



Indian Downstream Natural Gas Sector

Ballooning Natural Gas Supply-Demand Deficit to Fuel LNG Imports

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Summary Opinion

- India's natural gas supply has been adversely impacted in 2011-12 due to fall in KG D6 production to 46.6 MMSCMD in H1 2011-12 from 55.9 MMSCMD in 2010-11. KG D6 production is likely to remain at subdued levels over the next couple of years, especially in comparison to the earlier anticipated production of 60-80 MMSCMD. Overall, ICRA expects domestic natural gas supplies to increase to around 153 MMSCMD by 2014-15 from 143 MMSCMD in 2010-11. The current estimate is about 22% lower than our previous estimates of 195 MMSCMD primarily due to lower KG-D6 production and delays anticipated in commissioning of KG satellite fields.
- On the demand front, despite the significantly high potential across several sectors, the realisable demand for natural gas will be a function of gas supplies in the market at reasonable price, the price competitiveness of gas as compared to alternative fuels, timely commissioning of the proposed transmission pipeline infrastructure, and regulatory initiatives in the power sector. ICRA believes that demand will increase from new customers once the bottlenecks in the trunk pipeline are cleared in the near to medium term. Overall, ICRA expects gas demand to rise to around 410 MMSCMD by 2019-20 from the actual consumption of around 177 MMSCMD in 2010-11.
- ICRA believes that India, despite the long-term contracted LNG volumes with Australia and mid-term contracts signed by GAIL, needs to secure additional supply on a long-term basis, especially in view of less-than-anticipated domestic supply and possible shortage of LNG after a couple of years. India's high reliance on LNG is expected to increase further, which will pose significant risks in a scenario of tight LNG supply demand scenario, leading to low availability and high prices of spot LNG.
- As regards gas allocation and pooling, an inter-ministerial committee has recently recommended i) preferential allotment of available domestic natural gas to core sectors, that is, fertiliser and power sectors, along with a certain amount reserved for the CGD/CNG sector, ii) cap on domestic gas allocation to certain other sectors and iii) inferred gas price to be used as benchmark for domestic gas pricing. The committee has not suggested any form of pooling at the all-India level across industries but the objective has been assumed to be served by indirect pooling at the end of consumers, with price-sensitive sectors (fertiliser/power/CGD) getting a higher share of cheaper domestic gas. ICRA believes that the policy recommendations, if accepted, will provide more clarity to gas usage mix and pricing, which in turn would help companies across industries to formulate their capital expenditure plans (capex) and future requirements of natural gas.

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- As R-LNG is an expensive fuel as compared to domestic gas and domestic/imported coal, it is critical for a power producer to tie-up domestic gas for a large share of fuel requirements. ICRA believes that the additional demand from power (about 32 MMSCMD by 2012-13) along with lower KG D6 production pose significant fuel supply risk for gas-based power producers over the medium term. However, if the recommendations of the recent Inter-Ministerial Committee are accepted and implemented by the GoI, the risk might be partly mitigated as the new power plants could get domestic gas allocation to the extent of 60-70%. ICRA expects that levelled tariff for a new gas based power plant would be competitive in comparison to those based on imported coal, if R-LNG share as percentage of total gas requirement remains about 30-40%.
- As for ICRA-rated companies in the Indian downstream natural gas sector, most of them are in the process of implementing large capex programmes, considering that the sector is viewed to have good long-term demand prospects. While the large capex is a credit concern, track record of executing projects of a similar nature, comfortable capital structure, regulated returns and steady cash flows are the mitigating factors from the rating perspective.

Table 1: ICRA's Portfolio of Rated Companies in the Downstream Natural Gas Sector

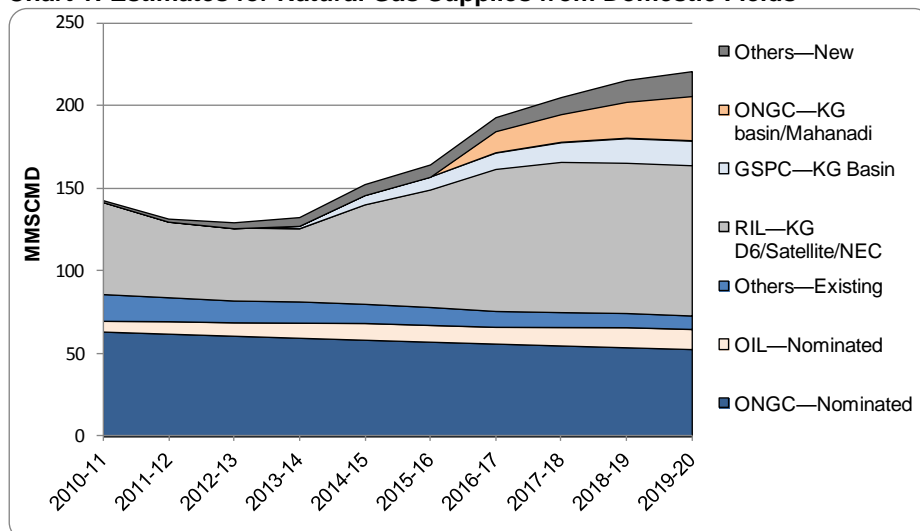
Company	Ratings Outstanding*
GAIL (India) Limited	LAAA (Stable)
Petronet LNG Limited	LAA (Stable), Ir AA (Stable) and A1+
Mahanagar Gas Limited	LAAA (Stable)
Indraprastha Gas Limited	[ICRA]AAA (Stable) and [ICRA]A1+
Sabarmati Gas Limited	LA+ (Stable) and A1+
Adani Gas Limited	LBBB+ (Stable) and A2+
Siti Energy Limited	LBB- (Stable) and A4
Saumya DSM Infratech Limited	LB+

