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Energy Security Insights

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Energy Infrastructure I

The term infrastructure in India commonly refers to the road and rail network, bridges, power plants, transmission grids, ports, and so on. Energy infrastructure could be defined as a sub-set covering refineries, oil and natural gas pipelines, both national as well as transnational, oil and gas storage, and so on.

For the past many years, the HVJ (Hazira–Vijaipur–Jagdishpur) gas pipeline has been the only inter-state transmission pipeline. It sources gas from offshore fields and supplies gas to major consumers in the western and northern parts of the country. With the new gas discoveries in the KG Basin, major transmission pipelines are being laid, not only to connect with the HVJ pipeline, but also to supply other markets. These developments will eventually lead to a national gas grid. Also, there needs to be last mile connectivity when supplying CNG (compressed natural gas) to the transport sector. In this issue of *Energy Security Insights*, Vijay Duggal has exhaustively discussed incentivizing the development of natural gas pipelines in India, addressing issues such as tariff setting, recovery of tariff, the determination of tariffs, and the regulatory regime that has been put in place but needs to be considerably expanded. In another article, C Dasgupta draws attention to the geopolitics of gas supply, particularly with regard to the Caspian region, and how the break up of the erstwhile Soviet Union is leading to a realignment of pipelines mainly to reduce dependence on Russia by virtue of it being a transit state. The article has been appropriately titled 'Aligning pipelines and politics'.

In the oil refining sector, not only in India but globally, refineries have operated very profitably at the time of high crude oil prices. With the global meltdown and crude oil prices at one-third the level that they were earlier, the profitability of the sector has considerably reduced. This makes investment in grass-roots refineries as well as improving the sophistication of existing refineries more problematic. Mahesh B Lal makes the compelling argument that, despite the financial crunch, now is the time for refineries to invest in additional facilities to enable them to process heavier crude oils, which are cheaper than the light crudes, bearing in mind the kind of global product demand as well as tighter quality specifications.

Finally, S L Rao analyses the impact of the drop in crude prices and global meltdown on financing of energy infrastructure, which requires many enabling conditions. He makes the point that provident and pension funds should be permitted to invest in energy infrastructure especially as the big players will be able to fend for themselves but the small players, who do not have a track record, will have problems in raising funds.

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Incentivizing development of natural gas pipelines in India

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It is quite ironical that although both crude oil and natural gas are born out of the same well, these fuels have absolutely different trade dynamics and yet end up competing with each other at the consumption stage. Perhaps crude oil is more of a fungible commodity (freely transportable and storable) than natural gas. Energy economists usually refer to natural gas pipeline and storage infrastructure as a 'natural monopoly' and the global gas markets are often viewed as nascent, developing, matured, and liberalized depending upon the extent and pervasiveness of infrastructure, and the extent of sophistication achieved in terms of trade and competition. Gas markets have matured with the development of infrastructure in terms of inter-connected pipelines, storage systems, and downstream network of distribution pipelines on the one hand and a movement from government control to sectoral regulatory interventions, followed by competition and liberalization on the other. While the European model (with the exception of Germany) started from infrastructure development by state-promoted gas companies, followed by their privatization leading to unbundling of monopolies and ushering of competition; the US model has always allowed private enterprise in development of gas pipelines, hubs, and storage systems before allowing competition to set in at various stages. Whereas the development of infrastructure has moved a trajectory following basic, emerging, restructuring, sub-mature, re-structuring, and mature formats; market sophistication has moved from the format of state monopoly to private monopoly, emerging (competitive), restructured, and liberalized markets. However, the deep parabolic relationships between the two have shown that no substantial gas markets have developed from fully liberalized ones. India, after more than two decades of gas supplies from fields nominated by state-controlled companies priced on APM (Administered Pricing Mechanism) basis (supplies that have largely remained stagnant, short of demand, and are also likely to dwindle fast in the medium term) and with the recent gas discoveries in the KG (Krishna–Godavari) basin, could now be classified as 'emerging in terms of infrastructure; yet caught between government/private monopolies in terms of market sophistication'.

This article deals with the principles and issues in developing natural gas pipelines from a global historical perspective. It presents a critical appraisal of the progress made by India in incentivizing the development of natural gas pipelines and eventually a gas grid, which is a pre-requisite for competitive gas markets.

Stakeholders' perspectives

In the nascent stages of gas market development, there is the need to enhance security against the risk of gas remaining stranded at the wellhead. The producer thus largely drives the development of pipeline infrastructure, and in this sense a natural monopoly becomes inevitable with the producer providing 'bundled' services in both gas transmission and distribution. It is, therefore, the absence of independent transmission and distribution risk appetites, which incentivizes a vertically integrated monopoly across the gas value chain. The consumer, though benefiting in the short term due to cost optimization (as against cost additive), is nevertheless seriously exposed to the risks of price, or discriminatory terms and conditions in the medium and long term, which could be partially driven by inefficiencies, complacency, transfer pricing amongst affiliates, and monopoly gains. The government, on the other hand, desirous of a balanced development of the economy and protection of consumer interest, usually seeks to control monopoly behaviour, before the sectoral regulator is set up

* This article has been contributed by the author in his personal capacity.

with a mandate to 'unbundle' across the gas value chain and create an environment for independent shipping interests leading to competitive gas markets.

The sophisticated form of a liberalized gas market has adequate producers, shippers, and consumers with instruments for trading in gas as a commodity, contracts for capacity booking in pipelines, and access to storage systems, with the regulator adopting a light-handed role of overseeing the market. Clearly, the Indian gas market is currently at least a decade away from achieving both infrastructure maturity and market sophistication, and needs to evolve.

Geopolitics versus development and economic principles

Geopolitics has played a critical role in the development of natural gas pipelines. The gas infrastructure in place in Italy, strong political power of ENI (Italian gas monopoly) with its vision of expanding its core competence and becoming an expert at laying deep water gas pipelines, the relatively under-developed Spanish gas market of the early 1980s, and relatively lower influence of Enargas (Spanish gas monopoly), saw the commissioning of a longer and difficult route for the Transmed pipeline from Algeria to Italy instead of the shorter offshore distance crossing by the Maghareb pipeline from Algeria to Spain. With the ongoing power struggle between technocrats (in government-controlled Sonatrach) and military (revolutionaries) in Algeria, whenever the former is in ascendance, commercial terms are followed, but otherwise supply and pricing terms for the Transmed pipeline have remained uncertain. Further, Gazprom's pipeline infrastructure in the erstwhile Soviet Union region has most often been used by Russia to extract deals from Ukraine. Closer home, geopolitics has delayed and put in jeopardy, if not caused to abandon, the TAPI (Turkmenistan–Afghanistan–Pakistan–India) and the IPI (Iran–Pakistan–India pipeline).

