GAS SHORTAGES IN DEVELOPING COUNTRIES

A report prepared for the International Gas Union

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Executive Summary

Developing countries are often affected by gas shortages. The paper focuses on Argentina, Bangladesh, Brazil, Pakistan, and Vietnam -- all of which have a rapid growth in gas consumption. Some countries limit access to gas. Others do not have sufficient delivery capabilities particularly in winter. Others had connections policies resulting in unplanned disruptions in gas supplies. These shortages can have far reaching consequences including power outages, switch to costlier or undesirable fuels, and ultimately, loss in GDP.

The shortages physically can originate in the upstream (i.e. insufficient gas production) or in the infrastructure (i.e. insufficient delivery capabilities). The main cause for these deficiencies is the lack of sufficient investment finance due to relatively low tariffs. Government often support low tariffs to households, without reckoning that only a small fraction of the population has access to gas.

In a high oil price environment, demand for gas will accelerate. Governments should realize that the current policies are not sustainable, in particular in the area of gas pricing. To avoid further deteriorations in the quality of supply, it is imperative that rational, predictable policies be introduced so that investors are attracted both to the upstream, and to transmission and distribution segments of the activity.
1. GAS SHORTAGES AND THEIR IMPACT

The security of energy supplies is recognized as a fundamental feature of energy systems. Because of its importance, Governments as well as commercial suppliers do their utmost to ensure that consumers are receiving energy reliably, and in the amounts they require and have contracted for. In developing countries, supplies can be inadequate, for a host of reasons, but does it have to be so? Five countries, Argentina, Bangladesh, Brazil, Pakistan and Vietnam were examined in this respect one should note that they are among the largest gas users in the developing world, and that in at least three (Argentina, Bangladesh, Pakistan), domestically produced natural gas is the main source of commercial energy.

Gas shortages appear in several forms: in broad terms: (i) some countries have an administrative allocation system whereby only qualifying consumers can be eligible for gas supplies – therefore, while not being subjected to supply disruptions, these consumers necessarily rely on less desirable fuels which are in all probability costlier, and/or more harmful to the environment than natural gas. (ii) unplanned shortage which often occur in systems which have been stretched over long periods by increasing loads, and without corresponding investments upstream or mid-stream (Bangladesh and Vietnam). And (iii) in some cases (Pakistan), gas supplies are interruptible during the winter so that some plants shut down (fertilizers) while others operate on costlier fuels (power generation) resulting still in a loss of economic output. (iv) allocation of gas to low value users and as a result reduced availability of gas to high value customers.

The consequences of gas shortages can be devastating. For instance, the cost to the economy in the case of gas used for power generation of an unserved kWh of electricity has been estimated at US$1, i.e. 10-15 times the cost of its production. This illustrates well the importance of reliable gas supplies to a power generator supplying industrial consumers. Similarly, depriving households of electricity can also have nefarious consequences, for instance in the children not being able to do their homework or have access to information and the lack of street lights can be conducive to increasing crime rates.

Disruptions in gas supplies can also affect households adversely. For instance, they may switch back to traditional cooking and heating fuels (fuel wood, charcoal) with harmful consequences to the environment and to their health (because of the exhausts fumes).

When gas supplies cannot be guaranteed, a solution often adopted is to have dual-fired plants. But these plants are costlier, require higher maintenance, and may produce expensive electricity because of the backup fuel (diesel in a combined cycle plant) or selected technology (fuel oil in a steam turbine plant).

In all of the above cases, gas shortages will act as an impediment to economic growth, with multiple effects such as fewer jobs being created, lower productivity, and ultimately lower outputs.

2. TECHNICAL CAUSES FOR THE SUPPLY DISRUPTIONS

In the gas industry, there is usually a clear distinction between the upstream (i.e. exploration and production) and the downstream (transmission and distribution). Each requires different sets of expertise and entails different level of risks. Yet, they both can trigger gas shortages.

In the case of the upstream, none of the five countries under study (with the exception of Vietnam, which is in a market build-up phase) were able to replacement their reserves since 2000 indicating that the exploration efforts were insufficient. In some, either little exploration took place because the fiscal and commercial terms were deemed inadequate (Argentina, Bangladesh); or there was an adequate level of exploration which did not result in sufficient significant finds (Pakistan). Given that in all five countries, demand is growing rapidly (5-7% or even more per annum), unless reserves are replenished, shortages will become more common.
Shortages can also be due to bottlenecks in the transmission and distribution systems. Transmission and distribution companies in almost all countries under review (with the exception of transmission in Argentina) are expected to carry the market risks by matching the demand for gas with the supply, not always an easy task given that gas suppliers, often private, will require a long term take or pay type contract. On the other hand, not all gas consumers will be able to enter into such arrangements, particularly in the small consumption brackets. Having resolved the issues of the timing and quantities of new supplies, in most cases, additional investments will be required, sometimes in significant amounts. This is where the financial ability of the transmission and distribution utilities comes into play, as they need to mobilize the financing for such expansions.

As a matter of fact, the framework under which the Transmission and Distribution operate will impact on the whole system development process. Upstream companies will undoubtedly hesitate to invest in further field development unless they can be persuaded that the Transmission and Distribution companies will do their part of the development investment as well. In countries such as Argentina and Bangladesh, this has become a major issue.

3. Why Gas Shortages Prevail?

The transmission and distribution of gas being a natural monopoly, this activity requires regulation. There are usually three main components in a gas tariff: (i) the upstream component paid to the producer; (ii) the Transmission and Distribution charges; and (iii) taxes. Notwithstanding that four of the five counties have regulatory bodies, it is the Governments which, for all practical purposes set retail tariffs – this often deters investors as tariff policies become a major concern (financial objectives, social objectives, consistency, periodicity of adjustments, cross subsidies, stability of agreements, etc.), particularly if the track record of living up to and living up to such tariffs is mixed. In all, poor gas pricing policies are often the main reason for system shortages.