Note: *: As on 20 October 2011

Natural gas market should continue to be in deficit in the foreseeable future due to significant growth in demand; fall in KG-D6 production to have an adverse impact on domestic supply over the medium term

India's natural gas production increased marginally by 10% to 143 MMSCMD in 2010-11 from 130 MMSCMD in 2009-10 primarily due to rise in production of RIL's D6 block in KG basin to 55.9 MMSCMD in 2010-11 from 42 MMSCMD in 2009-10. The production from KG D6 was, however, lower than the earlier envisaged production of 60-80 MMSCMD, and has fallen further to 45 MMSCMD in Q2 2011-12. Over the next couple of years, KG D6 production is likely to remain at subdued levels (around 45 MMSCMD, with further downside risks), especially in comparison to anticipated production of 80 MMSCMD. However, there would be marginal increase in supplies by other domestic sources over the medium term. Overall, ICRA expects domestic natural gas supplies to increase to around 153 MMSCMD by 2014-15 (about 22% lower from previous ICRA estimates of 195 MMSCMD primarily due to lower KG-D6 production and delays anticipated in commissioning of KG satellite fields). However, supply estimates over the longer tenure are at around 220 MMSCMD by 2019-20 (marginally lower than earlier estimate of 225 MMSCMD) on account of expected recovery in KG D6 production and increase in production from other sources. The other major sources that are likely to contribute towards supply increase include: KG basin satellite fields (owned by RIL consortium); NEC field (RIL consortium); Deen Dayal block in KG basin (GSPC consortium); KG-DWN-98/2 (ONGC); and MN-DWN-98/3 (ONGC). Further, ONGC is expected to begin gas production from several small and marginal fields given to it on nomination by the Government of India (GoI). However, ICRA does not expect significant net additions to production by ONGC from the nominated fields, given that the output from the existing fields of ONGC has been falling by 6-7% annually.

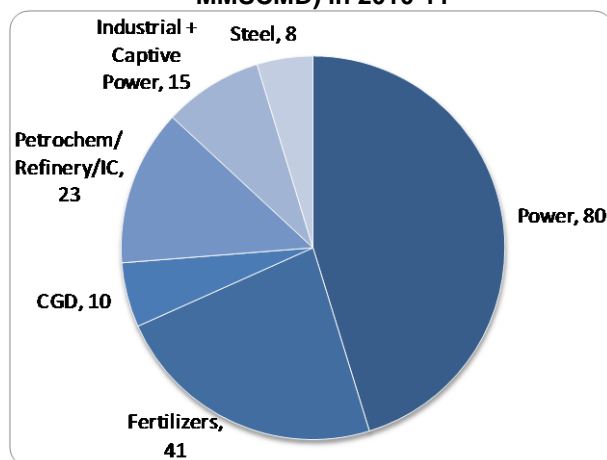
Chart 1: Estimates for Natural Gas Supplies from Domestic Fields



Source: ICRA's Estimates

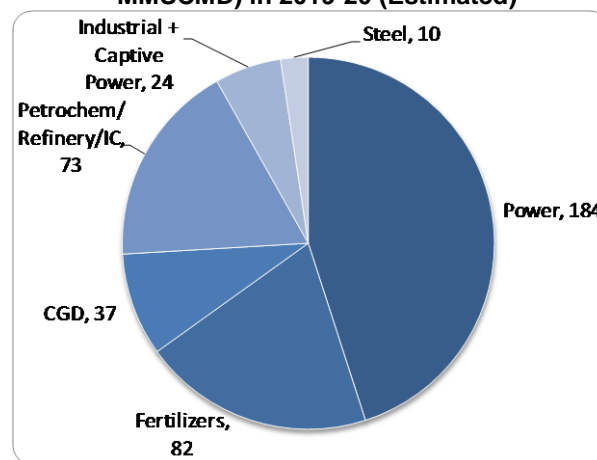
On the demand front, despite the significantly high potential across several sectors, ICRA notes that the realisable demand for natural gas will be a function of gas supplies in the market; the price competitiveness of gas as compared to alternative fuels; timely commissioning of the proposed transmission pipeline infrastructure and some regulatory initiatives in the power sector. Overall, ICRA expects gas demand to rise to around 410 MMSCMD by 2019-20 from the actual consumption of around 177 MMSCMD in 2010-11. Refer Charts 2 and 3 for the sectoral mix of gas consumption.

Chart 2: NG Consumption by Sectors (177 MMSCMD) in 2010-11



Source: Industry

Chart 3: NG Consumption by Sectors (410 MMSCMD) in 2019-20 (Estimated)



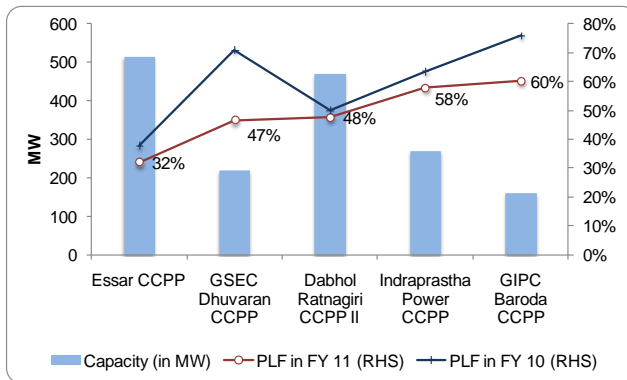
Source: ICRA's Estimates

The factors that ICRA see as driving the demand for natural gas in the various consuming sectors over the medium-to-long term are discussed in the following sections.