Very often, the development principle has been followed in designing and routing of natural gas pipelines, where bulk demand follows commissioning of spur lines along the route. The Gasbol pipeline between Bolivia and Brazil was commissioned in the 1990s when Brazil was a nascent gas market lacking investors' confidence. The pipeline was commissioned with World Bank aid on the premise that the Brazilian power market would develop thereby making gas-based power generation attractive (vis-à-vis hydropower). Also, the route of the HVJ (Hazira–Vijaipur–Jagdishpur) pipeline in India was conceived on the development principle, implying that the fertilizer plants expected to use natural gas as feedstock would be set-up closer to the agricultural markets in north and north-west India (highly dependent upon fertilizers, especially urea) thereby ensuring lower dependence on movement of fertilizers by rail and road. This pipeline has seen successive substantial capacity expansions with increase in gas demand from the power sector and additional availability of gas from the Panna–Mukta–Tapti fields.

There have been many instances where gas pipeline projects have been taken up purely on economic principles. Two long-distance gas pipelines commissioned in the 1990s in Argentina and one gas pipeline in Chile were robust projects requiring minimal support from the government and/or international financial institutions. Thus, economic considerations overtook developmental concerns in having alternative routes, which not only were grander but more risk-prone. Liberalization in gas and power markets in Argentina and Chile essentially made these pipeline projects commercially attractive. In India, the East–West gas pipeline of RIL (Reliance Industries Ltd) is another example where the economics of the gas market driven by the large discovery of gas in the KG basin guided the timing, routing, and capacity of the pipeline.

Tariff setting

A natural gas pipeline project is characterized by large upfront investments, long gestation period for commissioning, risk of low utilization, and uncertainties in take-off. The economic life associated with the production cycle of the gas field, relative economics of alternative fuels, and uncertainties due to inter-connectivity issues, too impact decisions with regard to pipeline projects. The shipper and consumer view transmission tariff as an important constituent of the delivered price of gas – constituting up to 25% of the end-price – and hence want the tariffs to be fair and reasonable. Various methodologies have been adopted in determining tariffs, taking into account economic conditions, gas availability and demand, affordability, taxation, and rate of return incentives to invest surpluses in developing national gas grids. The most prevalent methodologies of tariff determination are as follows.

Cost plus or cost of service

As the nomenclature suggests, here tariff rate is set considering a reasonable RoR (rate of return) applied on regulated asset base (RAB or capital employed consisting of normative fixed assets and normative working capital) plus efficiency-linked operating costs (including annual depreciation in the value of RAB) based on normative levels of capacity utilization. The RAB could either be based on historical capital cost, or on its replacement cost, or be adjusted for inflation. Alternatively, the RoR could be adjusted for inflation and applied on the historical cost of assets. The choice of asset base valuation is largely dependent on the accounting standards followed in the country, the inflationary trend, the level of WACC (weighted average cost of capital), beta (risk level), and the overall investment climate. As a rule of thumb, at lower levels of inflation, lower would be the RoR, and the RAB would most likely be adjusted for inflation. Alternatively, at higher levels of WACC, the rate of return would be higher owing to higher levels of beta (risk), and the RAB would be based on historical costs.

Normative levels of performance are expected to disincentivize 'gold-plating' in capex (capital expenditure), and allow opex (operating expenditure) linked to efficiency in operations and quality of service. Generally, capacity utilization standards provide for initial low levels of utilization, owing to low levels of demand and time required for stabilization of pipeline operations, incentives for above standard performance with retention of full tariff rates, and penalties for below par performance resulting in loss of tariff revenues.

Traditionally, time value of money was not reckoned in tariff setting, which resulted in unit tariff rates being higher in the initial period of the economic life of the project. These became lower over time due to the annual depreciation charge, reducing the value of RAB on which the RoR is applied. The discounted cash flow approach (which recognizes the time value of money) allows project inflows (tariff revenue) to be equated with the project outflows (capex and opex) at the desired level of RoR over the economic life of the project. The tariff revenue is the product of the resultant unit tariff rate at standard levels of capacity utilization with any incremental utilization allowed as an efficiency gain without reduction in the unit tariff rate (converse is true for below standard capacity utilization).

Tariff rate setting is generally valid for a block of time (three to five years), during which time the unit rate could either be kept uniform or be escalated annually (say, between 2% and 5%) to allow for low initial tariff rates as the demand and resultant capacity utilization generally increases with time. Any subsequent adjustment for incentives or disincentives in the tariff rates has a retrospective effect and the operator neither loses nor gains for any such adjustments. However, a significant variation for retrospective adjustment for capex or opex could result in the initial shippers gaining or losing at the cost of latter shippers. A careful and scientific assessment of levels of capex and opex, and an objective fixation of standards of capacity utilization and efficiency parameters, can help in narrowing such gaps.

Such a methodology is ideal for attracting investments in pipelines in nascent and developing natural gas markets, as the RoR is a fair way of compensating capital investments in an infrastructure project. A shipper or a consumer generally prefers a cost-plus approach for its relative transparency and fair predictability of tariffs over the economic life of pipeline project, which is essential for any long-term take-or-pay contract for booking of pipeline capacity.

However, this methodology could be criticized for possible subjectivities in either fixation of standards or in measurement of actual performance against such standards. Another ground of criticism could be that the actual project's internal RoR may either be too high or low as compared to the allowed RoR. The usual grossing-up of the RoR for the nominal rate of income tax versus allowing actual income tax as a pass-through in tariff setting is another possible ground of debate. Developed or mature gas markets have moved away from this protected or guaranteed tariff regime to other competitive tariff-setting methodologies.

Indexation

Under this system, the tariff is allowed to be fixed subject to an upper ceiling, which in turn is based on achievement of pre-set targets of performance. Such a methodology is usually followed in case of legacy situations, where a traditional tariff rate (fixed over a long period of time before the onset of revised tariff methodology) is allowed to be updated. This updation is based on neutralization of cost of inflation index subject to achievement of performance targets fixed on a scale of 1 to 10. The underlying logic being that the pipeline, having recovered returns on its investments much in excess of its initial investments, requires an incentive to operate for the remaining economic life for which no additional new investments are required. Shippers prefer this methodology as it ensures fair reward for achieving a minimum standard of service. Indexation system is an approved tariff setting basis in the UK and most of EU countries as well as under the FERC Regulations in the US.

This system is, however, not suitable for developing gas markets, as the critical focus on incentivizing investments in new pipelines is absent, and a pure performance-linked updation system is a deterrent to creation of additional capacity for future use.

Market-based rate setting

Tariff is allowed to be fixed by the entity on market-based rates in case it is established that the entity lacks significant market power. Such a system is in vogue in gas markets with mature infrastructure, and where other pipelines compete in the same gas market. It is an approved basis under the FERC Regulations in the US.