The upstream gas price framework in the five countries studies were elaborated in the 1990s (Bangladesh, Brazil, Vietnam) or earlier, during a time period characterized by relatively low energy prices, in particular lower oil prices. These gas prices have only been slightly increased as a result of the current high oil price level (beginning 2006) and some Governments (Bangladesh, where gas prices are linked to 2003 oil prices), put a cap on the prices to oil companies. While current gas consumers would benefit from low gas prices, Governments, in all likelihood, will have to revise the terms as otherwise: (i) the high differential will result in a massive, unplanned shift from petroleum products to natural gas resulting in additional burdens on the supply chain; and (ii) international oil companies when considering investments in E&P compare, inter alia, the exploration and production investment terms and risks, taking into account the prospectivity of an area, before making a choice., and thus decide where to invest.

Transmission and Distribution tariffs are often not transparent, they being included in the retail charges. Governments set retail tariffs in most of the five countries in accordance with their social or political objectives and with little regard to the sector’s needs. The underlying rationale to justify low gas prices is related to impact on low-income households and support to infant industries, i.e., to ensure low prices to support the competitiveness of domestic industries. Given that about 4% of the population has access to gas in Bangladesh and 20% in Pakistan, low-income households do not have access to piped natural gas and might end up with LPG or kerosene at much higher prices effectively. Protecting infant industries through low gas tariffs, and other measures, has proven to lead to less desirable outcomes than open, competitive systems, given that exposure to international competition makes industries very efficient.

In all short-sighted, politically motivated gas pricing policies will distort the demand, result in lower investments (both upstream and downstream) and trigger a switch to costlier liquid fuels.
4. WHAT SHOULD GAS PRICE BE?

4.1 Economic Pricing

A rational price structure is fundamental to maximize the contribution of the gas sector to the economy. The five countries analyzed only in some degrees allow for competition. A key element in these efforts is sound energy pricing. Prices should provide the correct signals to producers (when and how much to produce and expand production), and consumers (what, where and how much to consume). Correct price signals are fundamental for optimal investment and consumption choices. Deviations from economic prices are likely to promote misallocation of resources and reduced overall economic efficiency. Efficient prices in competitive markets should fulfill the following primary requirements:

**Economic or Allocative Efficiency:** This objective promotes an efficient allocation of resources; by guiding that demand is met at least cost. Under competition, the market-clearing price reflects the costs of the marginal unit. Price should thus be equated to the cost of producing the additional unit, in other words, to its marginal or incremental cost. Efficient prices in all markets would result in an optimal level of exploration and development for gas and provide incentives to households and industries to use energy more efficiently, i.e., at a level that maximizes their objective function (personal satisfaction, income and/or profits).

**Cost or productive efficiency:** aggregate production costs are minimized: each producer minimizes the cost of producing its output and the number of producers adjusts so that each unit of output is produced at minimum average cost.

4.2 Market value of gas and netback prices

In many countries the price of gas is linked to its closest substitute, such as gas oil or fuel oil and these fuel prices determine the market value of gas. When transmission and distribution costs are deducted the “netback” flows to the producer.

In the five countries reviewed this is the case in Vietnam (almost all gas is used to generate electricity and the gas price is in reality capped by the cost of coal) and Brazil (FO parity at Sao Paolo for imported gas). In the three other countries reviewed the situation is different: In Argentina, the upstream gas prices were determined in competition between producers (with a dominant supplier) until the Government imposed a price cap. In Bangladesh, gas prices are set by the Government without apparent financial/economic objectives. In Pakistan, tariffs are essentially set to cover the cost of gas as a commodity, the transportation and distribution costs, the allowed return (on assets) of the utilities and the cost of distribution.

In non-competitive markets, often with national gas (regional) monopolies (Vietnam, Bangladesh, Pakistan, Brazil) governments set the methodology for calculating domestic gas prices.

4.3 Gas Pricing considerations

In general, gas pricing ought to take into account the following considerations:

a. The gas price at the wellhead determined by market forces or (where competition in supply is limited), the cost of supply, often expressed as Long Run Marginal Costs. To achieve allocative efficiency, transmission and distribution tariffs for particular types of service and for different locations should to the greatest extent possible be cost-based (based on prudently incurred costs to avoid gold plating of installations and equipment).

b. The market value of gas: This is determined by the alternative fuel prices (or the opportunity costs): In the case of the five countries studied, the market value can be determined as: Vietnam: the price for imported coal as the main alternative for electricity generation; in Argentina, the price of oil products as an alternative and export tariff to
Chile; in Bangladesh, the price of oil products as an alternative for gas and the export price for gas to neighboring markets and to imported LPG.

The difference between the cost of supply and the market value is the economic rent that could be obtained in the gas market. In markets where gas-to-gas competition is present, the economic rent will be reduced over the long run as more production will enter the market. If one or a few producers control access to the transport infrastructure, dominate the market and are price leaders, gas-to-gas competition would be impossible.

If there are restrictions on entry and no access for producers to supply consumers directly, or other supply constraints, high prices for competing fuels will make it possible to obtain an economic rent. Depending on the level of competition in the sector and how transmission and distribution are regulated, the rent will normally be taken at the producer level as the producers will receive the netback from the end user prices.

However, from an economic perspective the distribution of the economic rent is a matter for negotiations between the parties and if it is collected by the upstream sector, the government has the possibility of collecting parts of it through taxation.

4.4 Financial Consideration

How does this translate into actual gas prices? If gas prices comply fully with objectives, they will promote efficient allocation of resources and be cost reflective. However the economic Efficiency pricing may lead to tariff levels below financial costs – needing to adjust the levels, such that the tariff structure preserves much of the appropriate price signal to users. Strict marginal cost pricing leads to tariffs that distinguish between the various costs of supply for each customer. The cost of supplying a consumer has several components:

a. The gas purchase price itself, (which should be passed on to all customers as a commodity charge). In fully competitive gas markets (Australia, UK, US,) gas prices at the wellhead are determined by market forces. In the five countries, the cost of supply at the inlet to the transmission system would be an appropriate measure.

b. The costs of maintaining sufficient supply in the pipelines to the user's premises (which can be related to the necessary pipeline investments due to customer annual and peak requirements), and

c. Administrative cost, including the costs of reading meters and collecting payment (which are largely independent of how much gas is sold)

In all, the required financial adjustments should be recovered from the inelastic component of the tariff (under a two-part tariff), i.e., by adding a fixed component (standing charge related to fixed costs) to the commodity charge.

