Natural Gas Sector Reform in India: Case Study of a Hybrid Market Design

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Abstract

The state-owned Indian natural gas sector has been slowly moving towards deregulation for close to a decade. However, rather than wholly introducing free market forces into the existing state-managed sector, India has developed a separate, almost entirely decontrolled gas market alongside the existing sector. The major challenge to complete gas sector reform that remains is how to transition gas users from the state-managed sector to the free market. This paper explains the origins of this hybrid market and its likely evolution.

The fertilizer and electricity sectors, which account for most gas consumption in India, are reviewed in detail. In both, while interlocking political forces have prevented full transition of the sector to the free gas market, some users have already made the transition. In electricity, parts of the sector, such as private power plants, are already shifting private gas supplies on their own because private gas, while more costly, is much more reliable. The ultimate viability of private gas in electricity and fertilizer production will depend on reforms within the offtaking industries.

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INTRODUCTION

A near financial crisis in 1991, brought on by a burgeoning public debt, initiated the deregulation movement in India. Throughout the 1990s, the central government opened the Indian economy to market forces and began to deregulate industries that had remained under state management for decades. Trade policies were liberalized, the electricity and telecommunications sector were opened to private investment, and the banking sector was overhauled.[1]

Along with the rest of the economy, the natural gas sector too has become the locus of reform. Gas exploration and production has historically been dominated by the state-owned Oil and Natural Gas Company (ONGC), which produced over 90% of India's gas prior to E&P reform.[2] In turn, this gas has been sold at artificially low rates to the state owned gas transmission company, Gas Authority India Limited (GAIL). GAIL transports close to 90% of the gas consumed in India and then sells it to end-users at rates set by the central government.[3] Most consumption occurs along GAIL's Hazira-Vijaipur-Jagdishpur (HVJ) pipeline, which supplies gas to the northwest of the country from the landfall of offshore gas in Gujarat, up through Delhi. GAIL also operates a number of regional distribution grids, including ones in Mumbai, Ahmedabad, and Andhra Pradesh. Figure 1 provides a breakdown of natural gas consumption in India by end-use. Electricity generators and fertilizer manufacturers are the major users of gas and collectively comprise about 75% of demand.[4]

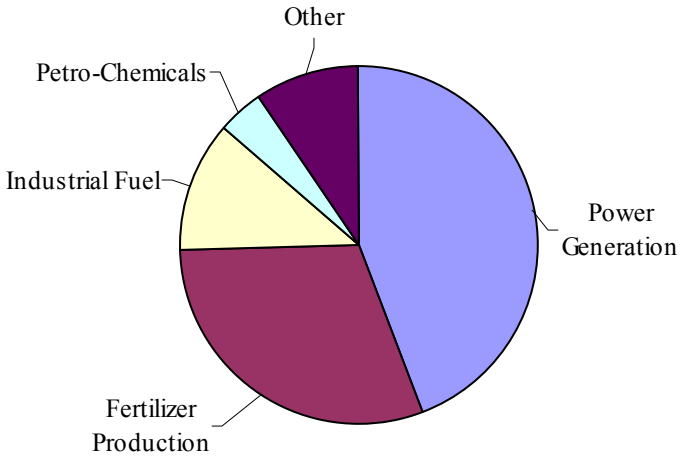
[1] Srinivasan, T.N. *Trade, Finance, and Investment in South Asia* (2002).

[2] Ministry of Petroleum and Natural Gas. "Petroleum Statistics (2004)." Reference year taken is 1991. The balance of gas was produced by Oil India Limited (OIL), another state owned enterprise. However, this gas is produced in the eastern region of the country, and as there are no pipelines to link these supplies to ONGC's, this is essentially an isolated market. For this reason, this paper will focus almost exclusively on ONGC as the state-run E&P company.

[3] Ministry of Petroleum and Natural Gas, *supra* note 2. Gas Authority India Limited, "Annual Report 2003-04."

[4] Ministry of Petroleum and Natural Gas, *supra* note 2.

Figure 1: Natural Gas End Use in India (2004)



Source: MoPNG, Petroleum Statistics (2004).
"Other" includes Domestic Consumption and Compressed Natural Gas (CNG) transportation fuels, Tea Plantations, and other niche uses.
Figure does not include captive use or LPG shrinkage.

Most analysts envision the transition to a liberalized gas sector as a process of incrementally introducing market forces to a state-controlled sector. Indeed, the original reform movement within India followed this model. In 1997, the central government mandated that gas prices would be linked to an international basket of fuel oils. This amount would rise from an initial 55% parity in 1997-98 to 65% in 1998-99 and 75% in 1999-2000.[5] A price band of Rs. 2,150/thousand cubic meters to Rs. 2,850 was set, and in October 1999 the price reached this ceiling.[6] But as international oil and gas prices continued to rise in 2000, plans to achieve full import parity were abandoned, and the gas price remained unchanged for the next five years. This stagnation can largely be attributed to the fact that the major consumers of gas, electricity and fertilizer producers are unable to absorb price increases and have used their political power to quash further price increases.[7]

Instead of this ideal reform process in which the entire sector moves towards decontrol, political and economic realities have resulted in private gas adoption only in the industries that are unable to avoid liberalization or who have actively sought private gas supplies as a remedy to chronic shortages. Liberalization has also been pushed by gas suppliers, including ONGC, who have a keen interest in higher prices.[8] The result is a hybrid market in which private suppliers sell market priced gas to niche offtakers, while the old government managed system remains at the core. The reform process of the sector

[5] T.L. Shankar et at, *Report of the Committee on Natural Gas Pricing*. New Delhi, December, 1996.
[6] Rediff.com. "Oil Ministry Pushes Gas Price Hike." July 14, 2003.
<http://www.rediff.com/money/2003/jul/14gas.htm>
[7] Rediff.com. "Natural gas price hike next." November 9, 2004.
<http://www.rediff.com/money/2004/nov/09gas.htm>
[8] The Hindu Business Line. "ONGC to net Rs 1,400 cr thanks to hike in gas prices." June 29, 2005.
<http://www.thehindubusinessline.com/2005/06/29/stories/2005062902610400.htm>

therefore becomes a process of constantly redrawing the boundary between these two markets to switch consumers from the public to the private market. The challenge to reform that remains is how to impose this transition on the major consumers of natural gas, electricity and fertilizer producers, while ensuring that they are able to compete in this new private market.

DRIVERS OF REFORM

The major motivations for privatization of the gas sector in India were to increase domestic gas supplies, reduce the huge government subsidies necessary to maintain artificially low prices, and allow efficient gas allocation and consumption.[9] The following section will explore these drivers in detail and consider the impacts of the hybrid market on the transition to a liberalized gas sector.

