utilise resources; prioritised exploration campaigns opening in less uncertain areas and moving to more frontier areas.

- Intensified and focused E&P work calls for a systematic capacity building and human resource strengthening. A national plan for capacity building must be launched and prioritized;

- Mandatory to increase number of G&G expert staff to monitor and re-develop producing fields.
- Exploration and development of new fields with state of the art technologies calls for interdisciplinary human capacities.
- Increase expertise in drilling techniques and well completions.
- Increase and strengthen cooperation between academia, national institutions and IOC for knowledge transformation and – experiences.

- Mandatory to attract IOCs for investments and technology transferring to develop deep offshore areas.

- Mandatory for the country to invest in multi-client and open seismic surveys to prepare for bidding rounds.

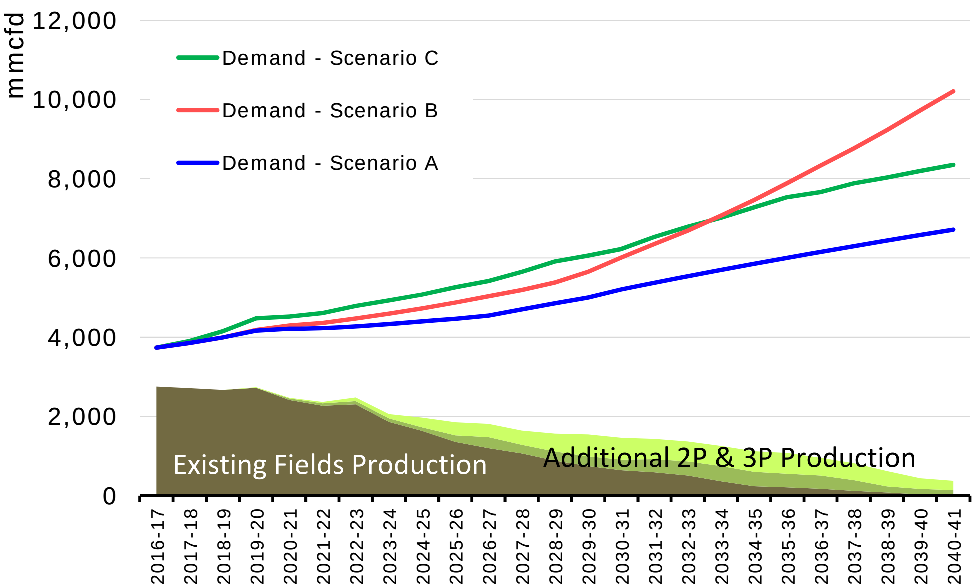
- Consecutive bidding rounds to open up for new licences; processed and open data packages must be available for the applicants

6. LEAST COST SUPPLY SOLUTION

6.1 Overall supply and demand

It is established in the previous chapters that the gas production from existing fields in Bangladesh is expected to start declining in coming years, while the demand is forecasted to be 2 to 3 times of current level by 2041. If nothing is done, the demand-supply gap will continue to widen (illustrated below), forcing Bangladesh into a severe energy crisis.

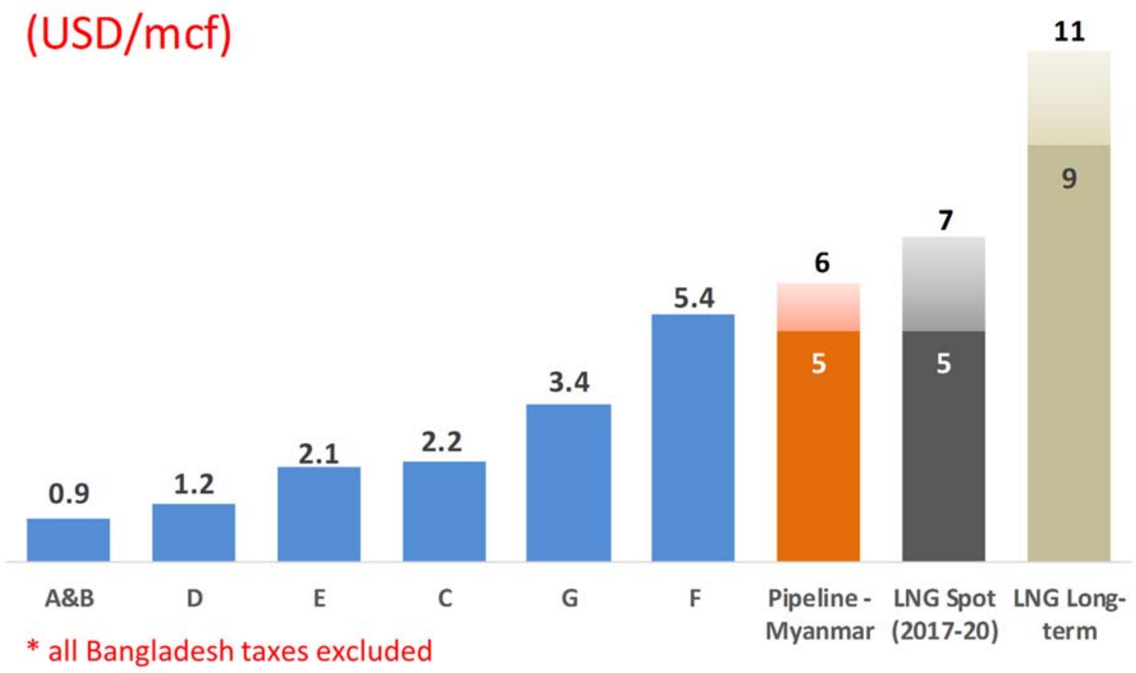
Figure 68: Gas demand and indigenous supply (existing discoveries)



To avoid such a scenario, it is necessary for Bangladesh to consider adding gas supply through both indigenous production enhancement and exploration, as well as imports via LNG and pipelines. LNG import, even FSRUs, will take some time to put into operation, thus there is likely to be a supply shortage in the short-term. In the long-term, significant additions to the indigenous supply are not likely to materialise until appropriate measures such as proper drilling programs and upgrade of human resource capacity have been achieved. We estimate this to be in the range of 6-8 years from today. However, the expected output will in all likelihood be higher than if the current short-term focused programs are maintained. The supply-mix strategy will be discussed in the later paragraphs.

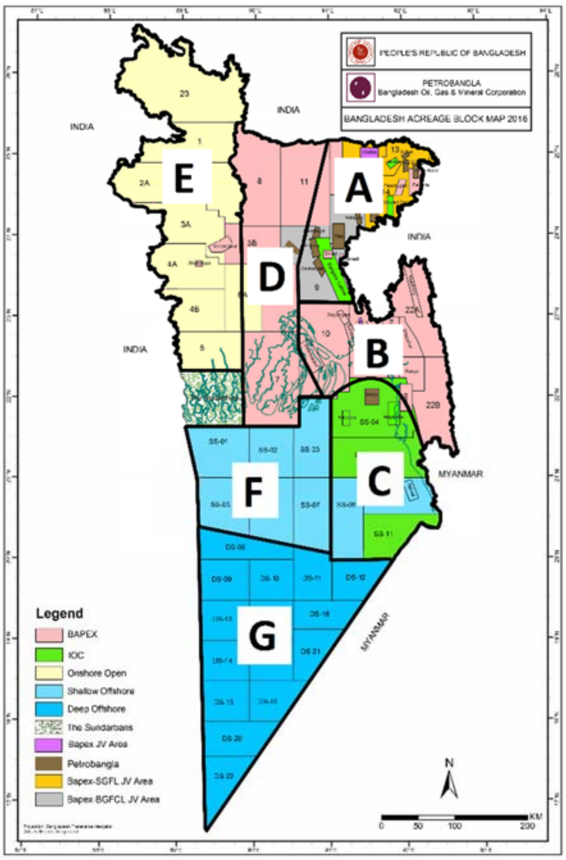
In this chapter, we will first present some indicative net costs of supply from Yet-To-Find (YTF) potentials in Bangladesh, imported gas through pipeline from Myanmar, and imported LNG. To make the cost comparisons meaningful, we consider the underlining net cost of gas to Bangladesh. For example, assuming the upstream gas price for some indigenous production is \$10/mcf where the upstream tax and/or government profit share is \$6/mcf, the net cost to Bangladesh will therefore only be \$4/mcf. In contrast, if some imported gas costs \$10/mcf, the cost to Bangladesh would be the entire \$10/mcf.

Figure 69: Indicative Net Cost of Supply (excluding all Bangladesh taxes) @USD60/bbl Oil



Source: Ramboll

Figure 70: Bangladesh acreage map by areas



Source: Ramboll

As shown in Figure 69 above, in the USD60/bbl global oil market environment, the net costs of Bangladesh's YTF potentials are estimated to be between USD0.9/mcf and $5.0/mcf, depending on the geological location. Meanwhile, the net costs of imported gas from Myanmar and international LNG are estimated to be USD5~6/mcf and USD5~11/mcf respectively. Notwithstanding the exploration risks and large volume uncertainties in the YTF gas resources, Bangladesh's potential indigenous supply appears to be a more economical option than imports, and it should be explored and assessed in depth.

The methods in deriving these indicative net costs of supply are as discussed in the sections below.

6.1.1 Indigenous Supply – Yet-to-Find (YTF) Resources

As discussed previously, there are still considerable gas potentials in the indigenous resources in Bangladesh. Based on historical data and references to both Bangladeshi and international projects, we have derived our assumptions (see Figure 71 and Figure 72 below) for new field discoveries/developments in Bangladesh. It shall be noted that there have been a lack of exploration and development activities in Bangladesh historically. Based on these limited data and reference, there are large uncertainties in our assumptions and they should be revised when more information becomes available.

Figure 71: Resource & production assumptions

Resource & Production (Mean Case)		Onshore			Offshore		
AREA		**A & B**	**D**	**E**	**C**	**F**	**G**
GIIP	bcf	1,000	1,000	1,000	1,000	1,000	2,500
Recovery Factor		70%	70%	70%	70%	70%	70%
Recoverable Resource	bcf	700	700	700	700	700	1,750
EUR per well	bcf	175	175	175	175	175	175
Plateau Production	mmcfd	200	200	200	200	200	400
Probability of Success (PoS)		32%	23%	13%	31%	13%	31%
Development Time (Post Discovery)	years	3	3	3	3	5	7

* The A&B PoS is an average of PoS for Area A and PoS for Area B

Figure 72: Upstream cost assumptions

Cost (USD million)	Onshore			Offshore		
AREA	**A & B**	**D**	**E**	**C**	**F**	**G**
Seismic & Studies	2	3	3	5	10	10
E&A Wells (per well)	15	15	15	30	30	50
Total E&A (sesmic & 2 wells)	32	33	33	65	70	110
Development Wells (per well)	15	15	15	30	30	60
Facilities (sweet gas, no H2S, no CO2 and low N2)	15	15	15	15	15	-
Offhsore Platform	-	-	-	-	-	500
Pipeline (trunk) cost per km	0,4	0,4	0,4	1,0	1,0	2,0
Pipeline - Onshore (10-50km)	4	10	20	-	-	-
Pipeline - Offshore Shallow Water (100km)	-	-	-	100	100	-
Pipeline - Offshore Deep Water (200km)	-	-	-	-	-	400
Opex per year (% of the total Capex)	3%	3%	3%	3%	3%	2%

There have been 26 gas fields in Bangladesh, with a P50 GIIP of 654 bcf and a Pmean (average) GIIP of 1,379 bcf. For the YTF resources, we assume that the discoveries have an average GIIP of 1,000 bcf for Area A-F, and an average GIIP of 2,500 bcf for Area G reflecting the expectation that only large prospects will be drilled in deep water blocks. This assumption consequently implies fewer explorations and discoveries in Area G than other areas. We also assume a Recovery Factor of 70% across all upstream acreages, a new generic field in Areas A-F will therefore produce 700 bcf of gas and a new generic field in Area G will produce 1,750 bcf of gas. For simplicity, no liquid productions are assumed for future discoveries.

As discussed previously, we define the net cost of gas supply as the net cost to the country, excluding any taxes and profit shares taken by the government. This is also the net profit per unit of gas that an upstream investor needs to receive so that a project is attractive enough for them to invest. To calculate this, we assume the investment hurdle is met when **EMV/E&A = 1**, where:

EMV **=** Expected Monetary Value of the project for the investor
= PoS*(NPV10 of the project if successful) **–** (1-PoS)*E&A

PoS = Probability of Success

E&A **=** Exploration and Appraisal cost (incl. seismic)

In essence, we assume that exploration and appraisal investments are made when the risk adjusted project value (EMV) is equal or greater than the exploration and appraisal cost (E&A). The net gas price required by the investor in this case can therefore be derived at this investment hurdle, this is also the economic net cost of supply to Bangladesh as mentioned above.

It should also be recognised that the exploration risks and uncertainties in GIIP can change when more information becomes available after each additional exploration. The economic net cost of gas can therefore change accordingly. For example, if a 10tcf field is discovered in a deep-water block, it will likely increase the PoS and the expected size of potential discoveries in neighbouring blocks – the economic net cost of gas of these blocks will therefore go down accordingly. One practical implication of such scenario is that Bangladesh can design a highly competitive PSC in order to attract IOCs to invest in 2 or 3 of its offshore blocks, and the fiscal terms can be revised and tightened up for other blocks once a significant discovery is made.

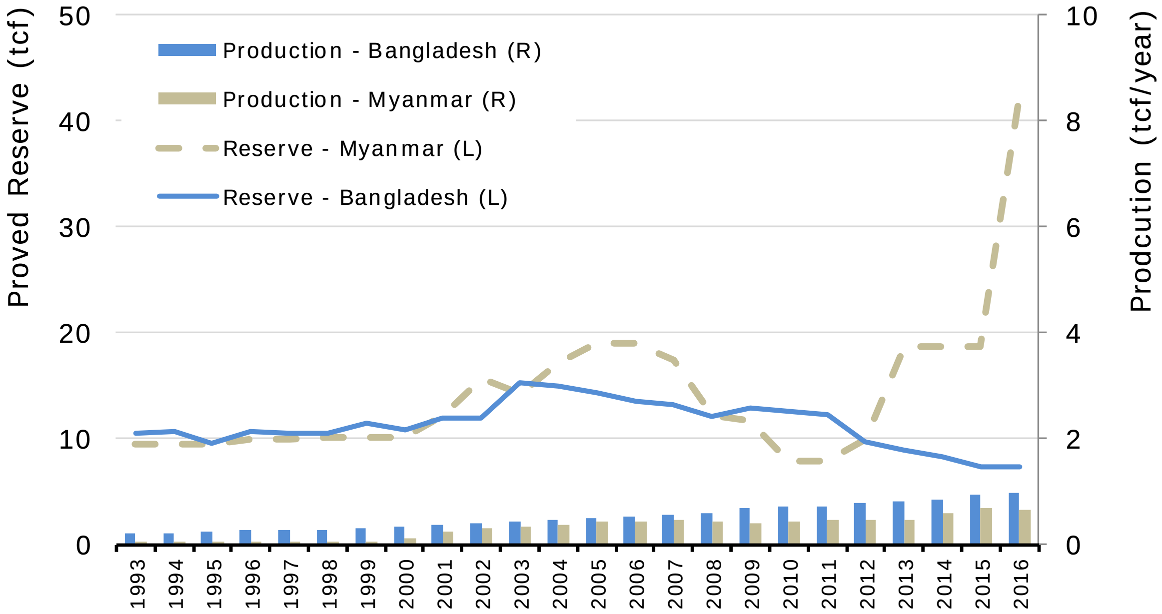
6.1.2 Import from Myanmar

According to the EIA, most of Myanmar’s current gas output comes from four offshore basins: the Yadana, Yetagun, and Zawtika fields in the Moattama basin, and the Shwe field in the Rakhine Basin.

Myanmar’s proved gas reserves have increased dramatically since 2012 (see Figure 73), thanks to large investments from IOCs in offshore exploration and appraisal programmes in the country. In 2016, Myanmar’s total proved gas reserve increased to 42 tcf (through new exploration and appraisal activities), six times as much as that of Bangladesh. For example, the state-run

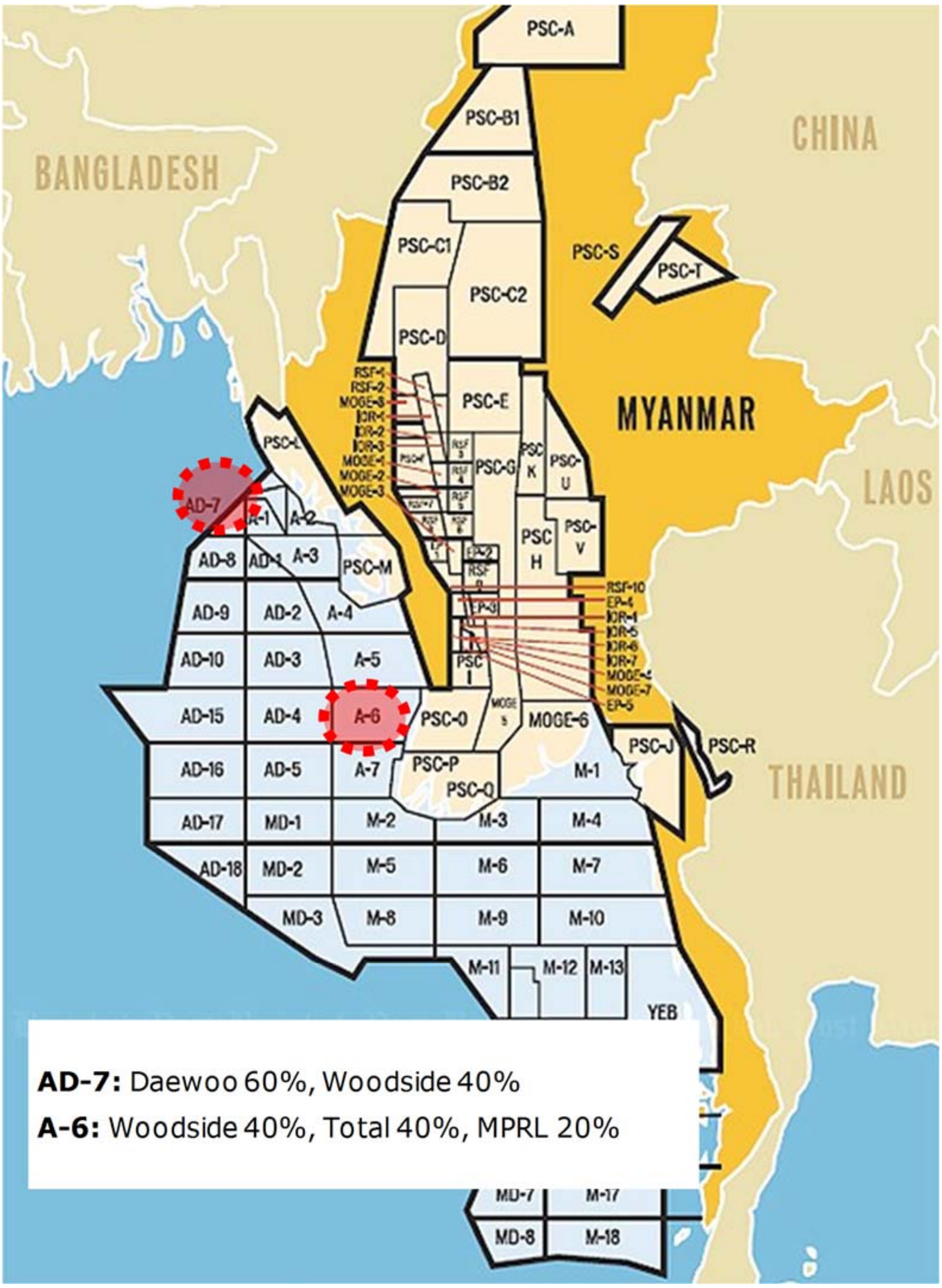
Myanmar Oil and Gas Enterprise (MOGE) and Australian stakeholder Woodside Petroleum announced in 2016 the discovery of two large natural gas wells at opposite ends of the Rakhine Basin, in Block A-6 (Woodside 40%, Total 40%, MPRL 20%) and Block AD-7 (Daewoo 60%, Woodside 40%). It is worth noting that Block AD-7 is right next to Bangladesh's deep-water block DS-12 which has been recently awarded to Daewoo International Corporation.

Figure 73: Proved gas reserve and production history in Bangladesh and Myanmar.



Source: BP Statistical Review 2017

Figure 74: New discoveries in Myanmar.



Source: EIA, Woodside, Ramboll

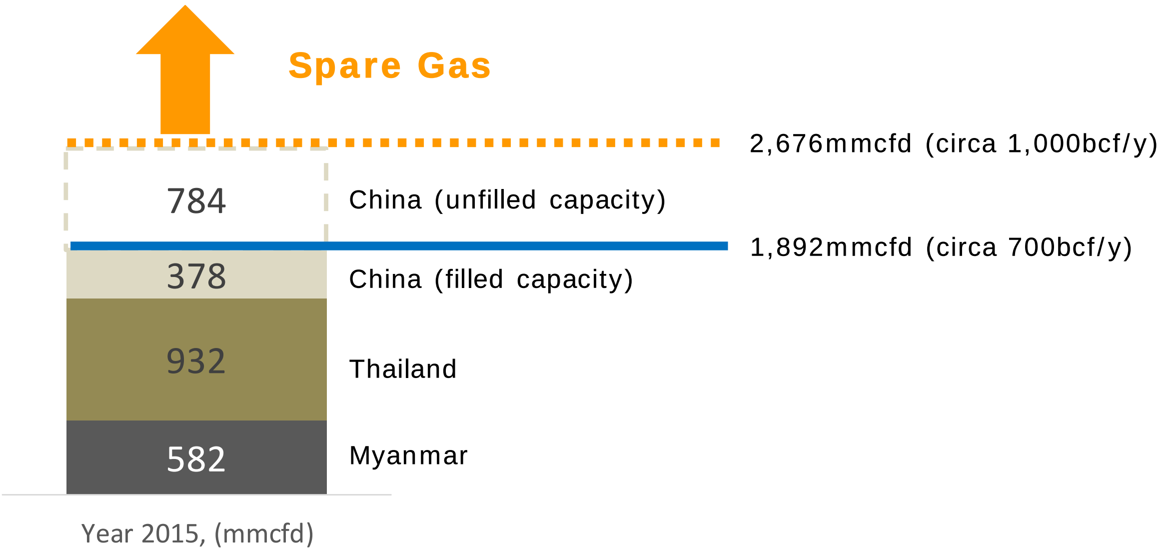
Most of Myanmar's natural gas production is exported to Thailand and, more recently, to China. According to EIA, the natural gas exports to Thailand accounted for roughly three-quarters of Myanmar's natural gas exports, totalled around 340 bcf/y (932 MMCFD) in 2015. Natural gas exports to Thailand are supplied from the Yetagun, Yadan, and Zawtika gas fields. The Zawtika project is the newest of Myanmar's major offshore gas projects, with Thailand's PTTEP launching commercial operations in the second half of 2014. The project exports natural gas to Thailand as well as serves Myanmar's growing domestic market.

Meanwhile, the natural gas exports to China commenced in mid-2013 with the development of the first phase of the Shwe natural gas project in the Rakhine Basin. In 2015, the Shwe field produced over 182 bcf (500 MMCFD) of natural gas, and Myanmar exported about 138 bcf (378 MMCFD) of gas to China by pipeline in the same year.

Myanmar and China have constructed twin crude oil and gas pipelines running from Myanmar's port of Kyaukphyu to Kunming in southwestern China. A consortium of Asian oil companies, including the China National Petroleum Corporation, commissioned the onshore natural gas pipeline with a capacity of 424 bcf/y (1,160 MMCFD) to carry exported gas from the Shwe gas project to China.

Myanmar's natural gas production is forecasted to rise as new offshore projects come online. The capacity of the China-Myanmar pipeline (784 MMCFD) is likely to be surpassed by additional gas production from these new field developments, creating spare gas (currently uncontracted gas) for potential export to Bangladesh. Such spare gas can be of significant size as IOCs in Myanmar continue making new discoveries and proving large reserves.

Figure 75: Myanmar gas production



Source: BP Statistical Review 2017, EIA, Ramboll

Based on our experience on projects in Myanmar, we estimate well-head price for Myanmar offshore gas to be around USD4~5/mcf in the USD60/bbl oil price environment. We estimate the Myanmar to Bangladesh transmission tariff to be max USD1/mcf, the gross cost of Myanmar gas for Bangladesh is therefore estimated to be around USD5~6/mcf.

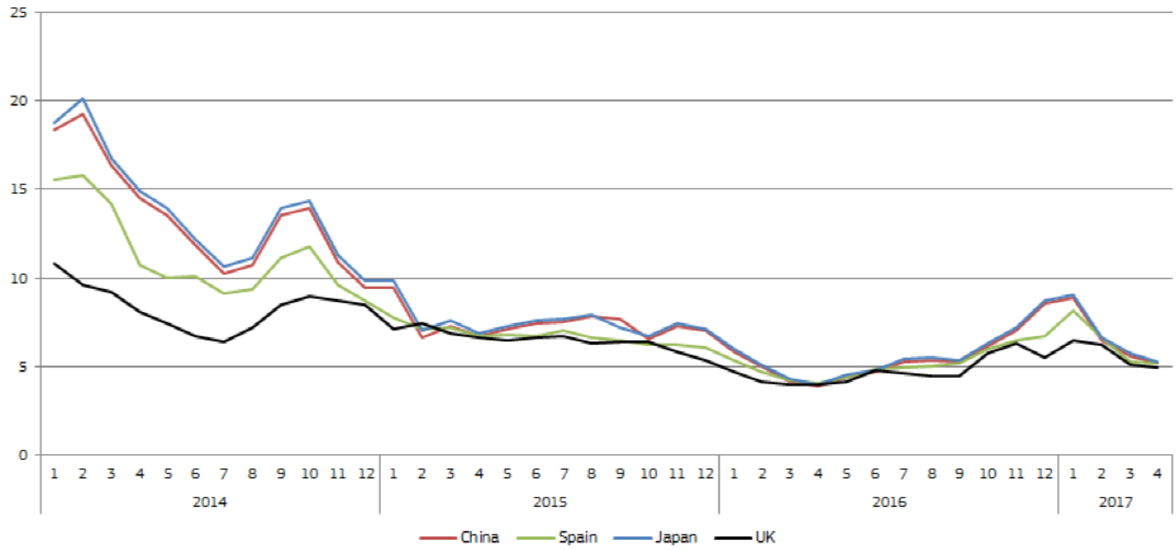
6.1.3 LNG

Given the uncertainties and lead time in developing the indigenous supply and pipeline gas imports from Myanmar, LNG undoubted offers greater flexibility and security in gas supply for Bangladesh. However, LNG is also expected to be the most expensive option.

Bangladesh can choose to source its LNG supply from both the spot market and long-term contracts (5~10 years). The spot market LNG price is determined by market dynamics, i.e. short-term demand fluctuations and marginal cost of supply. Meanwhile, many long-term LNG contracts are directly linked to oil price (e.g. Japan Customs-cleared Crude (JCC)) and others are mostly based on US Henry Hub price; negotiations for some new project are said to be based on a hybrid of JCC and Henry Hub, e.g. new projects in Mozambique and Canada as well as contracts with portfolio sellers e.g. IOCs.

Spot Market

Figure 76: Spot LNG DES prices in Europe and Asia, USD/mmbtu



Source: European Commission Quarterly Report on European Gas Markets, Q1 2017

As shown in Figure 76, spot LNG prices are highly sensitive to global market conditions. For example, the spot LNG price in Japan was as high as USD20/mmbtu in February 2014 and plunged to only around USD4/mmbtu in early 2016, as a combined result of weak demand in Asia, increasing global supply, and the fall of oil price. Similar trends are also observed in Europe although less dramatic.

During the 2016-2017 winter, Asian LNG prices rebounded to around USD9/mmbtu as a result of the cold weather, as well as a number of disruptions, including an outage at Train 1 of Australia's Gorgon facility lasting more than a month (from late November to early January). Prices fell back from February as demand weakened while Australian and US output continued to grow.

The total global traded LNG reached a historical high in 2016 at 258 MT. A 13.1 MT increase from the previous year, according to IGU. There is a consensus in the market that the global LNG demand will continue to grow. However, such growth in demand is most likely to be outpaced by the increases in supply capacity up to 2020, as additional liquefaction capacities are scheduled to come on stream in Australia and US over this period.

As a result of this persisted oversupply of LNG up to 2020, we expect the spot LNG price during this period to be around USD4~6/mmbtu at DES in Bangladesh, which gives USD5~7/mcf ex-regas terminal.

However, the spot LNG price beyond 2020 is difficult to forecast and subject to greater uncertainties.

Long-term Contracts

According to our market intelligence, major LNG buyers like Japan are currently able to secure long-term LNG supply at 11.5-12% to oil price for Delivered Ex Ship (DES) contracts, while such slope is 12.5% for smaller buyers like Pakistan. We expect Bangladesh to achieve similar terms as Pakistan with a price formula as the following:

LNG DES = 12.5%*Oil + 0.5

The significant shale gas production in recent years has turned the US from an LNG import country to an LNG export country, with the first export project commissioned in early 2016. The pricing for such LNG is different from the conventional oil linked formula (Brent linked) but based on Henry Hub price instead. The LNG pricing formula for US gas can be expressed as below:

LNG DES = Henry Hub + Pipeline Tariff + Liquefaction Tariff + Shipping

We assume the regasification tariff to be USD0.8/mmbtu for the LNG receiving terminals in Bangladesh. Adding this tariff to the LNG DES prices, we can estimate the ex-regasification terminal prices for the potential LNG arrives at Bangladesh.

At USD60/bbl oil price environment, we calculate that an oil-linked LNG long-term contract costs Bangladesh USD9/mcf, whereas a Henry Hub based long-term contract costs USD10/mcf. We also assume that long-term contract LNG via India terminals to Bangladesh requires additional USD1/mcf for transmission, therefore it would cost USD10~11/mcf when it reaches Bangladesh.

Table 23: LNG price estimates for Bangladesh

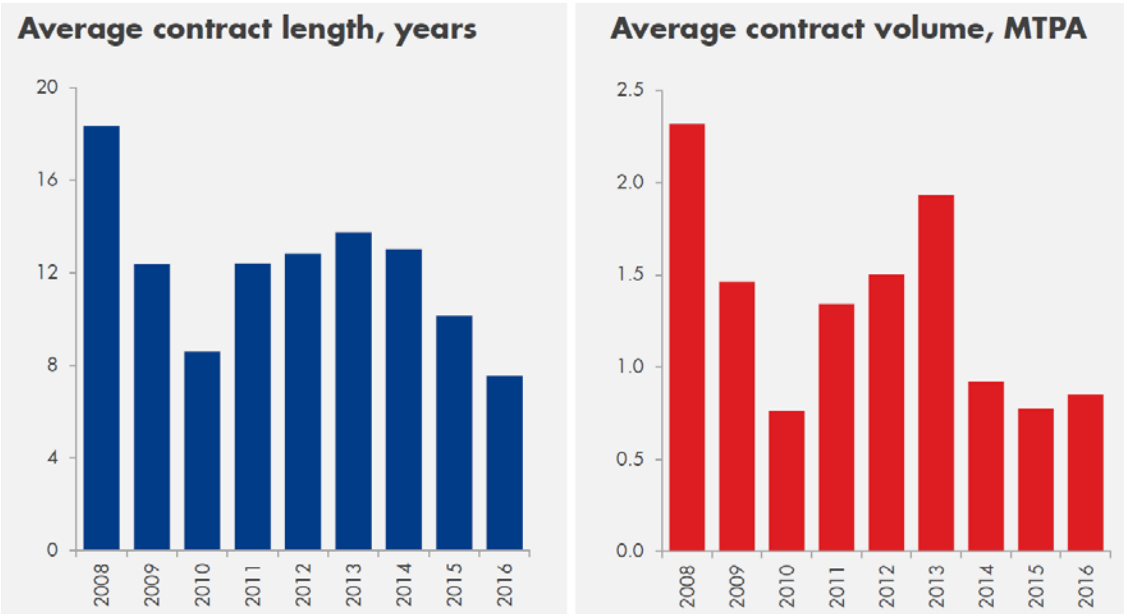
LNG Long-term Contract Pricing	Oil Price HH Price	Pipeline & Liquefaction Tariff	FOB Price	Shipping & Insurance	DES Price	Regas Tariff	ex-Regas Price	**ex-Regas Price**
	$/bbl $/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	**$/mcf**
Oil Linked Price @$60/bbl	60	-	-	-	8.0	0.80	8.8	**9**
Henry Hub-based Price @$3.5/mmbtu	3.5	3.5	7.0	2.0	9.0	0.80	9.8	**10**
LNG via shared terminals with India	*Plus $1/mcf Transmission Tariff from India to Bangladesh*							**10 ~ 11**

Source: Ramboll. NB: assume 1 mcf = 1.028 mmbtu.

It should be recognised that, as a new and relatively small LNG buyer, Bangladesh may be offered less favourable terms for long-term LNG contracts. To improve its negotiation position, we recommend Bangladesh to consider (i) making joint purchase agreements with its neighbour countries, (ii) balance its LNG supply portfolio with multiple suppliers, (iii) balance its LNG supply portfolio also with purchases from the spot market, and (iv) avoid destination clause in the long-term contracts, so that Bangladesh has the flexibility to resell the LNG to other markets when there is no or less need for LNG or when there are markets where the gas price is higher. Any success in securing pipeline gas imports from Myanmar and other countries should also help to improve Bangladesh's bargaining power in the LNG market.

Traditional LNG long-term contracts tend to cover 20 years at large volumes. However, new LNG buyers tend to sign for much shorter-term contracts at smaller volumes (see Figure 77), due to the uncertainties in the gas demand as well as upstream exploration in their respective countries. Such approach can also be adopted by Bangladesh to create greater flexibilities.

Figure 77: Global LNG long-term contracts

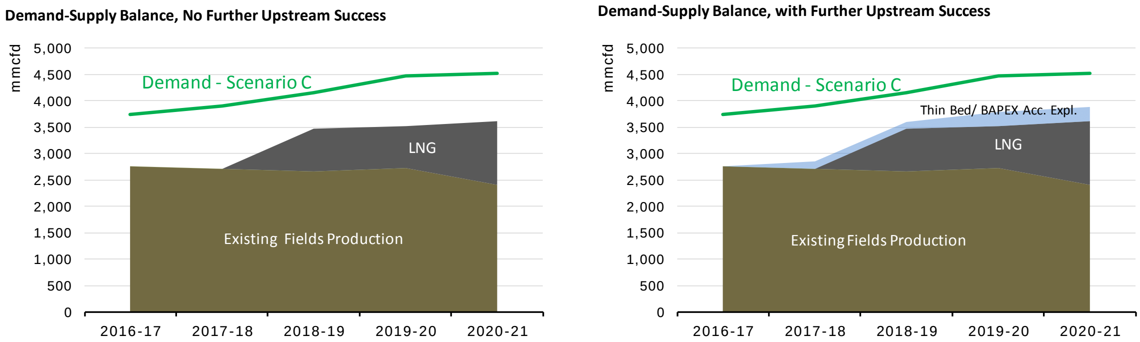


Source: Shell LNG Outlook 2017

6.2 Short-term Strategy (2017 – 2021)

In the short term, it is clear that the only secured option to increase supply is LNG imports. There can be additional production from thin bed sections of the existing fields as well some new discoveries in Bangladesh, however, such potential productions are coupled with significant uncertainties. It is also clear that the LNG import through Excelerate and Summit (1,000 MMCFD total capacity, assuming 800 MMCFD maximum average throughput) will still not be sufficient to meet the demand.