5. CONCLUSION

Whether gas was introduced in the 1950s or in the 1990s, the five countries have done remarkably well in developing gas grids and making gas available for industry, power generation, and households at affordable prices. And indeed, gas demand has grown by 5-7% per annum in recent years, and could have grown even faster had administrative restrictions not been in place. There is no question that gas has made a significant contribution to economic growth, in particular in connection with power generation in combined cycle plants.

Clearly, the supply chain has not been able to follow, given the perceived economic risks and benefits. As a result, shortages are becoming systemic in four of the countries (in Brazil, gas is used as a back-up for a large hydro system and is mostly required in years of drought). At the current high oil prices, the demand for gas grows even faster.
Governments have two choices – under the business as usual approach, current pricing policies will be maintained, and will result in an increasing inefficient infrastructure, serious shortages, and ultimately imports of liquid fuels, at a very high cost.

Alternatively, Governments could realize that the current policies are unsustainable and socially inequitable (who gets the benefits?) and formulate a transition program to realistic gas pricing policies. This program ought to be well publicized, and communicated effectively to the public and in parallel upstream petroleum fiscal terms should be evaluated to ensure the give the right incentives for an expansion and captures the economic rent from the high priced gas.

Realistic pricing policies will ensure that gas will be used where the value added to the economy is the highest. Through realistic pricing systems, consumers can make rational decisions and they are willing to pay more for the gas, and use gas consistently with its market value.

In any event, Governments will have to take realistic pricing decisions sooner or later. They might as well do so now, to increase the supply and to make better use of this valuable resource. The longer they wait, the harder the adjustments will be.
ANNEX 1

ARGENTINA

Background
Argentina is one of South America's largest and most important economies, second only to Brazil. Though it suffered through a severe financial crisis in 2001-2002, the country's economy has now almost fully recovered to pre-crisis levels. In 2004, GDP grew at an estimated rate of 8.0% in 2004, slightly lower than the 8.7% growth rate of 2003. Economic growth over 2004 and 2005 has continued at impressive rates over 6%.

Despite stronger economic growth, Argentina continues to deal with the 2002 default on its sovereign debt. In January 2005, the government initiated a program to exchange some $100 billion in old bonds for $50 billion in newly issued debt. Further, in late 2005 Argentina paid its debt up-front to the IMF. This debt restructuring is crucial for Argentina to regain its financial credibility and its ability to borrow for necessary domestic programs and infrastructure projects.

Argentina experienced an energy crisis in 2004. State-imposed caps kept energy prices low, resulting in a dramatic increase in industrial demand for gas that outstripped available supply. It resulted in curtailed, lower exports to Chile, Argentina even began importing natural gas from Bolivia and fuel oil from Venezuela, and additionally initiated a certain form of domestic energy rationing program. The crisis threatened to stifle Argentina's nascent economic recovery and strained the country's relations with Chile. To prevent future crises, the Argentina government initiated a set of energy sector reforms, including the establishment of a new, state-owned energy company (Enarsa), introduced incentives for greater investment in downstream infrastructure, and plans to eventually return to liberalized energy prices.

The energy price distortions emerged at the time of the decision to withdraw the currency pegged to the dollar. The new currency dropped rapidly to nearly 3 Pesos per US dollar, resulting in a corresponding drop in the well-head price and transport and distribution tariffs. The ‘pesoficacion’ triggered reductions in gas supplies, because neither transporters and distributors, nor the producers were ready to invest for increasing production and/or adding pipeline facilities. It also resulted in an increase in demand; including a 40% increase in CNG consumption and a significant increase in industrial loads (i.e. Argentina started to export cement and steel!). Over the last three years, the slow adjustment in prices\(^1\) has not yet erased the serious consequences of the shortage, including the loss of trust from the Chilean gas importers, who are seriously now considering other supply sources including LNG.

The Gas Sector
Argentina has Latin America's third-largest proven natural gas reserves, at around 21 trillion cubic feet (TCF). Natural gas production in Argentina increased steadily over the last decade, with the country surpassing Mexico in 2000 to become Latin America's largest natural gas producer. However, natural gas production began to stagnate following the 2002 economic crisis, a situation that continued during 2003-2004. Argentina's natural gas consumption has increased rapidly in the past decade and is now the country's dominant fuel source, accounting for 45% of primary energy consumption.

\(^1\) In April 2004 the Energy Secretariat and the producers of natural gas signed and agreement to gradually liberalized prices “Acuerdo para la Implementación del Esquema de Normalización de los Precios del Gas Natural en Punto de Ingreso al Sistema de Transporte, Dispuesto por el Decreto 181/2004”
The following table presents the gas consumption in 2003 in Bcm, broken down by sector:

<table>
<thead>
<tr>
<th>Sector</th>
<th>Bcm</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>6.91</td>
</tr>
<tr>
<td>Commercial</td>
<td>1.03</td>
</tr>
<tr>
<td>Industry</td>
<td>10.69</td>
</tr>
<tr>
<td>Power Generation</td>
<td>8.75</td>
</tr>
<tr>
<td>CNG</td>
<td>2.64</td>
</tr>
<tr>
<td>Others</td>
<td>0.81</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>30.83</td>
</tr>
</tbody>
</table>

The natural gas industry was at the center of the country’s 2004 energy crisis. Government-imposed caps on natural gas prices led to a surge in natural gas usage, exceeding the country’s gas supply. To prevent a similar crisis in the future, the government has promised to raise, and eventually liberalize, natural gas prices, though no timetable has been set.