Supply-Demand Shortfall

Artificially low prices have created a huge demand for natural gas in India. However, these low prices, along with restrictions on private investment in exploration and production, have also reduced the incentives and ability of ONGC to bring additional gas online. As a result, full demand in the country is estimated to be nearly double the availability of 70 million metric standard cubic meters per day (mmscmd).[10]

The shortfall between this latent demand and actual supply has necessitated a political process to allocate gas. The limited supplies are allocated by an inter-Ministerial body called the Gas Linkage Committee. The committee includes representatives from the Ministries of Petroleum and Natural Gas, Finance, Power, Chemicals and Fertilizers, and Steel, as well as ONGC, OIL, and GAIL.[11] Electricity and fertilizer producers as well as compressed natural gas transportation fuels receive priority in this allocation scheme, with the balance going to other industries.[12]

In the absence of new supplies, the natural gas supply gap is projected to grow in the coming years. The major ONGC offshore gas fields are close to 30 years old and production has already begun to decline.[13] The 10th Five Year Plan estimates ONGC's production will continue its decline, falling by 13% from 2002-07, from 65.5 to 57.03 mmscmd.[14]

New Private Gas Supplies

In an attempt to increase domestic production, in 1998 the central government initiated the New Exploration Licensing Policy (NELP) to open oil and gas exploration to private investment. It created five rounds of competitive bidding—with the fifth round ending on May 31, 2005—for previously unexplored sedimentary basins. The policy allowed for 100% foreign equity, streamlined permitting processes, and most significantly, granted producers the right to sell gas at market prices.[15] The first four

[9] T.L. Shankar, *supra* note 5.
[10] CLSA: Asia Pacific Markets. "Asian LNG – Boomtime." May 2005.
[11] Ministry of Petroleum and Natural Gas, "Natural Gas." <http://petroleum.nic.in/ngbody.htm>
[12] *Ibid*.
[13] Ministry of Petroleum and Natural Gas, *supra* note 2.
[14] Ministry of Petroleum and Natural Gas, *supra* note 2.
[15] Directorate General of Hydrocarbons. "New Exploration Licensing Policy: Background."

rounds have been a resounding success, leading to two major gas finds and a number of smaller fields. The first significant find was made by Reliance Industries in the Krishna Godavari basin off the Andhra Pradesh coast in 2002 with reserves estimated between 12 and 14 trillion cubic feet (tcf), yielding a projected output of 40 mmscmd by the end of the decade.[16] The second major find, made by the Gujarat State Petroleum Corporation in 2005, is the largest gas field ever found in India. This 20 tcf field is also in the Krishna Godavari basin and has a projected output of 80 mmscmd by 2010.[17]

In addition to private production, two LNG regasification terminals have begun operation and are selling gas at free market rates. The first is owned by Petronet LNG and is located at the port of Dahej in Gujarat. Petronet is a private joint venture between state-owned ONGC, GAIL, Indian Oil Corporation Ltd (IOCL), and Bharat Petroleum Corporation Ltd (BPCL), which each own 12.5% equity in the company, Gaz de France International (10%), and the Asian Development Bank (5.2%), with the balance held by the public.[18] The terminal has a capacity of 5 mmtpa (20 mmscmd) with a provision for expansion up to 10 mmtpa (40 mmscmd). Petronet has signed a 25-year contract with Qatar's Ras Laffan LNG (RasGas) for the supply of 7.5 mmtpa at prices linked to the Japanese Crude Cocktail (JCC).[19] This gas will supply the Dahej terminal as well as another planned terminal at Kochi in Kerala in the southwest of the country. GAIL, IOCL, and BPCL offtake the gas in a 60:30:10 ratio and market directly to end-users. The terminal received is first shipment in January, 2004 and commenced commercial operations in April of the same year.

The second LNG terminal is owned by Shell with Total Gaz Electricité Holdings France holding a 26% equity stake. It is located at the port in Hazira, near the mouth of the HVJ pipeline in Gujarat. The terminal has a capacity of 2.5 mmtpa with the potential to expand to 5 mmtpa with marginal incremental investments.[20] Unlike more conventional regasification terminals, the Shell facility does not have a dedicated liquefaction train to supply its LNG. Instead, the promoters hope to divert excess supplies from trains they hold equity in around the world, most likely coming from the Middle East and southeast Asia.[21] The facility received its first shipment in April 2005 and as of June 2005 had yet to scale up to full operational capacity.

There are numerous other planned LNG regasification terminals throughout the country. Petronet hopes to construct a 2.5 mmtpa terminal in Kochi, with a potential opening date of 2008. In January of 2005, IOCL signed a Memorandum of Understanding with the National Iranian Oil Company to supply 7.5 mmtpa of LNG for 25 years with a proposed starting date of 2009, but construction of a regasification

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<http://www.dghindia.org/nelp_background.html>

[16] Directorate General of Hydrocarbons. "Annual Report 2003-04," (page 44).

[17] Rediff, "Gas Find: GSPC Production by Dec '07." June 28, 2005.

[18] IOCL and BPCL are central government owned companies involved in the refining, transportation, distribution, and marketing of petroleum products.

[19] Alexander's Gas & Oil Connections. "RasGas and Mobil to supply 7.5 mm tpy of LNG to India." December 16, 1998.

[20] Royal Dutch Petroleum Company: Shell in India. "Hazira LNG Terminal and Port Project."
<http://www.shell.com/home/Framework?siteId=in-en&FC2=/in-en/html/iwgen/about_shell/sipl/zzz_lhn.html&FC3=/in-en/html/iwgen/about_shell/sipl/lng_hazira_bsl.html>

[21] Rediff.com. "Shell to import LNG for sale in India." November 23, 2004.
<http://www.rediff.com/cms/print.jsp?docpath=/money/2004/nov/23shell.htm>

facility in India has yet to commence.[22] The Dabhol facility in Maharashtra, which was abandoned in 2002 at 85% completion, has a nearly completed LNG terminal with a 5 mmtpa capacity.[23] In May of 2005, the central government announced hopes to revive the facility by mid-2006, with investment from GAIL and state-owned electricity generator National Thermal Power Corporation (NTPC).[24] There are numerous other proposed terminals, but no others have yet made it past the planning stages.

The final major supply of market priced gas in India comes from the Panna-Mukta and Tapti (PMT) fields, operated by a joint venture between ONGC (40%), Reliance (30%), and BG (30%). The consortium has historically sold its supplies through GAIL at government determined prices slightly above the subsidized ONGC rate, but has been granted permission by the central government to market some of the gas directly to customers at market prices. Of the 11 mmscmd currently produced, 6 mmscmd has been retained for sale to electricity and fertilizer consumers through GAIL for a one year transitional period, while the remainder will be sold directly by the suppliers at market rates.[25]

Gas pipelines have been discussed from India's neighbors, including Iran, Bangladesh, Turkmenistan, Myanmar, and even Oman. As all of these projects remain in speculative planning stages and would not become available for another several years, they fall outside the scope of this paper's analysis.

Clearly, India has been successful at attracting private investment to bring new gas supplies online. The two LNG projects were completed at an estimated cost of about $1.3 billion while the first four rounds of the NELP generated over $700 million in investment from 1999-2004 with an anticipated total investment of $4 billion.[26] This private gas has been welcomed by Indian consumers despite its higher price and the private market has grown as quickly as new supplies become available.