Figure 78: Short-term Supply and Demand Balance



Source: Ramboll

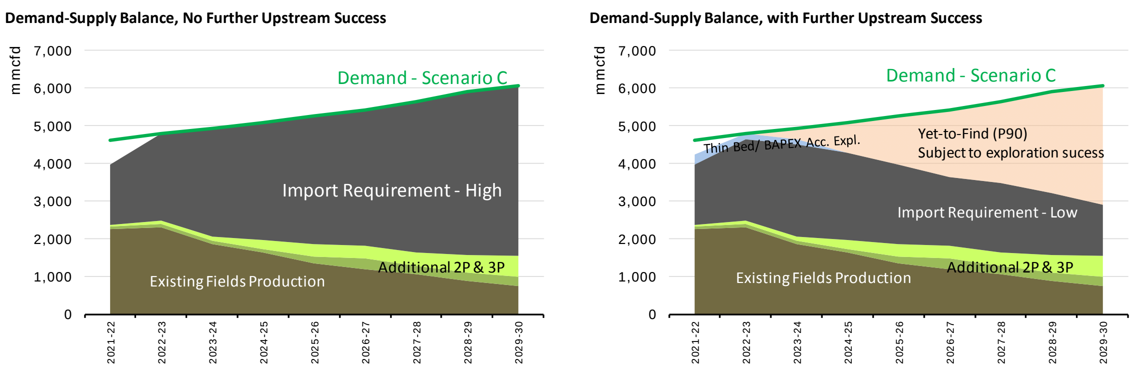
Therefore, the Consultants support additional LNG regasification terminals to be commissioned by 2021 where possible, e.g. Reliance FSU (500 MMCFD).

As discussed, long-term LNG contracts are linked to oil price, while the spot LNG price is likely to be kept low up to 2020 due to the oversupply situation in the global market; hence spot LNG is likely to offer more competitive prices during this period. Therefore, the GSMP Consultants recommend Bangladesh to import maximum quantity of LNG as its infrastructure allows, with majority of the LNG to be purchased from the spot market while small quantity from long-term contracts, creating a price and risk adjusted portfolio.

It needs to be recognised that the gas demand of Bangladesh is unlikely to be fully met during this period, due to infrastructure (LNG terminals and Transmission system) limitations. However, the development of infrastructures should be given high priority in order to avoid persistent infrastructure bottlenecks in the medium and long term.

6.3 Medium-term Strategy (2021 – 2030)

Figure 79: Medium-term Supply and Demand balance



Source: Ramboll

In the medium term, more gas can be imported through additional LNG regasification terminals in Bangladesh as required. In addition, Bangladesh can make connections to LNG terminals in India, utilising spare capacities of these terminals. If such pursuit with India is successful, the southwestern region of Bangladesh can benefit from an accelerate gas supply at a large volume. There can also be additional indigenous gas production if Bangladesh is successful in exploring its yet-to-find resources.

Moreover, Bangladesh can also greatly benefit from gas imports (via pipeline) from Myanmar, if it can successfully secure gas contracts from new discoveries in Myanmar. The Consultants also recommend the Bangladesh authorities to pursuit pipeline gas imports from Iran and Turkmenistan, although there are many challenges and the negotiations and developments can be a gradual and slow process. Nevertheless, successes in securing pipeline gas imports will likely to offer Bangladesh more affordable prices, as well as strengthen its negotiation power in LNG purchase.

Given the inherent uncertainties in the yet-to-find resources in Bangladesh, we recommend a flexible approach in sourcing its gas imports. For example, Bangladesh can negotiate for shorter contract length and flexibility in volumes for its long-term LNG contracts, so that it can easily reduce the level of LNG imports if indigenous gas explorations turn out to be very successful. Similarly, more pipeline gas and LNG imports should be pursuit if the early signs of indigenous gas explorations do not appear encouraging.

As discussed previous, the oversupply situation in the global LNG market may start to change after 2020, which in turn affects the price differentials in spot LNG and long-term contracted LNG. The Consultants therefore recommend Bangladesh to keep fine tuning the balance of its LNG portfolio in order to minimise its spending.

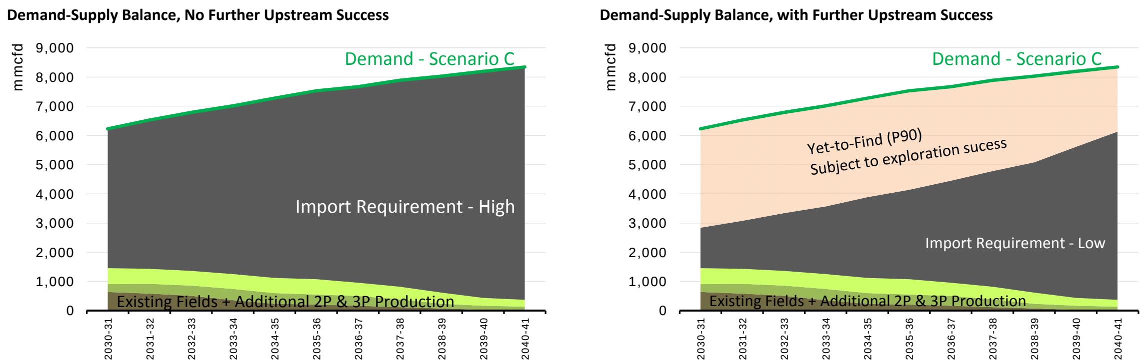
From a financial prospective, it could be rewarding for Bangladesh to invest more in its indigenous gas potentials, if there are not enough IOC investments. Looking at this in context, if long-term contracted LNG costs Bangladesh around USD10/mmbtu at ex-regasification terminal, the purchase of LNG at 800mmcf/d (0.3tcf/yr) will cost over USD3 billion for a single year. Such amount of money could be used to finance large exploration and development programmes both onshore and offshore, where significant yet-to-find potentials are expected.

Bangladesh can also consider acquiring interests in projects from where it imports its gas, favourable acquisition costs can be achieved under current oil price. This could also help to hedge against possible high oil and LNG prices in the future, as Bangladesh would be buying gas from its own oversea assets.

6.4 Long-term Strategy (2031 – 2041)

Our recommendation for the long-term strategy is largely a continuation of the medium-term strategy.

Figure 80: Long-term Supply and Demand Balance



Source: Ramboll

However, as the demand for gas grows, it can be a practical challenge to import enough gas if little indigenous gas is developed. Take a somewhat extreme example, Scenario C forecasts Bangladesh's gas demand to be 8,346 MMCFD (3 tcf) in 2041; assuming all of such demand is supplied with LNG, it will require 10~15 regasification terminals to be built in the limited region of Bangladeshi coast. The cost of such LNG import would also be significant: at USD10/mmBtu, it would cost Bangladesh more than USD30 billion in that year.

Therefore, it re-enhances the recommendation for Bangladesh to pursuit rigorous exploration and development programmes on indigenous yet-to-find resources as well as pipeline gas imports. It needs to be recognised that these options have a longer lead time than LNG imports. Therefore, Bangladesh is recommended to start developing such options at the earliest possible date.

Since the official submission of this Gas Sector Master Plan, Bangladesh has made speedy and impressive progress in its LNG import development, some of the key achievements are outlined in Appendix 9.

7. TRANSMISSION INFRASTRUCTURE PLAN

7.1 Gas transmission infrastructure planning

Gas transmission planning in Bangladesh is moving from serving the indigenous production with demand mainly around Dhaka to a system based on combination of production and import of LNG and connections to India and Myanmar for import of gas.

According to the scope of work, the main activities with respect to transmission system is to review and mature the following:

- “Transmission infrastructure plans of Petrobangla, GTCL and other state-owned entities, including inter alia issues to be addressed in the context of extension of network to the West and South Zone, including
- Review of the identified options for incremental capacity expansion of the existing gas transmission infrastructure to cope with the projected growth in demand in the short-term
- Review of the adequacy of the stand-alone pipeline projects to serve the demand of the so far un-served market, in particular supplies to new power plants and to the West and South Zone; and
- Completion of spatial assessment of further expansion needs
- Analysis should provide project-by-project details on CAPEX and OPEX, including the timelines needed to develop each segment of the infrastructure”

As part of the work, the GSMP Consultant has worked with GTCL to obtain information and obtain access to plans and feasibility studies. The GSMP Consultant got access to operational reports for the recent years and three feasibility reports. Further, the GSMP Consultant worked with the GTCL experts on pipeline studio flow model for steady state simulation of the transmission system.

In comparison with the GSMP 2006, there has been an increase in production and consumption of gas. This means that Bangladesh has moved to another league with respect to gas infrastructure and instead of smaller pipelines connecting fields and consumption, there should now be a focus on creating a major backbone connecting the new LNG import terminals with the existing system and allow space for future growth. Whereas the GSMP 2006 was much focused on recommending compressor stations to help bringing the domestic production from north to south, the present plan is more tilted towards increase in pipeline transmission capacity and hereby also creating line-pack for short term intraday storage.

The proposed transmission plan is guided and developed by the following principles and parameters:

1. Need for flexibility of the system as the future production and import mix is uncertain. The system should hence be developed with a high focus on flexibility.

2. High gas demand in comparison to area – Bangladesh gas consumption by area is in line with Germany and already three times higher than France and Denmark. Within the planning period, the gas density will become in line with UK and Japan in the medium term and The Netherlands in the long term. Location of demand is uncertain which suggests large diameter pipelines as it would make it possible to connect new consumers.
3. High cost of land and hereby high cost for right-of-way, which will favour large diameter pipelines and offshore pipelines.
4. Technically, the main challenges are crossing of rivers, flooding and environmental impact.
5. Relatively constant gas consumption over the year as compared to countries using gas for heating. This ensures a high utilisation of gas pipelines and focus should therefore be on gas pipelines rather than compressors, which will have a high operational cost if market prices shall be paid for fuel gas.
6. Need to meet demand in all parts of the country, in particular the Western and Southern part of the country.
7. Integration with India and Myanmar, and hereby ensuring the possibility for import of gas.

7.2 Natural gas transmission fundamentals

Gas transmission – economics of scale

The foreseen increase in Bangladesh gas demand makes it possible to achieve economics of scale to bring down unit transmission cost. So far, the largest installed pipeline in Bangladesh is 36”, while 42” pipelines are planned. For comparison, the largest onshore pipelines normally used in Europe are up to 56”. However, for practical reasons the pipeline diameter is often limited to 48”.

In Bangladesh, the main technical hindrance for use of large diameter pipelines will be the crossing of rivers by horizontal drilling. Here it is possible to have difference in diameter between crossings and the rest of the system, which will require additional valve stations and pig launchers/receivers.

The economics of scale is due to the difference in capacity and cost as function of diameter. The capacity of a pipeline is proportional with D^2.5, while the cost is almost proportional with the diameter. Consequently, the largest possible diameter pipelines will be the preferred solution if the capacity can be used. Even if the pipeline capacity is not fully used during the initial years, there will be advantages as less use of compressors and line-pack.

Transmission and line pack – a dynamic approach for short term storage

The main purpose of the transmission pipelines is to transport gas from entry to exit points in the integrated system. However, due to the interday variation in the gas consumption with highest electricity consumption and production during the evening, there is not a constant flow in the system. In order to maintain a constant production from gas fields, it is therefore necessary with short term storage of gas. This is also provided in the pipelines by increasing pressure during night and decreasing during day and evening.

The line pack capacity ensures the short-term storage for variation in consumption during the day. The maximum line pack capacity is:

Line pack (max) = volume of the gas pipeline system * Max-Min operational pressure

As an example, a 42” pipeline with 100 km length will have a line-pack capacity of approx. 100 mmscf, assuming a pressure difference between 100% and 50% of design pressure. A 24” pipeline will only have a third of this line pack capacity.

Design and operational pressure

The Bangladesh gas transmission system has in general been designed for an operational pressure of 1000 psig. The new system is designed for 1135 psig (78 bar). This is in line with some European countries, while some new European pipelines are designed for higher pressure up to 1500 psig. In view of the interconnection with the existing gas transmission system in Bangladesh, we find it reasonable to use 1135 psig. For offshore pipelines it will be possible to use higher pressure, up to 2000 psig or more.

Gas or electricity transmission – balance between power and gas master plan

New power plants are one of the drivers for new gas transmission projects, as the alternative is to locate power plants close to the gas sources and transport electricity with higher losses. To illustrate the choice between power and gas transmission;

- 42" pipeline – capacity 1000 mmscf/day – 15,000 MW
- 400 kV AC overhead line 500-1000 MW

Assuming an efficiency of 50 percent for a power plant, **it will hence require up to 15 overhead lines to transport the same amount of energy as a large diameter gas pipeline.**

For Bangladesh this is relevant for the location of the power plant when starting import of LNG. Should the power plants be located close to the LNG import or should gas be transported to power plants distributed over the country.

In the PSMP2016, a number of power plants are foreseen close to the LNG import as no certainty was given for gas transmission. The aim of this update of the gas sector master plan is to create sufficient gas transmission capacity to secure a distributed location of power plants.

In the overall economic optimisation, the cost of gas and electricity transmission should be combined and optimally a combined plan should be developed. As this is outside the scope for the present study, the aim has been to give flexibility with respect to location of power plants.

Onshore versus offshore gas pipelines

Bangladesh has the possibility to install offshore pipelines in combination with onshore pipelines. This includes connection to offshore field development on shallow and deep water, but also offshore pipelines in parallel to the coast from the LNG import terminals to the Western part of Bangladesh.

The advantages of offshore pipeline versus onshore are that it can be shorter and can be designed to higher pressure. Further, the offshore gas pipeline can be used as a manifold for future connections of offshore gas fields.

The advantages of onshore pipelines are that there is less need for advanced offshore installation equipment and that onshore gas pipelines can be looped in sections as the need occurs. In any case, one onshore pipeline is needed to supply the gas consumers along the coast from LNG import to Chittagong and further to the centre of the country.

Land acquisition and Right of Way

Land acquisition and Right of Way constitutes significant part of pipeline cost. Examples available show a range from 15 to 40 % for different diameters of pipelines. Typically, the need for land is not much different for different diameter pipelines, which gives incentives to install large diameter pipelines.

7.3 Underground gas storage, small scale LNG and biogas

7.3.1 Underground gas storage

With the introduction of LNG, there will be increased dependence of external gas supply and of the weather conditions. It can be expected that the LNG terminals will only be operational between 80 and 90 percent of the time.

Underground gas storage of larger onshore LNG storage can ensure the continuous supply of gas. One of the options is to convert existing gas production fields to underground gas storage. This can be on- or offshore gas fields.

As an example, the offshore Sangu gas field could be converted to underground gas storage. In this case, compressors and process facilities could be located onshore. Hereby, the compressors can be used for normal line compression when not used for injection into the storage. The feasibility of such gas storage should of course be investigated before any decision, to date we are not aware of any relevant studies.

The cost of conversion of the offshore gas field to underground gas storage is assessed in the order of 200 m USD. There is a need to develop the concept before accurate numbers can be given.

Underground gas storage has not been explicitly modelled in pipeline studio.

7.3.2 Small scale LNG

When LNG import is established, it will be possible also to use small scale LNG for peak load plants in the western part of the country and for supply to part of the country not yet connected by pipeline. This can be done by barge transportation along the rivers. As an example, it will be possible to use LNG barges to transport gas to Khulna for peak load supply and hereby obtain a better utilisation of the overall pipeline system. LNG can also be used for ship and heavy road transport.

Small scale LNG has not been explicitly modelled in pipeline studio.

7.3.3 Biogas

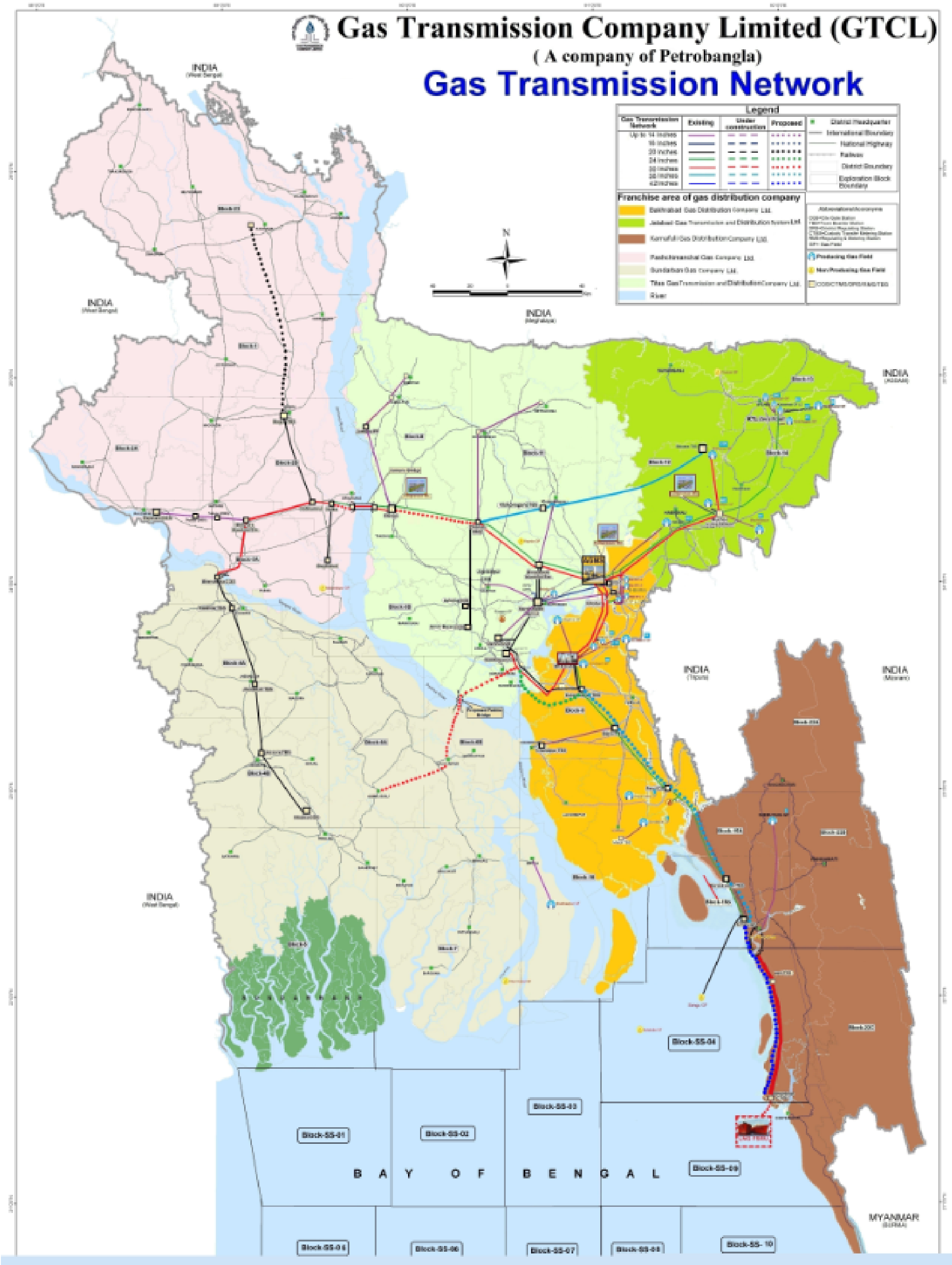
Biogas may become a considerable gas supply in Bangladesh. In some European countries up to 10 percent of gas supply is coming from biogas produced on manure, wood or other sources. In Bangladesh the infrastructure is still lacking and no input is taken into account in the modelling and planning.

7.4 Existing and planned gas transmission system

7.4.1 Existing system

The existing gas transmission system in Bangladesh has been developed over the last four decades based on the indigenous gas production and has grown organically by adding more new gas transmission pipelines and compressor stations.

Figure 81: Bangladesh gas transmission system 2016



Source: GTCL

Consequently, the system is most developed in the North-Eastern part of the country with connections to Dhaka, while the South and the West of the country has less developed gas transmission systems.

Due to the historical development of the system, the pipeline dimensions are small, with most pipelines having a diameter of 30” and less. This system has suited the historical supply/demand situation with a total daily consumption of up to 2500 mmscf. The demand has been higher, but has not been served due to lack of supply.

The challenge for the future gas transmission system is that the Bangladesh gas market will change in the following ways:

- Growth in gas demand
- Import of natural gas, via:
  - o LNG import facilities located south of Chittagong at Moheshkhali
  - o Import via pipeline from respectively:
    - Myanmar
    - India
- Location of new demand centres more evenly distributed over the country with new gas fired power plants and industries also in the South and Western part of the country

As the demand of natural gas will increase in the coming years, there is a need to install large diameter gas pipelines in order to achieve economies of scale and limit the number of pipelines in order to take up less space.

7.4.2 Projects under implementation and planned pipelines

A number of pipeline projects are under implementation, according to information from GTCL.

Table 24: GTCL list of gas transmission under implementation

Serial No.	Name of Pipeline	Dimention: (Dia x Length)	MAOP (psig)	Implementation Period	Location (District)
Pipeline Under Implementation					
1	Dhanua- Elenga and West bank of Bangobandu Bridge - Nolka Gas Transmission Pipeline Project	30"Ø x 67.20 km	1135	July 2014 - June 2017	Gazipur, Tangail, Sirajganj
2	Anowara-Fouzdarhat Gas Transmission Project	42"Ø x 30.00 km	1135	April 2016 - December 2018	Chittagong
3	Padma bridge Section Gas Transmission Pipeline Project	42"Ø x 6.15 km	-	July 2015 - June 2018	Munshiganj, Sariatpur
4	Chittagong-Feni-Bakhrabad Gas Transmission Pipeline Project	36"Ø x 181.00 km	1135	July 2016 - June 2019	Chittagong, Feni, Comilla, Chandpur
5	Maheshkhali-Anwara Gas Transmission Parallell Pipeline Project	42"Ø x 79.00 km	1135	July 2016 - December 2018	Chittagong, Cox's Bazar

Source: GTCL, Petrobangla, 2017

The aim of these pipelines is primarily to create a strong pipeline connection from the future LNG receiving terminals in the south to the Dhaka area.

GTCL has also planned a number of gas pipelines.

Table 25: GTCL list of proposed gas transmission pipelines 2017

Serial No.	Name of Pipeline	Dimention: (Dia x Length)	MAOP (psig)	Implementation Period	Location (District)
Pipeline Under Implementation					
1	Kutumbopur-Meghnaghat Gas Transmission Pipeline Project	30"Ø x 45.00 km	1135	July 2017 - June 2020	Comilla, Munshiganj, Narayanganj
2	2nd Bangobandu (Railway) Bridge Section Gas Transmission Pipeline Project	36"Ø x 10.00 km	-	July 2019 - June 2022	Tangail, Sirajganj
3	Langalband-Mawa and Janjira-Gopalganj-Khulna Gas Transmission Pipeline	30" x 175.00 km	-	January 2019 - December 2021	Narayanganj, Munshiganj, Sariatpur, Faridpur, Madaripur, Gopalganj
4	Bogra-Rangpur-Nilphamari Gas Transmission Pipeline Project	24"Ø x 160.00 km	-	July 2018 - June 2020	Bogra, Rangpur, Nilphamari
5	Zero point – Maheshkali CTMS	42"Ø x 7.00	-	-	Maheshkali

Source: GTCL, Petrobangla, 2017,

The aims of these pipelines are to strengthen the connection from the future LNG terminals and to create connection to the West of the country. This also includes creation of an east-west connection.

As described in the supply chapter about pipeline connections from Myanmar and India, there is a possibility to connect Bangladesh from Myanmar via the same pipeline which will be used for the LNG import. The most obvious connection from India will be in the western part of the country to Khulna from Haldia in India. Later on, there will be possibilities to connect with India in the North-West.

In our analyses of the need for new gas transmission systems, we assume that the projects under implementation and proposed Table 24 and Table 25 will be implemented as planned. In some cases, our analyses show that larger diameter pipelines should be used than proposed by GTCL.

7.5 Transmission system modelling

The transmission model aims to evaluate the capacity of the existing pipelines network that is used to supply Bangladesh with gas. The model is also used as a tool in order to investigate new pipeline sizes and routings within Bangladesh.

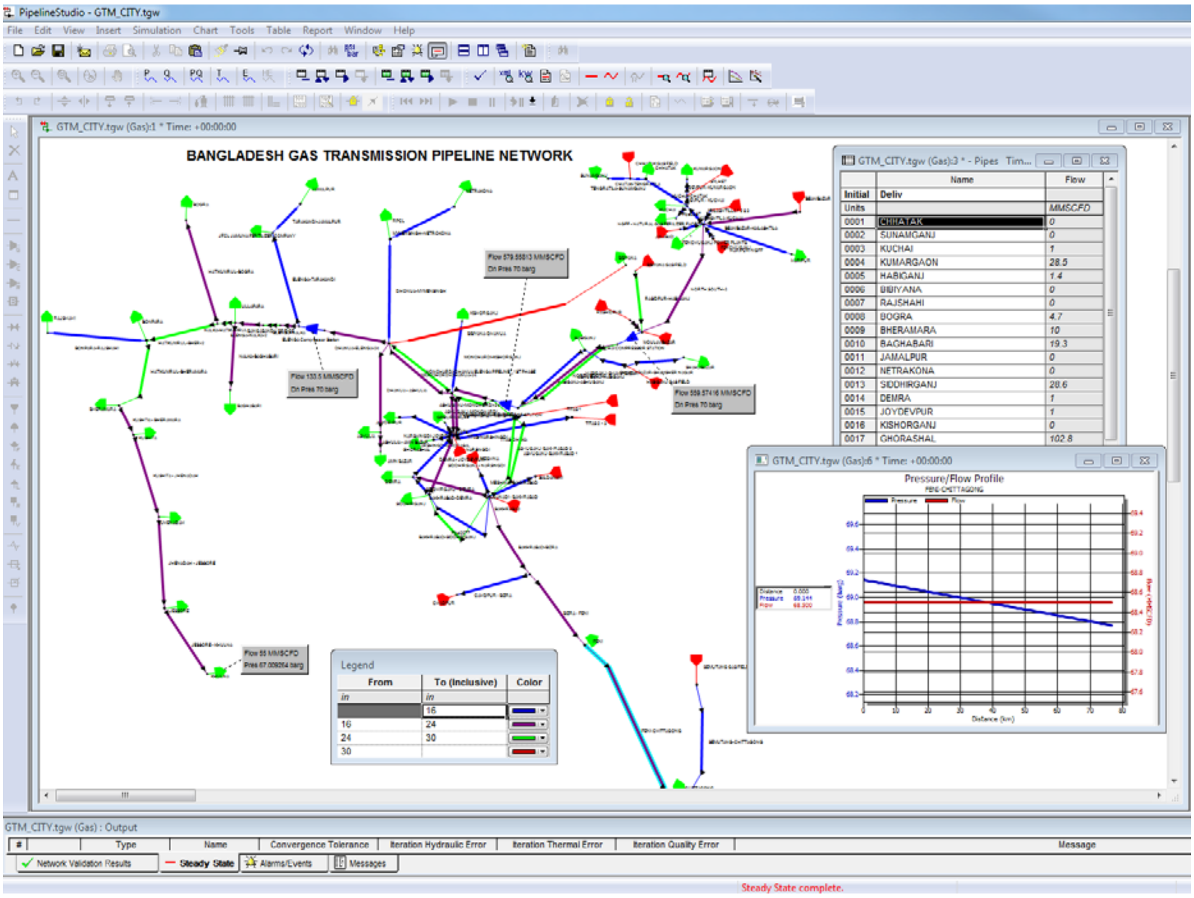
This investigation will make sure that from a technical stand point it is possible to meet the predicted increase of gas demand to different geographical areas within the Bangladesh gas transmission system. The model will fundamentally be used to run various scenarios on infrastructure based on the future gas demand and supply forecast.

7.5.1 Simulation tool

As the world standard for gas transmission system simulations, Pipeline Studio™, provides design and operations analysis for complex gas pipeline networks. A Pipeline Studio™ (gas) model for the country of Bangladesh's current transmission system has been built together with GTCL.

This includes the complex looped network system containing the multiple intakes from the individual gas fields, the main city gate delivery points, the major gas consumers as well as the compressor stations. The simulator incorporates advanced numerical solutions, detailed equipment modelling, and a graphical configuration environment as shown in the example in Figure 82.

Figure 82: Bangladesh Gas Transmission Pipeline Network Model



This model is to be used for designing any new required pipelines, to give an overall hydraulic analysis of the system network and to give an analysis of alternative development scenarios in line with future projections.

7.5.2 Model Input data

The model was built in conjunction with GTCL where their engineers supplied the exact input data and information required to represent the current operating infrastructure.

The gas qualities considered for the system evaluations are given in Table 26.

Table 26: Gas composition for capacity evaluations

Name	Value [Unit]
Specific Gravity	0.6
Heating Value	1000
Carbon Dioxide	0 %

The diameters and lengths for the existing pipelines are summarised in Table 61 in Appendix 4.

The operational conditions considered for the capacity evaluations are summarised in below Table 27.

Table 27: Operational conditions and assumptions for the pipelines

Parameter	Units	Value	Comments
System Minimum Operating Pressure	psig	300	Operation data shows lower cases
System Maximum Operating Pressure	psig	1050	
Pipeline inlet temperature	°F	65	
Maximum Compressor Discharge	barg	1030	ELENGA, ASHUGANJ & MUCHAI

7.5.3 Short term modelling with proposed new pipelines 2021

The Consultants have performed an analysis of the gas transmission system for the foreseeable short term focusing on the proposed projects up until 2021 and using the The Consultants production and demand forecast for 2021 from the previous sections. It is to be noted that only a steady state analysis has been performed and in reality the system is dynamic. Details of the modelling assumptions are given below.

Other model Assumptions:

a) The steady state is achieved by adding or increasing capacity wherever bottlenecks are identified.

b) Indigenous gas production is 2639 MMCFD;

c) Up to 1500 MMCFD of R-LNG is available at Moheshkhali;

d) Up to 500 MMCFD of R-LNG is potentially available from Odisha via a 70 km border pipeline with INDIA;

e) Total gas demand is 4610 MMCFD;

f) Gas fields can meet 1030 psig;

g) Gas is available via the cross-border connections at 1050 psig.

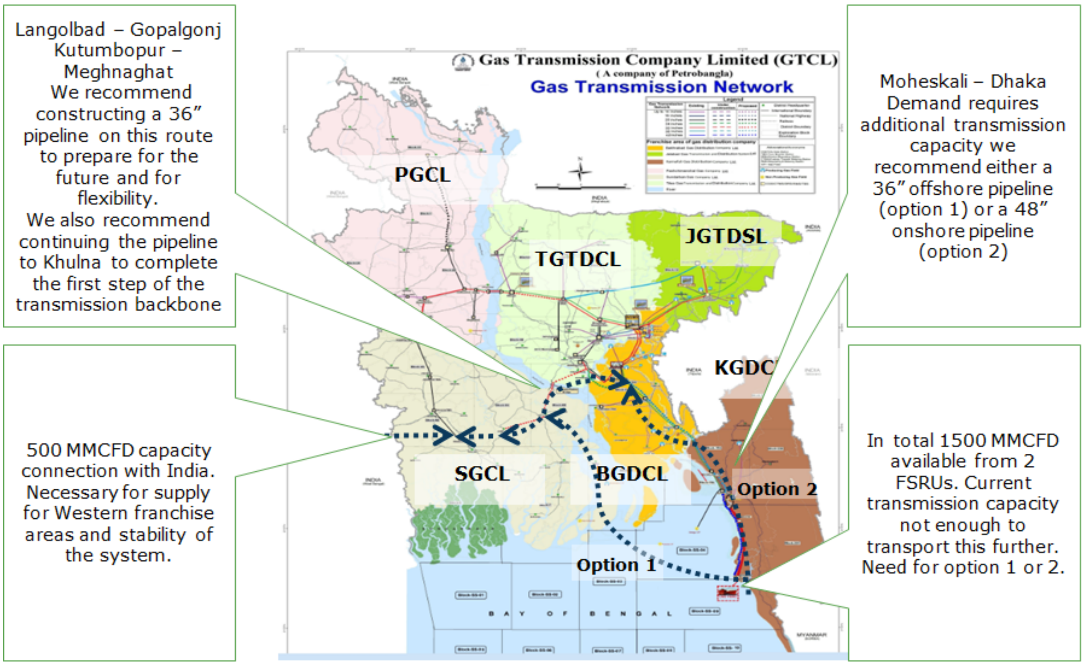
The transmission system is able to operate and supply the following amount of gas to each region:

Bakhrabad	518
Jalalabad	482
Karnaphuli	657
Pashchimanchal	175
Sundarban	524
Titas	2254
Total	**4610**

The first key finding in the short term is that with the transmission system as 2021 there will be challenges in meeting demand with a potential short fall of around 500 MMCFD. Theoretically, this shortfall could be spread out over the entire country. However, realistically, the shortfall in gas will be felt mostly at the end of the transmission system, specifically in Khulna in the SGCL franchise area, as gas either from the south east or from the north east would have to be transported across the country to reach the west. If this area is prioritised at the expense of another area, the Elenga compressor station would have to be turned on. The best solution for resolving the potential shortfall in volumes and corresponding transmission capacity has been identified and comprises of a pipeline from India (connection at Khulna), an additional 3rd LNG terminal in south east at Moheshkhali and a large onshore pipeline connection Moheshkhali to the west of the country via a system loop with pipelines from Langlband to Khulna.

The GSMP Consultant recommends the pipeline from India to Khulna as this connection will increase system stability, security of supply, and strengthen the bargaining position of Bangladesh towards external suppliers. Given the supply and demand situation in 2021, we recommend a third LNG terminal at Moheshkhali. This will trigger a need for additional transmission capacity from Moheshkhali. It can be argued whether this should be an offshore or onshore pipeline solution. Ideally from a technical perspective, we would recommend the offshore pipeline; however, this will take more time to plan and execute. It is also most likely that the onshore pipeline can be completed in the short term and therefore given the urgency required for meeting the short-term demand capacity. It is recommended to pursue the onshore solution first. The onshore solution also has the advantage that it can be built in sections and that investment money largely stays within the country. However, the offshore pipeline is still to be required in the mid/long term strategy, so it is recommended to start feasibility studies immediately for this.

Figure 83: Short term additional investments



Source: Ramboll

The second key finding of the short-term modelling is that if the India connection is not built, more volumes and capacity are needed which will need to come from the south east at Moheshkhali with a 4th LNG terminal (triggered by the additional volumes). With the current plans for LNG, the 4th terminal is likely to be a land-based terminal – in that case reaching completion by 2021 will be difficult. Alternatively, the volumes could be secured by connecting the transmission system with Myanmar (also from the south east); however, we also doubt this can realistically be achieved by 2021. In any case (Myanmar or a 4th LNG), the transmission capacity would need to be expanded.

System optimisation and usage of existing compressor stations

Finally, depending on the exact delivery demands and supply locations, it may be beneficial to lower the pressure at Ashuganj/Muchai compressor station in order to help the gas flow from the south east of the country to the west. A more detailed study is required to definitively determine this.

Prepare the system for future growth – exploit economies of scale

It will be essential for the supply of gas to the west that the 30" x 45 km pipeline Kutumbopur – Meghnaghat and the 30" x 140 km Langolbad – Gopalgonj pipelines are constructed. We recommend a higher capacity of the pipelines (36") to accommodate future growth in gas demand. We would also recommend connecting Gopalgonj and Khulna to complete the first step of the transmission backbone also creating a system loop. The connection would serve as an important part of the major transmission backbone of the country and facilitate further expansions and connections of power plants. Without these investments, the ELENGA compressor must be turned on to supply the west of the country with 500 MMCFD.

Looking at demand post 2021, it quickly becomes evident that the pipelines suggested by GTCL are undersized to carry the volume further in the system. Thus, at this stage, we recommend installing larger dimensions pipelines to accommodate with future demand. Of course, for pipelines where materials have already been purchased or even installed this might prove to be a challenge. In these cases, we suggest carrying on as is.

Short term gas transmission network development – 2021

Based on the pipeline studio modelling combined with the need for gas transmission in the long term, The Consultants' recommendations for the short-term network development will be the following pipelines and compressor stations in addition to the projects already under construction.