The following table presents the 2005 estimates for the domestic demand of gas in real terms (i.e. as delivered to final consumers) and at the field, considering the processing and transport losses, plus the demand from export contracts:

<table>
<thead>
<tr>
<th>Year</th>
<th>DEMAND Delivered to Consumers</th>
<th>At the field</th>
<th>EXPORTS</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005</td>
<td>29,748,615</td>
<td>36,732,518</td>
<td>11,008,689</td>
<td>47,741,208</td>
</tr>
</tbody>
</table>

**Exploration and Production**

The Neuquen, Austral, and Noroeste basins contain Argentina’s largest proven natural gas reserves. As of 2003, the Neuquen basin held 47% of the country’s proven natural gas reserves and accounted for about 65% of natural gas production. Argentina’s proven reserves could increase substantially in the future, as only five out of nineteen basins in the country have been drilled.

The following table presents the oil and gas production by productive basin:

<table>
<thead>
<tr>
<th>Basin</th>
<th>Crude Oil (bbl/day)</th>
<th>Natural Gas (Bcm/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austral</td>
<td>1,960,186</td>
<td>9,273,455</td>
</tr>
<tr>
<td>Cuyana</td>
<td>1,716,377</td>
<td>64,581</td>
</tr>
<tr>
<td>Golfo San Jorge</td>
<td>11,929,618</td>
<td>3,844,726</td>
</tr>
<tr>
<td>Neuquina</td>
<td>13,048,510</td>
<td>30,619,949</td>
</tr>
<tr>
<td>Noroeste</td>
<td>739,540</td>
<td>7,546,924</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>29,394,230</td>
<td>51,349,635</td>
</tr>
</tbody>
</table>

Argentina began deregulating natural gas production and well head prices in 1989 as part of its privatization of YPF. As with the oil industry, YPF (now Repsol-YPF) retains a dominant position in the upstream sector. During the first three quarters of 2003, Repsol-YPF produced 33% of the country’s natural gas, followed by Total Austral SA (19%). In 2004, Repsol-YPF announced two new, major natural gas discoveries in the Rincon del Mangrullo and Piedra Chenque blocks of the Neuquen basin.

**Downstream Activities**

During the privatization process, the gas transport system was unbundled into two companies (subsequently privatized). At the same time, the distribution system was divided into 8 regional companies. ENARGAS (Ente Nacional Regulador del Gas), the government agency created in 1993 through the Gas Act, regulates the transport and distribution tariffs. It also monitors
regulatory compliance with the law and the contractual conditions applicable to each transport and distribution company.

Following privatization, the main distribution utilities have been MetroGas, Gas Natural Ban, Camuzzi Gas Pampeana, and Camuzzi Gas del Sur, most of which have significant foreign ownership. Two companies, Transportadora de Gas del Sur (TGS) and Transportadora de Gas del Norte (TGN), control Argentina's gas transmission system. TGS is South America's largest pipeline company. The company delivers about 60% of total gas consumption, mainly in the greater Buenos Aires area. TGS operates the 3,400 kms, 1,024 MMCFD (million cubic feet per day) San Martin pipeline, connecting the southern part of the country with Buenos Aires, as well as the Neuba I and II pipelines.

TGN operates two main pipelines. The first pipeline, the 1400-km, 800 MMCFD in the North, runs from Campo Duran to the main compressor plant in San Jeronimo, eventually reaching Buenos Aires. The second pipeline, the 1,100-mile, 1,180-MMCFD Centro Oeste, runs from the Loma la Lata field, Neuquen province, to San Jeronimo.

One issue that emerged from the 2004 energy crisis was the inadequacy of Argentina's domestic natural gas transmission network to meet increasing demand. To remedy this situation, the Argentine government introduced several measures to promote investment in the system, including the creation of financial trusts that could raise money from international capital markets to build new transmission infrastructure. These financial trusts would then be authorized to charge higher tariffs in excess of government-established levels in order to repay any capital financing. The first two projects enacted under this new program were the $285 million expansion of TGS's San Martin, which will eventually add some 10% to its capacity, and the $169 million expansion of TGN's Norte pipelines.

**Gas Trade**

Argentina has extensive pipeline linkages with Chile. Three in the south; Tierra del Fuego, El Condor-Poseision, and Patagonia supply methanol plants in Chile. In the north, the 500-km, 300 MMCFD GasAtacama pipeline runs from Cornejo, Argentina to Mejillones, Chile. Owned by Endesa and U.S.-based CMS, GasAtacama supplies the companies' Nopel power plant. Also in the north, the 250 MMCFD NorAndino, operated by Belgium's Tractebel, runs parallel to GasAtacama. In the central region, the 288, 307-MMCFD GasAndes pipeline, majority owned by Total, connects the Neuquen basin in Argentina to Santiago, Chile. Also in the central region, the 510-km, 343-MMCFD Gasoducto del Pacifico connects Neuquen to central Chile. Majority owned by TransCanada (30%), El Paso (21%), and Gasco (20%), Gasoducto del Pacifico supplies municipal distributors and gas-fired power plants.

The 440-km, 100-MMCFD Parana-Uruguayana pipeline connects Argentina and Brazil. The pipeline provides natural gas to AES Brasil Energia's 600-MW power plant in Uruguayana. The Argentine section is operated by Transportadora de Gas de Mercosur; the 16-mile Brazilian section is operated by Transportadora Sul Brasileira de Gas. There are plans to construct a 620 km extension of the pipeline from Uruguayana to Porto Alegre, where the pipeline would supply thermal power plants.

In January 2003, Argentine natural gas began to flow to Montevideo, Uruguay, through the 400 km, 190-MMCFD Gasoducto Cruz del Sur (GCDS, Southern Cross pipeline). The GCDS project also includes a concession covering a possible extension from Uruguay to Porto Alegre in southern Brazil; major partners in the GCDS project are British Gas (40%) and Pan American Energy (30%).