[22] The Hindu Business Line. "India signs pact to import 7.5 mt LNG from Iran." January 8, 2005. <http://www.blonnet.com/2005/01/08/stories/2005010802690100.htm>

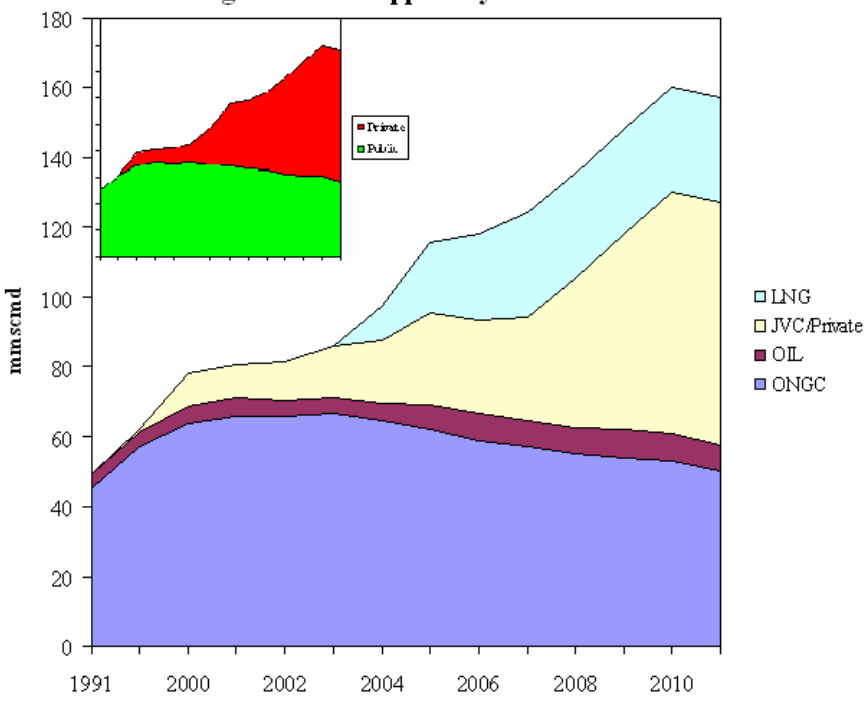
[23] The Dabhol terminal is an infamous independent power producer project sponsored by Enron to import LNG to fire a huge natural gas terminal in Maharashtra. Due to the high cost of the project and concerns over non-payment by the Maharashtra State Electricity Board, the project was abandoned in 2002.

[24] Rediff.com. "Gail, NTPC to take over Dabhol assets." May 04, 2005. <http://in.rediff.com/money/2005/may/04dpc.htm>

[25] The Economic Times. "Gas producers' earnings hit as Gail cuts offtake." May 1, 2005. <http://economictimes.indiatimes.com/articleshow/1094750.cms>

[26] Directorate General of Hydrocarbons. "The Success of New Exploration Licensing Policy." <http://www.dghindia.org/>

Figure 2: Gas Supplies by Producer



Source: MoPNG, Nexant, author's estimates. All growth in domestic production in the foreseeable future will come from private suppliers (see inset). By these projections, supplies in the private market will exceed the public market by 2007-08.

Because the availability of gas supplies has thus far been the limiting factor in the growth of the private market, it is possible to estimate the size and growth of this market by analyzing the timing of major new gas supplies over the medium time frame. Figure 2 shows the projected growth in gas supply in India based on the information currently available. As the figure shows, almost all of the new gas will be unsubsidized and sold by private producers to the highest bidder, rather than through the political system of linkages. As these private supplies come online, the private market could become larger than the government-managed core by as early as 2007-08. Thus, even in the absence of major policy reform, the gas sector as a whole will become increasingly dominated by the private suppliers and operate under increasingly free market principles.

THE OPERATION OF THE HYBRID MARKET

In the public market, consumer gas prices are set by the central government and have remained at Rs. 2,850 thousand cubic meters ($1.81/mmbtu) plus a transportation surcharge of Rs. 1,150 or ($0.73/mmbtu) since 1999.[27] Gas prices maintained at such a low level for so long have created a huge unmet demand, estimated at around 50 mmscmd. The limited gas supplies are allocated by the central government, leaving consumers vulnerable to supply disruptions from political factors. In addition, because

[27] Ministry of Petroleum and Natural Gas, *supra* note 2. This figure excepts gas produced and sold in the northeastern part of the country by Oil India Limited, because this market is relatively small and disconnected from the major gas markets in the west of the country. Gas sold in this region is provided at a price of only $1.07/mmbtu.

there are no "supply-or-pay" obligations from the central government, offtakers are not compensated for interruptions in supply.

In the private market, prices are set by individual contracts between supplier and offtaker. These prices are considerably higher than those in the public market and range from $2.97/mmbtu to $5.05/mmbtu. A summary of gas prices charged by private market suppliers as of May 2005 is given in Table 1. These private supplies have generally been sold under long term contracts and include both take-or-pay and supply-or-pay provisions.

Table 1: Public and Private Suppliers in the Indian Gas Market

Supplier	Purchased price (per mmbtu)	Delivered Price (per mmbtu)
Government Core		
ONGC	$1.81	$2.76
Private Suppliers		
Petronet	$3.66	$4.83
Shell	$3.70	$4.87
Panna-Mukta, Tapti	$3.86	$5.05
Reliance	--	$2.97

"Purchased price" is that charged by the supplier while "delivered price" is inclusive of transportation charges and local taxes. This figure assumes the 12% sales tax imposed on gas sold in Gujarat and a $0.73/mmbtu transportation charge through the HVJ pipeline. The Reliance contract referenced is inclusive of transportation charges and taxes and thus a purchased price is not applicable.

Sources:

ONGC: Ministry of Petroleum and Natural Gas, "Petroluem Statistics (2004)."

Petronet: *Standing Committee on Chemicals and Fertilizers, Sixth Report: Call for Grants. April 21, 2005. <http://164.100.24.208/ls/CommitteeR/chemicals/6rep.pdf>*

Shell*: The Economic Times. "Royal Dutch/Shell set to invest Rs 3,000 cr for Hazira terminal." May 18, 2005.*

Panna-Mukta, Tapti: *Rediff, "Oil cos to invest $500 mn in Tapti project." April 27, 2005. <http://www.rediff.com/money/2005/apr/27tapti.htm>*

Reliance (KG Basin)*: The Hindu Business Line. "Indo-Iran deal: LNG price competitive, say experts." January 7, 2005. <http://www.blonnet.com/2005/01/08/stories/2005010802230300.htm>*

There are a few important elements to note. The first is that the Reliance quote is probably lower than prices likely to be seen once supplies actually come online. The $2.97 figure is based on the only contract Reliance has signed thus far for its Krishna-Godavari gas. The contract is with NTPC to fuel two natural gas power plant expansion projects in Gujarat for 17 years and is for about one-third of all production expected from

Reliance's KG basin find.[28] As such, it is an anchor contract to help justify development of the newly discovered gas field by guaranteeing a portion of the offtake. Additional contracts from Reliance are likely to fetch a higher price.