Table 28: Gas transmission projects – short term up to 2021

		Type	Length	Diameter GTCL	Diameter Ramboll	CAPEX Cost	Finished
			km	Inch	inch	USD Million	
1	Moheshkhali-Anowara	Parallel	79	42	42	140	2018
2	Kutumbopur-Meghnaghat	Parallel	45	30	36	175	2021
3	Bangobandhu (Railway) Bridge Section	Parallel	10	36		20	2021
4	Langolbad-Maowa		45	30	36	60	2021
5	Gopalgonj to Khulna	New East-West	90	30	42	200	2021
6	Bogra-Rangpur-Nilphamari	Parallel	160	24	30	100	2021
7	Moheshkhali – Dhaka Region		320	48/52	48	480	2021
8	India- Khulna	New	70	36	36	150	2021
	Various smaller pipelines for connection of power plants 5@ 30 km	New and parallel	150		30	180	2017-2021
	Compressor					50	2021
	Meter station India					30	2021
	SCADA					40	
	Total					1625	

Source: GTCL, Ramboll

MEDIUM TERM (2031) TRANSMISSION SYSTEM MODELLING – SURGE IN DEMAND REQUIRES COMPLETION OF THE MAJOR TRANSMISSION SYSTEM BACKBONE

The medium term (2031) has been modelled building upon the infrastructure included in the short term and the connection to India at Khulna. In between 2021 and 2031, we project an increase in demand from approximately 4500 MMCFD to just above 6500 MMCFD. On the domestic supply side, we would expect that some E&P results have been achieved between 2021 and 2031 increasing the domestic production from 3000 MMCFD to 4800 MMCFD. These are uncertain figures and do of course rely on following the recommendations on the E&P. The import capacity has been set to allow up to 500 MMCFD from India (connection at Khulna). From the south east, we allow up to 2000 MMCFD. We do, however, on purpose not specify the source of the volumes from the south east as these can be achieved from either additional LNG, from Myanmar or from offshore domestic production. Time will show how these sources develop in feasibility and we find that keeping the flexibility to adjust is important and prudent.

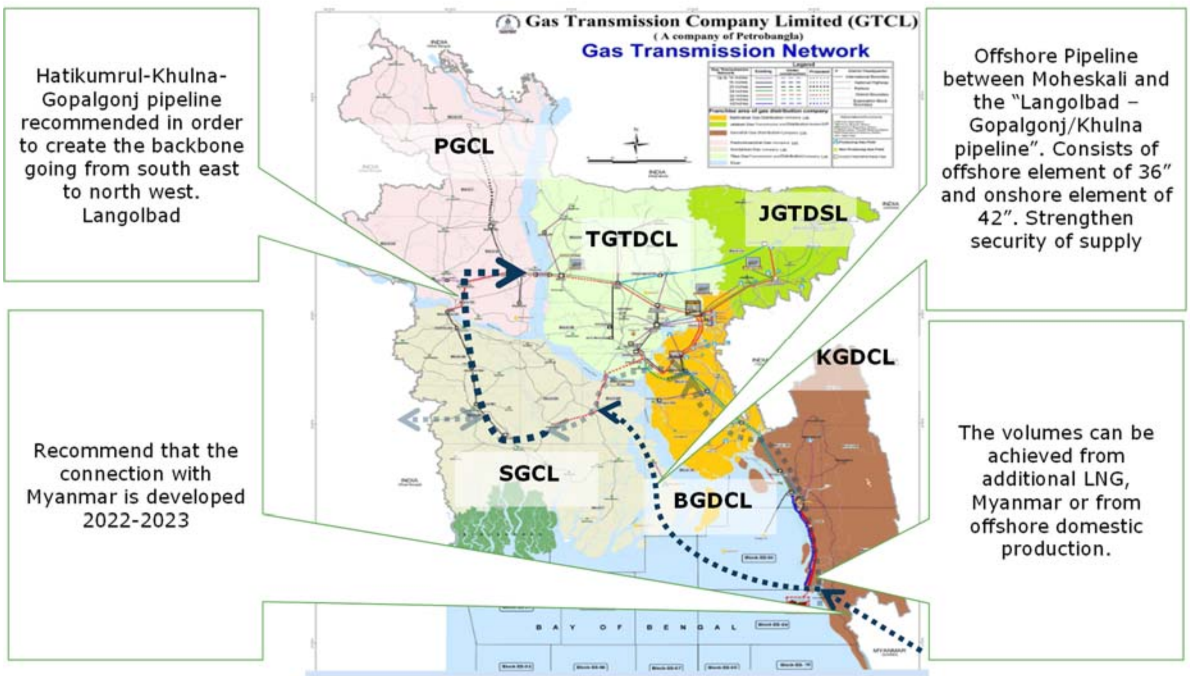
Large scale transmission capacity from Moheshkhali onshore and offshore required to facilitate import

Regardless of the source of the gas volumes from the south east, we find that in order to meet the gas demand in the Titas, Pashchimanchal and Sundarban regions, the following projects must be completed:

Offshore Pipeline between Moheshkhali and the "Langolbad – Gopalgonj/Khulna pipeline"

We recommend a 36" x 150 km offshore pipeline and a 42" x 150 onshore between Moheshkhali and the Langolbad – Gopalgonj/Khulna pipeline. The actual routing of the pipeline will have to be adjusted to connection points to power plants and other large consumers as well to right-of-way and environmental constraints. The connection will apart from evacuating the gas form south east at Moheshkhali, strengthen security of supply not only in the western part of the country but in fact help the entire country as dependence on the narrow onshore corridor is reduced. To facilitate the transport further in the system, it is necessary that the diameter of the connecting *Langolbad – Gopalgonj/Khulna pipeline* is 36".

Figure 84: Medium term additional investments



Hatikumrul - Langolbad – Gopalgonj/Khulna pipelines
As part of the backbone from south east to north west, we recommend that the offshore pipeline is continued (36” x 120 km) further to Hatikumrul in the north-western part of the country. The routing should preferably follow the existing transmission system.

Finally, one intermediate compressor station is potentially required between Moheshkhali and Dhaka. A detailed study is required to definitively determine this.

Medium term gas transmission network development
The investments in the medium term will depend on the actual development of the indigenous gas production. However, in all cases, we foresee the need to strengthen the gas supply from the LNG import facilities and/or Myanmar, which is the nearest country with surplus gas production.

Based on the pipeline studio modelling combined with the view of long term use of the gas transmission, the following investments are proposed. The actual of implementation will need to be adjusted as the market develops. Also, we have an underground gas storage in the period in order to allow for market integration and system balance which can facilitate import of gas but also ensure security of gas supply, better utilisation of LNG terminals and possible transit of gas from Myanmar to India.

Table 29: Transmission projects in the medium term to 2031

		Type	Length	Diameter GTCL	Diameter Ramboll	Cost	Finished
1	Myanmar	Inter			36		2022
2	Moheshkhali – West Bangladesh offshore pipeline		150		36	300	2026
3	Maheshkhali – West Bangladesh onshore pipeline		150*		42	250	2026
4	Hatikumrul - [Langolbad – Gopalgonj/Khulna pipelines]		120		36	180	2026
5	Compressor					50	2026
6	Underground gas storage					200	2026-2028
	Various smaller pipelines for connection of power plants 5@ 30 km	New and parallel	150		30	180	2022-2031
	Total investment from 2022 to 2031					960	

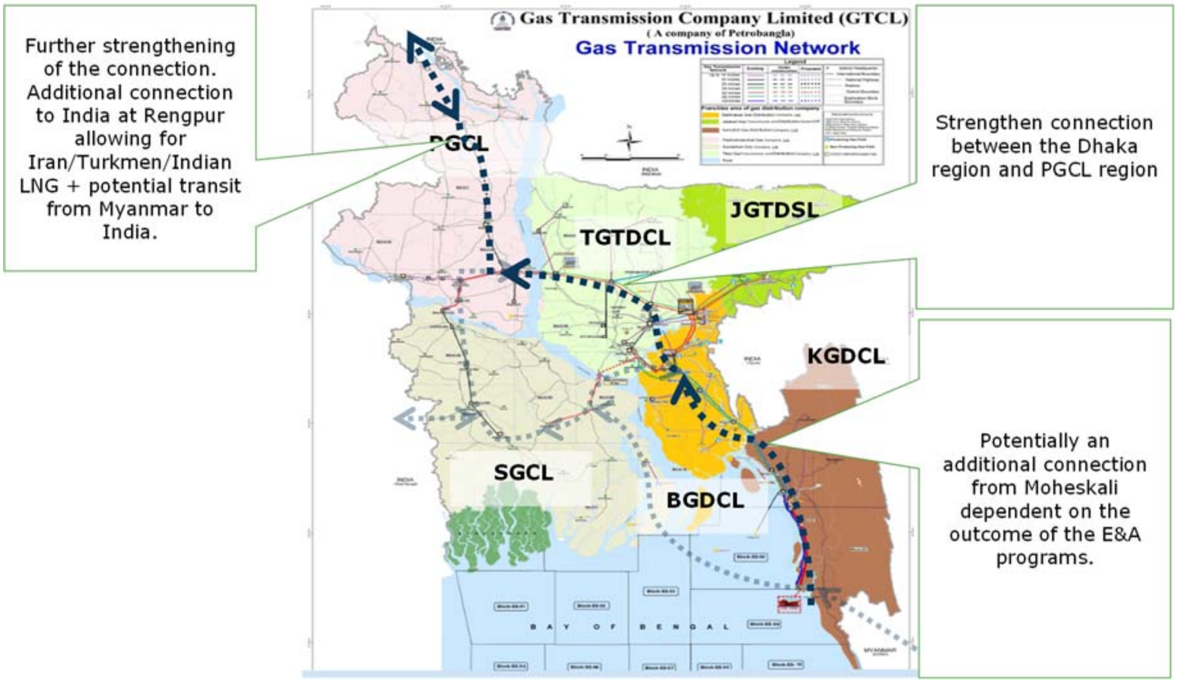
* Could be longer depending on landfall and chosen connection to the transmission grid

LONG TERM (2041) TRANSMISSION SYSTEM MODELLING – UNCERTAINTY AHEAD FOCUS ON FLEXIBILITY AND KEEPING OPTIONS OPEN

The situation in 2041 has so much uncertainty about the actual gas production, import via LNG and pipelines, as well as the actual location of gas consumption. Therefore, the GSMP Consultant has decided not to further attempt to get the model to converge for this year but instead envisions the design of a flexible system, which will be able to adapt to most of the uncertainty by creating a strong backbone of the gas transmission system from the LNG import terminals, south of Dhaka and further to the Western part of the country.

As the import of gas supply increases, the indigenous gas production will increasingly be used close to the gas production or cease to exist in 2041. This situation may result in an operation where the pressure in the system close to production can be somewhat lowered and perhaps even the flows reversed. Further to the gas transportation, a system with large diameter pipelines will also be able to provide additional line pack flexibility to ensure gas demand variations during the day. To further increase flexibility and as back up for LNG supply in case of severe weather conditions, the Consultants also recommend converting an existing gas field to underground gas storage.

Figure 85: High level Long Term Gas Transmission Plan[5]



Source: Ramboll

Post 2031, the GSMP Consultant estimates that there could be possibilities to get Turkmen/Iranian gas if the TAPI pipeline is constructed. Thus, an additional connection to India at Rngpur in the north is envisaged. The connection should also enable bidirectional flow allowing potential excess production from Myanmar to transit through Bangladesh to India. The length of

[5] The map shows the general envisioned back bone required for the long-term plan of the network. Exact sizes and routings should be studied further in feasibility studies but it is recommended at least one 42" pipeline connects the south east to the north west of the country and as large as possible pipelines should be implemented.

the backbone from the Myanmar to the Indian border is approx. 500 km. It is recommended to develop this as a large diameter pipeline, even if such diameter is only required in the longer term to avoid investing in small diameter pipelines.

In general, the system in Bangladesh has so short pipelines that intermediate compression is only necessary in few cases to ensure sufficient flow.

- One intermediate compressor station between Moheshkhali and Dhaka – location suggested at Feni
- Compressor station could be combined with offshore underground gas storage Sangu field – the feasibility of this should of course be investigated before any decision, to date we are not aware of any relevant studies.
- Border station Myanmar
- Border station India (Khulna)
- Gas field compression – in particular when fields are being depleted

In addition to line compressor stations, there maybe a need for field compressor stations when the production pressure becomes lower than the needed pipeline pressure. By using increased volumes close to the gas fields, it may be possible to lower the operational pressure of the pipelines closed to production.

Long term gas transmission investments

The long-term investments from 2032 to 2041 are difficult to break down into actual projects. However, some of the investments will include at least one large diameter pipeline extra from the LNG import point to Dhaka and further to the west as shown in Figure 8.

Table 30: Long term pipeline investments

	Type	Length	Diameter GTCL	Diameter Ramboll	Cost	Finished
1	Moheshkhali – Dhaka Region	250		56	560	2034
2	Dhaka region – Rangpur*	300		48	580	2036
3	India (Rangpur)					
4	Various smaller pipelines to power plants – 10 @40 km	400		30	480	2032 to 2041
5	Compressor				50	2036
6	New SCADA				50	
	Total investment from 2032 to 2041	950			1720	

* Subject to further evaluation. Gas could potentially be transferred by existing infrastructure

The actual routing of the large diameter pipeline will have to be adjusted to connection points to power plants and other large consumers as well as to right-of-way and environmental constraints.

8. REGIONAL GAS NETWORK

8.1 The regional Euroasian gas network and supply possibilities

The Bangladesh gas system is at present isolated from other countries. As gas networks in Asia are being developed, it will be possible to integrate the Bangladesh gas network to neighbouring countries and hereby also to supply from countries with large gas reserves. Most obvious will be the integration with India and Myanmar. However, if such integration shall make sense, it is also important to view how these two countries are connected to the rest of Asia.

In recent years, a number of major decisions on development on creation of an Euroasian gas market have been made, of which the more important are Myanmar-China pipeline, Myanmar-Thailand pipeline, Turkmenistan- China pipelines and Russia-China pipelines. With the demand developments in Bangladesh, it would be obvious to connect Bangladesh with the gas transmission systems of the neighbouring countries.

Figure 86: Pipeline infrastructure in the region

The next big step in this development may be the TAPI pipeline between Turkmenistan and India via Afghanistan and Pakistan. Iran-India is another possibility, either via Pakistan or via Oman and an offshore pipeline between Oman and India.

So far, the pipelines between Turkmenistan and Iran to India have been hold back due to lack of market in India. With a renewed increase in gas consumption in India and possible connection between India and Bangladesh there could be sufficient market for development of the pipelines.

For Iran, which so far does not have any LNG facilities, the South Asian market is interesting as gas prices have fallen so much that development of greenfield LNG facilities for the time being are hardly economically viable. Also for Turkmenistan, which the South Asian market is an attractive alternative to the EU market (via Iran and Turkey) or China (via Kyrgistan, Kazakhstan and Uzbekistan) is an attractive solution, with ensured long term demand. Russia and India have recently announced the study for a Russia to India pipeline, either directly via Himalaya or via Iran and Pakistan.

8.1.1 Tapi (international gas transmission pipeline)

The Turkmenistan–Afghanistan–Pakistan–India pipeline will transport Caspian Sea natural gas from Turkmenistan through Afghanistan into Pakistan and then to India. The total length of the TAPI pipeline will be 1,814 kms. A 214-km section of the pipeline will run through Turkmenistan, a 774-kilometer section will run through Afghanistan and an 826-kilometer section will run through Pakistan. The pipeline will be 56 inch diameter with a working pressure of 10,000 kPa. The capacity will be 33 billion cubic metres per year of which 5 billion cubic metres will be provided to Afghanistan and 14 billion cubic metres each to Pakistan and India. Six compressor stations would be constructed along the pipeline. The pipeline is expected to be operational by 2019.

8.1.2 India – Bangladesh – Myanmar gas pipeline (mbi pipeline)

This pipeline project has been conceived under the Hydrocarbon Vision 2030 for North-eastern region and is planned to connect Chittagong, Bangladesh then Sitwe, Myanmar with north-eastern states. A lot of gas is burned in the north-east as it cannot be supplied due to lack of infrastructure. As part of Hydrocarbon Vision 2030 for North-eastern region, 6,900 km pipelines would be laid connecting Sitwe (Myanmar), Chittagong (Bangladesh), most north-eastern states, Siliguri and Durgapur. Thirteen routes with a total length of about 6,900 km of pipelines have been proposed for the purpose.

8.1.3 Russia – India gas transmission business & plans

India and Russia have agreed to explore building natural gas from Siberia to India. The project envisions connecting the Russian gas grid to India through a 4,500-6,000km pipeline. The natural gas produced in East Siberian fields is to be pumped into Russian gas grid, which would be connected to India through the cross-country pipeline network.

The shortest route will entail bringing the pipeline through Himalayas into northern India, a route which poses several technical challenges. Alternately, the pipeline can come via Central Asian nations, Iran and Pakistan and into Western India. However, the route will be expensive when compared to the long discussed but shorter and cheaper Iran-Pakistan-India pipeline. Tehran may suggest India take its gas through IPI rather than building such an expensive pipeline.

8.1.4 Sage pipeline

Based on the discovery of Farsi Block gas field in Iran by OVL, India has already planned to transport the produced gas through pipeline or by means of LNG. Hence, India developed a master plan in early 2008 to transport the produced natural gas from Iran to India through subsea pipeline across the Arabian Sea & revalidated the same in 2010. This plan has been given to SAGE (South Asia Gas Enterprise Pvt. Ltd.) to develop further.

SAGE is promoted by the New Delhi based Siddho Mal Group, in Joint Venture with a UK-based Deepwater Technology Company. SAGE Pipeline Infrastructure plans to transport 8 TCF of Natural Gas over the next 20 years from the Gulf Region to the coast of India using the Deep-sea route. The pipeline passing through the Arabian Sea will reach depths of 3,400 metres under the sea and will have a length of approximately 1,300 kms.

Qatar, Iran, Iraq and Turkmenistan together have enormous Natural Gas reserves to the tune of 2,000 TCF and SAGE plans to transport some of this to India through its Deepwater Pipeline Infrastructure. The option of Gas Swaps between these nations is also being explored.

8.1.5 Jagdishpur-Haldia gas transmission pipeline (Gail)

Jagdishpur-Haldia Pipeline (JHPL) is an extension of gas transmission pipeline from Jagdishpur, Uttar Pradesh to Haldia, Kolkata. This pipeline connects the eastern part of the country with the national gas grid. JHPL will feed natural gas to industrial, commercial, domestic and transport sectors in West Bengal. The other phase of the JHPL will also connect Patna, Bihar. MoPNG has also proposed future extension of JHPL which would feed far North-eastern part (Guwahati, Assam) of India.

The JHPL is said to be 2620 Kms long and it will be constructed in different phases to connect Gaya, Patna and Haldia. The JHPL is laid with different size of pipes based on its requirement and it is expected to handle 16 MMSCMD of gas flow. As of now, 90 Km of pipeline has been laid and it is anticipated to be commissioned in 2019 - 2020.

Figure 87: Ongoing JHPL (Red Route) & Future Pipeline Extension to Assam (Blue Route)

8.2 Feasibility for gas transmission hook-up to Bangladesh from India

Due to increase in demand for natural gas in Asian countries like Afghanistan, Pakistan, India & Bangladesh, several Gas Transmission Pipelines have been proposed with mutual agreements and discussions to import natural gas from Gulf countries. Based on the recent pipeline project, development & extension of the gas transmission grid which connects Haldia & Guwahati eastern region of India marks the possibility of hook-up connection to Bangladesh.

The JHPL network which terminates at Haldia is forecasted to have Gas Boosting Station and considered to be hub for gas distributing city. Haldia is located approx. 125 kms southwest of Kolkata. This JHPL network is under construction which connects Gaya in between. From Gaya, it runs to connect Patna & Barauni, Bihar as well. A 750-km proposed natural gas pipeline will link the Northeast with the national grid to meet increasing fuel needs of households and factories in the region. The proposed pipeline will have a capacity of 15 MMSCMD and will source gas at Barauni from Jagdishpur-Haldia pipeline being built by GAIL to connect Guwahati, Assam.

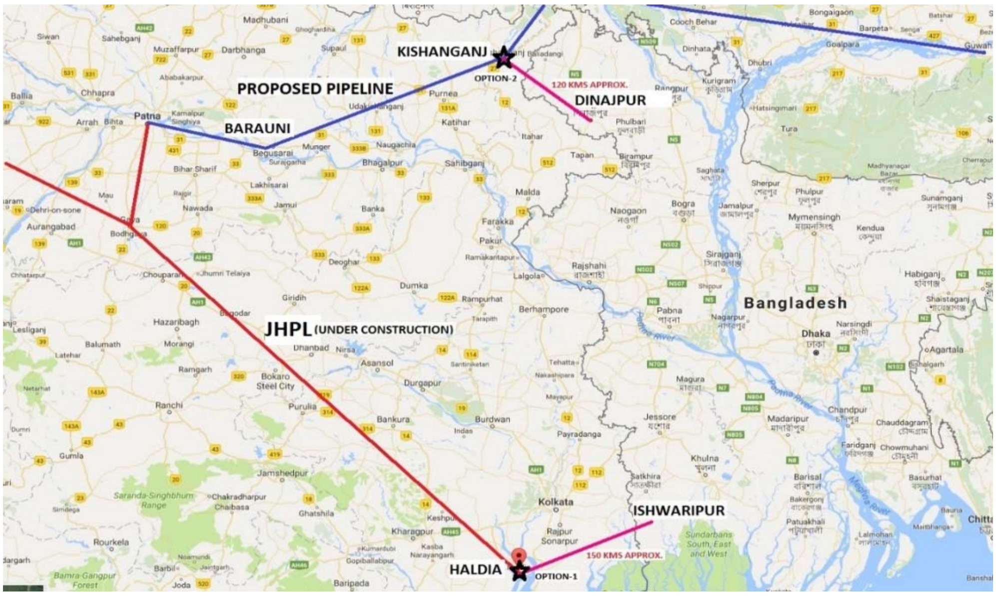
OPTION-1

For the transport of natural gas from India to Bangladesh, the feasible hook-up location will be Haldia, Kolkata as Jagdishpur-Haldia Pipeline is an ongoing project and from Haldia the natural gas can be transported to South-West part of Bangladesh. A pipeline of approx. 135 kms can be connected to Boalia, Satkhira, Bangladesh from Haldia, Kolkata This hook-up connection can supply gas to the southern region of Bangladesh.

OPTION-2

For the transport of natural gas from India to Bangladesh, the feasible hook-up location will be Kishanganj, Bihar. A pipeline of approx. 120 kms can be connected to Dinajpur, Bangladesh from Kishanganj, Bihar which shall see few river crossings as well. This hook-up connection can supply gas to the northern region of Bangladesh. It is to be noted that the blue route pipeline in the below figure is still under proposal stage by India.

Figure 88: Feasibility Options for Hook-up



The provided options above for the gas transmission pipeline which connects Dianjpur from Kishanganj and Ishwaripur from Haldia will see an important advantage as these cities will be nearby locations to planned Gas Transmission Grid in Bangladesh.

8.3 Myanmar gas network and supply situation

8.3.1 Reserves, production and consumption

Myanmar gas reserves have increased rapidly in recent years as the political development has attracted renewed interest in the sector. In 2016, the reserves according to BP more than doubled to 42 tcf from 2015 to 2016. The gas reserves in Myanmar are consequently more than six times the Bangladesh gas reserves and of the same size as the Indian gas reserves.

Gas production in Myanmar has increased rapidly in recent years and is now 1.8 bcf/year, while consumption is limited. Consequently, most of the gas was exported to China and Thailand, respectively.

Myanmar has the highest R/P ratio in South and South-East Asia.

8.3.2 Gas transmission infrastructure Myanmar

The gas transmission system in Myanmar is based on export of gas to Thailand and China, respectively.

The Myanmar-China gas pipeline connects the offshore gas fields of Myanmar to China. The pipeline was commissioned in 2013 and production and export have slowly increased.

The Myanmar-Thailand pipeline connects the Total operated gas fields in Myanmar with Thailand via off- and onshore gas pipelines.

8.3.3 Myanmar- Bangladesh trade options

For the GSMP2016 the import of gas from Myanmar was not considered. Instead, the Myanmar gas reserves were developed for export to China and continuous export to Thailand.

India has been developing plans for import of gas from Myanmar to India, with a possibility of crossing Bangladesh.

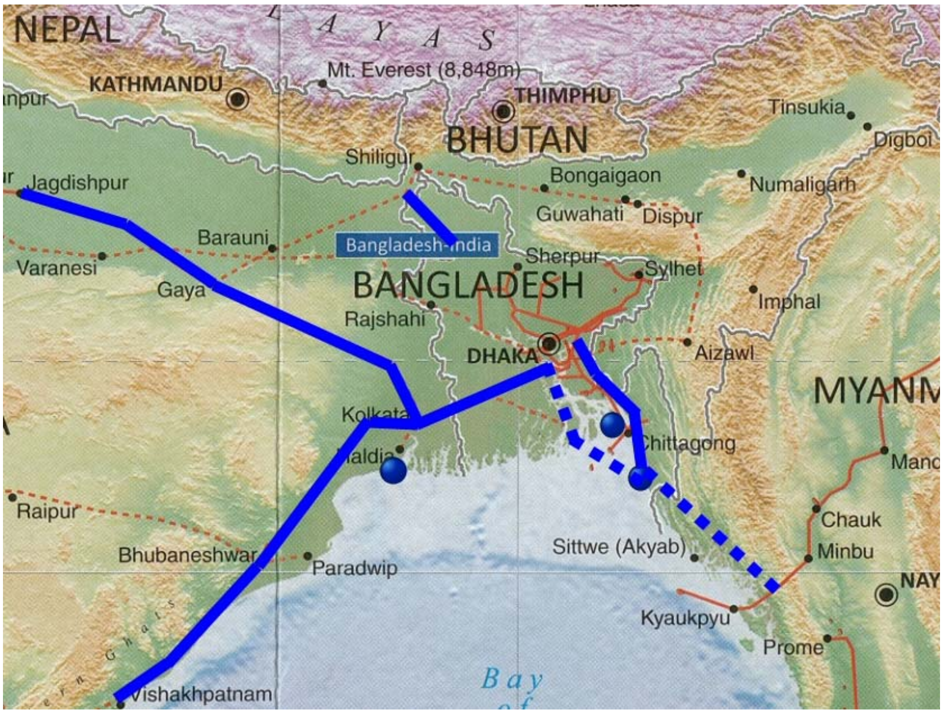
From a technical point of view, the development of gas trade between Myanmar and Bangladesh can take place by installing a short pipeline of around 300 km from the landfall of the Myanmar offshore gas fields to the planned LNG import terminals in Bangladesh, and hereby using the same infrastructure from this location to Chittagong and further to Dhaka. This route can also constitute a part of a future route to India.

As long as there are new discoveries and developments in Myanmar, it may be possible to purchase such spare gas.

8.4 Recommendations for integration in “Bay of Bengal” gas market

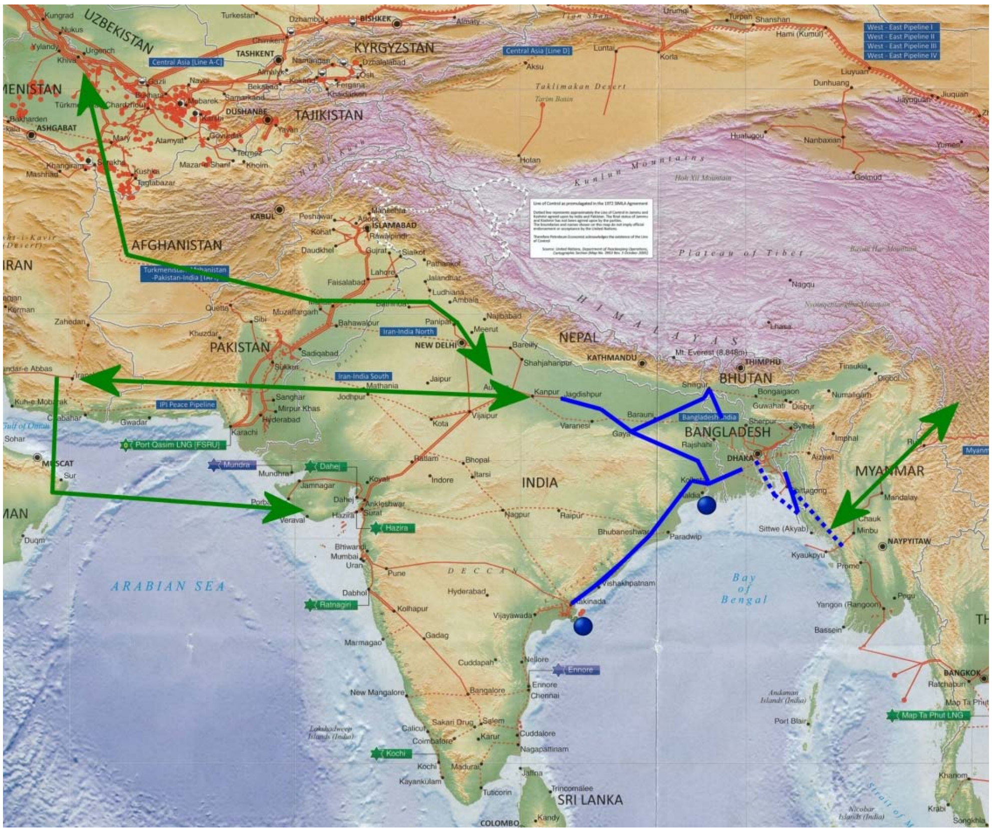
Based on the development in India, it is recommended to initially evaluate the possibilities for interconnection of India and Bangladesh already in the short run to share the LNG developments and need for back-up facilities. This will only require a relatively short pipeline of less than 200 km. A connection between Myanmar and Bangladesh will make Bangladesh an important bridge between South and South-East Asian gas markets.

Figure 89: Myanmar – Bangladesh – India pipeline connection possibility



On the longer term, Bangladesh can become part of an integrated Euroasian gas market with indirect connections and agreements to Russia, Iran and Turkmenistan. By connecting Bangladesh to Myanmar and India it is possible to create a “Bay of Bengal” gas transmission system and consequently also a gas market.

Figure 90: Possible "Bay of Bengal" integrated gas transmission system in Euroasia market



By integrating the gas transmission systems in Bangladesh with India and Myanmar, it will be possible to share the LNG import facilities in India and Bangladesh and hereby improve technical security of gas supply. This is in particular important as severe weather conditions in the Bay of Bengal can close more terminals in Bangladesh at the same time.

In the short term, it will be possible to increase the utilisation of the Indian LNG import terminals, which is presently only around 50 %.

Myanmar can benefit by having both Bangladesh and India as new markets for gas in addition to Thailand and China. This may make it easier to attract international oil and gas companies for exploration and development.

The Consultants strongly recommends accelerating the work on integration between the three countries. This can initially be done by creating a forum with participants from the three countries.

9. LNG IMPORT

LNG supply availability is of paramount importance to the continuity of gas supply in Bangladesh, since indigenous production is declining and there is no short-term production to offset the demand-supply gap.

As of January 2017, the total nominal capacity of global liquefaction plants is 340 MTPA. Liquefaction capacity additions are poised to increase over the next few years as 114.6 MTPA of capacity was under-construction as of January 2017. Furthermore, given the abundant gas discoveries globally and the shale revolution in the US, it can be expected that this figure will grow significantly in the years to come. According to the World IGU Report, this figure is around 879 MTPA. Global Regasification capacity increased nearly 800 MTPA by the beginning of 2017, mainly supported by additional capacity coming online in established markets such as China, Japan, France, India, Turkey, and South Korea.

With respect to LNG trade World, IGU report for 2017 informs that for the third (3) consecutive years, global LNG trade set a new record reaching 258 MT. This marks an increase of 13.1 MT (+5%) from 2015. The growth rate in 2016 was a noticeable increase from the average growth of 0.5% over the last four years. The continued addition of supply in the Pacific Basin, primarily in Australia, as well as the start of exports from the United States Gulf of Mexico (US GOM) enabled this increase.

As there are sufficient worldwide LNG resources to supply Bangladesh's gas import requirements, the import of LNG seems to be favourable.

9.1 Locations for all LNG Import facilities

As described previously, gas supply and demand balance forecast revealed the tremendous shortage of the natural gas supply. Therefore, the introduction of LNG would be the practical option in order to compensate the huge gap between the demand and supply. The LNG receiving facilities must be constructed in Bangladesh. The constructions of proven onshore facilities require a great amount of cost and time. While contrary, the offshore gas receiving facility has developed and does not require that much expenses and time.

The purpose of this section is to review the key elements that will allow securing the stable natural gas supply to bulk users such as power stations and fertilisers in the future. Several key challenges are anticipated from the technical perspective in order to achieve an economic and energy effective LNG terminal.

9.2 Overview of LNG Terminal Development Plans

Bangladesh will need to install sufficient LNG receiving and distribution facilities to support domestic gas demand requirements. Minimum commitments to purchase LNG will be necessary at levels to support the long-term financing, construction and operations of these faculties.

Based on the analysis done in Chapter 4, Bangladesh will need to procure significant amounts of natural gas until 2041. And the latter objective is aimed to be achieved with the following projects listed in the table below, provided by RPGCL:

Table 31: Proposed LNG terminals Bangladesh

SL. No.	Type	Terminal Operator	Operator Country	Location	Flow Rate (mmcfd)	Commissioning Schedule	Project Type	Status
1	FSRU	Excelerate	USA	Moheshkhali (E 91°49'07", N 21°32'04")	500	Apr-18	BOOT	TUA and IA signed
2	FSRU	Summit	Bangladesh	Moheshkhali (E 91°48'24", N 21°33'4.8")	500	Oct-18	BOOT	TUA and IA signed
3	Land Based Terminal	HQC	China	Moheshkhali (E 91°50'9.51", N 21°32'52.79") (E 91°50'41.39", N 21°33'19.41") (E 91°51'36.88", N 21°33'4.20") (E 91°51'5.93", N 21°32'37.44")	1000	Dec-21	BOOT	MoU signed and Contract signed for feasibility study
4	FSU	HSMPL	Bangladesh	Kutubdia (E 91°47'00", N 21°44'00")	500	Mar-20	BOOT	Term Sheet Agreement signed
5	Land Based Terminal	Petronet	India	Kutubdia (E 91°50'33.5272", N 21°51'48.2339") (E 91°50'50.5040", N 21°51'51.8732") (E 91°50'41.3246", N 21°51'16.5397") (E 91°50'58.3004", N 21°32'52.79")	1000	Dec-21	BOOT	HoU signed
6	FSRU	Reliance	India	Kutubdia (E 91°49'18.145", N 21°51'34.463")	500	May-19	BOOT	TUA intialed
7	Land Based Terminal	Sembcorp	Singapore	Moheshkhali (Coordinate not finalised)	1000	Dec-22	BOOT	MoU signed
8	FSRU (Energy Hub)	Beximco and TUMAS	Malta	Bashkali (Coordinate not finalised)	600-1000	-	BOOT	MoU signed
9	Small Scale	Gunvor	Singapore	KAFCO Jetty, Chittagong	200	Jul-18	BOO	GSA initialed
10	Small Scale	Trafigura	Singapore	CUFL Jetty, Chittagong	200	Jul-18	BOO	GSA initialed
11	Small Scale	Vitol	Singapore	SANGU, Chittagong	200	Aug-18	BOO	Negotiation going on

Table 32: Upcoming Near Future Large Scale LNG Import Projects

Project	Location	Capacity (mmscfd)	Leading Agency	Operating Entity	Status and/or operation	Project Operation

FSRU	Moheshkhali	500	Petrobangla	Excelerate Energy Bangladesh	April 2018	BOOT
FSRU	Moheshkhali	500	Petrobangla	Summit LNG	October 2018	BOOT

Source: Ramboll

Both projects will be constructed in the south of Bangladesh as shown below and indicated by the grey spot. The proposed sites are situated at the south-eastern region of Bangladesh within the Upazilla Moheskhali under the district of Cox's Bazar and spread along the Bay of Bengal.

Figure 91: Geographical positioning of the upcoming LNG import projects.