Argentina imports gas from Bolivia through the 450 km, 212-MMCFD Yabog pipeline. Argentina began importing natural gas from Bolivia during the 2004 energy crisis, which it had not done since 1999. And the two countries made agreements to continue the trade through 2006. To facilitate these increased imports, the Argentine government solicited bids for the construction of a $1 billion, 950 km Gasoducto Noreste Argentino between the two countries. The signing of a final agreement depends on the ending of the political stability in Bolivia and a satisfactory gas price agreement between the two countries.
**BANGLADESH**

**Introduction**

Bangladesh has over 138 inhabitants. It has made great strides in improving the life of its people since it gained independence in 1971, yet it remains one of the poorest countries in the world. During the last 10 years, its economy has regained pace and its GDP has been growing annually at a consistent 5-7%. The energy sector is a key driver behind this performance, including gas production to meet a growing power market.

**The Gas Market**

Gas reserves in Bangladesh have not been technically re-evaluated for at least 15 years. It is widely believed that gas reserves in the public sector are equivalent to 15 TCF and that the private companies Unocal (US) and Cairn (UK) hold another 3-4 Tcf. The R/P ratio for the public sector is believed to have been initially 13-14 year has now declined to 5-6 years, which is perilously low. The power sector alone accounts for 44% of gas use as gas-fired power plants generate 75% of electricity used in Bangladesh. The industrial sector uses another 37%, half of which is consumed by antiquated, energy inefficient fertilizer plants. Households account for only 4% of gas use; their loads are not metered, which does not give incentives for new connections.

The gas market in Bangladesh has experienced an average 7-8% sustained growth for the past decade, growing from 0.7 BCFD in 1995 to 1.4 BCFD in 2005, some 40% above the initial forecast. Given the absence of investments in the public sector, the production capacity of gas is declining and there are severe bottlenecks in the transmission and distribution systems. The whole system is operating at full capacity, from production to transmission and distribution. This results in gas shortages and selective load shedding, often on an arbitrary basis, leading to unpredictable impact on the major "interruptible" consumers such as the power sector, translating in turn in continuous and worsening in brown outs and black outs. Should the present trends continue, Bangladesh would have to consider importing gas, as early as 2012.

**Industry Structure**

The gas sector is under the management of the Bangladesh Oil, Gas and Mineral Corporation (Petrobangla), established to administer exploration and development of domestic oil and gas reserves. It operates through a set of operating companies which it controls active in Exploration, Production, Transport and Distribution. It also manages for the State, several Production Sharing Contracts (PSCs) with International Oil Companies (IOCs) and buys from them, all the gas they can produce consistently with the local markets requires.

**Natural Gas Pricing Framework**

The purchase price at which Petrobangla buys gas from the IOCs is pegged to that of fuel oil, and it is capped. Petrobangla also buys at a nominal price the production of its two Production Units; it pays a transportation charge to the pipeline transmission company. The transmission and distribution entities sell the gas to the consumers, on Petrobangla's behalf.

Retail gas prices do not reflect the full economic cost of developing, producing and delivering gas to consumers. Tariffs are adjusted from time to time by Cabinet, without referring to a target and there are no indications as to how the deficits thus created are to be funded.

Therefore, existing price structures and tariffs do not enable the public sector to generate a surplus for investments.
Operational Efficiency

Unaccounted for Gas or system technical and non-technical losses stood in 2005 at 28 bcf. They resulted in a yearly financial loss to the sector conservatively estimated at US$40 million at the current subsidized market price but worth over US$ 200 million at average international prices.

Collection is below 90%. This in turn result in at least 140 bcf of uncollected gas revenue and a revenue loss between US$200 million and 850 million (if priced at international level). These losses, which should be recovered.

The 2005 Gas Strategy and Master Development Plan

In 2004, the Government commissioned a Study to define a new Strategy and Master Plan, aimed at identifying and addressing the issues plaguing the sector. Since the power and industrial sector are the main consumers of gas, the 1995 Power Master Plan was also set for an update, to align both management tools, and ensure that future power demand would be met with adequate gas resources and performing, capable delivery systems. Since the old pricing strategy had been tried and failed to give adequate and timely results, the new Gas Strategy and Master Plan presented in 2005, is clearly in line with the planned power sector growth and international gas price movements and it intends to adapt in steps, the entire sector to market realities, with adequate pricing and investments.

This will start with bringing gas prices in line with world levels over a five year period, to avoid having to import gas as early as 2012. The next set of measures will bring existing production and transmission capacity back to their design level of performance first by simple, targeted and more rigorous management, better and timely preventive and predictive maintenance measures, Transmission and distribution debottlenecking measures such as pipeline pigging, intelligent pigging for ensuring the system's physical integrity, and finally looping and added compression capacity where required, to meet peak demand at all levels.

The Gas Master Plan is supported by a toolkit already in place and operational, which will help manage the preventable and predictable system’s failures and address them in real time, or before they occur. The toolkit will also help develop the system to respond in real time, to present and future demand by attracting investments to the upstream and midstream, in anticipation of projected market growth. Further upstream, projected new bidding rounds with more attractive terms, will also be launched soon to bring foreign direct investments upstream with due consideration to gas exports possibilities. This can happen however only once the domestic market is in balance again and if and only when local market prices reflect the true economic value of gas. By reconsidering its past policies successes and failures and adjusting them where required, the GOB and the Petrobangla Group and IOCs will be able to overcome the pending gas crunch and ensure its people and markets, abundant and secure gas supplies for power, industry and domestic consumers for decades to come.
Background

After real gross domestic product (GDP) growth of 1.5% in 2002, Brazil's economy slumped in 2003, contracting 0.2%, the worst performance in more than a decade. Since Brazil's economy is still waiting for a recovery.

Brazil is the 10th largest energy consumer in the world and the third largest in the Western Hemisphere, behind the United States and Canada. Total primary energy consumption has increased significantly in recent years, growing at an annual rate of 3% between 1992 and 2002, despite a drop in consumption in 2001. Over the past decade, Brazil has made great strides in increasing its energy production, particularly with regards to oil. In the early 1990s, for example, Brazil was a large net oil importer, but by 2003, domestic production, including that of "green" methanol, nearly met domestic demand. Increasing domestic production has been a long-term goal of the Brazilian government. The country hopes to be self-sufficient in oil production by 2006, with output eventually reaching 2.3 million barrels per day (MMBD) by 2010. Also in the 1990s, the Brazilian government introduced new laws which partly privatized state owned oil company Petrobras and state owned utility Eletrobrás. New agencies were established, such as the Agência Nacional do Petróleo (ANP) to regulate the petroleum industry and the National Council for Energy Policy (CNPE) to set energy policy. For the first time, private and foreign companies were allowed to participate in Brazil's energy sector.