The second is that the Shell terminal has introduced short term contracts to gas offtakers, broadly on the order of 1-3 years. The only contract Shell has signed thus far has been even shorter, at 210 days.[29] By contrast, the major contract for Petronet's gas with GSPC extends to the year 2018, while most other contracts are of 10 year duration.[30] Shell's supplies could be the first step towards developing a spot market within India. In light of the heavily uncertain terms of the future gas market in India, as well as the nature of many offtaking industries, short term contracts could provide private natural gas with a competitive advantage.

Despite their higher costs, private gas contracts offer a significant value added feature, the supply-or-pay clause. Existing gas and coal supplies in the country are subject to disruptions, both physical and political in nature, which introduces additional risk to already precarious investments in consuming industries like electricity generation. The advantages of the take-or-pay contract in this context will be discussed in more detail in the "Electricity" section.

Perhaps the most important dynamic in the hybrid gas market is that the private market is undeniably growing while the subsidized market is shrinking, both in volumes of gas and in market share. This means that for offtakers within the public market, even in the absence of additional policy reform, supplies of cheap gas will become increasingly scarce. The major gas offtakers in India, namely electricity and fertilizer producers, manufacture products whose prices are kept artificially low by the central government, rendering them unable to absorb the higher gas costs in the private market. As a result, beyond the initial market penetration, growth of the private market will be limited by demand from these major industries and no longer by supply. However, the risk of gas shortages should create a strong incentive within offtaking industries to deregulate in order to allow these industries to absorb market prices to gain access to new gas supplies.

Initial Private Market Penetration

Private gas suppliers have had very little trouble finding willing buyers in India and it appears that the growth in the size of this market could remain supply limited for some time. In February of 2005, Petronet managing director, Suresh Mathur boasted, "We have orders for the entire 5 million tons of production and there's appetite to absorb five times more."[31] Petronet's recent actions seem to reinforce this claim. Petronet has been able to sell the entire extent of its gas, and has actually been forced to turn down

[28] The Hindu Business Line. "Supplies to Kawas, Gandhar projects – NTPC to ink gas deal with Reliance by next week." March 29, 2005.
<http://www.thehindubusinessline.com/2005/03/30/stories/2005033001680200.htm>
[29] The Hindu Business Line. "Shell to pump in Rs 3,000 cr for Hazira terminal." May 18, 2005
<http://www.thehindubusinessline.com/2005/05/18/stories/2005051801380700.htm>
[30] The Hindu Business Line. "GSPC deal with GAIL for regasified LNG." February 9, 2004.
<http://www.gspcgroup.com/gspcgroup/hbl020904.html>
[31] Express India. "Economic Growth May Double LNG Imports by 2007." February 14, 2005. Available at: http://expressindia.com/budget/05/fullstory.php?content_id=82662

major potential purchasers.[32] After only a few months of operating the Dahej facility, the company has floated an international engineering, procurement, and construction contract (EPC) for both doubling capacity at the Dahej terminal and the greenfield construction of a new terminal in Kochi.[33]

Based on the characteristics of the Indian gas market, it might be expected that the first adopters of private natural gas would be industries that don't receive priority gas supplies, or priority consumers whose supplies have dried up. These are the end users who experience the major gas shortages who would be expected to pay for expensive gas in lieu of no gas at all. Beyond these consumers, private gas should be able to target consumers willing to pay a premium for the extra reliability and/or short-term contractual terms that private gas is able to provide. The last adopters would likely be industries that currently cannot afford market priced gas, but might eventually be able to enter into the private market.

After a little over a year of operation, most of the private gas has been consumed by industries within this first two categories. Non-priority industries such as steel, glass, and petrochemical manufacturing, as well as gas-deplete electricity generators, have eagerly purchased private gas. At the same time, the major electricity and fertilizer producers in the country have been reluctant to pay for such highly priced gas. The largest single customer of LNG so far has been the Gujarat State Petroleum Corporation (GSPC), a gas distribution company in Gujarat. Petronet's offtakers have signed contracts to supply a total of 6.25 mmscmd (31% of Petronet's supply) phased in through 2005.[34] Shell has signed a 210-day contract for the supply of 0.7 mmscmd and has been in talks with GSPC to purchase the terminal's full capacity. Currently over a third of GSPC's gas comes from LNG and is expected to expand as additional supplies become available. GSPC's customer base spans a range of industries as summarized in Figure 3.

[32] The Economic Times, "Petronet LNG declines gas supply to NTPC." April 24, 2005. <http://economictimes.indiatimes.com/articleshow/638075.cms>

[33] The Hindu Business Line. "Petronet LNG Pre-qualifies four foreign cos for Kochi terminal." May 25, 2005. <http://www.thehindubusinessline.com/2005/05/26/stories/2005052600520700.htm>

[34] Gujarat State Petroleum Corporation, *Annual Report 2003-04.*

Figure 3: GSPC Customer Base

Electricity

Ahmedabad Electricity Company
Gujarat Industries Power Company Ltd.
Gujarat State Energy Generation
Gujarat Electricity Board
Essar Power
Gujarat Paguthan Energy Corporation

Fertilizer

Gujarat Narmada Valley Fertilizers Co.
Gujarat State Fertilizer Company
KRIBHCO

Industrial

Gujarat Adani Energy
Gujarat Alkalies and Chemicals
Arvind Group
Essar Steel
Gujarat Gas Company
Videocon International

Source: GSPC, http://www.gujaratpetro.com/

Non-priority industries have shown a strong interest in LNG. Essar Steel has entered into a contract to purchase 1 mmscmd of regasified LNG from BPCL and is in talks to purchase an equity stake in the Shell Hazira port as well.[35] Steel Authority India Limited (SAIL) has negotiated the purchase of 3.56 mmscmd of regasified LNG from GAIL beginning in 2006-07.[36] Other offtakers include Haryana Sheet Glass, Indian Petrochemicals Corp. Ltd., and Maruti Udyog, India's largest automobile manufacturer.[37]

While there are some electricity and fertilizer consumers, many these facilities have turned to LNG because subsidized gas supplies have become unavailable. For example, with the arrival of new LNG supplies, the Ahmedabad Electricity Company is able to operate its 100 MW gas plant that has been closed for nearly three years due to gas shortages.[38] The Gujarat Industries Power Company Ltd is purchasing LNG to make up for supply shortfalls that have forced its 165 and 145 MW units to operate at low plant load factors and use expensive and inefficient naphtha as an alternative feedstock.[39]

Clearly there is a latent demand for natural gas in India even at prices considerably higher than those provided by government managed suppliers. Although the exact magnitude of demand from these niche consumers is unclear, at some point, private

[35] Financial Express. "LNG Demand Boom: Petronet Resorts to Spot Market." February 24, 2004. <http://www.financialexpress.com/fe_full_story.php?content_id=53380>

[36] The Hindu. "SAIL inks gas supply pact with GAIL." February 11, 2005. <http://www.hindu.com/2005/02/11/stories/2005021104491600.htm>

[37] The Hindu Business Line, "Dahej-Uran gas pipeline EPC tendering in a fortnight." February 9th, 2004. <http://www.blonnet.com/2004/02/10/stories/2004021000300300.htm>

[38] Project Monitor. "GSPC to have gas distribution to industrial units in Central Gujarat." June 4, 2005. <http://www.projectsmonitor.com/detailnews.asp?newsid=7831>

[39] Gujarat Industries Power Corporation Ltd. "Investor Information, April 4, 2005." <http://www.gipcl.com/invest.html>

supplies will exceed this demand and growth in the private market will shift from being limited by supply to being limited by demand.