Source: Ramboll

Comparing with the present & future gas consumers of the entire country, the LNG infrastructure development proposals are mainly centred in the Chittagong and Cox's Bazar (South-East regions of the country) areas. This will require significant investments in pipelines to transport natural gas through pipelines to the Western regions of the country. Therefore, RPGCL opines that in addition to the projects at Chittagong and Cox's Bazar areas, Mongla Port and Paira Port areas (proposed) may be considered as LNG terminal development locations, directly feeding natural gas into the gas grids for the Western regions of the country; this will ensure energy security also. RPGCL is working along with the Government policy and has keen interest for the success of the Government through proper implementation of the SDG action plans (Mid-Term and Long-Term development plans) up to 2030 and Vision – 2041 as well.

The Consultants support this approach as one of the steps in optimising LNG import configurations. At the same time, we encourage relevant stakeholders to have sufficient data available, e.g. site selection study, bathymetric and metocean data, feasibility study to justify these new locations. A thorough cost-benefit analysis should also be carried out against alternative options, before committing to any significant investments.

9.3 Update of FSRU terminal planning in Bangladesh

The FSRU will be located offshore near Moheshkhali Island in the Bay of Bengal.
The terminal will serve as a hub to provide the crucial infrastructure required for the country to access natural gas from global markets.

Moheshkhali Floating LNG will be a fully integrated turnkey floating LNG terminal with Excelerate Energy to develop, design, construct, install, finance, and operate the terminal. Excelerate Energy will operate the terminal for the first 15 years, after which the company will transfer ownership to Petrobangla. The FSRU will have 138,000 cubic metres of LNG storage capacity and a base regasification capacity of 500 million standard cubic feet per day (mmscfd) with the possibility of expansion to 600 mmscfd. The terminal is expected to be in operation in 2018.

Figure 92: Floating Storage and Regasification Unit illustration.

Source: Excelerate Energy

Another FSRU project has been signed and confirmed between the Summit Group and Petrobangla. A company of Summit group will install a Floating Storage and Re-gasification Unit (FSRU) at Moheshkhali Island in the Cox's Bazar. The state-owned Petrobangla signed on 20th of April 2017 a deal with Summit Liquefied Natural Gas (LNG) Terminal Company in this connection. The Summit will set up the floating storage and FSRU terminal, which is expected to go into operation after 18 months in October 2018.

The floating terminal will supply 500 million cubic feet of natural gas per day. The contractual agreement will be on Build-Own-Operate-Transfer (BOOT) basis. Summit will transfer the facilities to Petrobangla after operating it for 15 years. Summit will implement the project jointly with US-based GE (20%) as equity investment partner. On completion of the project, the gas supplied by the FSRU can potentially supply to existing oil-run power plants like Meghnaghat and possibly reduce power generation cost by less than half.[6]

Figure 93: Floating Storage and Regasification Unit illustration

Both projects proposed are based on the installation of an FSRU. Generally, the rapid growth of the FSRU market is mainly due to the lower cost, faster schedule, commercial flexibility and reusable asset feature of FSRUs when compared to land based (onshore) terminals which cannot be relocated and must be regarded as a sunk cost.

The following table provides pros and cons of FSRU over onshore LNG receiving terminal.

[6] http://www.thefinancialexpress-bd.com/2017/04/21/67590/Petrobangla,-Summit-sign-deal-for-2nd-LNG-terminal
http://www.thedailystar.net/business/summit-signs-deal-build-500m-lng-terminal-1340404

Table 33: Pros and cons of FSRU.

Pros	Cons
• **Since the initial investment cost (CAPEX) is low and construction period is rather short, it is beneficial to use the FSRU for the urgent or temporary requirements.** • **In terms of relocation the terminal can be moved for another use when no longer needed (lower demand than expected). Also, easiness of dismantling.** • **There are fewer environmental constraints compared to the onshore terminal.**	• Charter fee including operation and maintenance (OPEX) is high. In general, the total cost of FSRU for more than 10 years of operation tends to be higher than the total cost (CAPEX+OPEX) of an onshore terminal. • There are constraints in the expansion of LNG storage facilities and equipment. • Operational stability is affected by meteorological and oceanographic conditions.

Source: JICA Southern Chittagong Survey Team

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

The main purpose of this section is to compare and provide key aspects of the two different LNG Import infrastructures, FSRU and Land based LNG terminal. It is essential to note that each method has its own features and advantages.

FSRUs are based on LNG tankers and use essentially the same technology as onshore terminals. The only real difference is that the equipment is engineered to be suitable for shipyard construction and marine operation. For a new build vessel the equipment is normally integrated into the vessel. For a conversion the equipment is normally built as a separate module or modules and retrofitted to the LNG vessel in a shipyard to minimise time.

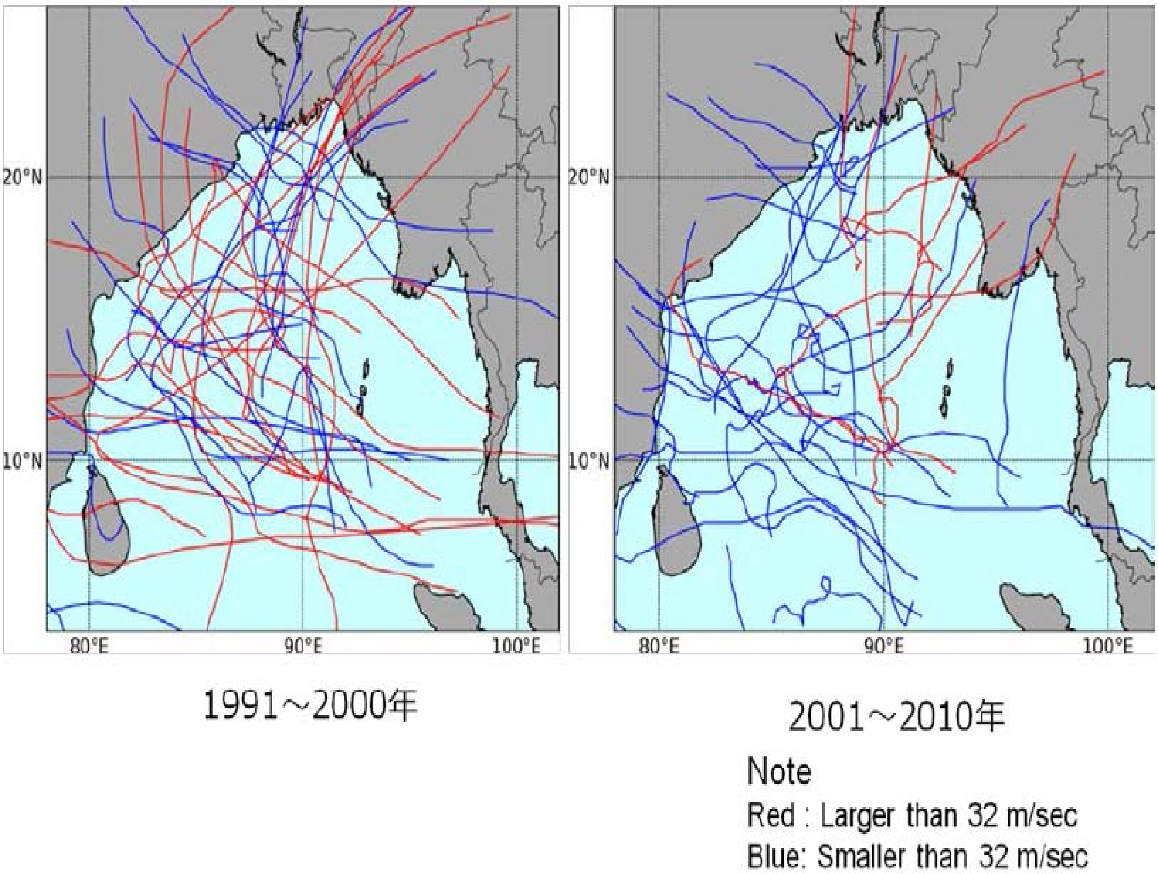
LNG loading to FSRU will be carried out by STS (ship to ship transfer). In order to supply 500MMCFD of gas, more than 60 shipments will be required in a year. The construction of FSRU is almost the same as that of LNG tanker. Old LNG tankers can be remodelled as FSRU to save construction cost.

Operation of FSRU is in general vulnerable to weather condition, and emergency evacuations plan must be in place if it is operating in the cyclone prone area. Land based LNG Terminal on the other hand requires a larger onshore footprint to minimise investment to the infrastructure and also to secure freedom to construct additional tanks to meet the incremental demand. The space required for such a land based LNG regasification plant is considered conservative. Initial tank numbers are assumed to be two and to be expanded with the increase of demand.

Many of the original FSRUs were based on Moss or Membrane LNG tanker conversions. The recent trend has been to construct new build vessels with typically around 170,000 m3 geometric storage and a 600-750 mmscfd send out rate. However, it is interesting to note that Höegh LNG has just placed an order with Maritime (engineering) and Wärtsila Oil and Gas for the conversion of an existing Moss tanker. It appears that the order is for the engineering and procurement of the long delivery equipment items only, to enable physical conversion work to be completed in just 12 months, rather than the normal 18 months if the equipment had to be ordered. Both of these conversion options are less than the 27-36 months required to construct a new vessel.

As earlier mentioned, the operation of FSRU is vulnerable to weather condition. The bay of Bengal is known as Cyclone. Frequency of Cyclone landing at Moheshkhali area is not high in comparison with other areas, but influences every year. The scale of Cyclone is reported to be increasingly larger than before. Thus, this is another fact which supports the idea of taking extra precautions, such as emergency evacuations plans etc.

Figure 94: Cyclone in Bay of Bengal.



Source: Nippon Koei Research Institute

Concerning the operation expenditure (OPEX) and capital expenditure, the following table summarises the key differences between FSRU and Land-based LNG Terminal.

Table 34: CAPEX comparison between FSRU and Land-based LNG Terminal.

	3 mtpa, 180,00 m3 storage	
Component	**Onshore**	**FSRU (new build)**
Jetty including piping	80	80
Unloading lines	100	N/A
Tanks 1x180,000 m3	180	in FSRU
FSRU Vessel	N/A	250
Process plant	100	in FSRU
Utilities	60	in FSRU
Onshore interface/infrastructure	N/A	30
CAPEX	**520**	**360**
Contingency 30% Onshore, 10% FSRU	156	36
Owners's Costs	74	54
Total CAPEX	**750**	**450**

Source: OIES Paper: NG 123 (The Oxford Institute for Energy Studies)

Table 35: Operation Cost Comparison between FSRU and Land-based LNG Terminal.

		FSRU (See Note 1)	Land LNG (See Note 2) Initial 3 tanks	Land LNG (See Note 2) Expanded to 14 tanks
Tank Capacity	M3	138,000	3*180,000	14*180,000
Annual LNG Delivery	Times/Year	59	40	186
Re-Gasification Capacity	Mmscfd	500	500	3,000
Construction Cost	MM USD		760	2,260
Operation Cost	USD/Mcf	0.49	0.64 (See Note 3)	0.33 (See Note 3)

Source: JICA Survey Team

Notes:

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

In terms of the construction time, the majority of construction work of FSRU is carried out at a shipyard and amount of on-site construction work is relatively small. Project schedule from Environmental Impact Assessment (EIA) to the commencement of operation is short and takes less than 3 years as depicted in the table below.

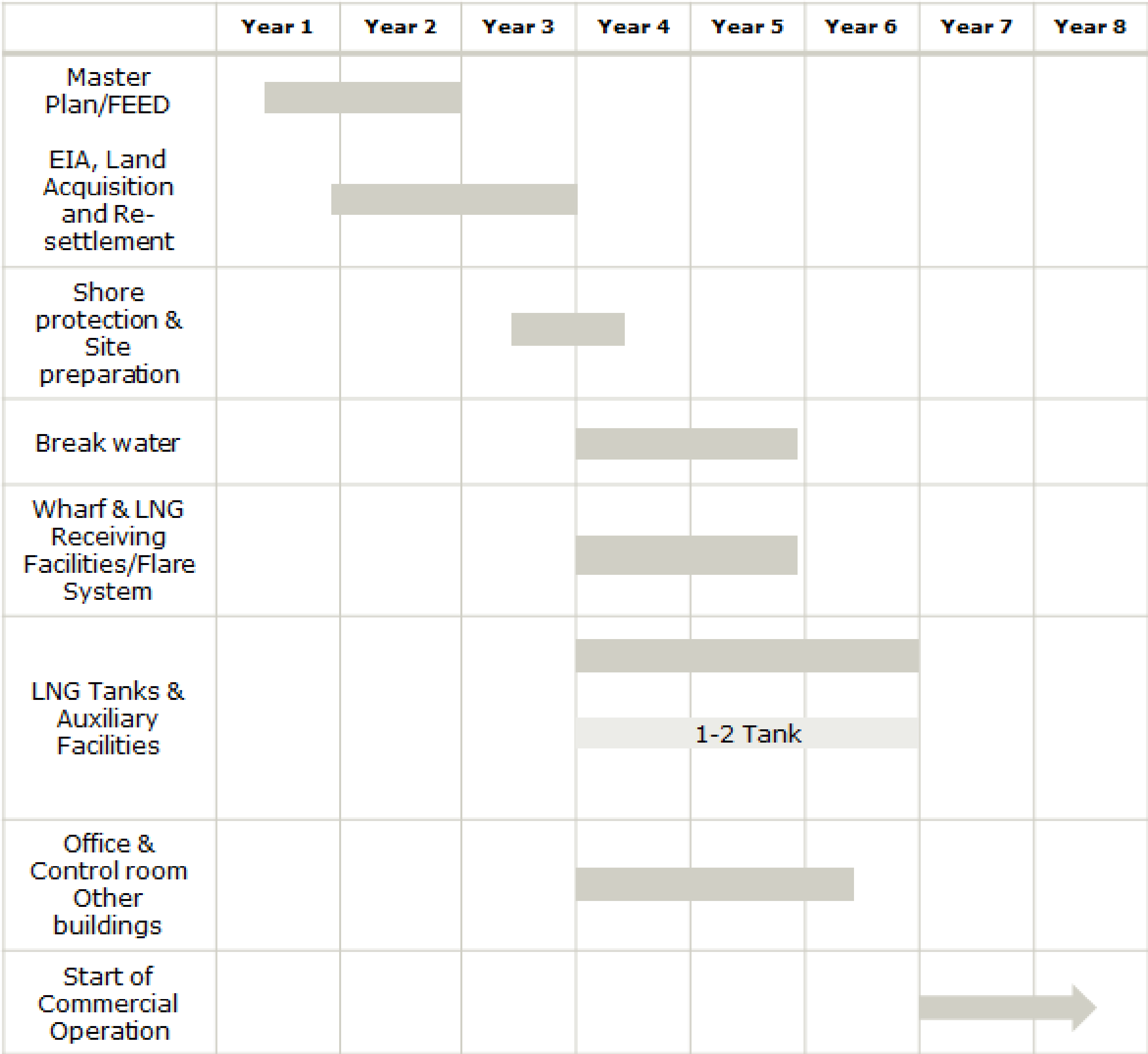
Table 36: Time Schedule for Large Scale FSRU Construction.

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Feasibility Study/ EIA Commercial Issues						
Onshore Pipeline						
SPM System & Submarine Pipeline						
FSRU Construction						
Marine Operation Facilities (Tugboat)						
Start of Commercial Operation						

Source: JICA Survey Team, Ramboll

The project schedule for Land-based LNG terminal is longer than that of FSRU. Significant time and effort must be taken into account as illustrated in the following table. This includes EIA agreement with the local people and re-settlement plan associated with land acquisition. Large scale land preparation work and infrastructure construction such as breakwater will be carried out if necessary. Construction of tank foundation to avoid uneven settlement is also time-consuming work.

Table 37: Time Schedule for Land-based LNG Terminal Construction.



Source: JICA Survey Team, Ramboll

10. LEGAL AND REGULATORY

10.1 Objective

The objective of the legal and regulatory analysis is to discuss the policy and institutional reforms necessary for a sustainable development of the sector and provide a path for implementation of these reforms. The link between such reforms and reduction in cost of supply will be investigated to ensure that investment is directed towards the efficient development of least cost options. Assessment of the policy framework includes a discussion of the ability of government to spur the development of least-cost solutions.

10.2 Review of legal and regulatory documents

The Consultants have reviewed key legal and regulatory documents for the gas sector, in particular:

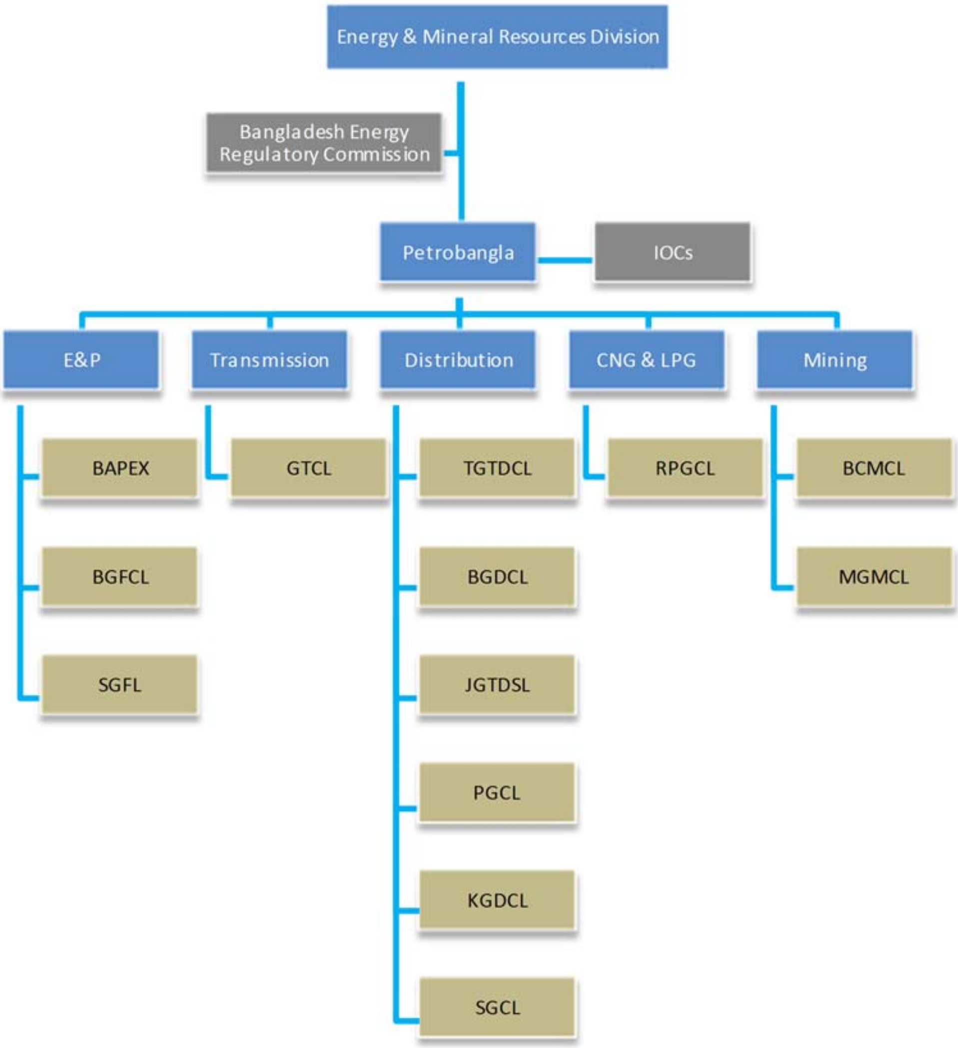
- Gas Act of 19 July 2010
- Bangladesh Energy Regulatory Commission (BERC) Act of 2003, Amendment 17 February2005, 24 February 2010
- Bangladesh Energy Regulatory Commission License Regulations, 2006. Amendment 7 September 2006
- Bangladesh Energy Regulatory Commission, Notification on Gas Tariff Methodology, 29 December 2010, Published 13 January 2011
- Bangladesh Energy Regulatory Commission, Public Notice on Gas Tariffs, 23 February 2017
- Petroleum Act of 1974, Amendment 26 July 2016
- The Bangladesh Oil, Gas and Mineral Corporation Ordinance from 1985 (Petrobangla)
- Petrobangla Annual Reports 2013, 2014, 2015
- Gas utilisation Guidelines, Petrobangla, 2013
- Tariff reforms and intersectoral allocation of natural gas, ADB 2013.
- Other relevant reports

The review forms the basis for the following chapters where the regulatory environment is described.

10.3 Key entities in the oil and gas sector and institutional set-up

10.3.1 Existing institutional setup

Figure 95: Existing institutional setup



Source: PetroBangla & Ramboll

10.3.2 The role of Petrobangla

The single-buyer model applies in Bangladesh through a complex system of administered internal transfer prices. Petrobangla acquires gas from IOCs at PSC contract prices, mixes it with its own gas from subsidiaries, then transmits the gas and distributes it to its customers. Ultimately, Petrobangla is allocating gas to consumers and administering a bundled gas price set by the BERC.

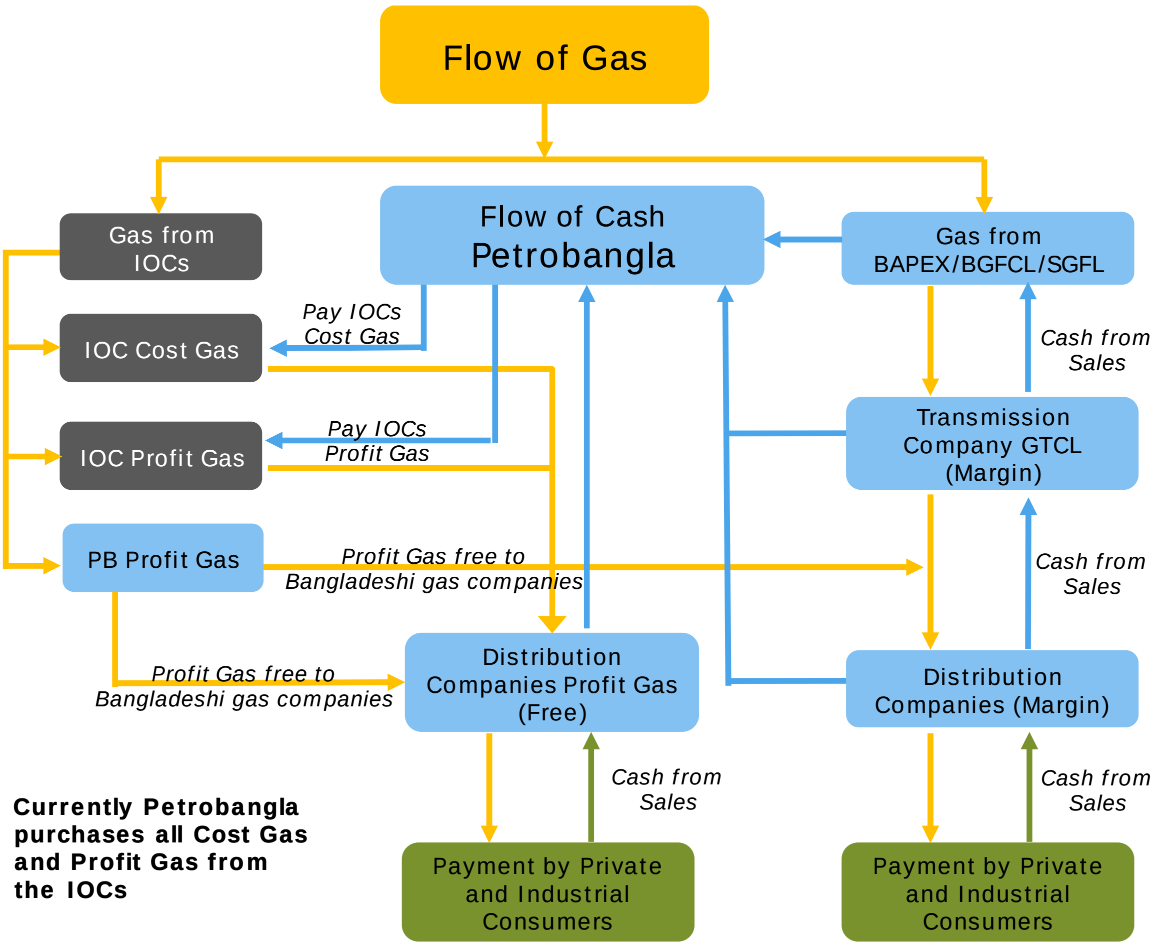
Petrobangla also has a role as the upstream regulator, supervising and monitoring the PSCs at the same time it is the counterpart to the contracts. It is also self-regulating its own operations, including its subsidiaries.

Petrobangla Annual Report for the year ending 30 June 2015 included a Statement of Profit or Loss, that showed an operating loss of BDT 1,272,296,773 (USD 15.7 million), net surplus of BDT 461,364,554 (USD 5.7 million) and a deficit on the Appropriation account of BDT 30,547,281,756 (USD 378.6 million) mainly from deficits brought forward from previous years.

10.3.3 Financial flows in the gas sector

The flow of gas and money in the Bangladesh gas sector is shown in Figure 96. Starting from the top of the figure, there are gas productions from IOCs and the Petrobangla subsidiaries i.e. BAPEX, BGFCL and SGFL. The IOC gas production under Production Sharing Contracts (PSCs) is split in "Cost Gas" (cost recovery of the investment and operational expenses) and "Profit Gas" (revenues in excess of cost).

Figure 96: Flow of gas and money in the gas sector in Bangladesh



Source: Ramboll, ADB.

The Profit Gas which Petrobangla receives is free of charge and is provided for free to its subsidiaries, called "Distribution companies" in Figure 96. The IOCs could in principle sell their profit gas to the highest bidder; however, in practice Petrobangla exercises its "right of first refusal" to purchase cost and profit gas and provide it to its subsidiaries.

The gas produced by Petrobangla subsidiaries BGFCL, SGFL and BAPEX is sold at gas tariff set by BERC, which include the transmission charges to GTCL and distribution charges. The Distribution companies sell gas to consumers at gas tariffs set by BERC.

As can be seen from Figure 96, the subsidiaries collect the revenue from the sale of gas and receive a margin to cover their expenditures. This structure results in a profit for all subsidiaries, while Petrobangla's consolidated account shows a loss, mainly due to the low-end user prices.

10.3.4 Petrobangla subsidiaries

Aside from exploring oil and gas and drilling, BAPEX is producing nearly 130 mmcfd. BAPEX made a post-tax net profit of BDT 654.0 million in FY 2014-15. BAPEX has formulated a time-bound action plan with a view to accelerating the exploration of oil and gas and augmenting production by 2021.

Bangladesh Gas Fields Company Limited (BGFCL) is the largest state-owned natural gas production company in Bangladesh. It is a public limited company registered under Companies Act and contributes about 35% of total gas production of the country. BGFCL earned a gross revenue of BDT 32,116.7 million and a pre-tax profit of BDT 6,983.8 million during the FY 2014-15.

Sylhet Gas Fields Limited (SGFL) is the second largest state-owned gas company. SGFL produced 54.08 BCF of gas in FY 2014-15 The gas is supplied to Jalalabad, Bakhrabad, Pashchimanchal and Karnaphuli gas distribution companies. During FY 2014-15, the company earned BDT 4,155.8 million from the sales of gas and BDT 12,515.5 million from the sales of finished liquid products. Company earned pre-tax profit of BDT 6,144.3 million in FY 2014-15.

Gas Transmission Company Limited (GTCL) was incorporated in 1993 with the objectives of (i) centralising operation and maintenance of the national gas grid; and (ii) expanding the national gas grid and as required, ensuring balanced supply and usage of natural gas in all regions of the country. Gas transmission pipelines built by other companies before creation of GTCL have been integrated with the GTCL system. It operates 1560 km of gas transmission pipelines, delivering gas to franchise areas of Jalalabad, Titas, Bakhrabad, Karnaphuli and Paschimancahal gas marketing and distribution companies respectively. GTCL earned an amount of BDT 6,369.7 million as revenue and BDT 5,340.3 million (USD 66.3 million) as pre-tax profit FY 2014-15.

Titas Gas Transmission and Distribution Company Limited (TGTDCL) is the largest transmission and distribution company with a 62% share of the Bengali market serving 12 districts including Dhaka. It owns and operates around 450 km high-pressure transmission pipelines, with lower capacity than those of GTCL. Petrobangla holds 75% shares of this company while private shareholders hold 25% of the shares. The company earned a net profit on operations before tax of BDT 12,101.3 million (USD 150.3 million) in FY 2014-15.

There are five other distribution companies, of which Jalalabad Gas Transmission and Distribution System Limited (JGTDSL) owns and operates transmission pipelines, same case for Karnaphuli Gas Distribution Company Limited (KGDCL), the youngest company established in 2010.

10.3.5 Unaccounted for gas

Unaccounted for gas, explained by Petrobangla as System loss, plus pifferage/system gain was at its maximum 33.7 bcf in 2005/2006, or 6.4% of total production, which was due to a sudden sharp growth in gas demand and had affected the pressure factor on gas metering, and fell to 0.4% in the second half of 2015 from 1.7% in 2014-15 (after some years in the negative (i.e., system gain). If this figure is correct and sustainable, Petrobangla has reached a level for Unaccounted for gas comparable to international best practice. The National Transmission System in the UK estimates Unaccounted for gas for gas transmission to 0.2-0.3 % of throughput in recent years.

10.4 Gas tariffs

The BERC Act from 2003 gave the Commission the mandate to regulate downstream gas tariffs. The Notification on Gas Tariff Methodology, 29 December 2010, provides the procedure and methodology to gas companies to calculate and request gas tariff revisions. The methodology determines how to calculate, how to allocate average and peak costs, the cost of service for different customer classes and the calculation of Revenue Requirement for service to each class. Rate of Return for distribution licenses on qualifying assets or rate base is determined based on a calculation of the weighted average cost of capital. To determine the return on equity, the Commission gives preference to a Capital Asset Pricing Model, but allows other calculation options.

BERC sets tariffs for 7 customer classes and residential consumption, which can be metered or unmetered. These customer classes are defined in the Gas Act. The latest price increases were 1 March and 1 June 2017 resulting in current prices shown in Table 38 By international standards these are low, in particular prices paid by the power stations, which take around 40% of all gas in Bangladesh, and the prices paid by fertilisers taking around 7% of the gas. Other large gas consumers, captive power and industry pay around three times as much as power stations and fertiliser for the gas, but still less than in most countries.

Table 38: Natural Gas Tariff. June 2017

	BDT / MCF	USD / MCF
Power	110.6	1.38
Fertiliser	94.9	1.19
Industry	271.6	3.40
Commercial	596.4	7.46
Tea estate	259.7	3.25
Captive power	336.7	4.21
CNG	1400	17.50
Residential		
Metered	392	4.90
Unmetered: Monthly		
Payment per burner	BDT	USD
Single burner	900	11.25
Double burner	950	11.88

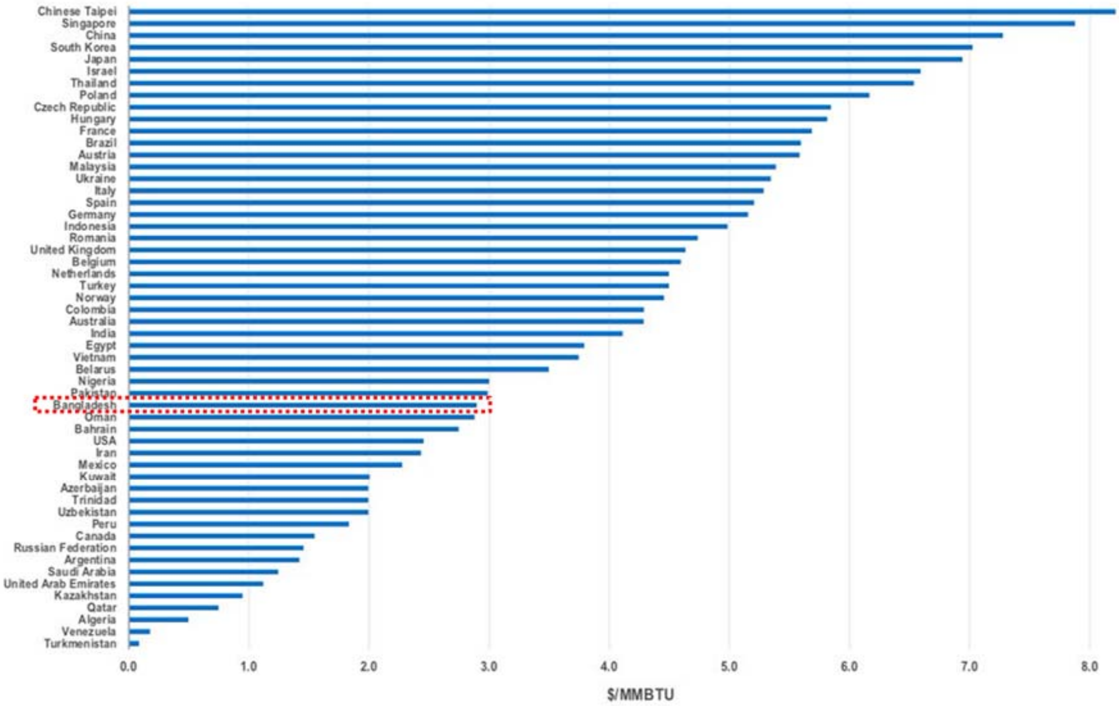
Source: BERC: Public Notice for Gas Tariff, 2017

Note: Converted at BDT 80/USD

Figure 97 provides an international comparison of wholesale gas prices in 2016. It shows that Bangladesh's gas prices are in the lower half compared with other gas markets (around the 40% benchmark). Since 2014, Bangladesh's gas price has gone up by almost USD 1/MMbtu, while gas prices have gone down in many countries due to lower oil prices and oversupply in the LNG market.

The exception to low prices in Bangladesh is the price of CNG. Its price is based on the price of the fuels it substitutes (Gasoline and Diesel): the price of 1400 BDT/Mcf (or USD 17.39/Mcf) translates into more than USD 100/barrel of oil.

Figure 97: Wholesale gas prices by country, 2016.



Source: IGU: Wholesale Gas Price Survey - 2017 Edition

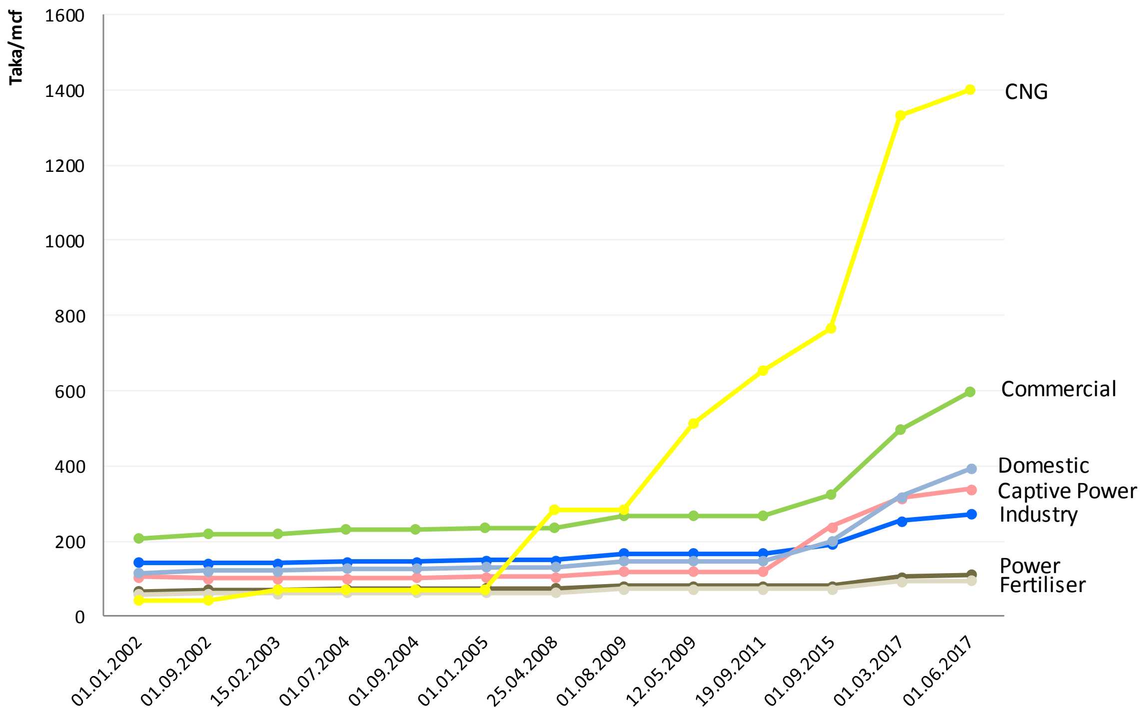
The latest gas price increases were the first since 2015 and before that, 2011. Figure 98 shows the development in gas tariffs in Bangladesh since 2002 for the key customer classes. Price increases for power and fertiliser have been moderate over these years and the prices are still low based on international comparisons. There have been recent sharp increases in the prices paid by commercial, captive power and domestic metered gas consumption. These three classes of customers account for almost 30% of total gas demand in Bangladesh, the commercial sector, however, consumes only a fraction of this (less than 1%).