Tariff based on bidding

A common basis for tariff setting is allowing competitive bids for tariffs over the economic life of the pipeline project. The basis is fair to all stakeholders, is transparent, and allows freedom to the bidding entity to bid tariff based on its real cost of capital. An emerging gas market could also adopt such a system, provided there exists enough competition in bidding, or alternatively where a vertically integrated monopoly present in all segments of the gas value chain is made to strictly comply with the affiliate code of conduct. This is to prevent transfer pricing between affiliates or in between different segments of the gas value chain by the same entity, which indeed is a great regulatory challenge.

Recovery of tariff

The recovery of tariff of natural gas pipelines is a far more complex issue and is guided by the length of the pipeline, capacity and volumes at each tap-off, deliverable pressure, and affordability.

A postalized basis for tariff recovery implies uniform tariff across the length of the pipeline. Such a basis is simple to operate and is often used by the government to ensure balanced economic development. The system does not discriminate between customers on the basis of distance or volume. However, the customers closer to the sourcing point of the gas pipeline criticize this system since the tariff is very high, given the distance from the source point. The users closer to the source allege subsidization of users far away from the pipeline. The HVJ pipeline initially followed a postalized tariff system till the Tariff Commission updated the tariffs on a zonal-postalized basis.

A point-to-point basis of tariff recovery assumes tariff linked to distance travelled and a telescopic basis of tariff recovery implies that the tariff gets linked to volumes transported over distance travelled. A more sophisticated form of tariff recovery system is the entry load–exit load model, which has a series of zones identified on a pipeline system, each having an entry point and exit point. The tariff charged in a zone is equal to the sum of entry point charge plus an exit charge for the exit zone in the network. Such a system, in vogue in the UK and recently introduced in the Netherlands, pre-supposes a mature network of pipelines with multiple sources and destinations for natural gas.

A variant that could be tried in a rapidly emerging gas market is to have a zonal postalized basis of tariff recovery. This implies that the tariff rate for a successive tariff zone could, at best be equal to or greater than the previous tariff zone, but remains uniform within that tariff zone and has the combined advantages of both postalized and telescopic systems of tariff recovery. This variant could become a precursor to the sophisticated entry–exit tariff model, and a switch to the latter could be attempted when a complex network of pipelines (a gas grid) having multiple sources of gas and destinations, emerges.

Fundamentally, tariff recovery is a function of the maturity of infrastructure and the sophistication of the gas market. A liberalized gas market ultimately moves towards trading in tariffs, and trading also in the pipeline capacity-booking contracts.

Important issues in determination of natural gas pipeline tariffs

Capacity of natural gas pipeline

The definition of capacity in a natural gas pipeline depends upon its intended application. An appropriate definition of capacity that can be taken into consideration is the theoretical maximum quantity of gas that can be physically transported on a pipeline network over a given period of time, assuming steady conditions and as a function of pipeline diameter and operating pressure.

- Design capacity is the technical maximum available capacity, assuming maximum pressure, and uninterrupted flow.
- Operating capacity is the maximum throughput possible under normal operating conditions.
- Commercial capacity is the capacity that can be guaranteed by a pipeline operator to shippers on a contractually binding basis.
- Firm capacity is the capacity made available during the period of contract based on 'take or pay', with settlement of tariff on capacity charge irrespective of actual utilization.
- Interruptible capacity is the capacity that carries risk of curtailment under peak load conditions, with settlement of tariff at commodity charge based on actual utilization.

Experience has shown that an under-declaration of the capacity in a natural gas pipeline could set up the unit tariff rates 25% higher with the differential capacity utilization passed on as efficiency gains. This could seriously imperil the interests of initial shippers in the natural gas pipeline. On the contrary, an arbitrarily determined capacity, which is much higher than that achievable (due to lack of demand or otherwise restricted by operations) could result in severe loss of tariff revenue to the pipeline operator at a time when the loan repayments are due.

The initial actual operating conditions do impact capacity utilization, and these should be reasonably factored in the fixation of normative levels of capacity utilization. There may be instances where over- or under-provided capacity pipelines could try to pass the test of fixing of appropriate normative levels of capacity utilization. What is required is a long-term view of capacity, to be conceived for the pipeline in time zero and which provides for demand requirements over its economic life. Extra capacity could also be created later, when required, by increasing the compression capacity, or by looping and adoption of other de-bottlenecking techniques. An economic analysis at this stage would ensure an appropriate decision on creation of extra capacity in time zero or expansion in capacity later.

Compression and deliverability

Natural gas services involve the business of delivery of energy to the consumer of requisite volumes, at requisite calorific value, and at steady pressure. Therefore, a pipeline provides for compression of natural gas to meet the natural drop of pressure and also due to reduction of pressure post delivery, which is an expensive proposition, both in terms of capex and opex requirements. An ideal pipeline design must factor in the differential pressure requirements of possible customers.

A refinery requiring gas for hydrogen generation for its hydro-cracker unit has very different deliverable pressure requirements as compared to a fertilizer unit or for that matter a petrochemical plant or power plant. While a fertilizer or petrochemical plant would need to give due consideration to gas composition, a power plant would be concerned about calorific value. This requires co-mingling of gas to meet the average customer demand across the pipeline system. Normally, a customer needs to look at the delivery profile upstream of its own delivery point, as a sudden drawl or extraction of olefins may affect the pressure or gas quality. Such instances have a bearing on tariff as the make-up volumes required to reach the same level of heat value of gas would require transmission of extra molecules of gas or its compression. Therefore, it would be advisable to have the pipeline tariffs expressed in terms of potential heat value (say, in mBtu [million British thermal units] or kilocalories).

Ship-or-pay arrangements

Gas pipelines are expensive to build and equally expensive to operate. Normally, a pipeline operator expects the capacity created as a result of aggregation of potential demand to be secured in terms of long-term ship-or-pay commitments, at least to the level of the commodity charge (the part of tariff attributed to fixed costs). A matured market could possibly have the pipeline tariff split between 70%–80% over the capacity charge and the balance over commodity charge, the latter being variable and linked to the actual volumes delivered. The capacity booked may at least be equal to the volumes that are expected to be paid for the capacity charge. A pipeline operator would expect most of the capacity to be booked in advance for long-term commitments, whereas a consumer would tend to move away from giving firm commitments. This means pipeline capacity is either available on firm basis, that is, on contract carrier basis; or for booking as and when the same is available, which is common carrier basis where new capacity bookings are always accommodated by pro-rating the existing capacity bookings. Though matured gas markets, like the US, have graduated to common carriage systems, globally the system of contract carriage or its variants are still in vogue. Contracts for capacity booking could also be designed to reflect interruptibility in deliveries by the pipeline operator in order to provide for a cushion against sudden imbalances due to operational factors, which allows for some discount in the tariffs.