REMAINING CHALLENGES FOR THE PRIVATE MARKET

Ultimately, the success of the hybrid gas market structure as a transitional strategy to complete deregulation will be evaluated by its ability to transition electricity and fertilizer producers from the subsidized to the private market. These two industries make up the bulk of the natural gas demand and are accustomed to priority gas allocations and subsidized prices. Most importantly, these offtakers will have a difficult time absorbing higher priced gas because their products are sold at government controlled rates. An examination of these two industries and their potential to consume private gas follows.

Fertilizer Producers: Existing Market and Regulatory Structure

The fertilizer industry is the second largest off-taker of natural gas in India, consuming 7.9 bcm (21.6 mmscmd) in 2003-04, equivalent to 26% of the national total.[40] Within the industry, the majority of this consumption comes from nitrogenous fertilizer producers, most specifically urea producers. As of March 31, 2004, India had an installed nitrogen capacity of 119.98 lakh (100,000) MT which, combined with a phosphatic capacity of 54.20 lakh MT, makes India the third largest fertilizer producer in the world.[41]

Fertilizers in India have historically been under central government control through a policy known as the Retention Pricing Scheme (RPS), enacted in 1977. Under the RPS, fertilizer prices to farmers were held at artificially low levels, while producers were able to recover their full costs through direct government payments. Producers were guaranteed to recover full costs and a 12% post-tax return based on unit-specific input and financial parameters. The unit-specific production cost is termed the "retention price." The central government provided the difference between the artificially low fertilizer prices and this retention price. This cost-plus, high growth policy has made India completely self-sufficient in urea production.

The magnitude of these subsidies is a huge financial drain on the central government. Despite decontrol of phosphatic (P) and potassic (K) fertilizers in 1992, the magnitude of fertilizer subsidies has continued to grow. This has been caused by an increased reliance on subsidized urea relative to P and K inputs and a shortage of gas supplies that has forced producers to use less efficient and more expensive feedstocks. In 2004-05, this direct urea subsidy topped $2.9 billion.[42]

Currently about 60% of urea production in the country uses natural gas as a feedstock; 30% use naphtha, and the remainder fuel oil/low sulfur heavy stock (LSHS).[43] Natural gas is the most efficient of these fuels and is generally preferred internationally for fertilizer production. From 1998 to 2004, naphtha prices in the country more than doubled to over $6/mmbtu, making it more expensive than private gas currently being

[40] Ministry of Petroleum and Natural Gas, *supra* note 2.
[41] Department of Fertilizers, *Annual Report 2003-04*.
[42] Ministry of Finance, Government of India. *Central Government Subsidies in India*. December 2004.
[43] Department of Fertilizers, *supra* note 41. Fuel oil and LSHS are generally used as reserve feedstocks while natural gas and naphtha are the more commonly used primary fuels.

sold in India.[44] Due to natural gas' superiority as a feedstock and its lower cost, the Indian central government has enacted a number of policies to encourage producers to shift to exclusive use of natural gas.

In 2003, the government eliminated the RPS and introduced the New Pricing Scheme (NPS). Under this policy, urea producers are placed in groups based on feedstock and vintage. These groups are pre-1992 natural gas, post-1992 natural gas, pre-1992 naphtha, post-1992 naphtha, fuel oil/LSHS, and mixed units that are essentially gas based but use more than 25% alternative feedstocks. Producers receive the weighted average retention price of their group or their unit specific price, whichever is lower. Outliers with a retention price more than 20% above the group average receive the group average plus 50% of the difference.[45] The Department of Fertilizers is expected to recommend further reforms in 2006 based on the experience of the NPS.[46]

The Hybrid Market and Fertilizer Sector Reform

There are two main obstacles to large scale adoption of private gas from the fertilizer sector. The initial problem is that the structure of the NPS discourages use of LNG, even though it is cheaper than naphtha. Beyond the regulatory hurdles, private gas supplies in India are probably too expensive to allow producers to compete with imported urea. Ultimately, urea prices must be raised to market levels for fertilizer producers to be able to purchase private gas supplies.

Discouragement from the NPS

Many fertilizer units are designed to operate with either naphtha or natural gas. The Ministry of Chemicals and Fertilizers estimates that current consumption is 20.50 mmscmd against a demand of 32.79 mmscmd, implying a supply gap 12.29 mmscmd.[47] The central government has tried to encourage naphtha plants to shift to natural gas in order to improve the efficiency of the sector and reduce the subsidy burden caused by fertilizer produced from expensive naphtha.

The major obstacle to adoption of private gas among fertilizer producers is that the NPS doesn't allow private gas to compete on price with naphtha. Instead, the NPS forces private gas to compete with subsidized gas by placing manufacturing facilities that operate on either source into the same group. Consider the disadvantage this confers on any fertilizer producer considering purchasing private gas. The Department of Fertilizers estimates that subsidized natural gas makes up 60% of the total operating cost of a urea plant.[48] Assuming a subsidized delivered price of $2.76/mmbtu against a delivered private price of $4.83/mmbtu, purchasing private gas would increase production costs by 42%.[49] As these producers would only receive the average retention price of subsidized gas producers, private gas will clearly be unable to compete.

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[44] Ministry of Petroleum and Natural Gas, *supra* note 2.
[45] This outlier clause was supposed to expire in 2004 but has been extended to 2006.
[46] Department of Fertilizers, *supra* note 41.
[47] Standing Committee on Chemicals and Fertilizers, Department of Fertilizers, Ministry of Chemicals and Fertilizers. *Second Report: Demands for Grants* (2004-2005).
[48] Department of Fertilizers, *supra* note 41.
[49] Assumes domestic price of $1.81 and a market price of $3.66/mmbtu, plus 12% Gujarat state sales tax, and $0.73/mmbtu GAIL transport charge.

The fertilizer industry has called upon the central government to develop a system for urea producers to purchase LNG. As of May 2005, a decision was still pending. There are a few possibilities for how the government could change the existing regulatory structure. The first would be to subsidize private gas supplies to fertilizer producers. A second is to create a seventh group within the NPS for private gas purchasers. A third would be to allow private gas to compete with naphtha. Finally, the government could do nothing.

Under the first two scenarios, the central government would absorb the extra cost of private gas. In the first case this would basically amount to a direct payment. In the second, the government would absorb the extra cost through an increased urea subsidy burden because the NPS still allows producers to pass through increased costs to the central government.