CNG is not shown in the graph. The price for CNG has more than doubled since 2011 and increased five times since 2008. CNG consumption accounts for around 5% of total gas demand in the country. Also not shown is the fixed payment for unmetered burners, which has doubled since 2009.

In 2009 and 2010 BERC rejected price increase applications from Petrobangla, on the grounds of the profitability of its retail, transmission and wholesale businesses and in 2016, BERC rejected the proposal of increasing gas prices, placed by Titas Gas Transmission and Distribution Company Ltd, saying that the company did not need to increase its distribution charges because the estimated revenue was above the revenue requirement[7].

[7] Dhaka Tribune, August 8, 2016.

Figure 98: Gas Tariff for key customer classes, 2002-2017



Source: Petrobangla Annual reports, BERC: Public Notice for Gas Tariff, 2017

The breakdown of the gas prices is shown in Table 39 The end user price is shown in the left column. The key components are a Government tax around 50% of the end user price, which is high by international standards. The other approx. 50% are allocated to Petrobangla companies in the form of margins:

- Thin margins for upstream operations: BAPEX and wellhead margin.
- Transmission and distribution margins are also very thin.
- Payments to provide a return on assets.
- Contributions to the petroleum development fund and the gas development fund.

BERC ordered the gas development fund to be set up when it increased natural gas tariffs in 2009, with the condition that the additional revenue generated following the increase would be transferred to the fund. The funds are used to carry out gas exploration and development and to enhance the capacity of the national exploration and production companies. In 2014-15, 19 investment projects financed by the gas development fund were under development.

Table 39: Gas price breakdown. 2017 tariff. (USD/Mcf)

	End User Price	Govt Tax	Price Deficit Fund Margin	Bapex Margin	Deficit Wellhead Margin for BAPEX	Wellhead Margin	Support for shortfall	Transm Margin	Distrib Margin	Gas Dev. Fund	Energy Security Fund
Sector											
Power	1.38	0.67	0.14	0.02	0.02	0.10	0.15	0.07	0.12	0.04	0.05
Fertilizer	1.19	0.62	0.12	0.00	0.02	0.10	0.06	0.07	0.12	0.07	0.02
CNG	13.91	6.46	2.65	0.05	0.09	0.13	2.17	0.07	0.07	1.37	0.87
Capt. Power	4.21	2.00	0.20	0.02	0.02	0.10	0.55	0.07	0.07	0.09	1.09
Industry	3.40	1.61	0.33	0.02	0.02	0.10	0.44	0.07	0.11	0.12	0.57
Tea Garden	3.25	1.54	0.33	0.02	0.02	0.10	0.42	0.07	0.11	0.12	0.48
Commercial	7.46	2.72	0.58	0.02	0.02	0.10	2.47	0.07	0.11	0.24	1.09
Domestic	4.90	1.67	0.31	0.02	0.02	0.10	1.83	0.07	0.11	0.12	0.65

Source: BERC 2017

Note: Converted from BDT/cm, assuming 35 cf/cm and BDT 80/USD

While the BAPEX and wellhead margin for upstream operations are thin, funds from the Price Deficit Fund Margin and a Deficit Wellhead Margin for BAPEX more than double the funds available for upstream activities under Petrobangla (in addition to investments from IOCs).

The transmission and distribution margins are extremely low, around 2% respectively 4% of the average gas price. The transmission margin does not provide GTCL sufficient funding for the expansion of a reliable transmission system to facilitate transport of new production and imported LNG to consumption areas. GTCL's reliance on public funding and donor assistance (ADB, JICA and World Bank) has meant that it has been unable to invest sufficiently to develop transmission infrastructure. In 2014-15, only two pipeline projects were self-financed by GTCL.

The Distribution margin is higher than the transmission margin as gas distribution of smaller volumes at lower pressure is more costly. The Distribution company margin is vital for a sustainable operation of the low pressure grid delivering gas to consumers. The margin does not support the distribution companies' capability in investments to expand the network. Distribution companies are also relying on donor assistance for investment projects.

The gas price breakdown shows that much larger funds are set aside for shortfall and energy security and funds set aside to carry out gas exploration and development and for the gas development fund. The margin for transmission and distribution should be increased, either through a higher gas price, possibly from funds set aside for other purposes. A better solution would be to develop tariffs for transmission and distribution of gas, providing transmission and distribution companies with sufficient funds for self-financing of their investment in expansions.

10.5 Gas allocation and pricing

10.5.1 Gas Utilisation Guidelines[8]

This Guideline reviews gas supply and demand balance, projects the future supply and demand balance and reviews gas fuel efficiency in the main sectors, including for various plants and equipment. It concludes with a sector-based priority for domestic gas allocation when shortages begin:

1. Fertiliser
2. Electricity
3. Industry/tea garden
4. Captive power
5. Residential/commercial
6. CNG

The guidelines also recommend a number of efficiency measures:

- To reduce gas to the fertiliser sector by 10%, and to increase the efficiency of fertiliser factories using more than 35 Mcf/ton of fertiliser, and closing the most inefficient plant;
- To limit the total allocation of gas to the power sector to 40% of the daily gas supply, only provide gas supply to new power plants that have more than 50% fuel efficiency, and are based on combined cycle technology and duel-fuelled. Suspend gas supply to low efficiency power plants;
- To reduce gas supply to filling stations, price increases for CNG, and
- To reduce gas supply to low-efficiency captive power plants.

An ADB study estimated the economic value of gas in domestic, transport, power and fertiliser sectors in 2011 in Bangladesh[9]. Willingness to Pay for natural gas used as CNG was concluded to be the highest, which was followed by gas substituting petroleum products in power generation, gas used to produce fertiliser and for household cooking.

Table 40: Actual price of gas, Marginal Value Product and Willingness to Pay for gas, 2011

If Natural gas price is equivalent of prices paid by the	Price paid by producers or consumers (Tk / mcf)	Price paid producers or consumers (Tk/m^3)	VMP† Tk/m^3			WTP Tk/m^3	
			Power, Coal Based	Power, Petroleum Based	Fertilizer	Cooking	Vehicle (CNG)
Power plants	79.82	2.81	13.03	30.13			
Fertilizer plants	72.92	2.57			5. 21.42		
Domestic (metered)	129.55	4.57***				12.59	
CNG gas price	688.00	24.28					36.96

Source: TARIFF REFORMS AND INTERSECTORAL ALLOCATION OF NATURAL GAS, ADB 2013

The study showed that the current gas allocation and pricing does not reflect economic values of gas. Only 9.3% of the value of gas is captured in the power sector when substituting petroleum products (although oil prices averaged USD 104 per barrel, around the double of the 2017

[8] Gas utilisation Guidelines, Petrobangla, 2013.

[9] Tariff reforms and intersectoral allocation of natural gas, ABD 2013.

average until July, the value captured is still low today), and 21.6% substituting coal. The bulk of the gas is allocated for power generation. In the fertiliser sector only 12% of the economic value was captured. The highest price was charged for CNG but it was only 66% of the Willingness to Pay. In the household sector the gas price was only about 36% of the Willingness to Pay for gas. Household sector received only 12% of the gas. This indicates severe under-pricing and inefficient allocation of natural gas in Bangladesh. If the economic efficiency is strictly followed, more gas should be allocated to the sectors where the economic value is highest, i.e., CNG, replacing petroleum products in the power sector, and in the fertiliser sector.

10.6 Upstream fiscal terms for the PSCs and Bidding process

The 2012 Offshore bidding round attracted little interest from private investors. The reason for the lukewarm response may include low gas prices and Petrobangla's right of first refusal to buy the gas production. The lack of access to good geological data was also a factor reducing contractors' interest.

The fiscal terms for the 2012 Round can be summarised as follows[10]:

- Exploration period: Seven years for onshore and eight years for offshore blocks.
- Contract term is 20 years for oil and 25 years for gas after approval of the Development plan.
- Contractor can dispose gas freely but Petrobangla has first right of refusal and will pay a discounted price (1-4%).
- Contractor has obligation to sell gas in the domestic market. Exports are not allowed.
- Biddable profit share on a sliding scale.
- Maximum annual cost recovery: 55% of the revenues.
- Offshore Gas Prices: Arithmetic Average Asian Petroleum Price Index for High Sulphur Oil 180 CST FOB with a floor at USD 100 per tonne (normally 20-30 percent below crude oil prices, approx. USD 2.6/MMBtu) and ceiling at USD 200 per tonne (approx. USD 5.2/MMBtu).
- Onshore gas prices are 75-90% of the Offshore price.
- Carried interest of 10% in all shallow water gas blocks for BAPEX.

In 2016, Petrobangla changed the strategy away from bidding rounds towards direct negotiations with interested parties. Petrobangla invited EOIs from interested IOCs for specific offshore blocks. Instead of finalising the model production-sharing contract before launching the bidding round, the contract terms will be fixed on the basis of the bids received, with following negotiations.

Compared with other countries in the region (see Appendix 5 for case studies of India, Pakistan and Vietnam), the lessons to be taken away are:

- India introduced an Open Acreage licensing policy. Contractors can select exploration blocks throughout the year without waiting for the formal bidding round from the government. It

[10] OIES: Natural Gas in Pakistan and Bangladesh. Current issues and Trends. Ieda Gomes. 2013

also introduced freedom for pricing and marketing of gas produced in the domestic market for contractors, a uniform licensing system and reduced royalty in all areas.

- India also linked the gas price for producers to prices in international gas hubs, rather than bunker fuel and set a higher ceiling for the gas price from high cost fields, such as those in deep sea and high-pressure high-temperature areas.

Myanmar had some success in its offshore waters adjacent to Bangladesh's continental shelf. Woodside Energy has made three gas discoveries in 2016 and 2017. Shell has an equity share in two of these and is operating five other blocks. Total has been operating the Yadana field since it started production in 1998 and started up production in Badamyar in 2017. Chevron, however, after signing a new PSC in 2015, put its assets up for sale in 2016. Key features of Myanmar's petroleum fiscal terms for PSCs are summarised in Appendix 6. A key difference from the terms in Bangladesh's PSCs is that exports of gas are allowed and that gas prices are not presented in the contract. On the other hand, the profit share in the Bangladesh contract is biddable, i.e., more flexible.

As for the bureaucracy involved in the selection of investors, there are no specific studies of the oil and gas sector. There are, however Benchmark studies of Public Procurement[11] providing a comparative evaluation of legal and regulatory environments that affect the ability of private sector companies to do business with governments in 180 economies. The Benchmarking shows that Bangladesh on average does better than other South Asian countries, including the two other oil and gas producers in the region, India and Pakistan, on needs assessment, call for tender, and bid preparation, bid submission phase, bid opening, evaluation, contract award phase and management of the procurement contract[12]. Bangladesh scores lower than the other countries on performance guarantee and on the time and procedure needed for suppliers to receive payment.

Having ruled out systematic barriers in the legal and regulatory environment, the reason for the low response to the bidding rounds in Bangladesh may be found in the institutional setup of the bidding round and the obligation to sell the gas in Bangladesh at a pre-determined price formula. Bangladesh has to align the risk/award framework to attract foreign investors in competition with other countries.

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[11] World Bank: Benchmarking Public Procurement. 2017 covers the procurement process and complaint review mechanisms and indicates how the legal and regulatory environment functions and how the procurement process works in each country.

[12] with one exception: India scores slightly better on needs assessment, call for tender, and bid preparation.

Box no. 1 Lessons learned from gas regulation in India, Pakistan and Vietnam

Appendix 5 reviews lessons for Bangladesh from case studies of gas regulation in India, Pakistan and Vietnam. Some lessons are:

Separate Regulation from policy function and operations: In India, the Upstream Regulator, DGH is the technical arm of the ministry and acts as a regulatory body having oversight on all concessions relating to oil and gas to avoid potential conflicts of interest between the NOCs and IOCs. In Pakistan, the upstream oil and gas activities are regulated by the Directorate General of Petroleum Concessions (DGPC). The downstream regulator in Pakistan is independent from the Ministry, and the government-controlled companies. Both DGH and DGPC are managing bidding rounds in their countries. Like Bangladesh, Vietnam has a dominant state-owned oil and gas company that is delegated by the government to carry out petroleum exploitation and exploration, signing oil and gas contracts and supervising IOCs operating in the sector. Its subsidiary, PV Gas links gas from the upstream gas supplies to the end-users and has the sole rights to distribution pipeline development. This model can benefit the sector in the early stages of oil and gas development but can also delay later developments due to potential conflicts of interest, self-regulation, and lack of independent regulation.

Update Petroleum policies: The Governments of both India and Pakistan issue petroleum policies on a regular basis, to adjust to the country's needs, to international markets and developments and to attract international investors. Bangladesh issued a Petroleum policy 1993 that has not been updated.

Options for a more competitive gas industry: The Government of Pakistan has been assessing the performance of Pakistan's natural gas sector and developed options for the future direction of the sector towards a competitive and deregulated sector with increased private sector participation. This would among other things involve overcoming the current barriers to selling directly to customers at prices that are higher than today and at the same time fully cover costs, including future gas supply and LNG imports.

10.7 Regulatory framework

10.7.1 Upstream Regulation

Petrobangla has a role as the upstream regulator, supervising and monitoring the PSCs at the same time it is the counterpart to the contracts. It is also self-regulating its own operations, including its subsidiaries.

PSC Directorate of Petrobangla has 30 years experience of administering the PSC and some opportunities are still left behind to strengthen the existing PSC structure of Petrobangla to boost up exploration activities.

The current model for upstream regulation in Bangladesh has been benefitting the sector especially in the early stages of oil and gas development. However, in the future it may delay oil and gas developments in later stages due to potential conflicts of interest, self-regulation, and lack of an independent regulator. The introduction of independent regulation can give potential investors confidence that conflict of interests between Petrobangla and the investors will not lead to biased decisions. Alignment with international best practice in the long term can therefore increase the investments in the offshore and boost gas production.

In the meantime, Bangladesh currently has a more complex bureaucratic system comparing to international average – some simplifications on this can accelerate investment cycles, and be more attractive to foreign investors as a result. It needs to be acknowledged that a tie-in of upstream regulation and exploration activities by two different organizations/agencies can be a time-consuming event. Petrobangla's experience of administering the PSC for last 30 years also needs to be recognised, such that Petrobangla's focus to boost up exploration activities should be supported but not hammered if relevant authorities consider setting up an independent regulation agency in due course.

Below are some key characteristics of an independent upstream regulator:

- Have regulatory functions only
- Not have Policy functions – they should be in the Ministry's domain
- Be an Adviser to the Ministry: Ministry signs Petroleum contracts on the advice of the Regulator
- Upstream Regulator should be placed under the line Ministry, not in the State-owned Oil and Gas Company
- Have independent funding and staggered staff appointments
- Streamline data and information gathering from the companies and provide information to the public
- The Upstream regulator manages the bidding rounds, and direct negotiations with petroleum investors
- Link the Upstream Regulator's funding to the revenue received from industry fees, but budget is still approved by the government
- Give incentives to improve efficiency and capabilities of staff

10.7.2 Downstream Regulator BERC

The Gas Act 2010 regulates the downstream gas sector: the transmission, distribution, marketing, supply and storage of natural gas. The Act regulates almost all forms of gases with energy content: Natural Gas, LNG, CNG, LPG, SNG, NGLs, CBM.

BERC is empowered to apply the provisions of the Gas Act to issue, renew, amend and cancel licenses for pipeline construction for gas transmission, distribution, supply and storage. The Act defines the customer classes for that are used for the gas tariff (see Table 39)**.** BERC sets the price for gas supply and storage of gas, except for gas sold under PSCs for which the price is set in the contract. Finally, the Act determines penalties for operating without a license or not following the license.

BERC was established by an Act in 2003, as an independent and impartial regulatory commission for the energy sector in Bangladesh. It is situated within the Ministry of Power, Energy and Mineral Resources.

The Commission shall consist of a Chairman and four Members who are full-time officers, appointed by the President on the basis of the proposal of the Ministry. The Chairman shall be the Chief Executive of the Commission. Each member is appointed for a three-year term. The date of appointment of each member is different and thus date of expiry of tenure of each member is also different.

The decision of the meeting of the Commission shall be taken by a majority of votes of the Members present. However, in practice most of the decisions are taken unanimously on consensus.

The main functions of the Commission include:

- to ensure efficient use, quality services, determine tariff and safety enhancement of electricity generation and transmission, marketing, supply, storage and distribution of energy (i.e., the electricity, gas and petroleum products), which includes the mandate to regulate downstream gas tariffs.
- to determine gas tariffs for transmission, marketing, supply, storage and distribution of gas (and other energy).
- to issue, cancel, amend, determine conditions of licenses, and exemption of licenses.
- to approve the overall program of the licensee.
- to promote competition amongst the licensees.
- to resolve disputes between the licensees, and between licensees and consumers,
- to ensure control of environmental standard of energy under existing laws.

10.7.3 Tariff Determination

Section 34 of the BERC Act 2003 provides the following policy framework for tariff determination:

1. harmonisation of the tariff with the cost of production, transmission, marketing, distribution, supply and storage of energy;
2. efficiency, least cost, excellent service, excellent investment;
3. consumers' interest.

BERC's License Regulations and Funding are summarised in Appendix 7.

10.8 Imports of LNG and move towards a competitive gas market

The costs of imports will be higher than the current cost of indigenous gas production. Bangladesh should start a discussion of how to price the higher LNG costs and which customers are going to pay the higher price.

Today's gas market structure can be characterised as a single-buyer model with a complex system of administered internal transfer prices. Petrobangla acquires gas from IOCs at PSC contract prices, mixes it with its own gas from subsidiaries, then other subsidiaries transmit and distribute it to their customers. In other words, the Government is allocating gas to consumers and administering a bundled gas price set by BERC. Bundled prices, which do not differentiate between the price of gas as a commodity and the cost of transmission and distribution, have undesirable implications as they lead to inefficient pricing, they do not show financial viability of the various segments production, transmission, and distribution, and they result in cross-subsidies.

Petrobangla has right of first refusal on all gas produced by IOCs under PSC contracts; if it does not exercise this right, producers can sell to third parties in Bangladesh at a price equal to the price Petrobangla pays. Producers compete to explore for and produce gas through the bidding on PSCs. Competition for PSC contracts is in theory good, but it will not necessarily reduce the price of gas for consumers as Petrobangla has no incentive to buy gas at the lowest possible price and pass through the cost savings to consumers under the current system. In addition, there is no pressure or incentive to reduce transmission and distribution costs.

In general, the options for introducing LNG in the current gas market structure in Bangladesh include:

1. As a single buyer of gas, Petrobangla can continue to mix the higher priced LNG imports with gas from PSCs and its own gas. GTCL and Petrobangla subsidiaries then transmit and distribute the gas to its customers at a bundled gas price set by the Government.
2. Establish two markets for gas: 1) The current low-priced gas supplied by Petrobangla subsidiaries to their customers at regulated prices, and 2) a market for new gas supply at (higher) market prices to customers willing to pay the higher price to get gas supply. LNG importers could be government–owned companies (Petrobangla, Power Cell) or private, selling gas at unregulated prices to customers willing to pay the price.

Single Buyer of gas

The first option continues the single buyer model: Petrobangla acquires LNG imports, gas from IOCs at PSC contract prices, mixes it with its own gas from subsidiaries, then transmits the gas and distributes it to its customers through GTCL and distribution companies. This would of course result in a higher cost base and reduce Petrobangla's margin, so higher sales prices would be required. These could be a general tariff increase to all consumer categories, or focusing the price increases to certain customer categories, able to pay the higher price.

This option is not recommended as it would continue cross-subsidies, inefficient allocation of resources and distorted pricing and reduce the economic growth rate in the medium and long term.

Dual markets for gas

The key issue in this option is to determine the customers' willingness and ability to pay a higher price to get gas supplied by new LNG imports. These customers would be creditworthy industries and new efficient power plants that have high base load and that are not able to get sufficient gas at the current tariff due to gas supply shortages. The remaining gas customers would continue to buy gas under the current tariff schedules. i.e. at regulated prices. These customers would be fertiliser, old power stations, tea gardens and residential/commercial.

To allow private or public importers of LNG to sell gas to creditworthy industries and power plants unable to get sufficient gas at the current tariff, they would need access to the transmission and distribution network to reach their customers unless they supply new customers close to the LNG landing points through their own pipelines.

Non-discriminatory access (Third Party Access (TPA)) to gas transmission and distribution networks will allow third parties to reach the customers using the existing gas infrastructure. The national gas transmission company, GTCL, was established to separate gas transmission system from distribution, and while not all gas transmission assets have been transferred to GTCL from other Petrobangla subsidiaries and while GTCL does not provide third party access today, its articles of association permit it to operate as a common carrier.

What does it take to introduce third party access? Box no. 2 shows the experience in the European Union, which of course is a more complicated case since it involves both opening up to competition in gas trade within countries and to cross-border trade between countries.

Box no. 2 Introduction of Third Party Access and competition in European gas markets

One of the core objectives of the European Union was a single market for gas. It took about 15 years to reach that objective.

1998 Gas Directive

It started with the 1998 Gas Directive, which introduced a new legal framework aimed at opening the gas networks to third parties. This was to be achieved through unbundling of the existing vertically integrated gas operators, thus allowing competition for supplies and customers within the natural monopoly network. Initially, big gas customers, such as power plants and big industrial consumers could choose their gas supplier. At least 20% of the national market had to be open for competition.

To ensure transparent and non-discriminatory access to all potential suppliers of the market, the operator of the transmission system was to be unbundled, minimum at an accounting level.

The monitoring of this new system was assigned to a regulatory body in each country, which had to be independent from the market and from the state, to ensure transparent and non-discriminatory operations on the market.

2003, the Second Gas Directive
Several markets opened more up to competition than the required consumption level (79% vs. the minimum of 20%). The second Gas Directive mandated regulated TPA as the basic rule for all existing infrastructure, opening of the market for all customers, as well as moving the level of unbundling of Transmission System Operators to the level of legal separation (e.g. regulated activities under the responsibility of separate entities).

2009, Directive on Internal market in gas
This Directive ruled that from 2012 Member States had to unbundle transmission systems and transmission system operators.

Some of the first steps shown in Box 2 have already been implemented in Bangladesh. A regulatory body has been established to monitor the transmission system: BERC regulates the downstream gas sector. A part of the transmission system has been unbundled as GTCL is unbundled at the accounting level. However, TGTDCL, KGDCL, and JGTDSL also own and operate transmission pipelines in their supply areas. These are integrated with GTCL's transmission pipelines, but owned and operated by the regional companies. These transmission assets need to be unbundled at the accounting level.

The next step would be to mandate non-discriminatory regulated TPA as the basic rule for the GTCL transmission network and legally separate GTCL from Petrobangla.

BERC's Act and License Regulations would need to be updated to include appropriate tariff methodology, new licenses and additional responsibilities for the regulation of TPA to pipelines to enable the downstream regulator to promote competition in the gas market and ensure a smooth transition.

The opening of the gas market could start with GTCL's 1396 km network and GTCL is currently expanding transmission capacity from Cox's Bazar where the LNG will be landed to Bakhrabad. However, it is recommended to continue the transfer of all transmission assets to GTCL, so that more industries and power plants could be served by TPA from the high-pressure pipelines or by a spurline connected directly to these pipelines.

For TPA to work, a number of technical matters needs to be solved. Licenses for import of gas (LNG), transmission, shipping and sale of gas (and later distribution of gas) will need to be drafted and agreed by the gas companies, traders and consumers and the regulator. A network code would need to be introduced for gas transmission to support market liberalisation. This includes a set of rules for gas flows in the system ensuring that competition can be facilitated on level terms. It includes transmission tariffs, determines Entry and Exit points for gas in the system, and governs processes such as the balancing of the gas system, network planning, and the allocation of network capacity. It should also be considered to include offshore pipelines in the TPA system to give incentives to the development of marginal offshore fields.

To reach a fully competitive gas market, the operation of GTCL would need to be unbundled from the Petrobangla ownership, and competition should be extended to customers served by the distribution companies. These companies would need to legally separate their trading and distribution functions to provide third party access through their networks and introduce distribution system network codes.

As part of the gas sector reforms in Pakistan, the Government decided to open up the country's gas market to third parties to promote imports of pipeline gas and LNG and facilitate the growth of the gas sector. The Government has issued policy documents for public comments to set the high-level principles for TPA, network code and gas transportation tariff (see Appendix 5).

10.9 Timing of introduction of dual markets

LNG imports are expected to start in 2018 when the first FSRU is commissioned, followed by a second FSRU in 2019 and a third unit in 2021 (see Gas Sector Roadmap). The Roadmap for the pricing and regulatory changes is based on the assumption that it will take 4-5 years to decide and implement the regulatory measures required to open the gas market to TPA. In this period, the higher costs of LNG imports should be mixed with gas from PSCs and Petrobangla's own gas. From around 2021, the licenses, rules for TPA and network codes will be in place so that eligible customers can buy gas directly from suppliers.

10.10 Findings and recommendations - legal and regulatory analysis

Our analysis and review of the institutional and regulatory framework in Bangladesh has been centred around answering the central question of how reforms could support a least cost supply solution to Bangladesh. It is clear from the previous analysis that the infrastructure needs are very much dependent on the development in both gas demand and supply. Gas demand and supply is in many ways a function of the regulatory environment, thus the choices and recommendations made in this respect will have an indirect impact on the infrastructure requirements.

MAIN FINDING: SHORTAGE OF GAS NECCESITATES RECONSIDERATION OF THE GAS UTILISATION GUIDELINES

RECOMMENDATION: RECONSIDER THE ALLOCATION OF GAS ON SECTORS AND THE GAS UTILISATION GUIDELINES FOR DOMESTIC GAS ALLOCATION WHEN GAS SHORTAGES PREVAIL.

The Economic value of gas is highest when used for CNG in vehicles, replacing oil products in power generation and to produce fertiliser. The Guidelines put fertiliser as the top priority and CNG as the lowest priority. The Consultants does not agree with this priority; More gas should be allocated to the sectors where the economic value is highest, i.e. CNG, replacing petroleum products in the power sector, and in the fertiliser sector.

MAIN FINDING: PRICING OF LNG IMPORTS AND SEGMENTATION OF THE MARKETS NEEDS TO BE ADRESSED

Since 2014, Bangladesh's gas price has gone up by almost USD 1/MMbtu. There has been a sharp increase in the price paid by CNG users, commercial, captive power and domestic metered gas consumption. However, Bangladesh's gas prices are in the lower half compared with other countries (around the 40% benchmark).

Soon LNG will be imported at higher costs than the current gas purchases from PSCs and Petrobangla subsidiaries. This will necessitate an increase in the gas tariff in the short term. However, a continuation of the current model in which Petrobangla acquires LNG imports; purchases gas from IOCs at PSC contract prices, mixing it with its own gas from subsidiaries, then transmits the gas and distributes it to its customers through GTCL and distribution companies, is not recommended as it would continue cross-subsidies, inefficient allocation of resources and distorted pricing and reduce the economic growth rate in the medium and long term. This should be phased out over the medium term.

RECOMMENDATION: INTRODUCE DUAL MARKETS FOR GAS PROTECTING THE DOMESTIC MARKET WHILE INTRODUCING MARKET BASED PRICES FOR THE MOST EFFICIENT AND CREDITWORTHY USERS

This option allows for a gradual transition to a more competitive gas market. As domestic gas production from existing fields continue to fall over time and higher cost supply from new fields and imports increase over time, more gas will be sold at the new, higher price. This may also spur new domestic production to come on stream. A key issue is to determine the customers' willingness and ability to pay a higher price to get gas supplied by new LNG imports.

The analysis in Table 40 showed that in key sectors, power generation and fertilizer, less that one quarter of the of economic value of gas is captured. At today's lower oil prices this would be correspond to less than 50% captured, indicating that the gas has a higher economic value for the customers in these sectors and they should be able to pay a higher price.

RECOMMENDATION: INTRODUCE NON-DISCRIMINATORY ACCESS TO TRANSMISSION AND DISTRIBUTION NETWORKS

The introduction of non-discriminatory access to transmission and distribution networks will contribute to a move towards more competition. Today, GTCL is already unbundled at the accounting level. However, three transmission and distribution companies also own and operate transmission pipelines in their supply areas, although integrated with GTCL's transmission pipelines. These transmission assets need to be unbundled at the accounting level.

It is recommended to develop tariffs for transmission and distribution of gas, that will ensure both transmission and distribution companies sufficient funds for self-financing of their investment in expansions of the gas networks to accommodate future growth.

RECOMMENDATION: EMPOWER BERC TO DETERMINE THIRD PARTY ACCESS TARIFFS FOR TRANSMISSION AND DISTRIBUTION OF GAS

BERC regulatory capabilities should be enhanced to determine transmission and distribution tariffs for third parties to enable customers to buy gas at deregulated prices. Third party access to storage should be added when relevant. BERC should also issue licenses for import of gas, transmission, distribution, shipping and sale of gas.

Network codes for transmission, distribution (and storage, when relevant) of gas should be developed by BERC.

MAIN FINDING: REGULATORY INDEPENDENCE DOWNSTREAM BUT UPSTREAM INDEPENDENCE LACKING

Although situated within the ministry, the setup of BERC provides a framework for independent downstream regulation through the Gas Act, the BERC Act, the funding provisions, appointment procedures and statutes. Petrobangla has a potential conflict of interest role as the upstream gas regulator, supervising and monitoring the PSCs and self-regulating its own operations, including its subsidiaries.

RECOMMENDATION: CONSIDER MOVING THE TECHNICAL UPSTREAM REGULATION INTO AN INDEPENDENT AGENCY AND KEEP THE POLICY FUNCTIONS IN THE MINISTRY

An independent upstream Regulator, for example BERC, separate from Petrobangla and the Ministry could potentially reduce potential conflicts of interests between Petrobangla, its subsidiaries and the regulated industry. It would be able to focus on regulatory functions only, and not have any policy functions, as they should be handled by the Ministry. This could create a more effective regulator to monitor and approve petroleum activities for compliance with regulations and work programs, collect and store data, manage bidding rounds and direct negotiations with petroleum investors, and granting PSCs. This could ensure a more timely execution of petroleum sector oversight, leading to increased activities and production in the long term. The 2006 Gas Sector Master Plan recommended an Upstream Licensing Authority to supervise and monitor the activities of the IOCs. This has not yet been implemented.

Nevertheless, it needs to be acknowledged that a tie-in of upstream regulation and exploration activities by two different organizations/agencies can be a time-consuming event. Petrobangla’s experience of administering the PSC for last 30 years also needs to be recognised, such that Petrobangla’s focus to boost up exploration activities should be supported but not hammered if relevant authorities consider setting up an independent regulation agency in due course.