Access issues and imbalances in pipelines

A pipeline system is designed to handle gases of specific quality and of desired inlet pressure. A specific range is provided for in the design considering the long-term availability of gases of different qualities. Injection of a low calorific value gas or a lean gas, which is below the tolerance level, may affect the composition of gas delivered and thereby result in breach of contractual commitments. On the contrary, a high calorific value gas may require adjustments in the burner configuration at the customer-end due to flammability considerations. Pipeline operators, therefore, need to specifically define the tolerance range of gases allowed to enter the pipeline system and deny access in case of variations beyond the tolerance level. Low calorific value gases could be treated to bring them within the tolerance limits or could be injected into separate dedicated pipelines designed for their monetization. Since tariffs are generally expressed in heat value terms, an adjustment in tariff for variation in the volumes due to changes in potential heat content is allowed.

An imbalance could occur in a pipeline system when the shipper is not able to offtake the volumes injected in the pipeline, that is, the offtake is either less or more than that injected in the pipeline system. This creates a positive or negative imbalance, which is immediately sought to be cured. Variation beyond a reasonable level or an uncured position results in payment of penalties to disincentivize indiscipline. It must be ensured that such imbalances are not viewed as a potential source of revenue by the pipeline operator. Scheduling and nomination of volumes of gas to be transported in a pipeline is a complex issue and implementation of an appropriate access code, followed by an appropriate uniform contractual format, is essential to keep away from system indiscipline and possible disputes.

Expansion and extension

It is almost always economical to expand or extend an existing pipeline as compared to laying another one along the same route. Some, however, have argued against this, and the FERC (Federal Energy Regulatory Commission) has allowed more than one pipeline emanating from the same source or to the same destination, even along the same route, on the grounds of free competition. Yet most other gas markets have adopted optimization of resources, and allowed a pipeline to saturate in terms of capacity and possible extensions, on the grounds that pipelines are expensive to construct and maintain. Redundancy is avoidable and limited resources could be better utilized on some other route—an argument has merit for developing gas markets with limited resources.

A pipeline when expanded or extended generally brings down the overall tariff due to economies of scale as incremental capacity additions come at only marginal investments. This brings forth a contentious issue: should pipeline design provide for a cushion for expansion and if so, should the initial users pay for that extra capacity? The best possible resolution could be to have the design levels defined initially in terms of the aperture, and capacity additions to be allowed only through additional compression. This means that while determining the tariff, the actual capacity may be kept at a level equal to the design (which is higher than the actual physical capacity initially created) and consider the actual investment when the additional capacity gets physically created. It must be ensured that it would be in the consumer's interest to have more pipelines laid from different sources to serve the same gas market as gas-to-gas competition brings in higher efficiencies and greater competition.

Economic life

Economic life of a pipeline is the period over which the pipeline operates as efficiently as before and is also the period reckoned for recovery of investments through fixation of tariffs.

The end of the economic life implies that the asset is due for replacement by an equally or more efficient asset. Pipelines have regenerative characteristics, which imply that adequate and timely repairs and maintenance, and replacement of critical equipment and facilities, add to the economic life of the pipeline. An assessment of the economic life means the balance useful life of assets is made along with their valuation and appropriate tariff adjustments made to arrive at applicable tariffs. Normally, a pipeline should repay for the investments and also provide for replacement through depreciation provisioning. Since the depreciation is allowed on historical costs, the accumulated depreciation at the end of the economic life is not adequate for replacement, which would be at a higher value considering the time value of money. Therefore, returns on replacement value of assets or inflation adjustment in the RoR, or simply allowing a higher RoR and tariff fixation on discounted cash flow basis, is followed to provide for assets recreation at the end of the economic life.

Contract carriage or common carrier regimes, unbundling and affiliate code of conduct

A contract carriage system implies that the capacity available in a natural gas pipeline is contracted by a shipper for a period generally in excess of one year and on payment of pipeline tariff. Since the capacity is specifically blocked for a volume and over a period of time, it is usual to have ship-or-pay commitments. The element of capacity charge (which both parties specifically decide upfront in the contract) in the pipeline tariff is paid irrespective of the volume of natural gas transported. The element of commodity charge in the pipeline tariff is settled for the actual volumes of gas transported. The pipeline operator has the right to refuse capacity booking in excess of availability. It is a popular system followed in nascent and emerging gas markets and is prevalent even today in some of the matured gas markets.

A common carrier system implies booking of pipeline capacity through a contract for a period of less than a year, and additional volume requirements of any new shipper are accommodated by pro-rating the previous capacity booking. Such a system is in vogue in the US, which has a matured gas market and also has a sophisticated capacity trading mechanism. The tariff settlement system is more flexible since capacity booking is not on a firm basis.

One of the obvious indicators of a competitive gas market is trading of pipeline capacity and also the commodity (natural gas), which can be achieved by 'unbundling' the transportation activity from that of the marketing of natural gas. An integrated monopoly that unbundles itself is expected to maintain 'an arms length relationship' between the activities of transportation and marketing of natural gas. This extends to the relationship with its affiliates as well. It is expected that at this stage, the sectoral regulator develops an affiliate code of conduct to specify the expected behaviour of a monopoly and also monitors its transactional relationships for booking of pipeline capacity, sale of gas, and contractual terms and conditions for any violations. A basic affiliate code of conduct would only provide for accounting bundling, which ensures that besides direct costs being identified correctly with a specific function or activity, the common costs are allocated over the activities of transportation and marketing, commensurate with the levels of service provided, and that there is no cross-subsidization of costs and violation of any transfer pricing guideline. As gas markets become more sophisticated, legal ownership and management control forms of unbundling, bringing in more transparency in transactional relationships and consequently competition.

Swap of gas

The inherent limitations in handling of natural gas, poor storage and expensive transportation through pipeline, can be economically managed through swapping of gas. This option implies that the 'title of ownership' in natural gas is bartered with that of another to enable delivery to the consumer, who is nearer, without having the gas to travel over avoidable and infructuous long distances. An enabling environment in terms of avoidance of double taxation, and a trading platform, facilitates swap arrangements, particularly in emerging gas markets.

The pre-regulatory tariff regime in India

In the Indian context, different basis for fixation of tariff for natural gas pipelines have been followed. The HVJ pipeline tariff was determined on a cost-plus basis by the MoP&NG (Ministry of Petroleum and Natural Gas) with a reasonable rate of return on net worth pegged at 12% post tax, and weighted average borrowing rate applied on the borrowing portion of the capital employed. This basis was later extended to GAIL's (Gas Authority of India Ltd) regional network of pipelines in Andhra Pradesh. The DVPL's (Dahej–Vijaipur pipeline) tariff was negotiated between GAIL and the relevant oil marketing companies (Indian Oil Corporation Ltd and Bharat Petroleum Corporation Ltd) on a similar principle as followed for HVJ, but recovery of tariff was agreed on a zonal-postalized basis. The tariff commission later adopted the discounted cash flow approach in tariff determination for these two pipeline systems and the tariff recovery on a zonal-postalized basis. Tariffs for the other regional network of natural gas pipelines of GAIL, AGCL (Assam Gas Company Ltd), GGCL (Gujarat Gas Company Ltd), and GSPL (Gujarat State Petronet Ltd) have largely followed a cost-plus approach, with the rate of return fixed on a commercial basis.