Such policies might make sense if the government was most interested in increasing domestic fertilizer production as they would eliminate the gas supply ceiling that has limited growth in the industry since 2000. However, India is already self-sufficient in urea production. In addition, supplies are expected to increase dramatically over the next few years as joint venture production facilities set up by Indian fertilizer companies in gas-rich countries come online. One such facility, operated by the Oman-India Fertilizer Company in Oman, has a production capacity of 1.652 million tonnes of urea, about 14% of India's current installed capacity. It is expected to commence supplies to India in July of 2005.[50] Other projects are being explored in the United Arab Emirates and Iran.[51]

The third policy might simply add market-priced gas units into the two naphtha NPS groups. Under this policy the government could avoid subsidizing the gas and simply let LNG-based units outcompete the existing naphtha ones. In most cases, because units are set up to run on both gas and naphtha, this would simply cause existing facilities to switch to the cheaper fuel. This would also avoid overproduction, allow market forces to determine gas allocations, and improve the efficiency of the sector by shifting it to natural gas.

The absence of any policy on the new private gas would maintain the (failing) status quo. Dwindling subsidized gas supplies will continue to shift the industry to expensive naphtha, and increase the central government's subsidy burden. Furthermore, rather than transitioning the production fleet to the internationally preferred feedstock, natural gas, the sector would become increasingly reliant on naphtha.

An inter-Ministerial group headed by the Finance Minister deferred the LNG pricing decision to the Tariff Commission in July of 2004. Recommendations from the commission are still pending, but will clearly have a huge impact on the adoption of private gas by fertilizer producers.

Gas Prices Too High for Long Term Growth

Although private gas could economically displace naphtha at current market prices, it is probably too expensive to expand much beyond this niche in the urea market. Although gas prices could fall as more supplies come online, ultimately urea prices in the

[50] Department of Fertilizers, *supra* note 41.
[51] Department of Fertilizers, *supra* note 41.

country need to reach market levels for producers to be able to purchase the more expensive gas.

Gas prices in the country are relatively high because most of the private gas currently available is from LNG. Petronet purchases from RasGas at $2.53/mmbtu, and after considering transport charges, regasification fees, and taxes, the gas is too expensive to compete in the urea industry. India would instead be much better off by importing fertilizer produced in gas-rich countries where the gas feedstock is very cheap. The joint venture projects in Oman, the United Arab Emirates, and Iran mentioned in the previous section are clearly a good start in this direction and the central government maintains a policy of encouraging such joint ventures. In addition, private domestic gas should be able to sell at lower prices, and as major supplies from the Krishna Godavari basin come online by 2008, there is the possibility for this gas to find a buyer in the fertilizer industry.

Gas prices are also too high for fertilizer producers because the market in India today is clearly a seller's market. The country has been starved of gas for years and marketers of Petronet's gas have actually had to turn customers away because they simply have no more gas to sell.[52] Clearly these producers have little incentive to lower their prices. As new supplies come online from domestic fields, international pipelines and LNG, they should help shift the balance of supply and demand and possibly reduce prices.

Before the urea industry can competitively purchase privately priced gas, fertilizer prices in the country must move towards market levels. As of May 2005, prices paid by farmers remains at Rs. 4,830(US$110)/tonne, less than half the international rate.[53] Because urea subsidies are paid based on the final cost of production, an increase in the cost of inputs like natural gas will simply be passed through to the central government in the form of an increased subsidy payment. Instead, the increased cost of natural gas must be offset by increasing the price fertilizer producers are able to charge for their product.

The dynamic of increasingly abundant supplies in the private gas market along with diminishing supplies in the subsidized market gives the urea industry a strong incentive to join the private market or risk a supply shortfall. But before these producers can pay market prices for gas, they must be able to receive market prices for their produced urea. Thus, the future of the urea industry in the private gas market will be dependent on the government's ability to muster the political will to allow urea prices to reach market levels. For a country in which agriculture contributes one-third of GDP and sustains two-thirds of the population, this obstacle remains formidable.[54]

Electricity Generators: Existing Market and Regulatory Structure

Like the urea industry, the electricity industry will have a difficult time absorbing privately priced gas because it is unable to charge market rates for its product. However, this problem is exacerbated in the electricity sector because whereas urea producers use expensive naphtha as an alternative fuel, electricity generators have coal as a cheap and

[52] The Economic Times, *supra* note 32.
[53] Department of Fertilizers, *supra* note 41.
[54] Tongia, Rahul: Program on Energy and Sustainable Development. *The Political Economy of Indian Power Sector Reforms* (2003).

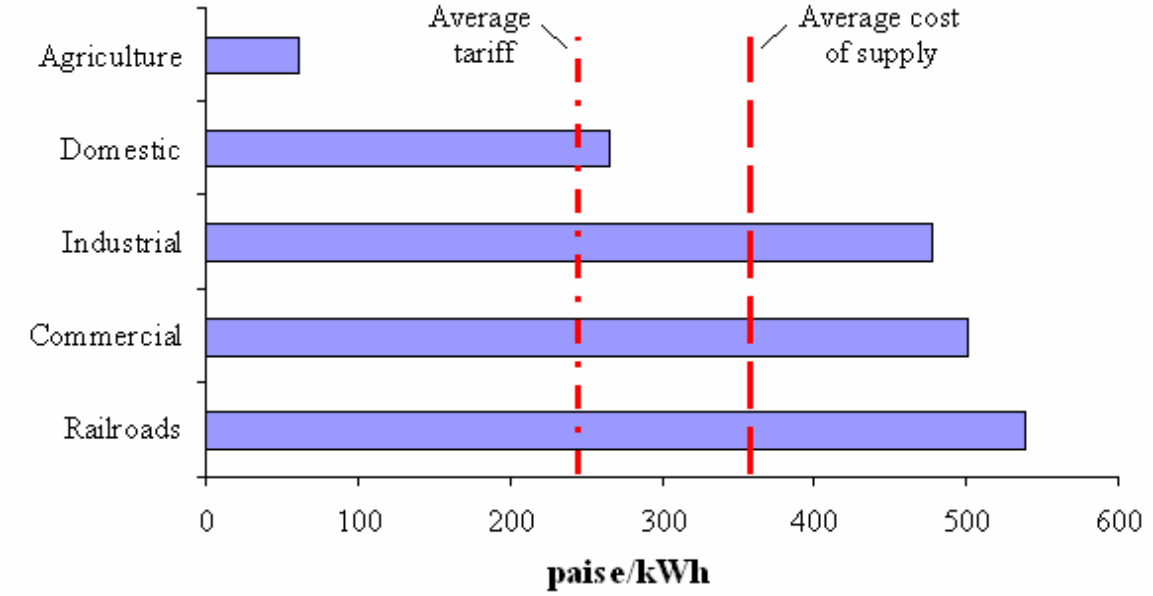
relatively abundant alternative. As a result, there are likely to be limited applications for private gas in India in the short-term, while the long-term viability of market priced gas seems to be dependent on both the dynamics of coal and electricity tariff reform.