APPENDIX 1: KEY DATA TABLES

Table 41: Historical Primary Energy Consumption per Capita

	Bangladesh	China	India	Indonesia	Myanmar	Pakistan	Thailand	Vietnam
Data Source	*World Bank*	*World Bank*	*World Bank*	*World Bank*	*World Bank*	*World Bank*	*World Bank*	*World Bank*
Year / Unit	*toe*	*toe*	*toe*	*toe*	*toe*	*toe*	*toe*	*toe*
1994	0.13	0.82	0.37	0.61	0.26	0.43	0.96	0.29
1995	0.13	0.87	0.39	0.66	0.26	0.44	1.04	0.30
1996	0.13	0.88	0.39	0.68	0.26	0.45	1.16	0.32
1997	0.14	0.87	0.40	0.69	0.26	0.45	1.16	0.34
1998	0.14	0.87	0.40	0.67	0.27	0.45	1.08	0.35
1999	0.14	0.88	0.42	0.69	0.26	0.46	1.14	0.36
2000	0.14	0.90	0.42	0.74	0.27	0.46	1.15	0.37
2001	0.15	0.93	0.42	0.74	0.26	0.46	1.17	0.39
2002	0.15	0.98	0.42	0.76	0.27	0.46	1.28	0.42
2003	0.16	1.12	0.43	0.75	0.29	0.47	1.37	0.44
2004	0.16	1.27	0.44	0.79	0.30	0.49	1.47	0.48
2005	0.16	1.39	0.45	0.79	0.30	0.50	1.50	0.50
2006	0.17	1.52	0.47	0.80	0.30	0.51	1.53	0.51
2007	0.17	1.63	0.49	0.79	0.31	0.53	1.59	0.54
2008	0.18	1.67	0.50	0.79	0.30	0.51	1.63	0.57
2009	0.19	1.78	0.55	0.85	0.28	0.50	1.62	0.62
2010	0.20	1.95	0.56	0.88	0.27	0.50	1.77	0.68
2011	0.21	2.09	0.58	0.83	0.27	0.49	1.76	0.67
2012	0.21	2.16	0.60	0.85	0.30	0.49	1.88	0.67
2013	0.22	2.21	0.61	0.87	0.31	0.49	2.01	0.67
2014	0.22	2.24	0.64	0.89	0.36	0.49	1.99	0.68

Table 42: Historical Bangladesh Statistics - Macro Factors

	GDP @ constant 2010 USD	GDP Growth Rate	GDP by Sector - Agriculture	GDP by Sector - Industry	GDP by Sector - Services	Primary Energy Consumption Per Capita	Electricity Consumption Per Capita
Data Source	*World Bank*	*World Bank/ Ramboll*	*World Bank*	*World Bank*	*World Bank*	*World Bank*	*World Bank*
Year / Unit	*USD Billion*					*toe*	*KWh*
1995/96	55.3	4.5%	24%	23%	53%	0.13	80
1996/97	57.8	4.5%	24%	23%	53%	0.14	81
1997/98	60.8	5.2%	24%	24%	52%	0.14	86
1998/99	63.6	4.7%	24%	23%	53%	0.14	94
1999/00	67.0	5.3%	24%	23%	53%	0.14	102
2000/01	70.4	5.1%	23%	24%	53%	0.15	112
2001/02	73.1	3.8%	22%	24%	54%	0.15	120
2002/03	76.6	4.7%	21%	24%	55%	0.16	126
2003/04	80.6	5.2%	20%	24%	56%	0.16	161
2004/05	85.9	6.5%	20%	25%	56%	0.16	171
2005/06	91.6	6.7%	19%	25%	56%	0.17	192
2006/07	98.1	7.1%	19%	26%	56%	0.17	201
2007/08	104.0	6.0%	18%	26%	56%	0.18	202
2008/09	109.2	5.0%	18%	26%	56%	0.19	220
2009/10	115.3	5.6%	18%	26%	56%	0.20	241
2010/11	122.7	6.5%	18%	26%	56%	0.21	258
2011/12	130.7	6.5%	17%	27%	56%	0.21	276
2012/13	138.6	6.0%	16%	28%	56%	0.22	294
2013/14	147.0	6.1%	16%	28%	56%	0.22	311
2014/15	156.6	6.6%	16%	28%	56%	n/a	n/a
2015/16	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Table 43: Historical Bangladesh Statistics - Gas Sector

	Gas Consumption - Power	Gas Consumption - Captive Power	Gas Consumption - Fertiliser	Gas Consumption - Industry (incl. Tea & Brick)	Gas Consumption - Domestic	Gas Consumption - Commercial	Gas Consumption - CNG	Gas Consumption - Total
Data Source	*Petrobangla/ Ramboll*	*Petrobangla/ Ramboll*	*Petrobangla/ Ramboll*	*Petrobangla/ Ramboll*	*Petrobangla/ Ramboll*	*Petrobangla/ Ramboll*	*Petrobangla/ Ramboll*	*Petrobangla/ Ramboll*
Year / Unit	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*
1995/96	304	0	249	79	57	8	0	698
1996/97	304	0	213	82	62	12	0	673
1997/98	339	0	219	92	68	13	0	730
1998/99	386	0	227	101	74	13	0	800
1999/00	404	0	228	116	81	11	0	841
2000/01	480	0	242	135	87	11	0	956
2001/02	521	0	216	150	101	12	0	999
2002/03	522	0	263	178	123	13	1	1099
2003/04	546	88	254	130	135	13	5	1171
2004/05	578	104	258	144	144	13	10	1250
2005/06	615	134	244	176	155	9	19	1351
2006/07	606	256	171	215	173	16	33	1470
2007/08	642	220	216	255	189	18	62	1602
2008/09	702	259	205	288	202	21	85	1762
2009/10	776	308	177	328	227	22	108	1946
2010/11	750	332	172	335	239	23	105	1958
2011/12	834	339	160	354	244	24	106	2060
2012/13	901	367	164	374	246	24	110	2187
2013/14	924	394	147	391	278	24	110	2269
2014/15	972	411	147	407	324	25	118	2404
2015/16	1095	441	144	430	388	25	127	2649

Table 44: Historical Bangladesh Statistics - Ln(GDP) and Ln(Gas Demand)

	Ln(GDP)	Ln(Gas_Ind)	Ln(Gas_Dom)	Ln(Gas_Com)	Ln(Gas_CNG)
Data Source	*Ramboll*	*Ramboll*	*Ramboll*	*Ramboll*	*Ramboll*
Year / Unit	*Ln(US$bn)*	*Ln(mcfd)*	*Ln(mcfd)*	*Ln(mcfd)*	*Ln(mcfd)*
1995/96	4.01	11.3	10.9	9.0	-
1996/97	4.06	11.3	11.0	9.4	-
1997/98	4.11	11.4	11.1	9.4	-
1998/99	4.15	11.5	11.2	9.5	-
1999/00	4.20	11.7	11.3	9.3	-
2000/01	4.25	11.8	11.4	9.3	-
2001/02	4.29	11.9	11.5	9.4	-
2002/03	4.34	12.1	11.7	9.4	6.3
2003/04	4.39	11.8	11.8	9.5	8.6
2004/05	4.45	11.9	11.9	9.5	9.2
2005/06	4.52	12.1	12.0	9.1	9.8
2006/07	4.59	12.3	12.1	9.7	10.4
2007/08	4.64	12.4	12.1	9.8	11.0
2008/09	4.69	12.6	12.2	9.9	11.3
2009/10	4.75	12.7	12.3	10.0	11.6
2010/11	4.81	12.7	12.4	10.1	11.6
2011/12	4.87	12.8	12.4	10.1	11.6
2012/13	4.93	12.8	12.4	10.1	11.6
2013/14	4.99	12.9	12.5	10.1	11.6
2014/15	5.05	12.9	12.7	10.1	11.7
2015/16	-	-	-	-	-

Table 45: Historical Bangladesh Statistics - Power Sector Mix

	Grid Power Generation - Gas	Grid Power Generation - Oil	Grid Power Generation - Coal	Grid Power Generation - Nuclear	Grid Power Generation - Renewables	Grid Power Generation - Hydro	Grid Power Generation - Import	Power Budgetary Support
Data Source	*BPDB Annual Reports*	*BPDB Annual Reports*	*BPDB Annual Reports*	*BPDB Annual Reports*	*BPDB Annual Reports*	*BPDB Annual Reports*	*BPDB Annual Reports*	*7th FYP*
Year / Unit	*% of total*							*Taka Billion*
1995/96	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1996/97	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1997/98	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1998/99	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
1999/00	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2000/01	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2001/02	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2002/03	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2003/04	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2004/05	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2005/06	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2006/07	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2007/08	86%	6%	4%	0%	0%	4%	0%	n/a
2008/09	88%	6%	4%	0%	0%	2%	0%	n/a
2009/10	89%	5%	4%	0%	0%	2%	0%	n/a
2010/11	82%	13%	2%	0%	0%	3%	0%	10
2011/12	79%	16%	3%	0%	0%	2%	0%	45
2012/13	78%	17%	3%	0%	0%	2%	0%	60
2013/14	72%	18%	2%	0%	0%	1%	5%	52
2014/15	69%	20%	2%	0%	0%	1%	7%	61
2015/16	69%	21%	2%	0%	0%	2%	7%	60

Table 46: Forecasts - GDP Growth and Power

	GDP Growth Rate - Scebario A	GDP Growth Rate - Scebario B	GDP Growth Rate - Scebario C	Total Power Demand - Scebario A	Total Power Demand - Scebario B	Total Power Demand - Scebario C	Gas Share of Total Power Gen - Scenario A	Gas Share of Total Power Gen - Scenario B	Gas Share of Total Power Gen - Scenario C
Data Source	*7th FYP/ Ramboll*	*7th FYP/ Ramboll*	*7th FYP/ Ramboll*	*PSMP2016*	*Ramboll*	*Petrobangla/ BPBD*	*Ramboll*	*Ramboll*	*Petrobangla/ BPBD*
Year / Unit				*TWh*	*TWh*	*TWh*			
2016/17	7.2%	7.2%	7.2%	62	62	62	70%	70%	n/a
2017/18	7.4%	7.4%	7.4%	67	67	67	70%	70%	n/a
2018/19	7.6%	7.6%	7.6%	73	73	73	70%	70%	n/a
2019/20	8.0%	8.0%	8.0%	80	80	80	70%	70%	n/a
2020/21	7.8%	7.0%	7.8%	88	87	88	66%	68%	n/a
2021/22	7.6%	7.0%	7.6%	96	94	96	62%	66%	n/a
2022/23	7.4%	7.0%	7.4%	104	102	104	59%	65%	n/a
2023/24	7.2%	7.0%	7.2%	112	110	112	55%	63%	n/a
2024/25	6.9%	7.0%	6.9%	121	119	121	52%	61%	n/a
2025/26	6.7%	7.0%	6.7%	130	128	130	49%	60%	n/a
2026/27	6.5%	7.0%	6.5%	139	137	139	46%	58%	n/a
2027/28	6.3%	7.0%	6.3%	148	147	148	43%	57%	n/a
2028/29	6.1%	7.0%	6.1%	156	157	156	41%	55%	n/a
2029/30	5.9%	7.0%	5.9%	166	169	166	39%	54%	n/a
2030/31	5.7%	7.0%	5.7%	175	181	175	36%	52%	n/a
2031/32	5.5%	7.0%	5.5%	185	195	185	34%	51%	n/a
2032/33	5.3%	7.0%	5.3%	195	210	195	32%	50%	n/a
2033/34	5.0%	7.0%	5.0%	206	226	206	30%	48%	n/a
2034/35	4.8%	7.0%	4.8%	216	243	216	29%	47%	n/a
2035/36	4.6%	7.0%	4.6%	227	262	227	27%	46%	n/a
2036/37	4.4%	7.0%	4.4%	237	282	237	25%	45%	n/a
2037/38	4.4%	7.0%	4.4%	247	303	247	24%	44%	n/a
2038/39	4.4%	7.0%	4.4%	258	327	258	22%	42%	n/a
2039/40	4.3%	7.0%	4.3%	270	352	270	21%	41%	n/a
2040/41	4.3%	7.0%	4.3%	280	377	280	20%	40%	n/a

Table 47: Forecasts - Gas Demand by Sector - Scenario A

	Scenario A Gas Demand - Total	Scenario A Gas Demand - Power	Scenario A Gas Demand - Captive Power	Scenario A Gas Demand - Fertiliser	Scenario A Gas Demand - Industry	Scenario A Gas Demand - Domestic	Scenario A Gas Demand - Commercial (incl. Tea)	Scenario A Gas Demand - CNG
Data Source	***Ramboll***	*Ramboll*	*Ramboll*	*Ramboll*	*Ramboll*	*Ramboll*	*Ramboll*	*Ramboll*
Year / Unit	***mmcfd***	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*
2016/17	**3736**	1796	480	316	542	425	38	139
2017/18	**3852**	1833	480	316	621	425	38	139
2018/19	**3996**	1887	480	316	710	425	38	139
2019/20	**4163**	1950	480	316	814	425	38	139
2020/21	**4214**	1890	480	316	925	425	38	139
2021/22	**4224**	1824	432	316	1044	425	38	145
2022/23	**4274**	1753	389	316	1169	457	38	152
2023/24	**4331**	1679	350	316	1299	490	38	159
2024/25	**4396**	1603	315	316	1435	524	38	166
2025/26	**4467**	1524	283	316	1575	557	38	173
2026/27	**4543**	1445	255	316	1718	590	38	181
2027/28	**4704**	1445	230	316	1863	624	38	189
2028/29	**4853**	1429	207	316	2009	656	38	198
2029/30	**5005**	1414	186	316	2156	689	38	207
2030/31	**5207**	1447	167	316	2302	721	38	216
2031/32	**5378**	1450	151	316	2447	752	38	226
2032/33	**5532**	1436	136	316	2589	782	38	236
2033/34	**5695**	1434	122	316	2728	811	38	246
2034/35	**5851**	1427	110	316	2863	839	38	257
2035/36	**6009**	1427	99	316	2994	867	38	269
2036/37	**6155**	1420	89	316	3119	893	38	281
2037/38	**6291**	1401	80	316	3244	918	38	294
2038/39	**6433**	1388	72	316	3368	944	38	307
2039/40	**6579**	1379	65	316	3491	969	38	321
2040/41	**6713**	1358	58	316	3613	994	38	335

Table 48: Forecasts - Gas Demand by Franchise Area - Scenario A

	Scenario A Gas Demand - Total	Scenario A - BGDCL	Scenario A - JGTDSL	Scenario A - KGDCL	Scenario A - PGCL	Scenario A - SGCL	Scenario A - TGTDCL
Data Source	***Ramboll***	*Ramboll*	*Ramboll*	*Ramboll*	*Ramboll*	*Ramboll*	*Ramboll*
Year / Unit	***mmcfd***	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*
2016/17	**3736**	420	391	533	141	424	1827
2017/18	**3852**	433	403	549	146	438	1883
2018/19	**3996**	449	418	570	151	454	1954
2019/20	**4163**	468	435	593	158	473	2035
2020/21	**4214**	474	441	601	160	479	2060
2021/22	**4224**	475	442	602	160	480	2065
2022/23	**4274**	481	447	609	162	486	2090
2023/24	**4331**	487	453	617	164	492	2118
2024/25	**4396**	494	460	627	166	499	2149
2025/26	**4467**	502	467	637	169	507	2184
2026/27	**4543**	511	475	648	172	516	2221
2027/28	**4704**	529	492	671	178	535	2300
2028/29	**4853**	546	507	692	184	551	2373
2029/30	**5005**	563	523	714	190	569	2447
2030/31	**5207**	585	544	742	197	592	2546
2031/32	**5378**	605	562	767	204	611	2629
2032/33	**5532**	622	578	789	209	629	2705
2033/34	**5695**	640	595	812	216	647	2784
2034/35	**5851**	658	612	834	222	665	2861
2035/36	**6009**	676	628	857	228	683	2938
2036/37	**6155**	692	644	878	233	699	3010
2037/38	**6291**	707	658	897	238	715	3076
2038/39	**6433**	723	673	917	244	731	3145
2039/40	**6579**	740	688	938	249	747	3217
2040/41	**6713**	755	702	957	254	763	3282

Table 49: Forecasts - Gas Demand by Sector - Scenario B

	Scenario B Gas Demand - Total	Scenario B Gas Demand - Power	Scenario B Gas Demand - Captive Power	Scenario B Gas Demand - Fertiliser	Scenario B Gas Demand - Industry	Scenario B Gas Demand - Domestic	Scenario B Gas Demand - Commercial (incl. Tea)	Scenario B Gas Demand - CNG
Data Source	***Ramboll***	*Ramboll*	*Ramboll*	*Ramboll*	*Ramboll*	*Ramboll*	*Ramboll*	*Ramboll*
Year / Unit	***mmcfd***	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*
2016/17	**3736**	1796	480	316	542	425	38	139
2017/18	**3852**	1833	480	316	621	425	38	139
2018/19	**3996**	1887	480	316	710	425	38	139
2019/20	**4183**	1971	480	316	814	425	38	139
2020/21	**4290**	1978	480	316	914	425	38	139
2021/22	**4361**	1982	432	316	1022	425	38	145
2022/23	**4472**	1983	389	316	1138	456	38	152
2023/24	**4595**	1982	350	316	1263	488	38	159
2024/25	**4730**	1978	315	316	1396	521	38	166
2025/26	**4876**	1972	283	316	1537	556	38	173
2026/27	**5033**	1964	255	316	1687	592	38	181
2027/28	**5189**	1942	230	316	1846	629	38	189
2028/29	**5379**	1942	207	316	2012	667	38	198
2029/30	**5651**	2011	186	316	2187	706	38	207
2030/31	**6012**	2159	167	316	2370	746	38	216
2031/32	**6354**	2276	151	316	2560	787	38	226
2032/33	**6691**	2379	136	316	2758	829	38	236
2033/34	**7068**	2510	122	316	2964	872	38	246
2034/35	**7461**	2648	110	316	3176	916	38	257
2035/36	**7891**	2813	99	316	3395	961	38	269
2036/37	**8331**	2981	89	316	3620	1007	38	281
2037/38	**8767**	3136	80	316	3851	1053	38	294
2038/39	**9231**	3311	72	316	4087	1100	38	307
2039/40	**9725**	3509	65	316	4329	1147	38	321
2040/41	**10208**	3690	58	316	4575	1196	38	335

Table 50: Forecasts - Gas Demand by Franchise Area - Scenario B

	Scenario B Gas Demand - Total	Scenario B - BGDCL	Scenario B - JGTDSL	Scenario B - KGDCL	Scenario B - PGCL	Scenario B - SGCL	Scenario B - TGTDCL
Data Source	***Ramboll***	*Ramboll*	*Ramboll*	*Ramboll*	*Ramboll*	*Ramboll*	*Ramboll*
Year / Unit	***mmcfd***	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*
2016/17	**3736**	420	391	533	141	424	1827
2017/18	**3852**	433	403	549	146	438	1883
2018/19	**3996**	449	418	570	151	454	1954
2019/20	**4183**	470	437	596	158	475	2045
2020/21	**4290**	482	449	612	162	487	2098
2021/22	**4361**	490	456	622	165	495	2132
2022/23	**4472**	503	468	638	169	508	2187
2023/24	**4595**	517	480	655	174	522	2247
2024/25	**4730**	532	495	674	179	537	2313
2025/26	**4876**	548	510	695	185	554	2384
2026/27	**5033**	566	526	717	191	572	2461
2027/28	**5189**	584	543	740	196	590	2537
2028/29	**5379**	605	562	767	204	611	2630
2029/30	**5651**	635	591	806	214	642	2763
2030/31	**6012**	676	629	857	228	683	2940
2031/32	**6354**	714	664	906	241	722	3107
2032/33	**6691**	752	700	954	253	760	3272
2033/34	**7068**	795	739	1008	268	803	3456
2034/35	**7461**	839	780	1064	283	848	3648
2035/36	**7891**	887	825	1125	299	897	3858
2036/37	**8331**	937	871	1188	315	947	4074
2037/38	**8767**	986	917	1250	332	996	4287
2038/39	**9231**	1038	965	1316	350	1049	4514
2039/40	**9725**	1094	1017	1386	368	1105	4755
2040/41	**10208**	1148	1067	1455	387	1160	4991

Table 51: Forecasts - Gas Demand by Sector - Scenario C

	Scenario C Gas Demand - Total	Scenario C Gas Demand - Power	Scenario C Gas Demand - Captive Power	Scenario C Gas Demand - Fertiliser	Scenario C Gas Demand - Industry	Scenario C Gas Demand - Domestic	Scenario C Gas Demand - Commercial (incl. Tea)	Scenario C Gas Demand - CNG
Data Source	***Ramboll***	*Petrobangla/ BPBD*	*Ramboll*	*Ramboll*	*Ramboll*	*Ramboll*	*Ramboll*	*Ramboll*
Year / Unit	***mmcfd***	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*
2016/17	**3736**	1796	480	316	542	425	38	139
2017/18	**3901**	1882	480	316	621	425	38	139
2018/19	**4151**	2043	480	316	710	425	38	139
2019/20	**4478**	2266	480	316	814	425	38	139
2020/21	**4520**	2197	480	316	925	425	38	139
2021/22	**4610**	2210	432	316	1044	425	38	145
2022/23	**4787**	2266	389	316	1169	457	38	152
2023/24	**4931**	2279	350	316	1299	490	38	159
2024/25	**5078**	2285	315	316	1435	524	38	166
2025/26	**5257**	2315	283	316	1575	557	38	173
2026/27	**5417**	2319	255	316	1718	590	38	181
2027/28	**5648**	2389	230	316	1863	624	38	189
2028/29	**5914**	2490	207	316	2009	656	38	198
2029/30	**6058**	2467	186	316	2156	689	38	207
2030/31	**6228**	2468	167	316	2302	721	38	216
2031/32	**6529**	2601	151	316	2447	752	38	226
2032/33	**6788**	2692	136	316	2589	782	38	236
2033/34	**7013**	2752	122	316	2728	811	38	246
2034/35	**7281**	2857	110	316	2863	839	38	257
2035/36	**7532**	2950	99	316	2994	867	38	269
2036/37	**7666**	2930	89	316	3119	893	38	281
2037/38	**7885**	2995	80	316	3244	918	38	294
2038/39	**8030**	2985	72	316	3368	944	38	307
2039/40	**8193**	2993	65	316	3491	969	38	321
2040/41	**8346**	2991	58	316	3613	994	38	335

Table 52: Forecasts - Gas Demand by Franchise Area - Scenario C

	Scenario C Gas Demand - Total	Scenario C - BGDCL	Scenario C - JGTDSL	Scenario C - KGDCL	Scenario C - PGCL	Scenario C - SGCL	Scenario C - TGTDCL
Data Source	***Ramboll***	*Ramboll*	*Ramboll*	*Ramboll*	*Ramboll*	*Ramboll*	*Ramboll*
Year / Unit	***mmcfd***	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*
2016/17	**3736**	420	391	533	141	424	1827
2017/18	**3901**	439	408	556	148	443	1907
2018/19	**4151**	467	434	592	157	472	2030
2019/20	**4478**	504	468	638	170	509	2190
2020/21	**4520**	508	473	644	171	514	2210
2021/22	**4610**	518	482	657	175	524	2254
2022/23	**4787**	538	501	682	181	544	2340
2023/24	**4931**	555	516	703	187	560	2411
2024/25	**5078**	571	531	724	192	577	2483
2025/26	**5257**	591	550	749	199	597	2570
2026/27	**5417**	609	566	772	205	616	2649
2027/28	**5648**	635	591	805	214	642	2762
2028/29	**5914**	665	618	843	224	672	2892
2029/30	**6058**	681	633	864	229	688	2962
2030/31	**6228**	700	651	888	236	708	3045
2031/32	**6529**	734	683	931	247	742	3192
2032/33	**6788**	763	710	968	257	771	3319
2033/34	**7013**	789	733	1000	266	797	3429
2034/35	**7281**	819	761	1038	276	827	3560
2035/36	**7532**	847	788	1074	285	856	3683
2036/37	**7666**	862	802	1093	290	871	3748
2037/38	**7885**	887	825	1124	299	896	3855
2038/39	**8030**	903	840	1145	304	912	3926
2039/40	**8193**	921	857	1168	310	931	4006
2040/41	**8346**	939	873	1190	316	948	4081

Table 53: Forecasts - Gas Supply - Indigenous Production

	Indigenous Production - Total	Indigenous Production - Existing Fields	Indigenous Production - Additional 2P	Indigenous Production - Additional 3P	Indigenous Production - Thin Bed and Accelerated E&P	Indigenous Production - Area A	Indigenous Production - Area B	Indigenous Production - Area C	Indigenous Production - Area D	Indigenous Production - Area E	Indigenous Production - Area F	Indigenous Production - Area G
Data Source	***Ramboll/ GEUS***	*Ramboll/ GEUS*	*Ramboll/ GEUS*	*Ramboll/ GEUS*	*Ramboll/ GEUS*	*Ramboll/ GEUS*	*Ramboll/ GEUS*	*Ramboll/ GEUS*	*Ramboll/ GEUS*	*Ramboll/ GEUS*	*Ramboll/ GEUS*	*Ramboll/ GEUS*
Year / Unit	***mmcfd***	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*
2016/17	**2754**	2754	0	0	0	0	0	0	0	0	0	0
2017/18	**2849**	2712	0	0	137	0	0	0	0	0	0	0
2018/19	**2806**	2669	0	0	137	0	0	0	0	0	0	0
2019/20	**3011**	2722	0	15	274	0	0	0	0	0	0	0
2020/21	**2743**	2414	40	15	274	0	0	0	0	0	0	0
2021/22	**2639**	2270	60	35	274	0	0	0	0	0	0	0
2022/23	**2616**	2306	78	95	137	0	0	0	0	0	0	0
2023/24	**2492**	1861	88	110	137	197	0	99	0	0	0	0
2024/25	**2758**	1636	88	245	0	427	99	263	0	0	0	0
2025/26	**3134**	1354	168	330	0	592	263	427	0	0	0	0
2026/27	**3586**	1198	278	335	0	658	427	592	0	0	0	99
2027/28	**3814**	1066	218	360	0	658	592	756	0	0	0	164
2028/29	**4262**	883	228	455	0	658	756	822	197	0	0	263
2029/30	**4703**	744	248	555	0	658	822	822	526	0	0	329
2030/31	**4845**	641	268	550	0	658	822	822	756	0	0	329
2031/32	**4886**	586	333	515	0	658	822	822	822	0	0	329
2032/33	**4818**	508	353	505	0	658	822	822	822	0	0	329
2033/34	**4698**	361	383	510	0	652	822	819	822	0	0	329
2034/35	**4515**	238	363	520	0	490	819	737	822	197	0	329
2035/36	**4473**	208	345	525	0	353	737	627	822	526	0	329
2036/37	**4173**	172	335	450	0	192	627	490	822	756	0	329
2037/38	**3929**	120	270	430	0	110	490	340	822	822	197	329
2038/39	**3572**	79	155	385	0	41	340	178	816	822	427	329
2039/40	**3023**	29	140	270	0	14	178	96	652	822	493	329
2040/41	**2591**	0	140	235	0	0	96	41	436	822	493	329

Table 54: Forecasts - Gas Demand Supply Blance - Scenario C with YTF Success

	Total Gas Demand - Scenario C	Gas Supply - Existing Fields	Gas Supply - Additional 2P	Gas Supply - Additional 3P	Gas Supply - Thin Bed and Accelerated E&P	Gas Supply - YTF	Gas Supply - Import	**Total Gas Supply - Scenario C**	**Gas Demand Supply Blance - Scenario C**
Data Source	***Ramboll***	*Ramboll/ GEUS*	*Ramboll/ GEUS*	*Ramboll/ GEUS*	*Ramboll/ GEUS*	*Ramboll/ GEUS*	*Ramboll/ GEUS*	***Ramboll/ GEUS***	***Ramboll/ GEUS***
Year / Unit	***mmcfd***	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	*mmcfd*	***mmcfd***	***mmcfd***
2016/17	**3736**	2754	0	0	0	0	0	**2754**	**-982**
2017/18	**3901**	2712	0	0	137	0	0	**2849**	**-1052**
2018/19	**4151**	2669	0	0	137	0	800	**3606**	**-545**
2019/20	**4478**	2722	0	15	274	0	800	**3811**	**-667**
2020/21	**4520**	2414	40	15	274	0	1200	**3943**	**-578**
2021/22	**4610**	2270	60	35	274	0	1600	**4239**	**-371**
2022/23	**4787**	2306	78	95	137	0	2171	**4787**	**0**
2023/24	**4931**	1861	88	110	137	296	2439	**4931**	**0**
2024/25	**5078**	1636	88	245	0	789	2321	**5078**	**0**
2025/26	**5257**	1354	168	330	0	1282	2123	**5257**	**0**
2026/27	**5417**	1198	278	335	0	1775	1831	**5417**	**0**
2027/28	**5648**	1066	218	360	0	2170	1834	**5648**	**0**
2028/29	**5914**	883	228	455	0	2696	1652	**5914**	**0**
2029/30	**6058**	744	248	555	0	3156	1356	**6058**	**0**
2030/31	**6228**	641	268	550	0	3386	1383	**6228**	**0**
2031/32	**6529**	586	333	515	0	3452	1643	**6529**	**0**
2032/33	**6788**	508	353	505	0	3452	1970	**6788**	**0**
2033/34	**7013**	361	383	510	0	3444	2315	**7013**	**0**
2034/35	**7281**	238	363	520	0	3395	2766	**7281**	**0**
2035/36	**7532**	208	345	525	0	3395	3059	**7532**	**0**
2036/37	**7666**	172	335	450	0	3216	3493	**7666**	**0**
2037/38	**7885**	120	270	430	0	3110	3956	**7885**	**0**
2038/39	**8030**	79	155	385	0	2953	4458	**8030**	**0**
2039/40	**8193**	29	140	270	0	2584	5170	**8193**	**0**
2040/41	**8346**	0	140	235	0	2216	5755	**8346**	**0**

Table 55: Bangladesh Gas Price Reviews

Sector	CNG	Commercial	Domestic Metered	Captive Power	Industry	Power	Fertilizer
Data Source	*BERC/ Petrobangla*	*BERC/ Petrobangla*	*BERC/ Petrobangla*	*BERC/ Petrobangla*	*BERC/ Petrobangla*	*BERC/ Petrobangla*	*BERC/ Petrobangla*
Date / Unit	*Taka/mcf*	*Taka/mcf*	*Taka/mcf*	*Taka/mcf*	*Taka/mcf*	*Taka/mcf*	*Taka/mcf*
01.01.2002	43.05	205.30	114.40	104.21	143.57	65.98	57.48
01.09.2002	43.05	220.00	120.00	100.00	140.00	70.00	60.00
15.02.2003	70.00	220.00	120.00	100.00	140.00	70.00	60.00
01.07.2004	70.00	228.50	126.10	100.00	145.20	72.45	62.15
01.09.2004	70.00	228.50	126.10	103.50	145.20	72.45	62.15
01.01.2005	70.00	233.12	130.00	105.59	148.13	73.91	63.41
25.04.2008	282.30	233.12	130.00	105.59	148.13	73.91	63.41
01.08.2009	282.30	268.09	146.25	118.26	165.91	79.82	72.92
12.05.2009	509.70	268.09	146.25	118.26	165.91	79.82	72.92
19.09.2011	651.29	268.09	146.25	118.26	165.91	79.82	72.92
01.09.2015	764.55	321.68	198.22	236.73	190.86	79.82	72.92
01.03.2017	1330.00	497.00	318.50	314.30	253.40	104.65	92.40
01.06.2017	1400.00	596.40	392.00	336.70	271.60	110.60	94.85

Table 56: World Bank Commodities Price Forecast (in nominal USD)

Commodity	Coal, Australia	Crude oil, avg	Natural gas, Europe	Natural gas, US	Natural gas LNG, Japan
Data Source	*World Bank*	*World Bank*	*World Bank*	*World Bank*	*World Bank*
Year / Unit	*USD/MT*	*USD/bbl*	*USD/mmBtu*	*USD/mmBtu*	*USD/mmBtu*
2014	70.1	96.2	10.1	4.4	16.0
2015	57.5	50.8	7.3	2.6	10.4
2016	65.9	42.8	4.6	2.5	6.9
2017	70.0	55.0	5.0	3.0	7.3
2018	60.0	60.0	5.2	3.5	7.4
2019	55.0	61.5	5.4	3.6	7.6
2020	55.4	62.9	5.6	3.7	7.8
2021	55.9	64.5	5.8	3.8	8.0
2022	56.3	66.0	6.0	3.9	8.2
2023	56.8	67.6	6.2	4.1	8.4
2024	57.2	69.3	6.4	4.2	8.6
2025	57.7	71.0	6.7	4.3	8.8
2030*	60.0	80.0	8.0	5.0	10.0

APPENDIX 2: LIST OF GAS FIRED POWER PLANTS

Table 57: Existing Gas-fired Power Capacity

#	Existing Gas-fired Power Plants	Output (MW)
1	Raojan (Chittagong) 2x210 MW	166
2	Raojan (Chittagong) 2x210 MW	166
3	SIKALBAHA (Chittagong) (60 MW)	39
4	Shikalbaha 150 MW PP	147
5	Ashuganj (B.Baria) 2x64 MW ST	89
6	Ashuganj (B.Baria) 3x150 MW ST	366
7	Ashuganj (B.Baria) 56 MW GT)	39
8	Ashuganj 50 MW Engine	44
9	Ashuganj 225 CCPP	218
10	Chandpur 150 MW CCPP	158
11	Ghorasal (Polash, Norshindi) 2x55 MW ST 1&2	78
12	Ghorasal (Polash, Norshindi) 210 MW ST 3,4,5&6	672
13	SIDDHIRGANJ (210 MW)	138
14	SIDDHIRGANJ 2x120 MW)	206
15	HARIPUR (96 MW) (Narayangonj)	59
16	Haripur 412 MW CCPP (EGCB)	400
17	TONGI (105 MW) (Dhaka)	103
18	Shahjibazar (Hobigonj) 2x35 MW GT 8&9	65
19	Lump GT Publick Gas ~30MW (SYLHET (20 MW)	19
20	SYLHET (150 MW) PP	139
21	Fenchuganj 97 & 104 MW CC BPDB	165
22	Lump GT Publick Gas ~100MW (Baghabari (Sirajgonj) 71 MW GT	69
23	Baghabari (Sirajgonj) 100 MW GT	98
24	Sirajganj 225 MW CCPP (1st Unit)	204
25	RPCL (Mymenshing) (210 MW)	202
26	Haripur Power Ltd. (360 MW)	360
27	Meghnaghat power Ltd. (450 MW)	450
28	Ghorasal 108 MW IPP (Regent Power))	108
29	Ashugonj 195 MW Modular PP	195
30	Bibiana-II 341 MW CCPP (Summit)	341
31	Bogra 15 Years RPP (GBB)	22
32	Kumargoan, Sylhet RPP (Energyprima)	50
33	Shahjibazar 15 Yrs RPP (Shahjibazar Power)	86
34	Shahjibazar RPP (Energyprima)	50
35	Tangail SIPP (Doreen)	22
36	Feni SIPP (Doreen)	22
37	Lump Gas Rental ~50 MW (Kumkargoan, Sylhet 15 Years RPP (Desh Energy)	10
38	Barobkundo SIPP (Regent Power)	22
39	Bhola 3 Years RPP (Venture)	33
40	Jangalia, Comilla SIPP (Summit))	33
41	Fenchuganj 15 Years RPP (Barakatullah)	51

42	Ashugong 55 MW RPP (Precision Energy))	55
43	Fenchugonj RPP (Energy Prima)	44
44	Ghorasal 45 MW QRPP (Aggreko)	45
45	Ghorasal 100 MW QRPP (Aggreko)	100
46	B. Baria 70 MW QRPP (Aggreco)	85
47	Lump Gas Rental ~100 MW (Ghorasal 78 MW QRPP (Max Power)	78
48	Ashugonj 80 MW QRPP (Aggreko)	95
49	Ashugonj 53 MW QRPP (United Power)	53
50	Shajahanullah Power Co. Ltd.	25
51	Summit Power(REB)	105
52	Bogra RPP (Energy Prima)	20
53	Lump SIPP Gas (Hobiganj SIPP (REB) (Confi-Energypac)	11
54	Ullapara SIPP (REB) (Summit)	11
55	Narsindi SIPP (REB) (Doreen)	22
56	Feni SIPP (REB) (Doreen)	11
57	Mouna, Gazipur SIPP (REB) (Summit)	33
58	Rupganj , Narayanganj SIPP (REB) (Summit)	33
59	Ashugonj 51 MW IPP (Midland)	51
60	Bhola 225 MW CCPP	225
61	Bheramara 360 MW CCPP	360
62	Baghabari (Sirajganj) 71 MW	71
	Subtotal	7,437

Source: PSMP2016, PGCL, SGCL

Table 58: Committed New Gas-fired Power Capacity

#	Committed Gas-fired Power Plants	Output (MW)
1	Siddirganj 335 MW CCPP	328
2	Ashuganj (North) CCPP	370
3	Ashuganj (South) CCPP	361
4	Ghorasal 363 MW (7th Unit) CCPP	352
5	Shajibazar CCPP	322
6	Shikalbaha 225 MW CCPP	218
7	Bibiana South CCPP BPDB	372
8	Bibiana III CCPP BPDB	388
9	Fenchugonj 50 MW Power Plant (NRB)	50
10	Sylhet 150 MW PP Conversion	221
11	Ghorasal 3rd & 4th Unit Repowering (Capacity Addition)	776
12	Kushiara 163 MW CCPP	163
13	Bagabari 71 MW PP Conversion	102
14	Sirajganj 414 MW CCPP (4th unit)	414
15	Shahajibazar 100 MW	98
16	Khulna 225 MW Power Plant	225
17	Khulna 800 MW Power Plant	800
18	Bhola 95 MW Power Plant	95
19	Sirajganj 225 MWCCPP (2nd Unit)	225
20	Sirajganj 225 MWCCPP (3nd Unit)	225
	Subtotal	6,105

Source: PSMP2016, PGCL, SGCL

APPENDIX 3: GAS SUPPLY VIA INDIA

Background

India's economic progress is closely linked to energy demand. As the economy expands, the need for oil and gas is expected to grow considerably. Due to increase in demand of Natural Gas, India decided to expand its in-house production of fossil fuel across the nation. Hence, vision 2030 has been formed to meet the supply demand of Natural Gas. Thereby, MoPNG (Ministry of Petroleum & Natural Gas) India started its survey across country for untapped fossil fuel reserve in remote areas as well despite ongoing political situations.

The Eastern region of India which marks the border for Bangladesh is endowed with abundant resource of Natural Gas particularly Assam & Tripura, which started contributing to India more than 2 centuries. The Natural Gas produced in Eastern region is being transported via pipelines to supply the Natural Gas requirements to several sectors like, Power & Fertiliser, Domestic & commercial industries.

The laying of new pipelines to connect Eastern region of India will benefit the neighbouring countries like Bangladesh and Myanmar to have transnational gas pipelines for their country's ongoing and future demand for natural gas. The last part of this section provides our optional views/possibilities for the gas pipeline hook-up to connect with Bangladesh.

Demand prediction in India

The Power, Fertiliser, Industrial and CGD segments are expected to contribute to the bulk of future growth of natural gas demand in India. Natural gas demand from the power sector is expected to be driven, not only by the shortage of domestic coal supply and the rising cost of its substitute i.e. imported coal but also by increased domestic gas supply and power sector reforms. Fertiliser industry is the only industry that uses chemical and thermal heat of gas for its production and remains a major contributor to natural gas demand in the country. Due to latest technology innovations in the fertiliser industries, it has been proposed to use LNG as feed/raw material replacement, leading to a higher demand from fertiliser sector. A higher emphasis on food security in India and increasing import price of urea are expected to drive the demand from the fertiliser sector.