Power

As the cost of power from domestic natural gas is more competitive than imported coal (with landed cost of US\$ 100 per MT), several power utilities have been seeking gas allocation from GoI. According to power industry sources (such as Central Electricity Authority), gas-based power plant capacity stands at 17,706 MW as on June 30, 2011, which requires around 87 MMSCMD of NG, assuming a plant load factor (PLF) of 90%. As of now, most of the gas-based plants are operating at a much lower PLF of 70-75%, as supply of domestic gas is falling short of allotment. The shortage is predominantly on account of RIL's inability to ramp up KG-D6 production, as mentioned earlier. A few power plants are operating at even lower PLF levels (less than 60%) primarily due to shortage of domestic gas supply along with prevailing low tariffs, which restricts the higher use of costlier R-LNG. Chart 4 reflects the PLF levels of few worst-affected gas-based power plants.

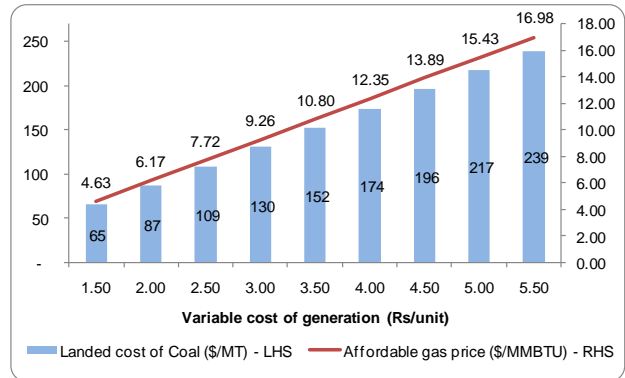
Chart 4: Few worst affected gas-based power plants



Source: Central Electricity Authority, ICRA Analysis

Note: The key assumptions for Chart 5 are: GCV for gas and coal-based power plants at 9000 Kcal/scm and 4500 Kcal/Kg, respectively; heat rate for gas and coal are based at 1800 Kcal/unit and 2300 Kcal/unit, respectively; Rs/US\$: 45

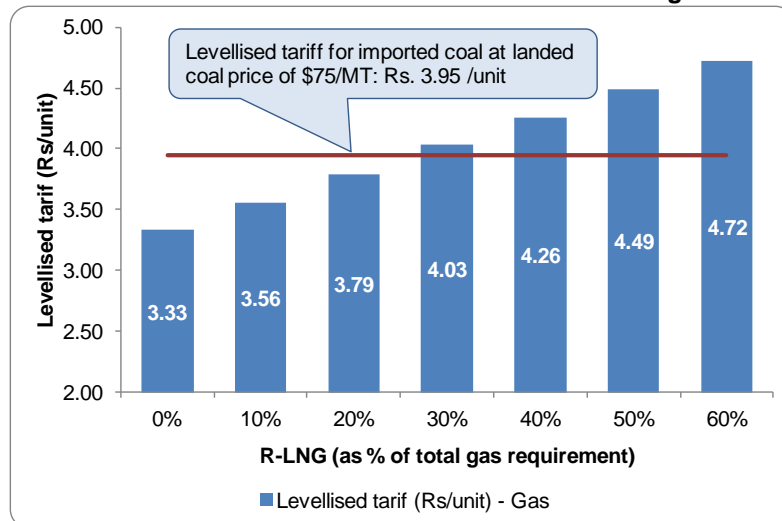
Chart 5: Affordability of Coal versus NG for power generation



Source: ICRA Analysis

Though power producers are free to use R-LNG, there is no power plant relying only on R-LNG because it is a significantly expensive fuel as compared to domestic gas and domestic/imported coal (refer to Chart 5 for comparative affordability of NG and Coal for power generation). Thus, it becomes critical for a power producer to tie-up domestic gas for a large share of fuel requirements. The situation is expected to exacerbate over the short-to-medium term, as around 8400 MW capacity addition¹ will take place by 2011-12 and early 2012-13, which would require about 32 MMSCMD of additional natural gas, assuming a modest PLF of 70%. ICRA believes that the additional demand along with lower KG D6 production pose significant fuel supply risk for gas-based power producers over the medium term. However, if the recommendations of the recent Inter-Ministerial Committee are accepted and implemented by the GoI, the risk might be partially mitigated as the new power plants to be commissioned in the medium term will get domestic gas allocation to the extent of 60%-70%. Assuming the balance requirements of gas to be met by R-LNG are sourced from the spot market, ICRA's estimates for levelised tariff for a new power plant are as follows, along with comparison of coal-based plants.