The electricity sector in India has historically been organized at the state level through vertically integrated utilities known as State Electricity Boards (SEBs). The central government also owns generating companies that sell electricity to the SEBs.[55] The individual states set electricity tariffs and as such rates are subject to local political considerations. As a result, tariffs have historically not been sufficient to cover the cost of supply and the SEBs as a whole operate at considerable losses. This debt is largely assumed by the central government and exceeded 1% of GDP in 2003.[56] The SEBs' inability to recover costs through tariffs has been worsening in recent years, declining from 82.2% cost recovery in 1992-93 to 68.6% in 2001-02.[57]

The politicization of the SEBs has created a customer tariff structure that is essentially the mirror image of what is seen in most developed countries. Agricultural and residential consumers are charged tariffs considerably below the cost of production, while industrial and commercial users are charged high prices to try to make up this shortfall. Figure 4 provides a summary of the electricity prices charged by end users in Gujarat, the major gas consuming state. As the figure shows, agricultural and domestic consumers are charged well below the cost of supply, and the high tariffs paid by other consumers is unable to make up the revenue shortfall, leaving the average tariff well below the average cost of supply.

[55] The major natural gas consumer within the central government owned companies is the National Thermal Power Corporation (NTPC), which operates 7 natural gas plants.
[56] Tongia, Rahul, *supra* note 54.
[57] Government of India, Planning Commission. *Annual Report on the Working of State Electricity Boards & Electricity Departments*, (2001-02).

Figure 4: Electricity Tariff By Customer in Gujarat (2002)



Source: Planning Commission, Annual Report on the Working of State Electricity Boards & Electricity Departments (2001-02).

As of January 31, 2003, India had an installed generating capacity of 107.5 GW, but output remains well below demand. In 2003, total generation fell short of demand by 9%, while the peak capacity deficit was over 12%.[58] The countrywide plant load factor is a mere 71.7 %, though this figure has steadily increased from 63% in 1995-96.[59] The Ministry of Power is targeting aggressive growth in new capacity through 2012, with a hoped 100 GW new capacity added between 2002-2012.

In 1991, generation was opened up to private participation. India's experience with independent power producers (IPPs) has attracted limited private investment as investors remain reluctant to finance new projects because of the perceived risk of non-payment from the financially weak SEBs. Ironically, despite the perception that private investment in generation capacity would address India's supply shortfall, public sector generation capacity actually grew twice as fast as private during the 1990s.[60] A breakdown of the generation capacity by ownership is provided in Table 2.

[58] Ministry of Power, *Annual Report 2002-03.*
[59] *Ibid*.
[60] Tongia, Rahul, *supra* note 54.

Table 2: Installed Generating Capacity in India (Jan. 31, 2003)

	Natural Gas Capacity	% natural gas	Coal Capacity	% coal	Total Capacity	% of total
Central	4,419	13%	22,628	69%	32,816	31%
State	2,982	5%	36,512	58%	63,067	59%
Private	4,160	36%	4,661	40%	11,650	11%
Total	**11,561**	**11%**	**63,801**	**59%**	**107,533**	

Source: Ministry of Power, Annual Report 2002-03

First Adopters of Private Gas: CPPs and IPPs

Much like the niche gas markets that absorbed the first quantities of private gas in the Indian economy, the first adopters of private gas in the electricity sector are likely to be isolated niches. These should include users who place a high value on the contractual terms of private gas and units that are able to absorb higher costs. The remaining market will be conventional electricity generators where the high price of private gas will remain a challenge in the absence of electricity sector reform.

As was mentioned previously, the first electricity generator customers of private gas were units whose assets had become stranded due to dried up subsidized gas supplies. In addition, like in the urea sector, there is the potential to displace some generating capacity operating on expensive naphtha. But the size of these markets is limited and the long-term potential of private gas for electricity generation will depend on its ability to spur new investment in gas generating capacity.

Captive power producers (CPPs) are likely to be among the first electricity generator customers of private gas. CPPs are basically generating units set up at an industrial facility for onsite consumption. In 2002, these facilities made up 13.5% of all generating capacity in India and over 20% of the capacity in Gujarat, where LNG and other private gas supplies are available.[61] In a study of the CPPs in Gujarat, Shukla et. al. identify four major drivers of the growth in captive generation. They are (1) the non-availability of power, (2) poor quality grid electricity, (3) high industrial tariffs, and (4) additional benefits from captive generation, such as combined heat and power.[62] Private natural gas supplies should be able to capitalize on some of these drivers.

On the question of non-availability of power, private gas supplies have the advantage of improving reliability of supply through a supply-or-pay clause in gas purchase agreements. These contracts will minimize the fuel supply disruptions that have closed down or forced fuel switching in many plants and possibly help attract investment to the sector by minimizing the fuel supply risk. Also important is that the availability of power has been declining in India over the past five years, increasing the value of back-up power supplies. The total generation gap has risen from 5.9% in 1998-99 to 9.1% in 2002-03. Over the same time frame, peak supply has fallen short of demand by a consistent 11-13%.[63]

[61] P.R. Shukla, et. al. *Electricity Reforms in India: Firm Choices and Emerging Generation Markets* (2004).
[62] *Ibid*.
[63] Ministry of Power, *supra* note 58.

From a cost of supply standpoint, CPPs are likely to be the first adopters of market priced gas because they have the lowest opportunity cost for switching. Industrial tariffs increased by over 40% from 1997-2002 and remain nearly double the average tariff in Gujarat.[64] This 476 paise/kWh (10.9 cents/kWh) tariff is considerably higher than the 230–330 paise/kWh (5.3–7.7 cents/kWh) generation cost range observed in existing CPP gas units operating on subsidized gas throughout Gujarat.[65] It would seem unlikely that private natural gas would produce electricity at rates higher than 10.9 cents/kWh, but even if some facilities did have higher costs, they would likely only be marginally more expensive than purchasing grid electricity. In addition, from an investment perspective, CPPs are a safer bet in electricity generation because the electricity is purchased by an onsite industry rather than the risky SEBs.

In addition, electricity is only one component of the cost structure of a CPP industrial unit, making cost increases easier to bear. Consider two hypothetical gas plants, one a CPP and the other an IPP. Assume electricity costs make up X% of the total facility cost for the CPP and that private gas increases the delivered cost of electricity by Y%. For the CPP, total costs will increase by X% * Y%, while total costs for the IPP will increase by Y%. Since X < 1, the CPP's total cost will be impacted less than the IPP and should be better able to accommodate price increases.

There has been limited CPP uptake of private gas supplies so far, but Essar Power has shown strong interest. The company is constructing a 125 MW captive gas plant using LNG feedstock for a petroleum refinery in Gujarat to open in November of 2005.[66] In addition, Essar Power has expressed interest in sourcing LNG for expansion of its 515 MW captive plant that provides electricity to Essar Steel and sells the remainder to the Gujarat SEB. It remains to be seen whether these facilities are the precursor to significant CPP adoption of private gas or just isolated interest.

The increased reliability of private gas could also spark new investment in IPPs by reducing fuel risk and helping to increase plant load factors (PLFs). The increased PLF is important not only because of the increased revenue stream, but because many of the IPP contracts in India are designed to provide significant financial incentives for PLFs above the contracted baseline.[67] In addition, in the event of a gas shortage these facilities are subject to dispatch restrictions from the SEBs that can prevent firing with expensive alternative fuels. Private natural gas supplies should help to reduce these investment uncertainties and make IPPs a more profitable investment.