Figure 99: Historical India gas demand break-Up

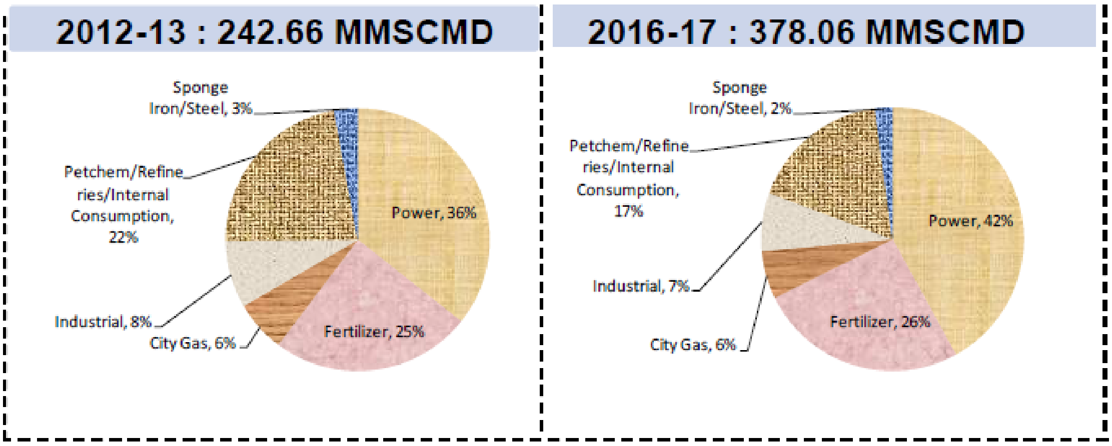
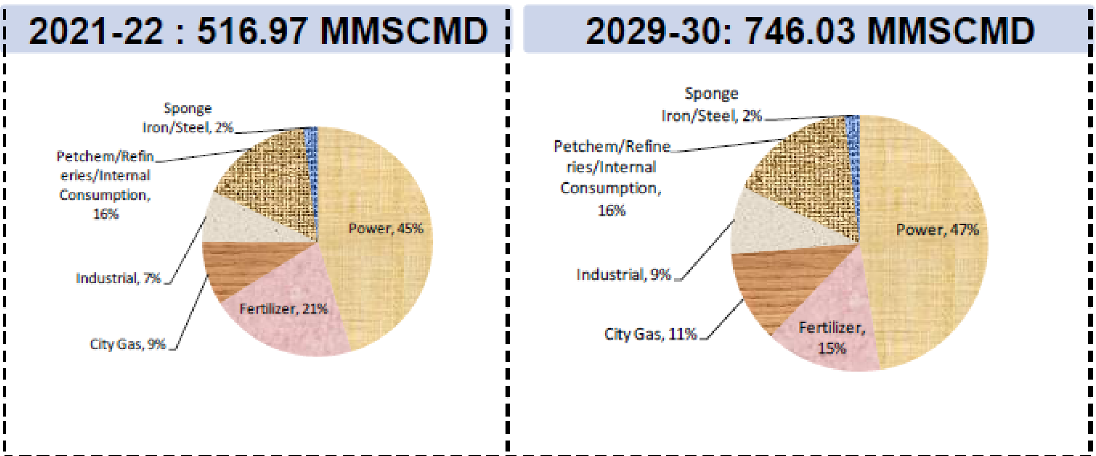


Figure 100: Future India gas demand break-Up



Supply prediction & plans in India

Currently, the natural gas demand far exceeds domestic supply in India and the situation is likely to continue in the future. The country's production of natural gas falling and additional demand is likely to be catered through LNG in the future or through transnational pipelines in absence of any large domestic discoveries, leaving the country to import natural gas as LNG from LNG exporting countries like Oman, Iran & Qatar.

An Indian consortium comprising ONGC Videsh Ltd (OVL), Indian Oil Corp. Ltd (IOCL) and Oil India Ltd (OIL) won a bid for the Farsi block in 2002 from National Iranian Oil Co. (NIOC). The Farsi Block has an in-place gas reserve of 21.7 Trillion Cubic Feet (TCF) of which 12.5 TCF are recoverable. OVL is preparing a Master Development Plan for the gas field. Gas produced from the field can either be converted into LNG by freezing at sub-zero temperature and shipping in cryogenic ships to India or transported through a pipeline.

LNG plays a critical role in partially bridging the gas supply gap in the country. India is currently the world's fourth-largest importer of LNG. Currently, India has the infrastructure to annually import and re-gasify 25 MMTPA of LNG through the four terminals (Dahej, 10 MMTPA; Hazira, 5 MMTPA; Dabhol, 5 MMTPA; and Kochi, 5 MMTPA) established on the west coast. However, the actual import capacity is less than 17 MMTPA due to lower utilisation of the Kochi and Dabhol terminals on account of pipeline connectivity issues and incomplete marine facilities.

India has remained interested in sourcing gas through cross-border pipelines from countries like Turkmenistan, Iran and other Middle-East countries for a long time. The Turkmenistan-Afghanistan-Pakistan-India (TAPI) pipeline is proposed for transporting Caspian Sea natural gas from Turkmenistan through Afghanistan into Pakistan and then to India. India plans to import 30-40 MMSCMD of natural gas from Turkmenistan through this pipeline, and negotiations are under way with Afghanistan and Pakistan over transit fee and other related matters.

Earlier to TAPI pipeline, India proposed a transnational pipeline which will transport natural gas from South Pars field in Iran via Pakistan and to India. But, due to some political and several other reasons this proposal is shelved. However, India is pursuing transnational pipelines to meet rising energy needs. The country is reliant on imports to meet about half of its natural gas needs. Hence, with support from Russian companies, India started reviewing the possibilities of Iran-Pakistan-India offshore pipeline in Arabian Sea. If this offshore pipeline comes into reality, India will have the required supply to meet its future demands.

Presently, India is importing natural gas apart from indigenous natural gas productions in terms of LNG to meet the current market demands. However, if the aforesaid pipeline projects rule out, India has already planned to import more LNG from LNG exporting countries. There are a number of Greenfield and Brownfield LNG projects at different stages of conceptualisation and development on the eastern and western coasts of India. Their viability and actual development is also predicated on the emergence of a robust gas market in India, with an appropriate policy framework to address the challenges faced by different segments of the industry.

Figure 101: LNG terminals India

LNG TERMINALS; EXISTING, PLANNED — Table 1

Location	Principals[1]	Capacity, million tpy	Onshore-FSRU[2]	Start-up	Capacity utilization, %[3]
Dahej, Gujarat	PLL	10, to be increased to 15 this year	Onshore	Operating	108.9
Hazira, Gujarat	Hazira LNG Pvt. Ltd.	5	Onshore	Operating	67
Dabhol, Maharashtra	RGPPL (GAIL-National Thermal Power Corp. Ltd. jv)	1.24 in Phase 1, to be increased to 5	Onshore	Operating	75
Kochi, Kerala	PLL	5	Onshore	Operating	3.4
Kakinada East Godavari, Andhra Pradesh	GAIL, Andhra Pradesh government	3.5	FSRU	2018	—
Ennore, Tamil Nadu	IOCL	5 in Phase 1 to be increased to 10	Onshore	2019	—
Mangalore, Karnataka	ONGC, BPCL	2.5	Onshore	2018	—
Mundra, Gujarat	Adani, GSPC	5	Onshore	2017	—
Gangavaram, Andhra Pradesh	PLL	5	Onshore	2018	—
Pipavav, Gujarat	Swan Energy Ltd.	5	FSRU	2018	—
Haldia, West Bengal	Hiranandani Group	4	FSRU	2019	—
Mumbai Port Trus, Maharashtra	India Gas Solution (BP-Reliance Industries jv)	5	FSRU	2020	—
Digha, West Bengal	H-Energy Pvt. Ltd., Excelerate Energy	4	FSRU	2019	—
Jaigarh, Maharashtra	H-Energy, Gateway Pvt. Ltd.	8	Onshore	2018	—
Chhara, Gujarat	SP Ports (Shapoorji Pallonji Group unit)	5	Onshore	2018	—
Dhamra, Odhisha	Dhamra LNG Terminal Pvt. Ltd.	5	Onshore	—	—

[1]RGPPL–Ratnagiri Gas and Power Pvt. Ltd., GAIL–Gas Authority of India Ltd., IOCL–Indian Oil Corp. Ltd., ONGC–Oil and Natural Gas Corp. Ltd., BPCL–Bharat Petroleum Corp. Ltd., GSPC–Gujarat State Petroleum Corp.[2]Floating storage and regasification unit.[3]April-September, 2015-16.
Source: LNG operating companies, Ministry of Petroleum & Natural Gas, GAIL

India is expected to have approximately 32,727 km of natural gas pipeline with a design capacity of 815 MMSCMD in place by 2030. However, the identification of new natural gas fields in India the supply point capacity to the markets is likely to increase to 582 MMSCMD. This capacity indicates the potential of the gas transport pipeline infrastructure to meet the demand in the country.

India's gas transmission infrastructure

For a country with huge population and extreme growth in all means, the demand for Natural Gas across the nation soars every day. The nation's MoPNG encompass its gas transmission infrastructure in terms of Gas Pipeline Network to supply natural gas across the country. India currently operates the longest Gas Transmission Pipeline connecting three major states (Gujarat, Karnataka & Andhra Pradesh). The gas transmission pipeline from these states is used to transport natural gas which is being produced in the country itself. The natural gas reserve in the country is on lower side compared to the current demand. Hence, India started importing LNG form Gulf countries as well. For LNG import India operates Dahej, Gujarat and Kochi as LNG import terminals mainly. At these terminals, the LNG is re-gasified and transported via pipelines. Based on the demand for natural gas in the country, design capacity of pipeline network in India is expected to reach 815 MMSCMD in 2029-30.

The Gas Transmission Pipeline network in India is being controlled by two major stake holders (GAIL – Public Corporation and RGTIL – Private Corporation).

GAIL

Gas Authority of India Limited referred as GAIL operates the country's 70% of gas transmission market. GAIL played a key role as gas market developer in India for decades catering to major industrial sectors like power, fertilisers, and city gas distribution. GAIL owns the country's largest pipeline network, the cross-country 2300 km Hazira-Vijaipur-Jagdishpur pipeline with a capacity to handle 33.4 MMSCMD gas. Presently, the company owns and operates a more than 11000 km long cross-country Natural Gas Pipeline in India with presence in 22 states in the country. GAIL has been given the responsibility of construction, operation & maintenance of Jagdishpur-Haldia/Bokaro-Dhamra Pipeline which is the extension of existing Hazira-Vijaipur-Jagdishpur pipeline.

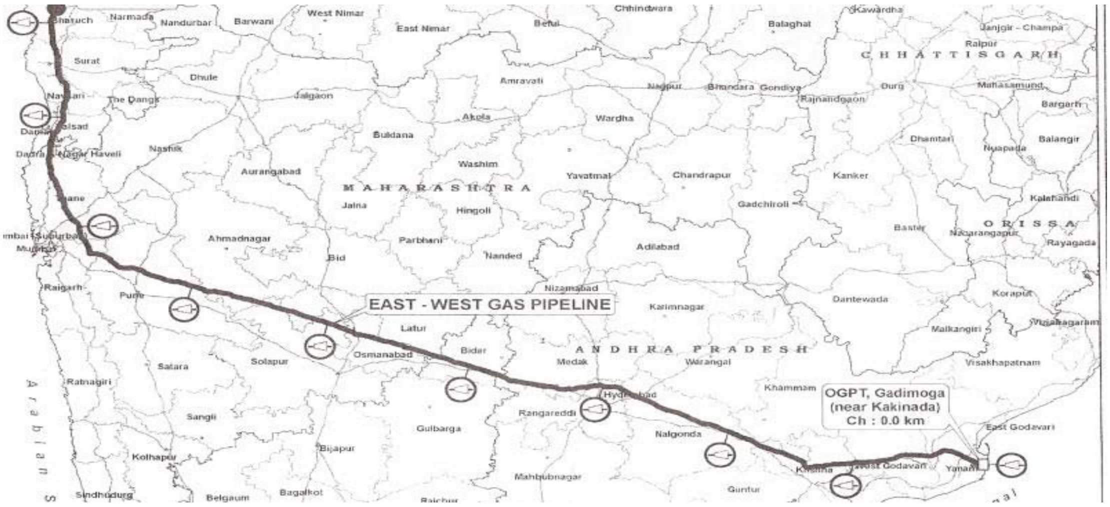
RGTIL

In the recent past, a private owned Gas Transmission Pipeline Network emerged in India to transport natural gas to the rest of the country. The private gas transport pipeline is owned and operated by RIL (Reliance Industries Limited) in the name of RGTIL (Reliance Gas Transportation Infrastructure Limited). RGTIL laid a gas pipeline of 1460 Kms to transport natural gas from east coast of the country to west.

The pipeline is referred as East West Pipeline (EWPL). The EWPL is currently transporting natural gas produced in Kakinada, Andhra Pradesh at KG-D6 Block to Baurach, Gujarat. This gas transmission supports Gujarat's power sector and Fertiliser industries.

RGTIL is now planning to extend its Gas Transmission Pipeline network from Kakinada, Andhra Pradesh (East Coast) to North-East region and Southern region of the country. The extension of pipeline for these 2 regions will be done with hook-up possibility in the GAIL pipeline network. Since, RGTIL/RIL has proposed LNG terminals which shall be referred as RLNG at East coast region and newly identified definitive natural gas resource in the deep locations of East coast.

Figure 102: EWPL Route Map



The newly proposed pipelines are referred to as Kakinada-Haldia pipeline (KHPL); Kakinada-Chennai pipeline (KCPL); Chennai-Bangalore-Mangalore pipeline (CBMPL); and Chennai-Tuticorin pipeline (CTPL) capable of carrying around 80 million metric standard cubic metres per day (MMSCMD) of gas. However, MoPNG stated that the entire natural gas produced at KG-D6 Block will be given to the existing pipeline leaving no gas transport for the proposed pipelines by RGTIL. Hence, the MoPNG declined RGTIL's interest on extension of gas pipelines on basis of declining gas production at KG-D6 Block.

Below table represents the list of operating gas pipelines in India (National Gas Grid).

Table 59: Operating pipelines in India

Network/Region	Entity	Length (Kms)	Design Capacity (MMSCMD)	Pipeline Size	Average flow 2016-17	% Capacity utilisation 2016-17
Hazira- Vijaipur- Jagdishpur Pipeline /Gas Rehabilitation & Expansion Projects pipeline/Dahej-Vijaipur Pipeline & Spur / Vijaipur- Dadri Pipeline	GAIL	4659.00	53.00	36"	33.16	62.57
DVPL-GREP Upgradation (DVPL-2 & VDPL)	GAIL	1119.00	54.00	48"	28.26	52.33
Chhainsa- Jhajjar -Hissar Pipeline (CJPL)	GAIL	265.00	5.00	36" /16"	0.97	19.34

(including Spur lines) commisioned up to Sultanpur, Jhajjar-Hissar under hold (111 Km).						
Dahej-Uran-Panvel Pipeline (DUPL/ DPPL) including Spur Lines	GAIL	875.00	19.90	30"/18"	12.62	63.41
Dadri- Bawana- Nangal Pipeline, Dadri-Bawana:106Km, Bawana - Nangal:501 KM, Spur Line of BNPL : 196 Km.	GAIL	834.80	31.00	36"/30"/24"/18"	4.66	15.03
Dabhol -Bangaluru Pipeline (including spur)	GAIL	1097.00	16.00	36"-4"	1.17	7.32
Kochi-Koottanad-Bengaluru- Mangalore (Phase-1)	GAIL	48.00	6.00	16"-4"	1.03	17.08
Assam (Lakwa)	GAIL	8.00	2.50	24"	0.37	14.80
Tripura (Agartala)	GAIL	61.00	2.30	12"	1.44	62.61
Ahmedabad	GAIL	133.00	2.91	12"	0.26	8.93
Rajasthan (Focus Energy)	GAIL	151.40	2.35	12"	1.44	61.28
Bharuch, Vadodara (Undera) including RLNG+ RIL	GAIL	538.00	15.42	24"/16"	4.08	26.47
Mumbai	GAIL	129.00	7.03	26"	6.31	89.76
KG Basin (including RLNG+ RIL)	GAIL	881.00	16.00	18"	5.31	33.19
Cauvery Basin	GAIL	278.00	8.66	18"	2.65	30.59
East- West Pipeline (RGTIL)	Reliance	1480.00	80.00	48"	17.00	21.25
Gujarat State Petronet Ltd.(GSPL) Network including Spur Lines	GSPL	2612.00	43.00	Assorted	25.33	58.91
Assam Regional Network	AGCL , DNPL	816.80	3.24	16" and others	2.25	69.44
Dadri -Panipat	IOCL	140.41	9.50	30"/10"	4.34	45.70
Uran -Trombay	ONGC	24.00	6.00	20"	3.80	63.33

Below table represents the list of future/under construction gas pipelines in India (National Gas Grid).

Table 60: Planned Pipelines in India

NETWORK/REGION	Entity	Length in Kms	Design Capacity (MMSCMD)	Pipeline Size	Status of Pipeline laid (Km)
Kochi - Koottanad - Bangaluru - Mangalore	GAIL(India) Ltd.	1063	16.00	24"/18"/12"	55.45
Dabhol -Bengaluru	GAIL(India) Ltd.	315	16.00	36"/30"/24"/18"	77.27
Surat - Paradip*	GAIL(India) Ltd.	2112	74.81	36"/24"/18"	0
Jagdishpur-Haldia-Bokaro-Dhamra (JHBDPL) (Phase-1 (755 KM), 7.44 MMSCMD capacity	GAIL(India) Ltd.	2539	16.00	30”/24"/18"/12”/8”/4”	86.6
Mallavaram - Bhilwada*	GSPC India Transco Ltd.	2042	78.25	42”/36"/30"/24"/18"/12”	0
Mehsana - Bhatinda *	GSPC India Gasnet Ltd.	2052	77.11	36”/24”/18”/12”	0
Bhatinda - Srinagar*	GSPC India Gasnet Ltd.	725	42.42	24”/18”/16”/12”/8”/6”	0
Kakinada -Vizag-Srikakulam *	A P Gas Distribution Corporation	391	90.00	24”/18	0
Shadol-Phulpur *	Reliance Gas Pipelines Ltd.	312	3.50	16”	304
Ennore- Nellore*	Gas Transmission India Pvt. Ltd.	250	36.00	24”/18”	0
Ennore-Thiruvallur-Bengaluru-Puducherry-Nagapattinam-Madurai-Tuticorin*	Indian Oil Corporation Ltd.	1385	84.67	28"/24”/16”/12”/10"	0
Jaigarh-Manglore*	H-Energy Pvt. Ltd.	635	17.00	24"	0

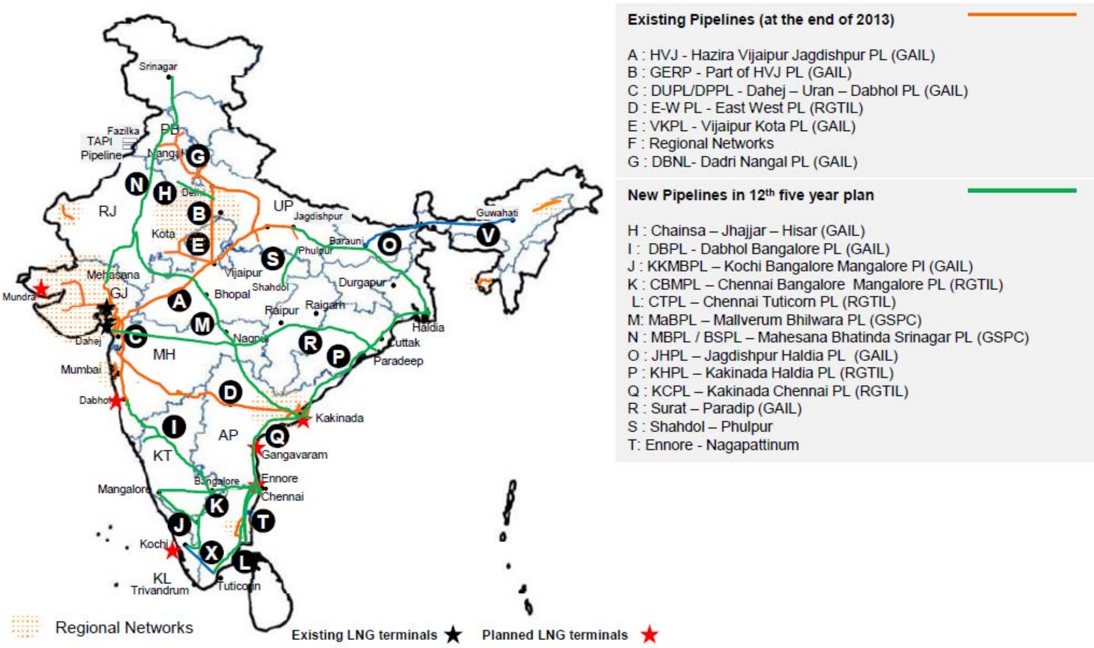
Natural gas demand in east India

The Government of India (GoI) announced a new agenda i.e. Power for All (PFA) jointly with every State Government in India. The aim is to achieve 24X7 availability of reliable power to all households, industrial, commercial and all other electricity consuming entities. Due to raise in Global Warming awareness and other environmental impact, GoI has planned to produce electricity by Natural Gas and Solar energy. Hence, the demand for greener fuel is escalated in all parts of the country.

Particularly, West Bengal located in the eastern region of the country is considered as the largest consumer of energy. Hence, to provide the need for energy, MoPNG has given GAIL the responsibility of natural gas transmission to the eastern part of the country. Though the eastern region of the country is identified with abundant resource of natural gas, the demand is still on the higher side. The lack in supply can be fulfilled by JHPL which is estimated/expected to transport the required demand by the region.

Figure 103 represents the Gas Transmission Grid in India to meet the supply demand graph for current and future natural gas requirement.

Figure 103: Gas Transmission Network in India (Existing & Future)



APPENDIX 4: PIPELINE INPUT DATA

Table 61: Pipeline input data

Pipe Units	Length km	Inside Diameter in	Wall Thickness in	Roughness in
BB-18km20in	18	19.188	0.406	0.001
J-15km 14in	11	13.376	0.312	0.001
NS0-FPS 15km24in	15	23.188	0.406	0.001
FPS-FG 5km24in	5	23.188	0.406	0.001
FG-RG 73km24in	73	23.188	0.406	0.001
RG-2km20in	1.7	19.188	0.406	0.001
MB-25km14in	22	13.376	0.312	0.001
FG-7.5km10in	7.5	12.25	0.25	0.001
J1-28km24in	28	23.188	0.406	0.001
HG-1km12in	1	12.25	0.25	0.001
J2-41km24in	41	23.188	0.406	0.001
J3-13km24in	13	23.188	0.406	0.001
L5-J2 0.5km12in	0.5	12.25	0.25	0.001
L3-L5 5km12in	5	12.25	0.25	0.001
FPS-1.5km12in	1.5	11.5	0.25	0.001
0.3Km 24in	0.5	23.188	0.406	0.001
A->M4k-24i	4	23.188	0.406	0.001
A-M 33k 24in	33	23.188	0.406	0.001
Pipe0002	3	12.25	0.25	0.001
Pipe0002-2	1	19	0.5	0.001
GGF->V12 49k-17	13.92	15.312	0.344	0.001
GGF->V12 32k	32.39	15.312	0.344	0.001
V11-V12 5.278k	5.618	13.376	0.312	0.001
MHRD-NSD	25	19.188	0.406	0.001
V12->GSL old 14in12k	12	13.376	0.312	0.001
V12->GSL old 14-2	12	13.376	0.312	0.001
GSL->JDP 24k	24	13.376	0.312	0.001
Mh'di-D'nua 36k	36	23.188	0.406	0.001
Dh'na->Elenga 52k	52	23.188	0.406	0.001
E'ga-EBJB 13.5k	13.5	23.188	0.406	0.001
JB 9K	9	28.874	0.563	0.001
Nl'ka->Baghabari 35k	35	19.312	0.344	0.001
Pipe0001	31.41	13.316	0.312	0.001
Pipe0002-3	3	19.188	0.406	0.001
Pipe0002-4	5	19.188	0.406	0.001

Pipe0002-5	30	19.188	0.406	0.001
Pipe0002-6	2	19.188	0.406	0.001
A-B line-2	18.5	28.874	0.563	0.001
Bangora	1.6	10.25	0.25	0.001
Pipe0004-2	56	12.25	0.25	0.001
Pipe0004	43	12.25	0.25	0.001
J3-13km30in-2	13	28.874	0.563	0.001
Pipe0007	48	28.874	0.5	0.001
BKB->G'Ria 49k	36	19.188	0.406	0.001
BKB->G'Ria 49k-3	4	19.188	0.406	0.001
BKB->G'Ria 49k-4	4	19.188	0.406	0.001
BKB->G'Ria 49k-5	4	19.188	0.406	0.001
Pipe0001-2	1.58	13.316	0.312	0.001
BKB->G'Ria 49k-2	3	19.188	0.406	0.001
GGF->V12 32k-2	12	15.312	0.344	0.001
MHRD-NSD-2	47	19.188	0.406	0.001
MHRD-NSD-3	13	19.188	0.406	0.001
20in54km	54	19.188	0.406	0.001
30in6km	6	28.874	0.563	0.001
24in10km_ii	10	23.188	0.406	0.001
24in5Km	5	23.188	0.406	0.001
8in-0.5k	0.5	7.625	0.5	0.001
Pipe0002-7	1	12.25	0.25	0.001
Pipe0001-3	1	13.316	0.312	0.001
Pipe0002-8	4	19.188	0.406	0.001
Pipe0001-4	0.005	13.316	0.312	0.001
Pipe0008	1	10.25	0.25	0.001
HG-1km12in-2	0.8	11.5	0.25	0.001
BKB->G'Ria 49k-6	13	19.188	0.406	0.001
L5-J2 0.5km12in-2	0.5	12.25	0.25	0.001
J-15km 14in-2	3	13.376	0.312	0.001
L3-L5 5km12in-2	40	12.06	0.25	0.001
L3-L5 5km12in-3	12	12.06	0.25	0.001
Pipe0010	0.005	6	0.25	0.001
Ghatura-V11-3	13	13.376	0.312	0.001
Ghatura-V11-2	30.772	13.376	0.312	0.001
12in53km	53	11.63	0.311	0.001
30in43km	44	28.874	0.563	0.001
30in34km	30	28.874	0.563	0.001
30in7km	8	28.874	0.563	0.001

Pipe0008-2	8	23.188	0.563	0.001
A-B line	10	28.874	0.563	0.001
A-B line-4	29	28.874	0.563	0.001
A-B line-3	1	28.874	0.563	0.001
20in46km	46	19.188	0.406	0.001
20in17km	17	19.188	0.406	0.001
20in27km	27	19.188	0.406	0.001
20in22km	22	19.188	0.406	0.001
S'da->bkb 35k	35	10.25	0.25	0.001
Pipe0009	28	8	0.25	0.001
Pipe0011	36	28.874	0.563	0.001
J3-13km30in-5	37	28.874	0.563	0.001
MHRD-NSD-5	25	19.188	0.406	0.001
E'ga-EBJB 13.5k-2	13.5	28.874	0.563	0.001
Pipe0014	1.6	11.75	0.5	0.001
J3-13km30in-3	41	28.874	0.563	0.001
J3-13km30in-4	28	28.874	0.563	0.001
a	37	28.874	0.563	0.001
a-2	10	28.874	0.563	0.001
a-3	6	28.874	0.563	0.001
a-4	3	28.874	0.563	0.001
A-B line-5	60	28.874	0.563	0.001
BD-1	100	34.624	0.688	0.001
BD-2	37	34.624	0.688	0.001
a-5	5	28.874	0.563	0.001
20in27km-2	51	28.874	0.563	0.001
E'ga-EBJB 13.5k-3	52	28.874	0.563	0.001
M-A-1	40	28.75	0.625	0.001
KR	30	40.496	0.752	0.001
M-A-2	47.5	28.75	0.625	0.001
M-A-3	40	40.496	0.752	0.001
M-A-4	40	40.496	0.752	0.001
CB1	75	34.622	0.688	0.001
CB1-2	90	34.622	0.688	0.001
CB1-3	15	34.622	0.688	0.001
K-M	45	28.874	0.563	0.001
JB 9K-2	9	28.874	0.563	0.001
36x140km	140	34.624	0.688	0.001
30inx45km	45	28.874	0.563	0.001
36inx70km	70	34.624	0.563	0.001

APPENDIX 5: LESSONS LEARNED FROM GAS REGULATION IN OTHER COUNTRIES

This appendix reviews lessons learned from gas regulation in other countries with an expanding natural gas sector with participation from international oil and gas companies, and who are considering importing (more) gas, have high population density, and strong economic growth. The countries whose gas sector the Consultant draws lessons from for the Update are India, Pakistan and Vietnam.

Case study 1: Pakistan

Background[13]

Like Bangladesh, Pakistan projects a strong increase in gas demand over the next decades, and domestic gas production is expected to decline if no new discoveries are made. In 2015, the gas deficit was around 20 bcm (2000 MMCFD/d) and it is expected to triple. Several import projects are planned to fill the gap. In this respect, it is very similar to Bangladesh.

The upstream gas sector consists of Government-controlled companies like the Oil and Gas Development Company Limited., OGDCL and Pakistan Petroleum Limited, PPL, local private companies and IOCs. The private companies produce around 50% of Pakistan's gas output, OGDCL 28%, and PPL around 20%.

Two partially Government-owned gas utilities; Sui Northern Gas Pipeline Ltd (SNGPL) and Sui Southern Gas Company Ltd (SSGC), engage in the purchase, transmission, distribution, and supply of natural gas in Pakistan. They operate and maintain high-pressure gas transmission and distribution systems in their respective territories in the Northern and Southern provinces. In addition, independent pipeline systems supply gas to power and fertiliser plants. These are also owned partially by the government through OGDCL and Mari Gas Company Ltd.

Petroleum policies

The Government of Pakistan has issued Petroleum policies since 1991 and revised them on a regular basis. The latest is from 2012. It aims at attracting both local and foreign private sector investments in the Pakistani oil and gas sector. It determines the licensing process based on three onshore and one offshore Zones and provides four types of licenses. The system is based on Petroleum Concession Agreements in the onshore zones, and Production sharing contracts for the offshore zone.

Gas exports is subject to the "L15" concept: Gas reserves that exceed the net proven gas reserves, including firm import commitments, vis-à-vis the projected gas demand, can be exported. Given the current gas deficit, exports are hypothetical.

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[13] OIES: Natural Gas in Pakistan and Bangladesh. Current issues and Trends. Ieda Gomes. 2013.

The E&P companies operating in Pakistan can sell their share of the gas to SNGPL, SNGC or to other transmission and distribution companies and to third parties (other than residential and commercial customers) at negotiated prices. Alternatively, E&P companies can request the Government to purchase 90% of their share of gas through a nominated buyer. They also have the right to sell 10% of their share of the gas to any buyer (with the consent of the Provincial Government).

The Petroleum Policy and decisions by OGRA (the downstream regular, see below) allow for third party access to existing transmission and distribution pipelines. After an exclusivity period for SNGPL and SNGC to supply gas to their existing customers (which lasted until 2012), large consumers, such as industry and power, could in principle be supplied directly by gas producers through third party use of SNGPL or SSGC network up to a certain portion of their production. However, this has not worked in practice.

Gas Pricing

The price to producers for Associated or Non Associated Gas is linked to a basket of crude oil import in Pakistan. The Petroleum Policy determines a floor of $10/barrel of oil corresponding to a gas price of $1.75 per MMBtu, and applies a sliding scale up to a ceiling for the oil price of $110, resulting in a max price of $ 6 per MMBtu in Zone III, $ 6.6 per MMBtu in Zone I, and $8 per MMBtu Offshore (Deep) and $9 per MMBtu (UltraDeep).

OGRA advises GOP on the price of gas for each retail consumer category, and MPNR notifies end-user tariffs for various tariff categories based on OGRA's determinations.

Upstream regulation

The Ministry of Petroleum and Natural Resources (MPNR) serves multiple roles in the sector, including policy-making, allocation of gas to various consumers, and regulation of upstream petroleum activity. MPNR also has a role in the setting of wellhead prices. The Government Holding (Private) Limited (GHPL) manages the Government's ownership interest in petroleum exploration and production joint ventures. GHPL is also a Licensee of the Government for Offshore petroleum exploration and production operation.

MPNR's mission statement[14] is to ensure availability and security of sustainable supply of oil and gas for economic development and strategic requirements of Pakistan and to coordinate the development of natural resources of energy and minerals.

The MPNR is responsible for dealing with all matters relating to petroleum, gas and mineral affairs. Its detailed functions are:

- Policy, legislation, planning regarding exploration, development and productions policy guidelines to regulatory bodies in oil and gas sectors;

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[14] http://www.mpnr.gov.pk

- Policy guidelines and facilitation of import, export, refining, distribution, marketing, transportation and pricing of all kinds of petroleum and petroleum products;
- Matters bearing on international aspects;
- Federal agencies and institutions for promotion of special studies and development programmes;
- Facilitate the development of petroleum and mineral sectors;
- Attract the private investment.

The upstream oil and gas activities are regulated by the Directorate General of Petroleum and Concessions (DGPC), which is situated in MPNR's Policy Wing as one of five directorates. The other directorates are Oil, Gas, Special projects (LNG), and Administration.

DGPC functions are to:

- Grant petroleum rights, i.e. reconnaissance permits, exploration licenses, development and production leases;
- Facilitate exploration & production and services companies/activities;
- Analyse Oil and Gas fiscal regimes and recommend adequate policies in view of international practices;
- Promote petroleum exploration, negotiations with foreign and local petroleum exploration companies;
- Manage petroleum exploration, development and production operations in accordance with good international oil field practices, applicable rules and Petroleum Concession;
- Ensure realisation of the Government receipts (dividend, royalty, rents, application fees etc.);
- Compile investment data and manage and scale technical data.

Downstream regulation

The Oil and Gas Regulatory Authority (OGRA) regulates midstream and downstream activities of the oil and gas sector. OGRA was formed in 2002 to foster competition, increase private investments and ownership in the midstream and downstream petroleum industry and protect public interest.

OGRA is independent from MPNR and the government-controlled companies, and is situated in the Government's Cabinet Division. In the gas sector, OGRA regulates gas transmission and distribution, and Liquefied Petroleum gas (LPG) and Compressed Natural Gas (CNG), and determines revenue requirement for transmission and distribution companies (including allowed Unaccounted-For Gas, or UFG).

LNG

Pakistan began importing spot cargoes of LNG in January 2016. Cargoes were delivered to the 151,000 cob FSRU provided by Excelerate Energy. The FSRU is operated by Engro Elengy and was Pakistan's first import terminal at the Port Qasim, Karachi and has a 690 MMCFD send-out capacity.

In February 2016, Pakistan signed its first long-term LNG contract with Qatar. Qatargas will supply fuel to state-owned Pakistan State Oil (PSO) from 2016 to 2031. The price for each LNG cargo in a particular month has been agreed at 13.37% of Brent where Brent value is average of the preceding three months. Qatargas will supply 3.75mn MT/yr of LNG to PSO.

In October 2016, Qatargas and Pakistan's Global Energy Infrastructure (GEIL) signed a 20-year LNG deal. According to the contract, Qatargas will supply 1.3mn MT/yr of LNG to Pakistan for 20 years, with provisions allowing the volume to increase to 2.3mn MT/yr. The price is confidential. The LNG will be supplied from Qatargas 2 with the first cargo expected to be delivered to Pakistan in 2018 by Qatargas-chartered Q-Flex vessels. GEIL signed a long-term contract with Höegh LNG for a FSRU in Port Qasim in December 2016. The project is the first private LNG import terminal in Pakistan.

Options for a more competitive gas industry

The Government of Pakistan has been assessing the performance of Pakistan's natural gas sector and developed options for the future direction of the sector towards a competitive and deregulated sector with increased private sector participation. This would among other things involve overcoming the current barriers to selling directly to customers at prices that are higher than today and at the same time fully cover costs, including future gas supply and LNG imports. To remove barriers to competition, the separation of trading and infrastructure operations and transmission and distribution are being discussed.

A key issue to decide is the timing of the revisions to the regulatory framework, the restructuring of the gas sector and the price increases to cover the higher costs of future gas supplies.