The regulatory regime in India

Dismantling of the APM (administered price mechanism) system effective 1 April 2002 led to the formation of the PNGRB (Petroleum and Natural Gas Regulatory Board) on 1 October 2007 under the PNGRB Act 2006. It was formed to regulate refining; processing, storage; transportation; distribution; marketing, and sale of petroleum, petroleum products, and natural gas excluding production of crude oil and natural gas so as to protect interests of consumers and entities engaged in specified activities relating to petroleum, petroleum products and natural gas and to ensure uninterrupted and adequate supply of these in all parts of the country; to promote competitive markets and for matters connected therewith or incidental thereto.

The PNGRB Act, inter alia, provides for the legal framework for downstream oil and gas sector regulation, development (including fixation of tariff) of petroleum and natural gas pipelines, and city or local gas distribution networks. However, it does not envisage fixing or controlling the selling price—neither at the producer level nor at the retail consumer level. The PNGRB, in its initial two years of existence, has notified several regulations for natural gas pipelines covering authorization, regulation of tariff for common carrier or contract carrier, access code and technical and HSE (health, safety, and environment) standards in design, construction, and maintenance of natural gas pipelines.

The following section of the article examines the likely impact of current government policies and of the PNGRB's regulations on the development of natural gas pipeline infrastructure. It also suggests possible options for the development of competitive gas markets in India.

Development of natural gas pipeline infrastructure

The foremost requirement is of a rapid pipeline infrastructure roll out, so as to have a basic national gas grid operational. This is required to handle different sources of natural gas and re-gasified-LNG (and perhaps cross-border gas), over multiple destinations spread across the length and breadth of the country, catering to a complex sectoral demand mix of power, fertilizer, petrochemical, refineries, other industries (including SMEs), and CGD (city gas distribution) networks. In this context, the following initial initiatives have begun in right earnest, yet some clarifications and rectification of some critical anomalies are required.

i) The GoI (Government of India) policy for natural gas pipelines and CGD networks of November 2006, the Income Tax Rules 2007, and the regulations on authorization of natural gas pipelines, provide for creation of extra capacity of at least 331/3% of the owner's own requirements plus firm capacity to be provided on a common carrier basis. Such upfront provision of extra capacity qualifies for infrastructure benefits under section 80-IA of the Income Tax Act 1961. Thus, the twin objectives of having an optimal pipeline design providing for future demand requirements, and of the resultant extra capacity being made available on competitive terms to third parties on a non-discriminatory basis, have thus been met. Additionally, the MoP&NG has already authorized nine new pipelines (five of GAIL and four of RIL) before the appointed day, as common carrier. These, when completed (estimated by early next decade), would provide the basic national gas grid and the operationalization of a rudimentary gas management system. The tariff regulations of the PNGRB further provide for an incentivizing cost-plus tariff structure (on discounted cash flow basis) for these nine proposed pipelines as well as the existing common carrier pipelines (which incidentally are required to be first declared as common carrier). This is provided with an assured post-tax return of 12% (to be grossed-up for the applicable nominal rate of income tax) on capital employed plus normative levels of operating costs, both on achieving the normative levels of capacity utilization. This assures freedom to an entity to freely plan the gearing of the capital employed in the pipeline project based on its dynamic evaluation (including re-engineering) of the risk and returns associated with the capital and the debt markets, and design its own specific plans for raising funds. The tax incentive available in the form of income tax exemption on profits under section 80-IA is an additional sop, as the same is not proposed to be reduced while grossing-up the aforementioned rate of return of 12% by the nominal rate of income tax. Tax shield, available in case of efficient tax planning and thereby keeping the actual tax outgo lower than the nominal rate of income tax, is also allowed to be retained by the entity. These upfront sops on return, and tax incentives, should make large-scale investments in pipelines, an attractive proposition. However, the PNGRB should endeavor to reach a progressively stringent fixation of normative levels of performance in the future, which would be in the interest of both the entity and the consumer. This is needed in order to mutually benefit from a superlative performance against a stringent benchmark while disincentivizing a below-par performance.

ii) A closer examination of the provisions in the Income Tax Rules 2007 reveals that the provision of levels of extra capacity is at variance with that of the GoI policy on pipelines and the PNGRB regulations. It is hoped that the anomaly shall be rectified in the ensuing union budget.

iii) The policy as well as the PNGRB Act, 2006 uses the terminologies 'contract carrier or common carrier' interchangeably. As discussed earlier, an emerging gas market like India should follow the same generic path in the development of natural gas pipelines—a contract carriage system always precedes the common carriage system of capacity booking. Therefore, an amendment in the basis of making available the extra capacity first on contract carriage basis and then on common carriage basis, subject to availability of capacity, in the Income Tax Rules 2007 and the GoI policy on pipelines, would certainly balance the perspectives of both entities and the consumers.

iv) The MoP&NG while granting the aforementioned authorizations has allowed the clubbing of capacity requirements of the affiliates of an authorized entity with the 'own requirements' of the entity. The regulations of the board on declaring pipelines as common carrier or contract carrier has also adopted the definition of 'own capacity' requirements of an entity as inclusive of capacity booking by the affiliate.

v) This clubbing provision seemingly contradicts the provisions of the PNGRB Act 2006 on the following counts.

   A) The objective of any government policy as well as that of the sectoral regulator is to ultimately have competitive markets, which can be met only if unbundling takes place along the gas value chain on a progressive basis. To create a new authorization on a 'bundled basis' only to be 'unbundled' later may have serious consequences in the future, as are being currently seen in the French and German gas markets.

   B) The aforementioned clubbing has the potential of a serious monopoly abuse, if the authorized entity were to create an affiliate, which in turn, could book the entire balance capacity available after meeting the entity's genuine own capacity requirements. This would imply that the consumer would have no option but to have a bundled contract option and that from either the authorized entity or its affiliate.

   C) It is important to create an enabling environment for independent shipping interest (implying that the marketing interest is not bundled with the transportation interest) in booking of capacity in a natural gas pipeline, which is a pre-requisite for competitive gas markets. An entity being an owner of a pipeline with bundled marketing operations is a natural barrier to the creation of an independent shipping interest.

   D) The provisions in the affiliate code of conduct may come in conflict when the affiliate capacity requirements are to be assessed. In this regard, Section 21 of the PNGRB Act 2006 clearly emphasizes the need for fair competition, and availability of natural gas across the country.