The Private Gas Market and Utility Electricity Consumption

The utility generation market might be the most challenging hurdle for private gas. However, the Electricity Act of 2003 introduces a number of welcome reforms to help depoliticize the sector. It calls for the unbundling of the SEBs, open access to transmission infrastructure, and delegates rationalization of the tariff structure to the

[64] Government of India, Planning Commission, *supra* note 57.
[65] Shukla *et al.*, *supra* note 61 & Government of India, Planning Commission, *supra* note 57.
[66] The Essar Group, Power. "Essar Power to Set Up Vadinar plant by Nov." Press Release May 11, 2005. <http://www.essar.com/power/news/2005_05_11.htm>
[67] For example, the Spectrum Power Generation IPP contract, established a 68.5% PLF as the baseline. For 68.5% < PLF < 80.5%, the company was guaranteed a 0.4% increase in return on equity (ROE) for every 1% increase in PLF above 68.5%. For 80.5% < PLF < 85.5%, the increase raised to 0.5% and for PLF > 85.5% there is a 6% increase in ROE for every 1% increase in PLF above 68.5%.

Central Electricity Regulatory Commission. These regulatory changes, if implemented successfully, will help to make private gas supplies much more viable for electricity generators.

The availability of cheap coal as a generation fuel alternative along with the lingering financial uncertainty of the SEBs will make the utility generation market very difficult for expensive gas supplies to penetrate. However, reforms like the Electricity Act of 2003 will help to increase access to the grid for private players and should help to shift the industry towards more private participation. These reforms, along with the need for dramatic new investment in electricity generation over the coming decade, create the potential for private natural gas to penetrate into electricity utility generation.

India is the third largest coal producing country in the world, with production of 367 million tonnes in 2003.[68] 95% of domestic production comes from the state-owned Coal India Limited. India's coal reserves are primarily found in the eastern region of the country, far away from the major demand centers in the west. It generally has a very high (40-45%) ash content and is transported primarily by rail. However, due to railway bottlenecks and high transportation costs, India has been a net coal importer since 1985.[69] As of 2000, coal prices in the country were decontrolled, and in 2004 import duties on non-coking coal were lowered to allow import of coal for power generation.

Electricity from coal is very cheap in India, with national average cost of 105 paise/kWh (2.4 cents/kWh) in 2002.[70] However, supply bottlenecks have slowed the growth in coal capacity in recent years and subjected generators to frequent supply disruptions. The construction of interstate transmission capacity in India in the next few years will help expand the market for coal by creating a market for pithead coal generation. Current interstate transmission capacity is 8,000 MW and is projected to reach 23,000 MW by 2007.[71] As power trading and interstate transmission continue to develop, pithead coal could avoid many of the bottlenecks that have plagued the coal industry and bring cheap and abundant power to market.

In order to remain competitive with coal, NTPC has identified $3/mmbtu as the benchmark for new natural gas generation capacity. Such low prices in the private market were proven to be technically feasible when NTPC sign its contract with Reliance for 13 mmscmd at $2.97/mmbtu. The gas will supply NTPC's expansion of its Kawas and Gandhar plants in Gujarat from 350 to 1,300 MW each. However, as mentioned previously, this contract is likely the floor price for private gas supplies in India as it was for such a huge quantity of Reliance's production and provided the offtake guarantee Reliance needed to begin developing the gas field.

While there may be the potential to deliver other gas supplies to electricity generators at costs near $3/mmbtu, the market doesn't appear likely to provide at such a low price. The LNG suppliers have thus far had no trouble at all selling gas at close to $5/mmbtu, and until demand begins to taper off they are unlikely to lower their prices. A showdown between NTPC and the suppliers from the Panna-Mukta & Tapti fields will be very informative as to the size of demand for this new private market. NTPC is one of the major purchasers of PMT gas and has refused to pay the $3.86/mmbtu being charged for

[68] BP Statistical Review of World Energy, 2004.
[69] *Ibid*.
[70] Government of India, Planning Commission, *supra* note 57.
[71] Ministry of Power, *supra* note 58.

the gas as of April 1, 2005. GAIL, the marketer of this gas, is attempting to find other potential buyers in the event that NTPC continues to hold out. If GAIL succeeds in finding willing buyers for the gas, it is unlikely that private suppliers will look to lower prices anytime soon.

As with the fertilizer producers, the main obstacle to electricity generator adoption of private gas is the generators' ability to charge market rates for their product. The Planning Commission estimates that the SEBs' rate of return on capital is -33% with the central government subsidy and a dismal –44% without this subsidy. It estimates that electricity rates will need to rise on average 110 paise/kWh from a current level of 240 paise/kWh in order for the SEBs to simply break even.[72] As Figure 4 indicated, this price increase would have to fall mainly upon would be agricultural and residential customers. In a country with a populist political system so heavily reliant on agriculture, such reforms will be very difficult to make and will determine the market penetration of private gas into the electricity sector.

CONCLUSION

Action taken by the central government in May 2005 identified the transition of electricity and fertilizer into the private gas market as the major challenge to the hybrid market. The Cabinet Committee for Economic Affairs approved a proposal to raise the price of natural gas to electricity and fertilizer producers by Rs. 350 to Rs. 3,200 (from $1.81 to $2.03/mmbtu). At the same time, it moved all other consumers into the private market, by allowing ONGC to sell to these customers at market rates. The transportation sector and very small gas consumers have been spared any price hike for 3-5 years.

The hybrid natural gas market structure in India will help facilitate the transition to decontrol of the sector and its offtaking industries. The creation of a private market solves many of the problems associated with government control of the gas sector by attracting private investment, increasing domestic gas supplies, and reducing the subsidy burden on the state-owned gas companies. In this sense, the hybrid market eliminates the rush to deregulate the sector because it allows these problems to be addressed prior to full deregulation.

This market structure is possible because of the gas shortfall in the country as well as the huge market potential a country the size of India offers. The shrinking subsidized market combined with a rapidly expanding private market creates a natural driver for offtakers to move into the private market. For heavily controlled offtakers, this creates a need for liberalization in order to be able to competitively bid for the new gas supplies. This decontrol of offtaking industries is important to ensure that uptake of private gas doesn't simply pass the extra cost on to the central government.

The first markets for this private gas are basically niche industries that fell outside the original subsidized market structure. As private gas begins to penetrate the major gas consuming industries, similar niche customers will be the first to adopt while the sector as a whole reforms to be able to accommodate the new gas supplies. Rapid transitions to the private market are prevented by limited supplies. Because private suppliers are able to find willing buyers at relatively high prices, other consuming industries like the electricity and fertilizer sectors will have to wait until additional supplies become available.

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[72] Government of India, Planning Commission, *supra* note 57.

As additional supplies come online, growth of the private market will shift from being supply limited to being limited by demand. The success of the hybrid gas market as a deregulation strategy will ultimately be evaluated by its ability to shift major offtaking industries into the private gas market. While there are signs of this transition taking place already, it will take a concerted political will to ensure that the move to liberalization continues to progress.