Chart 6: Power Tariffs at Various Levels of R-LNG Usage



Source: ICRA's Estimates

Note: The key assumptions for the above are: domestic gas price at 6.5 \$/mmbtu, R-LNG price at 13 \$/mmbtu; Coal Price at 75 US\$/MT, GCV for gas at 9000 Kcal/scm, Heat rate for gas-based power plant at 1800 Kcal/unit; GCV for coal at 4500 Kcal/Kg, Heat rate for coal-based power plant at 2300 Kcal/unit; capacity: 600 MW; capital cost for gas-based and coal-based plants: Rs. 4.5 Cr/MW and Rs. 5.0 Cr/MW, respectively; PLF is assumed at 80% for both gas-based and coal-based plants; Rs/US\$: 45

¹ Reliance Power's 2,400 MW Samalkot project, RVK Energy's 436 MW project, 100 MW Panduranga project, Torrent Power's 1,200 MW project and GSPC's 700 MW Pipavav power project) are expected to be commissioned in the short term.

Besides the cost advantages, there are several benefits of natural gas such as shorter gestation (for setting up a gas-based power plant); higher thermal efficiency; greater ability to meet peak load requirements and minimum greenhouse gas emissions, among others. The other key drivers of gas demand in the power sector could be distributed co-generation plants (that is, combined cooling, heating and power plants) and peaking power plants, if the enabling regulatory support like time of the day tariff regime comes through.

Fertilisers

Proposed introduction of NBS for urea should enhance the affordability of high-cost gas for existing plants; however, brownfield urea projects have failed to materialise because of concerns over gas availability, high gas prices and inadequacy of reimbursement linkage to imported urea prices: The power and fertiliser sectors (specifically the urea segment) has been accorded the highest priority in the allocation of RIL's KG D6 gas by Gol, a position which has been reiterated by the recent recommendations of an Inter-Ministerial Committee. Under the existing cost plus subsidy mechanism of urea, an increase in gas prices is a pass through, thereby facilitating absorption of high-cost R-LNG. ICRA notes that an empowered group of ministers have approved partial price decontrol and adoption of nutrient-based subsidy (NBS) for urea in the near term, while the final approval of the Cabinet Committee on Economic Affairs (CCEA) is awaited on the same. Under the aforesaid subsidy mechanism, the gas-based urea units would get a fixed subsidy under four sub-groups and gain access to gas at a uniform pooled price. The pooling mechanism would be operated by the Department of Fertilisers in such a manner that the difference between the actual weighted average gas price of individual companies and the industry pooled price would be compensated/recovered by the Gol. As a result, ICRA expects urea producers to have high ability to absorb costlier gas for their existing operations at least over the medium term.

As per ICRA's estimates, the fertiliser sector is expected to require an estimated 35 MMSCMD during the period from 2011 to 2015, with the demand coming from: (i) conversion of naphtha-based plants (8.12 MMSCMD) (ii) conversion of FO-based plants (3.75 MMSCMD) (iii) expansion and revamp projects (13.90 MMSCMD) and (iv) revival of FCI and HFC's plants (17.6 MMSCMD). ICRA notes that the demand from the first two sources is more or less certain and is expected to materialise by April 2013. However, the plans for the brownfield urea plants have not yet materialised, as the existing investment policy leads to suboptimal returns under a scenario of i) high gas prices (due to likely reliance on R-LNG) and ii) prices of imported urea ruling at the lower end of the price band². Gol is, therefore, working on modifications to the above new policy changes to propose increase in floor prices; percentage linkage with IPP and linkage to gas prices, which are expected to be announced in the near term. As per the recommendations of the Inter-Ministerial Committee, despite the anticipated gas shortages, new urea plants should get at least 75% domestic gas, with only the balance to be sourced through R-LNG which may benefit the new projects.

Chart 7: Urea Brownfield Project IRR with Landed Cost of Gas at US\$8/MMBTU

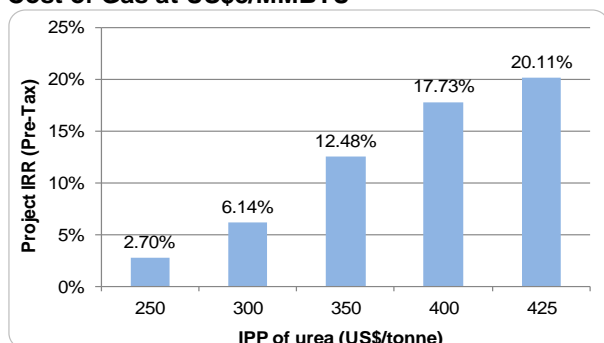
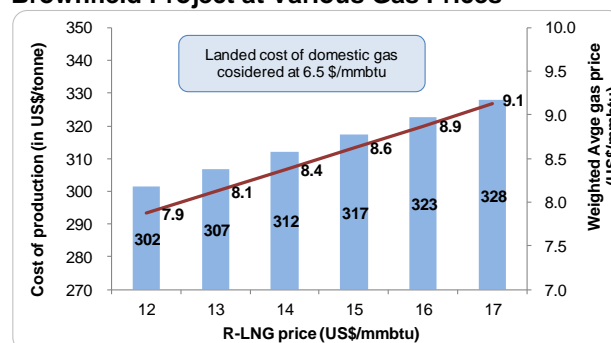


Chart 8: Cost of Production of Urea from a Brownfield Project at Various Gas Prices



Note: The key assumptions for the above are: Project cost at Rs. 42 billion for a 3,500 tpd urea plant; Energy consumption at 5.2 Gcal/tonne of urea; LCV of gas at 8,100 Kcal/m³; Rs./US\$: 45

Source: ICRA's Estimates

Assuming that the companies contemplating brownfield projects are able to contract gas at 75%:25% ratio of domestic gas: R-LNG and their respective landed costs are considered at US\$6.5/mmbtu and US\$12-17/mmbtu; cost of production of urea is expected to be as per Chart 8. Under the existing subsidy policy for