Brazil's energy sector is facing serious issues: (i) Private sector participation has stalled, and Petrobras’ presence in the oil and natural gas sectors remains pervasive, possibly slowing the development of competitive markets and the attraction of foreign investment; and (ii) Brazil is still recovering from the 2001 energy crisis, which forced the government to implement a power rationing program.

At the time of the construction of the gas pipeline from Bolivia to Sao Paulo, gas was expected to become a major supply source for electricity generation. However, demand following the economic recession has not materialized as anticipated, and favorable hydro years have reduced the importance of gas imports from Bolivia. The crisis highlighted Brazil's dependence on hydropower and its need to diversify the country's fuel mix. Since then, the government has introduced new legislation for electricity and natural gas that would help avert a future energy crisis, but it remains unclear whether the new regulations will be effective. Analysts are also skeptical about Brazil's attempt to become oil self-sufficient, questioning how long the country would be able to maintain this status once reached, particularly with a burgeoning population and a recovering economy. With oil consumption likely to increase significantly in coming years, the question remains whether increased domestic oil output will simply offset domestic demand.

Sector Organization

Prior to 1997, Petrobras (created in 1953) had a full, monopoly to explore, produce, refine, and distribute petroleum products in Brazil. On November 9, 1995, the Brazilian Congress amended the Brazilian Constitution, authorizing the Brazilian government to contract with any state or privately-owned company to carry out activities related to the upstream and downstream segments of the Brazilian oil and natural gas sector. Accordingly, this amendment eliminated Petrobras’ government-granted monopoly. The amendment was implemented by the adoption of the Oil Law, which revoked the country's initial Oil Law of 1953. The new law also created National Petroleum Agency (Agência Nacional do Petróleo - ANP), charged with issuing tenders, granting concessions for domestic and foreign companies, and monitoring the activities of the oil sector, including establishing rights to explore for and develop oil and natural gas in Brazil. One of the main goals behind opening the oil sector was to increase oil production in order to reduce dependence on oil imports and eventually to achieve self-sufficiency.

Petrobras is leading the Brazilian government’s plan to become self-sufficient in oil production by 2006 and a net exporter thereafter, with oil production aimed at reaching 2.3 MMBD in 2010.
Petrobras, the country’s largest oil and natural gas producer, has made positive steps towards reaching this goal. In 2003, Petrobras increased its total oil production to 1.54 MMBD, a 2.6% increase year-on-year and a 21% increase since 2000.

The Gas Sector

Brazil's natural gas reserves stood at 8.5 trillion cubic feet (Tcf), as of January 2004. The Campos and Santos basins hold the largest gas fields. Other gas basins include Foz do Amazonas, Ceara e Patiugá, Pernambuco e Paraíba, Sergipe/Alagoos, Espírito and Amazonas. Recent discoveries in the Santos Basin will likely increase Brazil's natural gas reserves considerably in coming years. In September 2003, Petrobras reported that these discoveries could hold up to 14.8 Tcf of gas. It will likely take several years, however, for these fields to be thoroughly evaluated and commercialized.

Overall, gas plays a small role in Brazil's energy mix. In 2002, it accounted for only 5.7% of total primary energy consumption. Consumption, however, has been steadily increasing. In early 2004, gas represented 7.5% of the primary energy-mix. Nonetheless, the demand for natural gas is still not large enough to use effectively the minimum contractual volumes agreed with Bolivia as follows:

Petrobras is the largest producer and importer of gas in Brazil, as well as the largest supplier to local distributors. Under Brazilian law, each state has the monopoly right to distribute natural gas in its jurisdiction. In recent years, the states have sold stakes in their distribution companies. Petrobras reportedly has minority stakes in 17 natural gas distribution companies in Brazil. The largest distributor is CEG in Rio de Janeiro, controlled by Spain's Gas Natural.

Pipelines

Brazil has two existing international pipeline connections. The first pipeline was the Bolivia-to-Brazil pipeline (Gasbol), tapping Bolivia's Rio Grande sources. Gasbol covers almost 3,200 kms, with a terminus in Porto Alegre. Brazil's second operational international natural gas pipeline links Paraná, Argentina, to Uruguaiana, Brazil. The pipeline, Transportadora de Gas del Mercosur, is 420 km long. The pipeline supplies natural gas to a 600-MW power plant in Uruguaiana. In January 2004, the Brazilian and Argentine governments agreed to proceed with a 620-mile pipeline extension, the Transportadora Sulbrasileira de Gas (TSB), which would connect Uruguaiana to Porto Alegre.
**PAKISTAN**

<table>
<thead>
<tr>
<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td>Population (million)</td>
<td>140</td>
<td>Overall Market (bcf)</td>
</tr>
<tr>
<td>Use of Modern Fuels (Mtoe)</td>
<td>50.8</td>
<td>Households %</td>
</tr>
<tr>
<td>of which Natural Gas (Mtoe)</td>
<td>25.3</td>
<td>Commercial %</td>
</tr>
<tr>
<td>Gas as a %</td>
<td>49.7%</td>
<td>Petrochem/Fert. %</td>
</tr>
<tr>
<td>Household Connections (mln)</td>
<td>3.97</td>
<td>Industry %</td>
</tr>
<tr>
<td>% Population with Access*</td>
<td>19.8</td>
<td>Power Generation %</td>
</tr>
<tr>
<td>Regulatory Agency (Y/N)</td>
<td>Y</td>
<td>Others %</td>
</tr>
<tr>
<td>Average tariff ($/MMbtu)</td>
<td>2.50</td>
<td></td>
</tr>
<tr>
<td>Household average %</td>
<td>74%</td>
<td></td>
</tr>
<tr>
<td>Commercial %</td>
<td>136%</td>
<td></td>
</tr>
<tr>
<td>Petrochemical/Fert. %***</td>
<td>63%</td>
<td></td>
</tr>
<tr>
<td>Industry average %</td>
<td>121%</td>
<td></td>
</tr>
<tr>
<td>Power generation %</td>
<td>121%</td>
<td></td>
</tr>
</tbody>
</table>

Source: Energy Year Book, 2004

**Introduction**

With a consumption of gas of 23 million toe equivalent in 2004, Pakistan is one of the larger users of gas among developing economies. Gas now represents about half of the supplies of modern energy used in Pakistan, and its relative share continues to increase rapidly.