In general, options include:

- Establish two markets for gas: The current low-priced gas supplied by SNGPL and SSGC to their customers at regulated prices and a market for new gas supply at (higher) deregulated prices.
- How to introduce LNG imports? As a private sector import at unregulated prices sold to customers willing to pay the price? Or introducing regulation of the price for LNG?
- Introduce a single buyer in the form of a transmission company

Provincial ownership

An Amendment to the Constitution in 2010 changed the ownership of oil and natural gas in Pakistan. In particular Article 172(3) vests oil and natural gas resources jointly and equally between the Federal Government and the oil and gas provinces. Article 158 gives each province precedence over gas produced in its territory. Article 154 enshrines the provinces' role in the Council of Common Interest (CCI).

Lessons for Bangladesh

Separate Regulation from policy function and operations

BERC regulates the downstream gas sector in Bangladesh and is empowered to apply the provisions of the Gas Act. It is situated within the ministry. The downstream regulator, OGRA in Pakistan is independent from the Ministry, MPNR and the government-controlled companies, and is situated in the Government's Cabinet Division.

The regulation of the upstream sector is different in the two countries;
The upstream oil and gas activities in Pakistan are regulated by the Directorate General of Petroleum and Natural resources (DGPC), situated in Ministry's Policy Wing. The Government's ownership interest in petroleum exploration and production joint ventures is managed by a private Government Holding company.

In Bangladesh, Petrobangla has a role as the upstream regulator, supervising and monitoring the PSCs. At the same time, petrobangla is the counterpart to the contracts which can pose potential conflicts of interests. The Government has authorised Petrobangla to enter into agreements with international oil companies on behalf of the Government. Pakistan's upstream regulatory system is cleaner than that of Bangladesh; however, an independent agency would be even better placed to avoid potential conflicts of interest. Examples of countries with more independent upstream regulators are Canada and Norway.

Petroleum policies
The Government of Pakistan revises the Petroleum policies on a regularly basis to keep them up to date with development. Bangladesh issued a Petroleum policy in 1993.

Provincial ownership of resources
In Bangladesh, the Government has the ownership of the oil and gas resources. In Pakistan, oil and natural gas resources are owned jointly and equally between the Federal Government and the Provinces. The upstream regulator in Pakistan is under consideration to be re-organised. The first step of the reform is to separate the regulatory and the policy roles, and investigate how to integrate the Provinces in policy and regulation. This must be further advanced before a conclusion can be drawn about the impact and results on regulation.

LNG Imports
Pakistan has started importing LNG through a state-owned company and soon LNG will be imported by a private company as well. The costs of these imports are higher than the cost of indigenous gas production. Bangladesh should start a discussion on how to price the future higher LNG costs and which customers are going to pay the higher price.

Case study 2: Vietnam
Background
The gas industry started in 1994 with the production of associated gas from the Bach Ho oilfields in the Cuu Long Basin in the South-East offshore continental shelf. This was followed in 2003 when the first non-associated gas field came on stream in the Nam Con Son basin also in the South-East offshore, followed by other blocks in the same basin. 2007 saw the first deliveries of

gas from the PM-3 development in the Malay-Tho Chu in the Phu Khanh in the South West offshore area, jointly administered with Malaysia, and more recently gas production began in the Song Hong basin in Northern offshore. This production is expected to increase gradually. The largest gas discovery in Vietnam, Blue Whale in the Central offshore is expected to come on stream around 2025. Other fields in the South West are under negotiation to be developed.

Figure 104: Oil and Gas Basins in Vietnam

The three gas producing areas are not connected by pipelines. In each case, the projects have been developed on a project-by-project basis to supply gas to power projects and in some cases fertiliser production as well. Very little gas is consumed by the industry. In 2016, Vietnam produced 10.7 bcm of natural gas[15]. Around 80% of the gas is consumed in power generation, 11% in fertiliser production and 9% in industries. Gas accounts for around 15% of Vietnam's energy matrix. Around one third of the country's power is generated with gas and around three quarters of the fertiliser production. There is very little commercial and residential consumption of natural gas in Vietnam.

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[15] BP Statistical Review of World Energy, 2017

Gas production has been around 10 bcm since 2013 as production in old fields is declining. New fields are coming on stream replacing these fields and investments in infrastructure are overcoming bottlenecks, such as the capacity of the Nam Con Son pipeline.

Gas Master Plan

In January 2017, the Prime Ministry approved the Master Plan for Vietnam Gas Industry Development to 2025 with an outlook up to 2035[16]. The goal is to achieve a gas production of 13-19 billion cubic metres per year by 2025 and 4 bcm of LNG imports, and a production of 17-21 bcm and up to 10 bcm of LNG imports by 2035.

On the demand side, the plan will continuously develop the gas-fired power plants which should use about 70 – 80% of total production (including imports of LNG); develop an oil and gas based petrochemical sector, strengthen investment in natural gas processing; develop domestic industrial production; continuously sustain and extend gas distribution with an aim to protect environment and increase the value of gas use; at the same time develop low pressure and compressed natural gas distribution systems.

PetroVietnam

Vietnam Oil and Gas Corporation (Petrovietnam) is delegated by the government to carry out petroleum exploitation and exploration and signing oil and gas contracts. It also cooperates with international partners in either Production Sharing Contracts (PSCs) or joint ventures for upstream operations and approve and supervise work programs of PSCs. In practice, PetroVietnam self-regulates. Under authority of the Prime Minister, Petrovietnam has the sole rights to buy gas offshore and to sell gas to end users.

PetroVietnam’s subsidiary Petro Vietnam Gas Corporation (PV Gas) is responsible for the midstream and retail gas activities in Viet Nam. PV Gas has sole rights to distribution network development and sells gas to the state-owned power utility, Electricity Vietnam (EVN), to IPPs, and is also increasingly participating in downstream consumption of gas, including power generation facilities through its ownership of the Ca Mau power plant in the South West receiving gas from gas from PM-3, and at the Nhon Trach power complex receiving gas from Nam Con Son, and in fertiliser production as well.

Gas pricing

Gas pricing issues are dealt with project-by-project, rather than generically. Each project has been negotiated in its own rights with the IOC holding the license/PSC in terms of the volume, build up period, price and which customers to serve. For instance, for the first non-associated gas project, the pricing was negotiated by Petrovietnam with a consortium led by BP (which included a Petrovietnam stake) to supply gas from the Lan Tay and Lan Do fields in the Nam Con Son basin to the power complex at Phu My outside Hi Chi Minh City. With the addition of gas supply from additional fields in the Nam Con Son Basin and new power plants, including two IPPs, the total capacity reached 3,800 MW, and gas is also consumed in fertiliser plants at Phu My.

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[16] Vietnam Energy Online, Jan. 20, 2017.

The price for gas delivered at Phu My was agreed at around USD 3.2 per mmbtu with an indexation of 2% p.a. when gas started flowing in 2003. This was higher than the price of the associated gas from Bach Ho, but still low by international standards setting an expectation of low gas prices for later developments. This expectation has delayed new field development as higher development and production costs have not been recognised and alternative fuel pricing, linking the gas price to the fuels it would substitute, coal, LNG, petroleum products, has not been considered.

Legal Framework

The Legal framework is summarised in Box. No 3. There is no independent gas regulator. The ministry is responsible for the state management of petroleum activities. PetroVietnam is responsible for technical regulation and self regulates (see previous section).

Box. No. 3. Legal and regulatory framework for the oil and gas sector in Vietnam

National Assembly

- Approve Petroleum Law and related laws
- Approve projects of national importance

Government & Prime Minister

- Approve National Strategy, Master Plans
- Approve category A projects, petroleum contracts, oil & gas fields reserves and development plans
- Issue Directives on gas prices and gas allocations
- Approve cooperation contracts in overlap areas and oversea contracts
- Approve PetroVietnam Group's organisation & charter, nomination of key staff

Ministry of Industry and Trade

- Responsible to Government for state management of petroleum activities, assisted by the General Directorate of Energy (GDE)
- Strategies, master plans, plans for petroleum industry development
- Coordination of submissions to Prime Minister for approval: petroleum contracts; investment projects; reserves reports; field development plans; bidding results relating to concession blocks
- Prepare and submit approval blocks list to Prime Minister
- Monitor petroleum activities, report on progress
- Approve programs, and full range of activities from project initiation to decommissioning

SOURCE: ESMAP: VIETNAM GAS SECTOR DEVELOPMENT FRAMEWORK FINAL REPORT NO. 52865-VN

How to meet the objectives of the Gas Master Plan and LNG imports

The objectives in the Gas Master Plan will be met in each of the four gas producing regions as follows:

Northern region:

- Find solutions for the collection of gas from the dispersed small fields with an aim to strengthen gas supply ability for industrial customers in the region
- Study and invest in infrastructure for LNG imports to supply industrial customers and power plants, according to the Power Master Plan

Central region:

- Develop infrastructure to collect, transport and handle gas from Blue Whale field for supplying gas-fired power plants according to the Power Master Plan;
- Develop petrochemical industry based on Blue Whale gas
- Develop low pressure gas distribution system, and small-scale CNG/LNG for supplying industrial customers in the region

Southeast region:

- Strengthen exploration and field development to maintain gas supply in the region
- Invest in infrastructure for LNG imports to supplement the depletion of domestic gas production
- Supply power plants according to the Power Master Plan

Southwest region:

- Improve infrastructure to collect and transport gas
- Invest in infrastructure for LNG imports to sustain gas supply for customers and develop new power plants using LNG

Options for a more competitive gas industry

The lack of physical interconnection between the regional gas markets and the limits on the size of the markets are barriers for gas trade in Vietnam. The legal and regulatory framework described in Box no. 1 and Petrovietnam's role in the gas sector does not support a development towards a competitive gas market. Petrovietnam is self-regulating and negotiates prices on a project by project basis, and PV Gas has the sole right to distribution network and sales to EVN and IPPs. There is no separation of policy making from economic regulation and no independent body responsible for economic regulation.

The GMP projects an introduction of LNG in all four regions, probably in around five years. International LNG prices are higher than current gas prices in Vietnam and the start of the LNG imports could be a first step towards market based pricing. However, LNG is likely to be introduced before any market reforms which implies that Petrovietnam will import LNG and PV Gas will transport it, giving rise to a number of questions:

- Would LNG be integrated as an additional supply source or a standalone supply option?
- Is it priced separately so that dual markets are established? And how would that impact the demand?

Conclusion

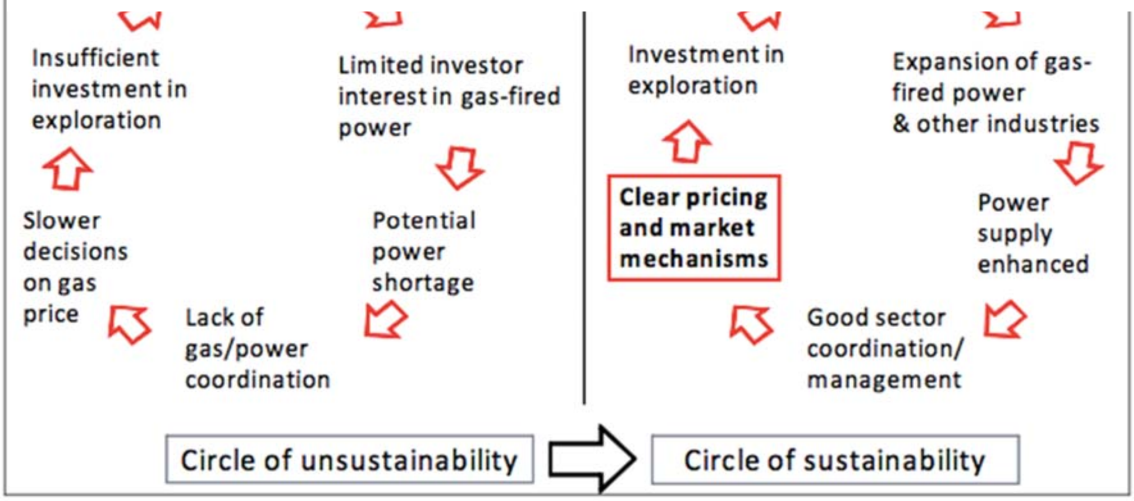
Gas development in Vietnam has been delayed by the lack of a gas pricing policy and a market for gas. By negotiating projects and prices on a case by case basis, the industry has difficulty evaluating the financial returns on oil and gas production from prospective fields, and the government has difficulty deciding on an efficient development for energy resources and optimising the petroleum fiscal system to provide the right incentives and fiscal revenues.

The three (soon four) regional gas markets in Vietnam are not connected by pipelines, which is not desirable from a supply security perspective and for the creation of a functioning gas market. Most of the gas is consumed by the power sector whose power transmission network connects the gas producing regions.

The shortage of natural gas in Vietnam can be explained by the “circle of unsustainability”. The Gas Shortage shown at the top in the left panel in Figure 105 is due to insufficient investment in domestic exploration and lack of clarity and slow decision-taking on the price for gas in new developments. This leads to fewer investments in gas fired power generation and potential shortage of power. This is the “circle of unsustainability”.

If clear pricing signal and market mechanisms for gas are introduced, investments in exploration and production will increase gas supply and more gas can be sold to the power sector increasing the power supply to fuel Vietnam’s large demand for power. This is the “circle of sustainability”.

Figure 105: Circle of Sustainability



SOURCE: ESMAP: VIETNAM GAS SECTOR DEVELOPMENT FRAMEWORK FINAL REPORT NO. 52865-VN

Lessons for Bangladesh

Develop an appropriate gas pricing policy

The development of a gas pricing policy that meets the interests of the government, industry and consumers, sends clear pricing signals and is a step in the direction of developing a market for gas which will get Bangladesh into the “Circle of Sustainability”.

Reconsider the role of the SOE

Like Bangladesh, Vietnam has a dominant state-owned oil and gas company delegated by the government to carry out petroleum exploitation and exploration, signing oil and gas contracts and supervising IOCs operating in the sector. Its subsidiary, PV Gas, links gas from the upstream gas supplies to the end-users and has the sole rights to distribution pipeline development.
This model can benefit the sector in the early stages of oil and gas development but also delay later developments due to potential conflicts of interest, self-regulation, and lack of independent regulation.

Determine an LNG pricing policy

Vietnam is planning to import LNG. The costs of these imports will be higher than the cost of indigenous gas production. Bangladesh should start a discussion of how to price the future higher LNG costs and which customers are going to pay the higher price.

Case study 3 India

Background

In 2015, India produced 29.2 bcm of natural gas and consumed 50.6 bcm. The difference is LNG imports of 21.7 bcm, 13.5 bcm of which was imported from Qatar.

Currently, the majority of gas is produced in the western offshore region and almost all of it comes from conventional hydrocarbon sources. Gas production is set to rise in the next four to five years as western and eastern offshore discoveries are brought into production. Chapter 4 described the main public and private companies in the sector, the main transmission pipelines and demand centres, including planned projects and projections.

This section will focus on the policy and the legal and regulatory framework in the gas sector in India.

All minerals in India are owned by the state which holds exclusive authority to mine. India has a quasi-federal constitution where both the federal and the state governments have legislative powers. However, under the Indian constitution, only the federal government is empowered to make laws relating to regulation and development of oil and gas. Offshore licenses are granted by the federal government. Onshore leases are granted by the state government with prior approval from the federal government.

Legal Framework

Exercising its constitutional powers, the government passed the Oilfields (Regulation and Development) in Act 1948 and the Petroleum and Natural Gas Rules in 1959. Together, they regulate the grant of petroleum mining leases and provide the provisions for regulating petroleum operations and granting licenses and leases for exploration, development and production of petroleum in India. From time to time, the government formulates policies under which concessions for exploration of oil and gas are awarded through a transparent competitive bidding system to private/foreign investors and national oil companies (NOCs) on the same fiscal and contractual terms[17].

The Petroleum and Minerals Pipelines (Acquisition of Right of User in Land) Act 1962 provides the framework for acquiring rights to lay pipelines for transporting petroleum, minerals and other connected substances.

Government policies

The Government formulated a policy called *New Exploration Licensing Policy (NELP)* in 1997. The main objective was to attract significant risk capital from Indian and foreign companies, state of art technologies, new geological concepts and best management practices to explore oil and gas resources in the country to meet rising demands of oil and gas. Since then, licenses for exploration have been awarded only through a competitive bidding system and NOCs are required to compete on an equal footing with Indian and foreign companies to secure Petroleum Exploration Licenses. Nine rounds of bids were concluded under NELP, in which production sharing contracts (PSCs) for 254 exploration blocks were signed[18].

The *Integrated Energy Policy* was developed by an expert panel of Planning Commission and adopted by the government in 2008. The policy seeks optimal exploitation of domestic energy resources and also vigorous exploration and acquisition of energy assets abroad, so that energy security can be attained effectively. The broad vision behind this policy was to create a regime to reduce dependence on imports and reliably meet energy demands with safe, clean and convenient energy at minimum cost. [19]

More recently, India announced a new *Hydrocarbon Exploration Licensing Policy (HELP)* to correct various issues that had arisen in NELP. These included separate policies and licenses for different hydrocarbons. New unconventional hydrocarbons (shale gas and shale oil) have entered the market. NELP was based on PSCs that have some well-known advantages and disadvantages. While the contractor takes the exploration risk, the Government pays the contractor costs back in the form of cost of oil or gas, which in most cases implies that the *profit sharing* of the oil and gas produced comes after the cost recovery of the contractor’s investments is completed

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[17] Oil and gas regulation in India: overview by Vebkatesh Raman Prasad and Abhishek Kumar Singh

[18] http://www.petroleum.nic.in/natural-gas/natural-gas-policies-and-guidelines. New Exploration Licensing Policy (NELP)

[19] Oil and gas regulation in India: overview by Vebkatesh Raman Prasad and Abhishek Kumar Singh

(depending on how much cost oil or gas that can be deducted each year). The process of approval of the contractor's activities and their cost is a major source of delays and disputes between the government and the contractor in many countries. Another feature of NELP was the bidding system: exploration was confined to blocks that have been put on tender by the Government.[20]

As for pricing under NELP, the producer price of gas was fixed administratively by the Government and royalties were uniform. They did not distinguish between shallow water fields and deep/ultra-deep water fields where risks and costs are much higher.

The HELP introduces:

- A single license to explore conventional and unconventional oil and gas resources. A uniform system covering all hydrocarbons (such as oil, gas, coal-bed methane, shale gas/oil, tight gas and gas hydrates).
- Marketing and pricing freedom. Departing from earlier policies, the HELP introduces marketing and pricing freedom. The contractor will have freedom for pricing and marketing of gas produced in the domestic market. (see gas pricing below)
- A Revenue sharing model. *Production* sharing contracts are replaced by *Revenue* sharing contracts that will be simpler, easier to administer and provide operational freedom, i.e. the contractor does not recover any costs directly, but retains a larger share of the revenue stream to cover the cost.
- An Open Acreage licensing policy. Contractors can select exploration blocks throughout the year without waiting for the formal bidding round from the government.
- A concessional royalty regime will be implemented for deep water (5%) and ultra-deep water (2%) areas. In shallow water areas, the royalty rates shall be reduced from 10% to 7.5%.

Apart from HELP, the government also adopted the Marginal Field Policy in 2015 to bring marginal fields belonging to national oil companies (which have not been monetised to production as soon as possible. The first round of auctions for discovered small and marginal fields (67 fields in 46 contract areas) took place in 2016. The government used a revenue-based contract to auction its marginal fields.

HELP also set up a central repository for E&P data, the National Data Repository for ease of access to existing data, for sharing and secure storage of data.

Regulation

Upstream

The Upstream Regulator, Directorate General of Hydrocarbons (DGH), was established in 1993 under the administrative control of Ministry of Petroleum and Natural Gas through Government of

[20] http://www.iasparliament.com/article/hydrocarbon-exploration-licensing-policy

India Resolution. The Ministry of Petroleum and Natural Gas manages and oversees upstream oil and natural gas exploration and production[21].

The DGH is the technical arm of the ministry and acts as a regulatory body having oversight on all concessions relating to oil and gas, including coal bed methane, shale gas etc. Objectives of DGH are to promote sound management of the oil and natural gas resources having a balanced regard for environment, safety, technological and economic aspects of the petroleum activity. Most of the manpower requirement of DGH is provided by the NOCs (ONGC, Oil India Limited, Indian Oil Corp. Ltd, Hindustan Petroleum Corporation Ltd., Bharat Petroleum Corporation Ltd. and GAIL (Gas Authority of India Ltd).

Downstream

The Petroleum and Natural Gas Regulatory Board (PNGRB) regulates the midstream and downstream sector. It is an independent regulator constituted under the Petroleum and Natural Gas Regulatory Board Act 2006.

The PNGRB's objective is to protect the interests of consumers and entities engaged in petroleum, petroleum products and natural gas activities and to promote competitive markets.

Pipeline regulation

Permission to construct and operate both oil and gas pipelines is granted after a bidding process by the PNGRB under its regulations. The tariff for transporting oil and natural gas is determined by the PNGRB (Determination of Natural Gas Pipeline tariff) Regulations 2008.

Third Party Access

Third party access to pipelines and other infrastructure is permitted. The regulations provide a contract carrier system and a common carrier system to make excess capacity available for transporting natural gas or petroleum products through the pipelines. The period of use covers one year and the parties are free to agree their own terms within the confines of the law. The company laying, building, operating or expanding a common carrier or contract carrier pipeline has the right of first use for its own purposes. The common carrier capacity is allocated to any company seeking it on a "first come first served" basis.

Gas pricing

In 2014, the Indian government issued Gas Pricing Guidelines[22]. The Guidelines contain the following key features:

- The wellhead gas price is determined in USD per MMbtu based on a formula that includes annual average of daily prices at Henry Hub in the USA, the National Balancing Point in the UK, annual average of monthly prices at Alberta Hub in Canada, and Russia (Federal

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[21] http://dghindia.gov.in
[22] New Domestic Natural Gas Pricing Guidelines, 2014.

Tariff) less the transportation and treatment charges (estimated at USD 0.50/MMBTU).

- It is reviewed and updated by the government every six months.
- For the North-East region, the government is to provide 40% subsidy on the price of gas.
- With the new price guidelines there is no distinction between the previous Administered Pricing Mechanism (APM) and non-APM, and the price notified by the government under the policy is applicable to all gas produced in India (conventional, shale, or coal-bed methane), except in the following circumstances where:
    - prices have been fixed contractually for a certain period of time;
    - the PSC provides for a specific formula to index or fix the price of natural gas;
    - the PSC pertaining to the regime prior to the NELP does not provide for government approval of formulae or the basis for gas prices;
    - natural gas is produced from small or isolated fields in the nomination blocks of NOCs;
    - gas is produced in the Krishna Godavari field (KG-D6).

Since the gas pricing guidelines were issued there has been a shift in the government's policy on gas pricing towards more flexibility in the recent policy initiatives. The HELP policy introduced pricing and marketing flexibility for gas in the domestic market. The Marginal Field Policy 2015 helped marginal fields and producers can charge a higher price for gas from discoveries in deep water/ultra-deep water/high temperature-high pressure areas.

The latest price revision for the April-September 2017 period based on prices in international gas hubs set the wellhead price at USD 2.48 per MMbtu, and the ceiling for gas from difficult fields such as those in deep sea and high-pressure high-temperature areas, which is linked to alternative fuels, was set at USD 5.56/MMbtu23. Since the introduction in 2014, the wellhead gas price has dropped more than 50% due to the decline in international gas prices.

Domestic wellhead gas prices have fallen below the average cost of production for many companies, such as ONGC and Oil India Limited, which have an average cost of production of USD 3.59 per MMBtu and USD 3.06 per MMBtu[24]

Under the new price regime, there is no clear guideline on the end-user price mechanism. When the gas pricing guidelines were issued in 2014, they resulted in an increase in the wellhead price which raised the issue of pass-through of gas costs to consumers. The more than 50% decline since then has helped resolve this issue.

Imported LNG prices are market-based. India has renegotiated contracts with Qatar since the oil and gas prices started falling in 2014 and the average import price is estimated to USD

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[23]http://economictimes.indiatimes.com/articleshow/57942083.cms?utm_source=contentofinterest&utm_medium=text&utm_campaign=cppst

[24] Oil and Gas Financial Journal: Gas pricing in India. Dec. 14/2016

5.61/MMBtu in May 2017[25]

Lessons for Bangladesh

Separate Regulation from policy function and operations

In India, the Upstream Regulator, DGH is the technical arm of the ministry and acts as a regulatory body having oversight on all concessions relating to oil and gas to avoid potential conflicts of interest between the NOCs and IOCs.

Petroleum policies

The Government of India issues policies on a regular basis, New Exploration Licensing Policy (NELP) in 1997, the Integrated Energy Policy 2008, and Hydrocarbon Exploration Licensing Policy (HELP) in 2017 to adjust to the country's needs, to international markets and developments and to attract international investors. Bangladesh issued a Petroleum policy 1993 that has not been updated since.

Gas Pricing

The Government of India has linked domestic wellhead gas prices to international gas prices to attract international investors, and LNG is imported prices at international prices and passed through to the customers.

[25] FERC: National Natural Gas Market Overview: World LNG Landed Prices, May 2017.

APPENDIX 6: KEY PETROLLEUM FISCAL TERMS FOR PRODUCTION SHARING CONTRACTS IN MYANMAR

Three types of PSCs are awarded; onshore blocks, shallow water offshore blocks, and deep water offshore blocks.

Deep Water Offshore: The exploration period is for three years and requires seismic in the first year, one well drilled in year 2 and in year 3. It can be extended one year two times. The production period is 20 years, signature bonus and data fee payable with 30 days of the contract signing. Royalty is 12.5 % of available petroleum. Cost recovery 50%-70% from 600-2000 feet water depth. Domestic Market Obligation 25% of natural gas of contractor's share (at 90% of fair market value). State participation up to 20 % (25% if reserves are greater than 5 Tcf), income tax 25% (5 years tax holiday), 25% local content. If a significant discovery is made, the contractor submits an appraisal work program for approval. If commerciality of the field is determined, the contractor can go ahead on the terms in the PSC, although a renegotiation clause opens the possibility for renegotiation of the fiscal terms.

The production split for gas is a sliding scale depending on water depth and gas production. In waters less than 2000 feet, the contractor receives 35% up to 300 MMcf/d, 10% over 900 MMcf/d. Over 2000 feet, the contractor receives 45% up to 300 MMcf/d, 20% over 900 MMcf/d.

APPENDIX 7: BERC LICENSE REGULATIONS AND FUNDING

License Regulations

BERC's License Regulations from 2006 determine rules for obtaining licenses for gas distribution, transmission and storage (as well as rules for power generation and distribution of electricity and petroleum products).

BERC evaluates applications based on

- (a) technical, administrative, and financial competencies in operating controlled activities of the applicant;
- (b) capability of sources of energy supply;
- (c) impact on transmission, transport, storage and distribution of existing facilities by the proposed project;
- (d) technical details of proposed production, transmission, transport, storage, distribution and other relevant facilities;
- (e) estimated demand of proposed energy production, transmission, transport, storage, distribution or sales;
- (f) justification of the project: (i) capital and financial expenditure of the project; (ii) avoidance of duplication with other energy systems; and (iii) evaluation of economies of scale.

General responsibilities and duties of licensee include:

- (1) comply with all applicable laws, rules for which the license is granted;
- (2) supply the energy with quality specified from time to time by the commission;
- (3) abstain from discriminatory behaviour or partiality to any consumer or energy producer;
- (4) provide energy transmission, transport, storage, distribution services or sales to all eligibility individuals;
- (5) strictly comply with environment laws and regulations.

Funding of the Regulatory Commission

The "Bangladesh Energy Regulatory Commission Fund" was set up to receive funding from:

(a) grants from the Government or Statutory body;

(b) loans borrowed by the Commission;

(c) fees and charges deposited under the BERC Act; and

(d) money received from any other source.

APPENDIX 8: FEASIBILITY STUDIES OF CURRENT PROJECTS

For some of the pipeline projects is given a short summary with description of challenges and cost.

Moheshkhali-Anowara

For this project a feasibility study report is available from GTCL.

The main parameters from the selected solution are:

- Design throughput: 1200 mmscfd
- Length: 83 km
- Design pressure: 1135 psig
- Dimension: 42"
- Wall thickness: 19,1 mm API X 70

The main cost break-down for this pipeline will is estimated to the following:

	Lakh Taka	USD Million	Percentage
Land acquisition and right of way	19955	24.9	18%
Construction and design work	44235	55.2	40%
Line pipe and equipment	45106	56.3	40%
Contingencies	2185	2.7	2%
Total	111488	139.4	100%

The average cost per m and inch is hence 40, which we find normal for such terrain and including one big river crossing.

The Consultants agree with the use of 42 inch pipelines, even if the capacity will not be fully used at the commissioning of the project. This is in order to prepare for future market development.

Kutumbopur-Meghnaghat

For this project a feasibility study report is available from GTCL.

The main parameters from the selected solution are:

- Design throughput: 250 mmscfd
- Length: 45 km
- Design pressure: 1135 psig
- Dimension: 24"
- Wall thickness: 14.3 mm API X 60

The main cost break-down for this pipeline will is estimated to the following:

	Lakh Taka	USD Million	Percentage
Land acquisition and right of way	21680	27.1	36%
Construction and design work	20268	25.3	34%
Line pipe and equipment	14516	18.1	24%
Contingencies	2754	3.4	5%
Total	59482	74.3	100%

The average cost per m and inch is hence 69, which we find to be high, but can be explained by many river crossings, requiring foreign contractors.

The Consultants find that with such high cost for land acquisition, crossing of rivers and need for a further strong East-West connection, a larger diameter pipeline should be chosen. Otherwise there will be a need for looping of the pipeline when LNG supply has to be transported to the West of the country. Depending on the technical possibilities, we recommend at least a 30 inch pipeline, but preferably a 36 or 42 inch line. This will also contribute to line pack capability for the power plant in Meghnaghat.

APPENDIX 9: RECENT DEVELOPMENTS IN BANGLADESH'S LNG IMPORTS

Bangladesh has made speedy and impressive progress since the latest submission of this Gas Sector Master Plan. As part of this report update, some of the key developments are outlined as below:

In order to set up an FSRU with the capacity of 1000 mmcfd (7.5 mtpa) at Payra, EoI is invited for short-listing potential terminal developer. Besides, Tokyo Gas Engineering Solutions (TGES) is conducting feasibility study to select sites in Moheshkhali/Payra/ any other suitable places for land based LNG terminal and in order select Terminal Developer for the Construction of the Land Based LNG Terminals in Moheshkhali/Payra or any other suitable places, shortlist has been made after evaluation of received proposals against EoI.

Regarding LNG importation, the activities are as follows:

To import LNG for Long Term Contract basis, Petrobangla and RasLaffan Liquefied Natural Gas Company Limited (3), Qatar have signed LNG Sales Purchase Agreement (SPA) for 15 (fifteen) years.

Again, to import LNG, Petrobangla and Oman Trading International (OTI); Petrobangla and Pertamina (Indonesia) have signed separate MoU on G to G basis. It may be signed Long Term Contracts between them.

Petrobangla and Astra Transcor Energy (Swizerland); Petrobangla and Gunvor (Singapore) have signed separate MoU and it may be signed Mid-Term contracts between them.

To import LNG from Spot Market, shortlist has been made after evaluation of received proposals against EoI.

The LNG pricing will be determined according to Oil index based Brent formula or Henry Hub formula as per contracts.

APPENDIX 10: QUESTIONNAIRE ON GAS FIELD EXPLORATION, DEVELOPMENT, OPERATION AND PRODUCTION AUGMENTATION FOR BANGLADESH

Content

Objective and deadline

With reference to the on-going project “Update of Gas Master Plan of Bangladesh” (contract package No. S-75) authorized to the Consultant (Ramboll Denmark A/S in cooperation with the Geological Survey of Denmark and Greenland (GEUS) and EQMS) the present questionnaire aim to facilitate data and information transfer between Petrobangla and the Consultant.

The Consultant kindly request response no later than 20th of March 2017 in order to include nature of response in the Interim Project Report due by 29th of March 2017. The Consultant also request for power to revert with clarifying questions.

Introduction

A Gas Sector Master Plan (GSMP) was prepared for Petrobangla and the World Bank by Wood Mackenzie Ltd. in 2006 with a time horizon to 2025. The update of the GSMP is designated to a time horizon to 2041, consequently the present questionnaire focus on the development in the gas field sector from present day to 2041.

The main focus for the questionnaire is to update the Consultant on the present-day and future gas deliverability from the gas fields in Bangladesh. As the main focus of the update of the GSMP is the future gas demand-supply projection to strengthen a long-term plan for the development of the gas sector in Bangladesh it is critical that individual gas reserve numbers are documented as well as any assessment on future reserve increments. Further, the Consultants ask for documentation for known plans for gas production augmentation and an assessment for the future potential (not yet planned).

The questionnaire is divided into four sections; 1) exploration, 2) field development and operation, 3) production augmentation and 4) current geo-scientific technology stock and human resources in the Public gas sector. For each section a series of questions are listed and needs to be answered field by field and by prospects.

1. EXPLORATION

Main focus on prospects and prospective areas, leads and plays only if description can illustrate/document exploration strategies.

1.1 Seismic surveys

1) Map with present-day seismic surveys (2d/3D) with field/license delineations and acquisition dates.
2) Map with planned seismic surveys (2D/3D) with field/license and prospects delineation and planned year for acquisition.
3) A list of amount of seismic data acquired (km/km2) pr. year.

1.2 Exploration wells

1) Map with present-day exploration and appraisal wells with field/license delineations and spud dates.
2) Map with planned exploration drilling with field/license and prospects delineation and planned year for drilling.
3) List of wells drilled (exploration, appraisal and/or production) with location (UTM coordinates) of wells, spud date, purpose, results, status and other relevant information.
4) List of approved wells and their location (UTM coordinates) and purpose.

1.3 Exploration license bidding round

1) Plans for future license bidding round with block description.
2) Results of past exploration rounds, discoveries made, wells drilled.
3) Exploration programmes scheduled both by Public and Private Sectors.

2. FIELD DEVELOPMENT AND OPERATIONS

Main issues are to give an update on reserve numbers and any incremental reserves from additional field development (approved or planned). To give update on production performance and production forecasts.

2.1 Field Development Plans (FDP)

2.11. Location of fields (UTM coordinates) and delineation of fields.

1) Latest approved FDP;
   - 1.1. Date for production start.
   - 1.2. Reserve numbers with description of methodology.
   - 1.3. If update on reserve numbers; date and description of methodology.
   - 1.4. Production forecast.
   - 1.5. If update on production forecast; date and methodology.
   - 1.6. Production mechanism (*i.e.* natural depletion, water drive etc.).
2) Filed FDP for approval;

2.1. Date for planned production start.

2.2. Reserve numbers with description of methodology.

2.3. Production forecast.

2.4. Production mechanism (*i.e.* natural depletion, water drive etc.).

2.2 Field operations

1) Well status;

1.1. Number and date for wells on stream.

1.2. Well location and completion interval(s)

1.3. Yearly production pr. well.

2) Field production;

2.1. Yearly production.

2.2. Depletion strategy.

2.3. Decline curve analysis.

2.4. 3D seismic to delineate/discover productive zones.

2.5. Appraisal drilling/logging to delineate/discover productive zones.

3. PRODUCTION AUGMENTATION

Main focus is to describe plans and potential/possibilities for production augmentation. Provide best estimates for incremental production on existing production forecasts.

3.1 Wells

1) Work-over and maintenance strategy.
2) Well stimulation strategy.
3) Completion strategy and recompletions.
4) Number of wells and well locations (top of structure/closure, down flank).

3.2 Production facilities

1) Wellhead flowing pressure (relative to export pressure).
2) Compression installation.
3) Water production facilities.
4) Optimized production rate.

3.3 Tail end production

1) Depletion strategy (cf. §2.2).
2) Additional drilling to prove up P2 and P3 reserves.

4. G & G CAPACITY

Main focus is to describe the Status of the geo-scientific technology stock and human resources in the upstream gas sector of Bangladesh.

1) Description of the geo-scientific technology stock
2) Description of the human resources in the Public gas sector.

APPENDIX 11: LIST OF KEY REFERENCES

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