² The price band, as suggested by the current policy, is US\$250-425/tonne. According to the existing subsidy policy for brownfield projects, the total realisation has 90% linkage to the Import Parity Price (IPP), subject to a floor and cap of US\$250/tonne and US\$425/tonne, respectively. The subsidy is the difference between the total realisation and the farm gate price of urea. For total realisation, IPP is computed as the sum of the f.o.b. price and oceanic freight, without any incidental port charges.

such projects, project IRR will be as per *Chart 6*. As shown in *Chart 7*, under a scenario of weighted average landed cost of gas at US\$8/mmbtu (assuming domestic gas at US\$6.5/mmbtu and R-LNG at US\$12-13/mmbtu), the economics suffer when urea prices rule lower than US\$350/mmbtu. However, with minor modifications in policy (as anticipated by the industry), the project economics can be boosted up.

CGD, Refineries and Petrochemicals

The demand growth from refineries, petrochemicals and industrial segments is expected to remain favourable owing to replacement of liquid fuel for captive consumption or power generation by natural gas and demand from the expansion projects. It is, however, likely that consumers in these industries will have to rely largely on R-LNG, as the domestic supplies will be earmarked for the core sectors. Further, ICRA expects the prospects for the CGD business to remain good in the long term, given the under-penetration of city gas in India in the absence of adequate gas and transmission pipeline capacity. Nonetheless, the anticipated lower availability of domestic gas and higher dependence on expensive R-LNG might limit demand from sensitive segments such as PNG-domestic and CNG for diesel run buses/cars, which compete with subsidised fuels such as domestic LPG and HSD.

Improved prospects for LNG in India due to lower-than-anticipated domestic supply in the medium term and projected significant demand-supply deficit over the long term; provides scope for additional regasification terminals:

The prospects for LNG have improved over the last one year, as KG D6 production has decreased considerably and is expected to remain subdued over the medium term. Consequently, the lower domestic supply prompted consumers to increase consumption of R-LNG, which is costlier than domestic gas but still economical in comparison to liquid fuels (at prevailing high crude oil prices). Further, on transnational pipelines front, since there has not been any significant progress on the proposed Iran-Pakistan-India (IPI) pipeline and the Turkmenistan-Afghanistan-Pakistan-India (TAPI) pipeline, the incremental demand is expected to be met largely from R-LNG and hence the analysis here focusses only on opportunities in the R-LNG space in the Indian market.

For over seven years now, India has been using R-LNG and has two operational terminals at Dahej (owned by Petronet LNG Limited or PLL) and Hazira, Gujarat (owned by Shell Hazira LNG). The availability of contracted LNG has improved, following the expansion of Dahej terminal. Going forward, additional LNG will be available following expansion of the Hazira terminal; completion of the partially built terminal at Dabhol (Maharashtra) and establishment of other greenfield terminals. As for greenfield ventures, the Kochi (Kerala) terminal project by PLL would have higher capacity of 5 MMTPA in place of earlier planned capacity of 2.5 MMTPA; and is expected to get commissioned by Q3 2012-13. The other greenfield projects, namely, Mundra, Gujarat terminal (by GSPC-Adani JV) and Ennore, Tamil Nadu (by Indian Oil Corporation Ltd) are expected to be implemented in the next 4-5 years. Besides, terminals are proposed in Mangalore, Karnataka (by ONGC) and in the east coast (by PLL and IOC) although they are still in the planning stage.

A key challenge for all these new terminals, however, is their ability to tie up LNG supplies through long-term contracts at competitive prices. In the case of PLL, LNG has been tied up for 7.50 MMTPA on long-term contract for the Dahej terminal, against the terminal's nameplate capacity of 10 MMTPA; the company will use the balance capacity to regasify LNG sourced through spot, short or mid-term contracts. For the Kochi terminal, PLL has tied up to the extent of around 1.44 MMTPA on long-term contract, against the terminal's capacity of 5 MMTPA. As for Shell, it has been using its Hazira terminal exclusively for regasifying spot LNG as part of its global business strategy. For the other terminals (Dabhol, Mundra and Ennore), LNG is yet to be tied up on a long-term contract basis. Overall, the total LNG contracted on long-term basis is only 31.3 MMSCMD as on date, as against the projected cumulative capacity of 118 MMSCMD of these terminals.

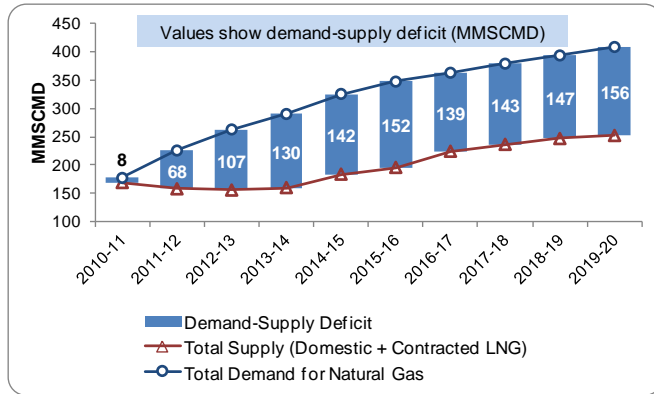
Table 2: Projected LNG Capacity in India