   The proviso to sub-section (1) of Section 21 of the PNGRB Act, 2006 provides for the application of the provisions of the affiliate code of conduct for separating the activities of marketing from transportation of natural gas for pipelines. It may also be seen that the mention of 'right of first use for its own use' in sub-section (1) of section 21 of the Act is with reference to an entity laying, building, operating or expanding a natural gas pipeline. Further, the reading of the definition of entity as defined under sub-section p of Section 2 of the Act implies that the reference is to the type or constitution of an entity and clearly an entity cannot and does not include its affiliate. Therefore, it logically follows that an assessment of 'own capacity requirements' of an entity does not envisage inclusion of the capacity requirements of its affiliate.

Development of natural gas pipeline, post the appointed day

The board in its regulations has provided a two-part bidding process for authorizing entities to lay, build, operate or expand natural gas pipelines after the appointed day. The technical qualifications are a credible hurdle to be crossed and thereby ensure bidding by serious entities alone. On the other hand, a weightage of 30% to the highness of the present value of the capacity in the natural gas pipeline over its economic life, and a weight of 70% to the lowness of the present value of natural gas pipeline tariff over the economic life of the project (with higher sub-weightage for the lowness of the incremental increase in the unit tariff over previous zone) as two financial bidding criteria seem to balance the requirement to create maximum capacity in a pipeline along the route at the least possible tariff.

The bidding process in the next few years is likely to focus on building of intra-state medium pressure natural gas pipelines, from entities having interests in domestic gas E&P (exploration and production), which is but natural considering the associated risk of not being able to monetize the gas. In the interest of competition, both the upstream regulator and the PNGRB in the medium-term would need to provide a platform for more competitive bidding, by especially focusing on creating pure transportation interests, independent from both E&P and marketing interests.

Recovery of tariff: is the basis progressive?

The tariff regulations of the PNGRB have settled for a zonal-postalized tariff recovery mechanism. This attempts to balance the perspectives of the entities in terms of providing flexibility and advance tariff planning, with that of diverse consumer interests, as the issues regarding distance and volumes have been balanced with the aspirations for a balanced regional development in the country.

i) The recovery of tariff has been linked to the location of a customer in a notional tariff zone, which has a length of 300 kilometres along the route of the pipeline and has a width of 50 kilometres on either side of the pipeline. The tariff for all consumers within a notional tariff zone shall be uniform, but for a single source of gas (implications discussed under sub-para ii below).

ii) The tariffs in each of the successive tariff zones could be at least equal to or more than the tariff over the previous tariff zone. This implies that the tariffs could either be uniform or at best increase at a decreasing rate across the successive tariff zones along the pipeline, which is in line with the economics of a pipeline project.

iii) The entity could factor in the estimates of gas volumes and distances traveled at the bidding stage itself, based on the route of the pipeline, and accordingly bid a tariff based on a scientific basis. However, since the tariffs are to be bid for 25 years, the entity should base its estimates for both the location of the proposed tap-off points, and the volumes, on a sound basis. Any major variation in these estimates could upset the economics of the pipeline.

iv) A particularly complex issue has emerged in the context of the amendment in the definition of 'tariff zone' carried out in regulation 2 (h) of the regulations dealing with the authorization of natural gas pipelines and the tariff regulations. The amended definition has the effect of creating an anomalous situation of having different tariffs in the same tariff zone based on different sources of gas. This is explained in the diagram below:

Gas A (Figure 1) with well-head price of $3/mBtu enters pipeline at T1 and exits at T8 (tariff till that point being $0.70/mBtu). It is available to the customer in T8 zone for $3.70/mBtu.
Gas B with well-head price of $4.20/mBtu enters another pipeline to reach the first pipeline in T5 zone incurring a tariff of $1/mBtu implying that the cost at the point of intersection is $5.20/mBtu. As per the definition of tariff zone in the regulations, Gas B could move in either direction (although in the reverse direction is a physical impossibility as long as Gas A is moving in the first pipeline and supplying customers beyond T5 zone) and the applicable tariff for this gas at the point of intersection shall be the one which was applicable for T1 (that is, $0.50/mBtu). Further, for Gas B, the subsequent tariffs shall be the same as are applicable to the next subsequent zones for Gas A in the first pipeline. Therefore, Gas B gets priced for the customers in T8 at $5.72/mBtu and not at $5.90/mBtu, which would have been the case had the point of interconnection been counted as T5 and not T1. A careful analysis shows that there are multiple tariffs in the same tariff zone and the difference in tariff of $0.12/mBtu is an advantage

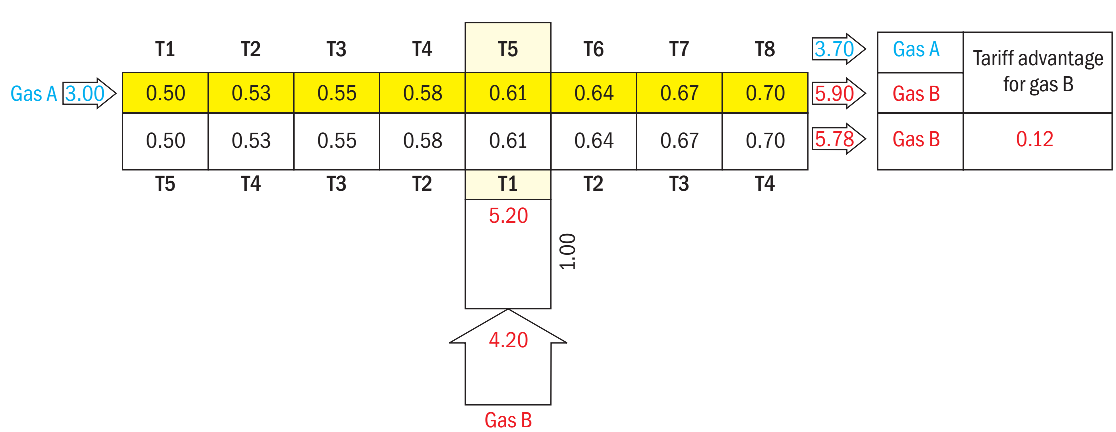

Figure 1

for Gas B on the ground that it should bear the tariff only for the distance travelled. Such an argument may hold good in a matured gas market where multiple gas sourcing points and delivery points exist and the capacity, tariff, and commodity prices get traded. However, in a nascent gas market, it could create serious issues of imbalance. The only option left for Gas A to get back its pricing advantage would be to force its pipeline tariff setting in the first pipeline on a postalized basis, which would mean loss in tariff revenues. Clearly, Gas B becomes more tariff competitive than Gas A, even though it travels lesser distance from the point of interconnection. In case of reverse flow, in the absence of any trading platform, 'unofficial' swap positions could do more harm to the nascent gas markets by forcing premature gas-to-gas competition. Thus, the customer in T8 in real terms does not benefit as the tariff difference accrues as additional netback for Gas B.