Gas in commercial quantities was first discovered in Pakistan in the 1950s with the giant Sui field (11 TCF in place). The field encouraged the development of a gas grid comprising 8519 km of high pressure transmission pipelines extending from Karachi in the South to Peshawar in the North, and Quetta to the East. All major Pakistani cities are now connected to the gas grid.

At present, some 4 million households (an estimated 20% of the population) are using natural gas primarily for heating and cooking.

**Gas Reserves and Imports**

With gas reserves of 25 TCF, Pakistan has approximately 20 years equivalent of gas at current consumption rates. However, many potential customers are denied gas (notably the cement industry and some power plants) so that the real demand for gas is not known with certainty. Moreover, particularly over the past year, there have been many requests for gas connections which could not be satisfied, given insufficient gas reserves and/or gas transmission constraints.

Given the high growth rate of the gas market in recent years (6-7%), and the economic outlook, it is anticipated that gas demand will continue to grow rapidly in the future. Hence Pakistan has embarked on a program to import LNG, and is considering various options to import natural gas by pipeline.

**Government involvement in the gas sector**

The Government has been traditionally controlling the sector since the 1970s, as owner, regulator and policy maker. Since 2000, significant reforms have been introduced with the creation of a regulatory body (the Oil and Gas Regulatory Authority -- OGRA); the establishment of transparent policies for pricing gas at the wellhead; divestment of some state-owned assets; and the initiation of a reform program.
Legal and regulatory framework

An overall Petroleum Policy, announced in 2001, is in effect and defines the parameters for exploration and production, producer-level pricing, allocation and purchase of gas, and other related matters. Exploration blocks are bid out in a competitive manner under Petroleum Concession Agreements (PCA), and a specialized Directorate oversees the performance under these Contracts. Provisions of PCA provide the legal basis for the determination of wellhead prices. Tariff and Licensing Rules for transmission, distribution and sale have been issued by OGRA, and form the legal basis for the determination of tariffs and regulation of non-tariff performance for these activities. Under the existing framework, responsibility for setting retail gas tariffs rests with the Government.

Gas pricing

The wellhead gas pricing framework has gone through a number of refinements over the last twenty years, as follows:

- **pre-1985**, Cost plus or Rate of Return formula – only one major field (called Mari Gas) is still under this pricing framework;
- **1985-1991**, wellhead gas price was linked to 66% of international High Sulphur Fuel Oil (HSFO) price less negotiated discounts;
- **1991-1994**, wellhead gas prices were linked to first 75%, and then 100% of HSFO price, and finally allowed 100% of HSFO with a floor price;
- **1994-1997**, prices were linked to a basket of international crude oil prices, with the linkage percentage of 66.5 – 77.5%, depending on the risk of the exploratory zone;
- **1997-2001**, the pricing formula was improved to provide a floor and ceiling price ($10-25 per barrel), with protection in case of drastic drop in international crude price, and sharing of windfalls in case of steep increase; and
- **2001-todate**, the pricing framework was further improved to change the floor and ceiling to $10-36 per barrel of crude oil.

Wellhead prices (except Mari field) for different fields under the above pricing arrangements ranged between $2.4 – 3.6 per MMBtu in July 2004. These prices are adjusted every six months.

Consumer prices are determined by OGRA after taking into account the weighted-average cost of gas purchased from the producers, and allowing a transmission, distribution (T&D) charge. The T&D charge is regulated but allows certain stipulated returns to the utilities, and is determined through a well-defined regulatory process with public consultation. Wellhead price plus T&D constitutes what is called the Prescribed Price. The Federal Government then decides upon the tax element (called Gas Development Surcharge) for different consumer categories, and when added to the prescribed price, results in the consumer price. The July 2004 consumer prices are as follows:

<table>
<thead>
<tr>
<th>Consumer Category</th>
<th>Rs/ MMBtu</th>
<th>$/MMBtu</th>
</tr>
</thead>
<tbody>
<tr>
<td>Domestic (Weighted-average tariff for four consumption slabs)</td>
<td>111</td>
<td>1.85</td>
</tr>
<tr>
<td>Commercial</td>
<td>205</td>
<td>3.41</td>
</tr>
<tr>
<td>Fertilizer (Weighted-average feedstock and fuel tariff)</td>
<td>95</td>
<td>1.58</td>
</tr>
<tr>
<td>Industry</td>
<td>182</td>
<td>3.03</td>
</tr>
<tr>
<td>Power Generation</td>
<td>182</td>
<td>3.03</td>
</tr>
</tbody>
</table>

Source: OGRA
Current and future gas demand and Shortages

Gas consumption in FY2004 was 1051 bcf, but power generation and industrial sectors were drastically curtailed especially during the winter season. While accurate estimate of the suppressed demand is difficult to make it is generally assumed that another 50% gas volume could be easily absorbed in the system\(^2\). Based on the current gas price structure, there are also problems in assessing “economic” gas demand for sectors where it is subsidized e.g. domestic and fertilizer industry. A number of long-term studies have been undertaken to estimate future gas demand under assumptions of national economic growth, and likely developments in different consumption sectors. When compared with likely domestic gas supplies, shortfalls are anticipated which are proposed to be filled up through imports (see below):