(in MMTPA)	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
PLL Dahej	10	10	10	10	10	10	10	10	10
PLL Kochi	0	1.25	5	5	5	5	5	5	5
Shell Hazira	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Dabhol	0	2	5	5	5	5	5	5	5
Mundra	0	0	0	0	5	5	5	5	5
Ennore	0	0	0	0	0	5	5	5	5
Total capacity	13.7	16.95	23.7	23.7	28.7	33.7	33.7	33.7	33.7
Possible supplies at 100% capacity (MMSCMD)	48.0	59.3	83.0	83.0	100.5	118.0	118.0	118.0	118.0

Source: ICRA's estimates; Note: 1 MMTPA= 3.50 MMSCMD of LNG

As reflected in *Chart 9*, ICRA's analysis indicates that there could still be fair demand for spot/short/medium term LNG, given that domestic supplies and the volume of LNG on long-term contracts may not be sufficient to meet domestic demand. *Chart 10* below compares the NG demand supply deficit with untied LNG capacity, reflecting the scope for additional regasification terminals of 5 MMTPA capacity. In line with the commissioning of Kochi (in 2012-13), Dabhol (2012-13), Mundra (2015-16) and Ennore (2016-17), the requirement of additional regasification terminals appear lower during 2012-14 and 2016-18, respectively, but increases thereafter, showing significant scope for more terminals over the longer term.

Chart 9: Estimated Demand for Additional R-LNG

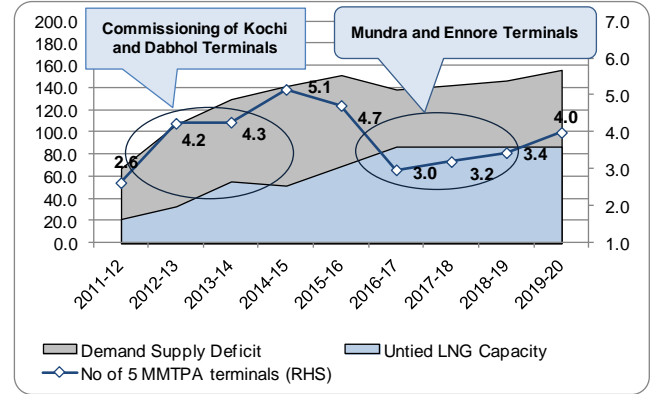


Source: ICRA's Estimates

Note: Demand Supply Deficit = Total estimated demand for gas – Supplies from domestic fields – LNG supplied through long-term contracts

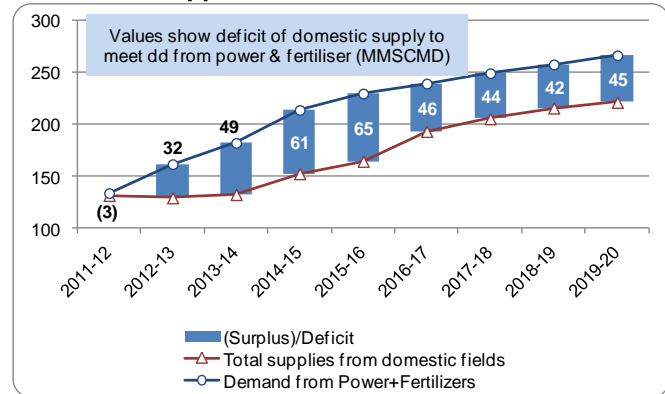
ICRA notes that the demand for R-LNG is price-sensitive and believes that domestic gas will continue to be significantly cheaper than R-LNG. Hence, domestic gas would be the first choice for price-sensitive consumers in the regulated power and fertiliser sectors. However, as domestic supplies of gas would be limited in relation to the demand from these consumers, part of the residual demand would have to be met with the more expensive R-LNG. Also, incremental demand from the other major consuming segments might be met primarily from R-LNG. A key risk to this expectation is the possibility of any further large gas discovery being made in the country. This risk would, however, be partly offset by: (i) the long lead time for commercialisation from the date of discovery, which can be anywhere from three to eight years, depending on the nature of the field, that is, onshore, shallow water, or deepwater; and (ii) the potential for additional demand for domestic gas from several power sector consumers to the extent of around 410 MMSCMD.

Chart 10: Potential for New Regasification Terminals



Source: ICRA's estimates

Chart 11: Demand from Power and Fertilisers Sectors versus Gas Supplies from Domestic Fields



Source: ICRA's estimates

In the light of the demand-supply situation anticipated, ICRA expects the prospects for third-party marketers of natural gas to be good in the long term. However, ICRA also believes that marketing margins could undergo a modest downward revision, as competition in the marketing segment intensifies with more players operating in pipeline and marketing segment.

Global LNG supply demand position is expected to tighten over the medium term, leading to higher prices; may ease by end of the current decade, following significant capacity additions during 2015-18: Global LNG market has seen supply glut over the last couple of years in line with capacity additions and muted demand growth until CY 2009; however, the scenario is set to change, as LNG demand reported a growth of over 22% in CY 2010, absorbing most of the capacity additions in the recent years. The global demand for LNG is expected to be robust (more than 12% in CY 2011 and about 6% per annum thereafter), primarily driven by traditional markets (continued economic growth in South Korea and Taiwan, higher requirements in Japan to compensate for the loss of nuclear power) and emerging countries (anticipated LNG demand growth of more than 30% for China and India in CY 2011). The other important demand driver would be LNG imports by the United Kingdom, which overtook Spain as the third largest LNG importer (after Japan and South

Korea) with 60% growth in LNG imports during Q1 CY 2011. The demand growth, however, could be partly offset by improving supply in the United States on account of development of unconventional gas resources (including large shale gas discoveries).