The above anomalous situation may send discouraging signals to new investments in pipelines since a prospective bidder may now have to plan the tariff recovery on a two-way basis. He may not be left with any economic option but to charge tariff on a postalized basis since the reverse flow may not take place at the same level of volumes as in the case of a forward flow. This may result in huge uncertainties in tariff recoveries.

The way forward

The government in terms of its policy on pipelines and tax holiday benefits has set the ground conditions for incentivizing creation of infrastructure. It is for the PNGRB to closely look at the nascent stage of infrastructure development, lack of shippers in the mid-stream of the gas value chain, complete absence of pipeline capacity and commodity trading platform and the existing arrangements of transportation and marketing services being provided on a 'bundled' basis, and therefore consider creating an appropriate regulatory framework, which brings in a level playing field and healthy competition.

Financial hurricane strikes refining sector: strategic responses

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The financial slowdown, which has struck the global economy and left national governments and businesses in a state of shock and confusion, has not spared the global oil business either. Not that the oil industry is a stranger to the ups and downs of business cycles and volatility in the market, but this time around the speed and savagery with which changes shook the oil business are quite unprecedented.

While there has been a sudden contraction of demand for petroleum products, notably gasoline in the US and other western countries, crude oil prices have tumbled from a high of $147 per bbl to close to $60 per bbl and finally steadied to some extent. For the first time in several years, the light heavy crude oil differential (which was $11–$12 per bbl sometime ago) actually reversed for some time and remains very close to zero. Gasoline and naphtha cracks have declined sharply, whereas diesel and fuel oil prices have managed to hold fairly well.

In the pre-crisis period, the business environment had lured several investors into developing plans for new refinery investments, to a large extent in the Middle East and India, and some other countries. There are about 100 crude oil capacity expansion projects and an equal number of projects involving building of new refineries that have been announced. If all these announced projects were implemented, this would add more than 30 MBD to global refining capacity by 2015. However, many projects are highly speculative and are not expected to materialize.

The main driver for the growing interest in the sector was an eight-year boom that saw demand for petroleum products steadily moving northward, while projections into the future showed significant gaps between refining capacity and demand. The world economic situation has changed, however, and there is every possibility of delays in and cancellation of projects. This holds for India too. Given growing Indian consumption and the large export potential, both the public and private sectors were considering expansion of refining capacity, which is already considerably surplus with respect to indigenous demand. Now, most, if not all, of these planned expansions are being put on hold. Refining margins, which had remained high for a long time, are now considerably lower. Refineries with higher complexity which were able to process heavier 'dirtier' crude oils, have high yields of distillate products, and produce products to higher specifications, have performed significantly better than those without the same processing capabilities.

Today, while the short-term outlook appears unattractive, one will need to wait and see how the situation develops in the long term. Assuming that revival efforts (mainly through the large fiscal stimulus) bear fruit, demand could once again pick up. This could happen in the next one or two years. On a global basis, a few changes appear highly probable in the future.

- A changing petroleum product mix is one possibility. With the exception of the US, where gasoline is still the major product consumed, most other countries – especially those in Europe – prefer diesel over gasoline. Improved diesel engine technology, better and more efficient road performance, as well as reduced emission levels from diesel vehicles, are the reasons, which have given a fillip to diesel (over gasoline) as a transportation fuel.
- In order to ensure reduction in emissions, more and more countries are likely to adopt increasingly stringent standards of transportation fuel quality. This calls for extremely low sulphur levels in fuel, besides changes in other parameters like aromatics and olefins.
- IMO (International Maritime Organization) has already taken a decision to cap sulphur level at 0.5% from 2020 onwards for marine fuels. This, together with the continued decline in global furnace oil demand in the future, will call for a sharp change in process configuration of refineries.

When the global economy picks up again, it is likely that the demand for oil products will also grow in consonance. This would put increasing pressure on prices, more than it would have been in the absence of the present crisis, because investments both in upstream E&P activities as well as in refining are currently being put on hold. The resultant 'supply squeeze' may cause a tightening of the supply situation and consequently put further pressure on prices. If India's dependence on imported crude oil continues to remain high, as is likely, it could bring home to the Indian economy, all the problems associated with high international crude oil prices.

Before the article delves into the emerging situation in the Indian refinery sector and possible strategies for development of Indian refineries, it may be useful to enumerate some of the basic characteristics of the refining sector in general.

- The refinery sector constitutes a capital-intensive industry, with a typical grass-roots project's cost ranging from $4 billion to $10 billion, depending on size and complexity.
- Refinery projects have fairly long gestation periods – often three to five years – depending on organization and location.
- Crude oil comprises 90% of the operating cost of a refinery.
- If one examines a long-term historical trend, refining in general has been a low-return business especially the period prior to 2003/04.
- Exit costs are fairly high.
- There are definite economies of scale especially with the use of single-train configurations to the extent feasible.
- There is a range of products produced simultaneously from a refinery, some of which like the distillate products (LPG, petrol, diesel, aviation fuel, and so on) are higher in value than crude oil. The production of these therefore adds to the refinery margin. There are other heavy end products like fuel oils that are lower in value (because of their low demand and easy substitutability).
- Crude oils vary significantly in terms of quality especially with respect to levels of sulphur, density (which makes it lighter or heavier), chemical composition, and so on.
- Refineries, by virtue of their design configuration, can be substantially different in

terms of their ability to produce high-quality distillate products, and also in terms of their ability to process more difficult crude oils, which are generally heavier, and have high sulphur content. The traditional Indian refinery set up in the 1950s and 1960s had moderate conversion capabilities with units such as FCC (fluid catalytic cracker), visbreaker, and some desulphurization capacity added when Euro II/III grades fuel were made mandatory. Now, to further reduce heavy ends production and make suitable lighter products, it will be necessary for these refineries to select one or a combination of the more severe conversion units such as coking units, resid hydrotreater FCC, resid hydrocracker, solvent deasphalting with bitumen/power, and gasification with combined cycle, and also add considerably more hydrotreatment and desulphurization capacity.

The Indian scenario

Crude oil availability

The indigenously available crude oil utilizes only up to about 20% of refining capacity in India. Most of the crude oil available indigenously is the low-sulphur type. The balance is being imported, largely from the Gulf countries. Low-sulphur crudes are being imported from South Africa and Far East, and small quantities are being sourced from Australia and Algeria. Heavy crudes are being imported from South America mainly Venezuela. Public sector refineries buy 70%–90% of their crude oil on term contract basis and the remaining in the spot market, so as to balance their needs and to take advantage of opportunity crudes.
It is understood that private sector refineries also buy a major portion of the crude oil on term basis. The extent of term versus spot crude is decided based on supply security, and the refinery management's perception of market behaviour in the future. Most low-sulphur crudes are available only on spot basis except small quantities from Malaysia, Brunei, and other countries. This 20%–30% of crude purchase on spot basis provides an opportunity to refiners to improve profitability by planning and scheduling the right crude mix of various types and from various sources, and optimize the crude blend for the refinery. To be able to do this, the refinery requires adequate crude storage and blending facilities.