### Projected gas supply and demand

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<thead>
<tr>
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<tbody>
<tr>
<td>Supplies</td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>Demand</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Moderate</td>
<td>3,730</td>
<td>4,692</td>
<td>5,177</td>
<td>5,973</td>
<td>6,541</td>
</tr>
<tr>
<td>Demand</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Optimistic</td>
<td>3,800</td>
<td>5,232</td>
<td>5,945</td>
<td>6,977</td>
<td>7,818</td>
</tr>
<tr>
<td>Scenario</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Scenario 1-Moderate</td>
<td>111</td>
<td>-222</td>
<td>-1,401</td>
<td>-2,705</td>
<td>-4,339</td>
</tr>
<tr>
<td>Scenario 2-Optimistic Demand</td>
<td>41</td>
<td>-762</td>
<td>-2,169</td>
<td>-3,709</td>
<td>-5,615</td>
</tr>
<tr>
<td>Source: SSGC</td>
<td></td>
<td></td>
<td></td>
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</tr>
</tbody>
</table>

Impact of gas shortage

Pakistan’s economy is currently growing at 7-8% per annum, and this trend is expected to continue over the next 10-15 years. A number of new industries are being established, and based on increasing need for electricity, industrial development, mechanization of agriculture, increase in transportation activity, and overall socio-economic improvement of population, the need for commercial fuels is rapidly increasing. If future economic growth were to be sustained, availability of energy resources is paramount. Since Pakistan has a well-developed gas transmission and distribution infrastructure, and has substantial domestic production, reliance on the gas resource is increasing and contribution of gas in the overall energy-mix is now about 50%. Based on the sharp increase in international oil prices in recent years, Government is laying more emphasis on gas as the engine of economic growth. Therefore, there are serious implications of gas shortage from an economic viewpoint, and also on account of quality of life of the population.

\(^2\) Caution must be exercised regarding the suppressed demand; gas requirement for power generation are seasonal in nature and are dependent on a number of other factors (hydro-generation, etc).
Vietnam’s gas industry is currently at an early stage of development. Since associated gas from the Bach Ho (White Tiger) was brought onshore in 1995, natural gas consumption has reached 5 Bcm in 2005. Gas is mostly used for power generation.

With many discoveries still at the appraisal stage reserves have been tentatively estimated at 417 BCM (12 TCF).

Existing transmission and distribution infrastructure includes the following:

- PetroVietnam’s Bach Ho pipeline transports associated gas from the offshore Bach Ho and Rang Dong oil fields to power plants at Ba Ria and Phu My; and

- The Nam Con Son pipeline, owned by PetroVietnam (51 percent), BP (33 percent operator), and ConocoPhillips (16 percent) transports non-associated gas from the offshore Lan Tay and Lan Do fields also to Phu My. Gas from the Rong Doi field will soon be connected to the system. The current pipeline capacity is around 7 Bcm per year.

- PetroVietnam’s subsidiary PVGas operates the Gas Distribution Center at Phu My and a small low pressure pipeline distributing 6-700,000 cm/y gas to industry, in particular ceramics.

A number of projects for additional gas supply for power generation are currently being considered in the existing basins as well as in the South West of Vietnam.

Government Involvement in the Gas Sector

Since 2003, The Ministry of Industry has been entrusted with the energy sector since 2003, including oil and gas. Until then, the Prime Minister’s Office oversaw the activity.

Oil and gas exploration and development activities are undertaken by the state petroleum company, PetroVietnam, and private sector operators through a system of PSCs and joint ventures. PetroVietnam is the primary operator in the small downstream gas sector through its subsidiary PVGas.

The Petroleum Law 1993 and subsequent amendments (Law No. 19/2000), the Petroleum Decree No. 48/2000, and the Petroleum Bidding Procedures Decree (2001) provide the policy and regulatory framework for the upstream. The Petroleum Law governs oil and gas exploration and production activities in Vietnam, and defines the so-called state management responsibilities in the areas of policy, petroleum rights management, and regulation.

There is currently no regulatory framework or law in place for regulation of the downstream gas sector in Vietnam.

Gas Pricing

The associated gas produced in the Bach Ho field is provided to PetroVietnam at no cost and the custody transfer is at the production platform. The first gas sales contract was signed with Electricity Vietnam (the State Electricity Company) in the US $2-3/MMBtu range. The Rang Dong contract includes provisions that allow the producers to sell associated gas to Petrovietnam. The price of non-associated gas in the Lan Tay/Do gas field is somewhat higher resulting in an average gas prices gas price from all sources at the power plant gate at around US $3/MMBtu.
Table 1: Gas prices at Power Plant Gate

<table>
<thead>
<tr>
<th>US $ /MMBtu</th>
<th>2005</th>
</tr>
</thead>
<tbody>
<tr>
<td>Estimated average of current gas supply</td>
<td>2.9</td>
</tr>
<tr>
<td>South West estimated range</td>
<td>3-4</td>
</tr>
</tbody>
</table>

Current and Future Gas Demand
Gas used for power generation is likely to remain the dominant use for the foreseeable future. The demand for gas is expected to rise significantly in the medium term because of increasing urbanization and industrial growth, which will drive demand for increased electricity generation capacity. Other uses of gas will include consumption associated with industrial and chemical fertilizer production.

Table 2: Potential Gas Supply 2010 and 2015

<table>
<thead>
<tr>
<th>Bcm/y</th>
<th>2010</th>
<th>2015</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bach Ho pipeline/ Pot. New pipeline</td>
<td>1-2</td>
<td>2-5</td>
</tr>
<tr>
<td>NCS pipeline</td>
<td>7-8</td>
<td>7-8</td>
</tr>
<tr>
<td>SW</td>
<td>3-4</td>
<td>3-6</td>
</tr>
<tr>
<td>Total</td>
<td>11-12</td>
<td>12-18</td>
</tr>
<tr>
<td>Gas from other fields and new discoveries</td>
<td>5-10</td>
<td></td>
</tr>
</tbody>
</table>

In the power generation development plan, the assumption is that natural gas is supply constrained at around 15 Bcm resulting in plans for more coal fired power plant and discussions of the introduction of nuclear. From being the most rapidly growing fuel future gas supply is now perceived to be short in supply.