On the supply side, the global LNG supply is expected to increase by about 15% to around 300 MMTPA by CY 2014 from the level of 260 MMTPA in 2010; however, it will fall short of rise in demand (about 40% during 2010-14). Overall, the current LNG supply demand surplus is expected to reduce to nil or result in deficit by CY 2014 in line with significant LNG demand growth in emerging countries, the limited capacity additions in the next three years and the expected short-term shortage of LNG supply by some countries (due to technical issues or political unrests). Thus, the tightening supply demand scenario is expected to lead to higher prices for spot LNG along with the possibility of signing up long-term contracts at relatively higher crude-linked slope. Post CY 2015, the supply, however, is expected to increase considerably with about 44% rise in capacity during 2014-20, leading to total world LNG capacity of about 430 MMTPA by 2020, which should ease tightening in supply-demand situation to a certain extent.

Major countries that are expected to contribute to capacity additions are Qatar, Australia (especially during 2015-20), Angola, Algeria and Papua New Guinea. Australia is expected to overtake Qatar to become the world's largest LNG producer by the end of the current decade with increase in its LNG supply capacity from the current levels of about 20 MMTPA to 60 MMTPA by 2017 and about 100 MMTPA by 2020. On the regasification front also, capacity additions are reported to be robust with regasification capacity additions (about 90 MMTPA over 2011-15) being higher than the additions to liquefaction capacity.

ICRA believes that India, despite the long-term contracted volumes with Australia and mid-term contracts signed by GAIL, needs to secure additional supply on long-term basis, especially in view of less-than-anticipated domestic supply and possible shortage of LNG after a couple of years. India's high reliance on LNG is expected to increase further, which in the absence of long-term contracts will pose significant risks in a scenario of tight LNG supply demand scenario leading to low availability and high prices of spot LNG.

As for the prospects of Indian regasification terminal operators, their credit risk profile would be influenced largely by how the key risks involved in the business, such as LNG price risk, LNG offtake risk, LNG transportation risk, take-or-pay liabilities, and project construction risks, are addressed by their business model. If these risks are addressed adequately, the earnings would be largely predictable because regasification charges are worked out on a "normative cost plus return" basis.

Gas pooling policy suggests preference in allocation of domestic gas to core sectors and inferred price for domestic producers: The Inter-Ministerial Committee on pooling of natural gas prices (headed by Dr. Saumitra Chaudhuri, Member, Planning Commission) has recommended preferential allotment of available domestic natural gas to core sectors, that is, fertiliser and power sectors, along with a certain amount reserved for the CGD/CNG sector. The committee has not suggested any form of pooling at the all-India level across industries, but the objective has been assumed to be served by indirect pooling at the end of consumers with price-sensitive sectors (fertiliser/power/CGD) getting a higher share of cheaper domestic gas. The preferential allotment is expected to be with respect to the incremental needs of the preferred industry, rather than their existing usage. The committee suggests fertiliser and power sectors to meet a certain portion of incremental NG demand by R-LNG; the proportion of R-LNG to total requirement is recommended at 22% for the fertiliser sector and 27% for the power sector based on their current gas usage mix; projected availability of domestic gas and estimated capacity additions in the sectors. The committee has also suggested putting a cap on domestic gas allocation to certain other sectors; for example, a cap of 6 MMSCMD for CGD/CNG sector, 23.5 MMSCMD for non-priority sectors and 1 MMSCMD for other court mandated customers. Thus, all the incremental requirements of these sectors surpassing the cap will have to be met by R-LNG.

As for the pricing of domestic gas, the committee has recommended a procedure for arriving at an *inferred price* by taking the **average**³ of (i) the 12-month trailing Henry Hub price and (ii) the 12-month trailing producer net back price (computed as Japan Korea Marker (JKM) price or equivalent Asian LNG price less liquefaction and shipping charges). On the basis of this inferred price, GoI could then set a premium or a discount to maintain gas prices that are not high for consumers but at the same time are adequate for attracting investment in E&P to ensure energy security. ICRA believes that the policy recommendations, if accepted, will provide more clarity to the gas usage mix and pricing, which in turn would help companies across industries to formulate their capex plans and future requirements of natural gas. Nonetheless, domestic gas prices (such as APM, KG-D6 gas) could increase by more than 50% from the prevailing

³ The committee has suggested the average to reduce the impact of large disparity between two prices, that is, i) Henry Hub prices prevailing in the United States, the largest gas market, and currently hovering at about \$ 4-4.5 /mmbtu and ii) Asia Pacific Prices (which is highly dependent on LNG and LNG prices being traditionally linked with crude oil prices have ranged in \$ 10-14 /mmbtu over the last few months).

levels, if the recommendations are accepted, which is likely to have a cascading impact for different end users.

Significant increase in gas transmission pipeline to facilitate incremental demand; significant increase in competitive intensity in new pipeline bidding could lower the regulated returns:

India's current gas transmission pipeline length is estimated at 11,900 km (GAIL: 8000 km; GSPL: 2000 km; RGTIL: 1400 km; OIL/AGCL: 500 km), and has a capacity of 283 MMSCMD. Although the capacity *per se* appears high in relation to the current gas availability in India, several bottlenecks and disparate development in the existing pipeline infrastructure have left some potential end-users to be gas-starved. The two largest pipelines, HVJ and DVPL of GAIL (accounting for ~30 % of India's capacity), have been operating at almost full capacity in the recent past, thereby preventing any further transmission for end-users in the northern part of India. At the same time, GAIL's regional pipelines (in Gujarat, Rajasthan, Mumbai, the Cauvery basin and Assam) have been operating at sub-optimal capacity utilisation due to limited supply of gas. Further, the pipeline network in India currently covers mainly the western, central and northern parts, with the network being limited in southern and eastern India. Even within western, central and northern India, there are several cities waiting to be connected. As a result, the market has developed only in areas that are in proximity to the existing pipeline network. Going forward, ICRA expects this scenario to change, given that the incumbents have announced large projects (with an estimated capex of Rs. 500 billion) to expand their coverage. Besides, the regulator PNGRB has also called for bids for a few new pipelines in regions hitherto not served. ICRA, however, notes that progress in some of the pipeline projects has not been satisfactory, as the developers have been going slow, pending clarity on the availability of gas for these new pipelines.

ICRA notes that the natural gas transmission industry is witnessing a gradual evolution of regulations, namely, *pricing* (including change in calculation of methodology from 12% post tax RoE to 12% post tax RoCE) and *competitive bidding for award of new pipelines*. With respect to pricing, the PNGRB regulations for trunk pipeline projects, provide for a return of 12% (post tax) RoCE, on normative cost, subject to the pipelines attaining normative capacity utilisation. The change in tariff calculation methodology from RoE to RoCE has resulted in lower transmission tariffs for old pipelines due to depreciated asset base; however, the tariffs for the new pipeline are higher under the new method. Nevertheless, the key risk factor for the new pipelines would be the adequacy of gas tie-ups, which would determine their capacity utilisation. In this regard, all the three players (namely, GAIL, RGTIL and GSPL) face some risk with regard to lack of visibility or delay in gas supply tie-ups at present. Hence, the participants may not be in a position to achieve the normative returns in the initial few years, which may, however, be made up for in the subsequent years, as the volume scale-up happens.

The award of new pipelines (beyond the ongoing expansions/projects) through competitive bidding has increased the competitive intensity in the business, which should benefit the consumers through lower transmission tariff over the longer term. Among the latest bid invited by PNGRB, GSPL in consortium with IOCL (26%), HPCL(11%) and BPCL(11%) has been awarded rights to lay three pipelines (aggregate capacity 100 mmscmd) from i) Mallavaram, AP to Bhilwara; ii) Rajasthan; Mehsana, Gujarat-Bhatinda, Punjab and iii) Bhatinda-Jammu-Srinagar pipeline. The consortium is reported to have quoted aggressively to make an entry into Inter-State transmission pipeline market. Although GAIL has challenged PNGRB's above decision in the Supreme court (SC) stating that the same was not in accordance with the SC order of decision-making made by a multi-member board, the increased competitive intensity could lower the long-term growth opportunities for incumbents; moreover, the actual returns from such bidded pipeline projects could be lower than the normative parameters of PNGRB.

Table 3: New Trunk Pipelines Projects

Company	Kms
GAIL	
Dadri Bawana Nangal	594
Chainsa-Jhajjar- Gurgaon	349
Dahej-Vijaiapur-GREP Upgrade	610
Dhabol Bangalore	1414
Kochi-Mangalore-Bangalore	1126
Jagdishpur Haldia	2050
Total	6143
RGTIL	
Kakinada-Basudevpur-Howrah	928
Kakinada-Chennai	577
Chennai-Tuticorin	585
Chennai-Mangalore-Bangalore	538
Total	2628
GSPL	
Gujarat Expansion	450
Recently awarded	
GSPL-IOC-HPCL-BPCL Consortium	
Mallavaram to Bhilwara	1600
Mehsana-Bhatinda	1670
Bhatinda-Jammu-Srinagar	740
Total	4010

Source: Companies' Announcements and PNGRB

ANNEXURE**LIST OF KEY ABBREVIATIONS USED IN THE REPORT**

AGCL	Assam Gas Company Limited
BPCL	Bharat Petroleum Corporation Limited
CBM	Coal Bed Methane
CGD	City Gas Distribution
CNG	Compressed Natural Gas
FCI	Fertilizer Corporation of India Limited
FO	Fuel Oil
Gcal	Giga Calories
GNFC	Gujarat Narmada Valley Fertilisers Corporation Limited
Gol	Government of India
GSPC	Gujarat State Petroleum Corporation Limited
GSPL	Gujarat State Petronet Limited
HFC	Hindustan Fertilizer Corporation Limited
HSD	High Speed Diesel
IOC	Indian Oil Corporation Limited
KG	Krishna Godavari Basin
KRIBHCO	Krishak Bharti Co-operative
LCV	Lower Calorific Value
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MMBTU	Million Metric British Thermal Unit
MMSCMD	Million Metric Standard Cubic Metres Per Day
MN-DWN	Mahanadi deepwater basin
MOP	Ministry of Power, Gol
MoPNG	Ministry of Petroleum and Natural Gas, Gol
NEC	North Eastern Coast
NG	Natural Gas
NGO	Non Government Organisation
OIL	Oil India Limited
ONGC	Oil and Natural Gas Corporation Limited
PNG	Piped Natural Gas
PNGRB	Petroleum and Natural Gas Regulatory Board
RIL	Reliance Industries Limited
R-LNG	Regasified Liquefied Natural Gas
RoCE	Return on Capital Employed
RoE	Return on Equity
tpd	Tonnes per day

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