The low differential price of light and heavy crudes at present does not offer much incentive to refineries to preferentially process heavier crudes for better margins, to the extent that the refinery processing configurations allow. However, such a situation may not prevail in the long run especially when demand and price pick up. When lighter crudes are again priced higher than the heavy ones, those refineries with higher 'complexity' will have a definite and specified advantage.

Refining

In recent years, the Indian refining industry has undergone rapid change with the addition of private sector world-class refining capacity of 76 MMTPA to the existing PSU refining capacity of 105 MMTPA. The pace of change in the last 10 years or so has made the country a refining hub in South Asia (Table 1).

With limited oil and gas resources within the country, the downstream oil companies in India had to adopt a different business model than the traditional industry model of vertically integrated

Table 1 Capacity addition in India

Refinery	*Tenth Plan* (2007)	*Current capacity*	*Eleventh Plan* (2012)	*Twelfth Plan* (2017)
IOC (Indian Oil Corporation)	60.2	60.2	81.4	94.7
HPC (Hindustan Petroleum Corporation)	13.0	15.0	32.9	32.9
BPC (Bharat Petroleum Corporation)	22.8	22.0	30.8	30.8
MRPL (Mangalore Refinery and Petrochemicals Ltd)	9.69	12.5	15.0	45.0
RPL (Reliance Petroleum)	33.0	62.0	62.0	62.0
Essar	10.5	12.0	14 .0	32.0
Nagarjuna			6.0	6.0
Total	**148.9**	**183.7**	**242.1**	**303.4**

Source Industry Data and MoPNG (Ministry of Petroleum and Natural Gas) oil companies, where profitability is viewed within the context of the entire supply chain. For these companies, the primary business is refining and then marketing/retailing of petroleum products, which makes it essential for them to ensure stand-alone viability of each. This is necessitated by the need to earn market rates of return for investors, and also to have returns sufficient to support investments in expansion, technological improvements, meeting environmental regulations, and infrastructure requirements.

The Indian refining sector has a mix of both private and public sector players. Historically, 1976 onwards for about 25 years, it was a PSU dominated industry. Now, about 50% capacity is in the private sector. The public sector refineries started out with a predominant focus on satisfying the domestic market and much of their capacity was also geared to absorb and process indigenously available crude oil, which incidentally is largely of the lighter and low-sulphur variety. As a result of this history, these refineries had a comparatively lower complexity and size, and had limited capacity to process heavier high-sulphur crudes (generally not more than 50%–60% of capacity). Product yields and product quality were also determined in accordance with domestic market needs, which implied a significant fuel oil/heavy end production and quality as per the Auto Fuel Policy (2003) approved by the Government of India (not necessarily with export market requirements). Several of these too are now reaching limits on space available to them for putting up facilities. In terms of location, most of these refinery units are well placed, being close to the market or the crude source.

Though, in general PSU refineries have operated in a protected market, they have achieved a fairly high level of operating efficiency. All these refineries have expanded capacity and responded well to the changing demands of the market. Most have added capabilities with regard to desulphurization, hydro cracking, catalytic reforming, amongst others, to meet Euro III and Euro IV matching grades of transportation fuels required as per the Auto Fuel Policy. From time to time, technology has been upgraded by way of retrofits (both in software and hardware), which has improved energy and operating efficiency, reliability, and safety.

The newer private sector players are of two types: one with large-size, very sophisticated refineries capable of matching the best in the world, and the second includes some new projects which are under construction and are characterized by modest size (and perhaps configuration) but presumably with lower capital cost (achieved by importing used mothballed refinery equipment). Unless some additional facilities are included in the latter, their complexity may also remain low. Table 2 provides a snapshot of Indian refineries' yields.

The data in Tables 3 and 4 shows that a refinery with the right process configuration (which can optimize crude selection by blending and processing a heavier higher sulphur crude mix, and produce high-quality products with a high distillate yield) can command a considerably higher margin. It also shows that there is tremendous scope for PSU refineries to improve their performance by developing capability to process high-sulphur crudes and by incorporating heavy end upgradation facilities to convert a significant portion of heavy distillate to desirable middle distillate like diesel. The average heavy ends (fuel oil and others) yield of 20%–25% could be reduced to 8%–10% since technologies to achieve this are available. However, these upgrading facilities call for substantial investments in refineries to the order of $1–1.5 billion for an average-sized facility, and no company can afford a situation where these investments do not pay off in the long run. Stable pricing by the government can help companies better plan their investments.

Taking into account the current capacity and the new projects under construction, refining capacity in India is likely to be considerably surplus over indigenous demand for several years. As shown in Table 1, in India, with current available processing capacity of about 180 MMTPA and domestic market demand of just above 130 MMTPA, there is surplus capacity of 50 MMTPA. Taking into account the ongoing projects and some capacity creep, there is much likelihood that this surplus scenario will continue well into the future.

When this is viewed in the context of a declining global demand (demand has contracted

Table 2 Performance pattern of various Indian refineries (crude versus yield)

	HPC Mumbai	*HPC Vizag*	*BPC*	*KRL*	*IOC KOY*	*IOC MAT*	*IOC HAL*	*CPCL*	*MRPL*	*RIL*
Crude (%)										
Indigenous (2004/05)	26.0	28.4	39.9	30.2	63.7	16.6		9.5	30.9	
Imported (HS)										
2004/05	74.0	44.7	31.7	43.8	25.9	54.6	72.8	69.8	69.0	100
2005/06	69.0	47.0	44.0	58.0	24.1	0.0	71.1	85.6	72.0	
2006/07	65.1	56.0	53.0	58.6	22.6	56.3	70.3	79.5	69.6	
2007/08	61.7	62.5	49.4	55.8	26.6	58.9	70.8	73.4	79.6	
Imported (LS)		27.9	28.4	26.0	10.4	28.8	27.2	20.7	0.1	
Products (%) (2004/05)										
Light ends	18.1	27.3	27.7	23.4	15.9	18.9	17.1	18.7	20.1	41.2
Mid district	42.4	46.8	45.1	49.3	47.9	52.2	43.7	48.3	53.3	40.0
Heavy ends	30.7	18.8	20.6	16.9	29.7	23.7	29.4	23.1	20.3	11.1

Source Industry Data and MoP&NG
Note: HPC – Hindustan Petroleum Corporation; BPC – Bharat Petroleum Corporation; IOC – Indian Oil Corporation; HAL – Hindustan Aeronautics Ltd; CPCL – Chennai Petroleum Corporation Corporation Ltd; MRPL – Mangalore Refinery and Petrochemical Ltd; RIL – Reliance Industries Ltd.

Table 3 Capacity utilization

Refinery	2005/06	2006/07	2007/08
IOC	81.3%	92.9%	100.1%
HPCL	109.5%	129.2%	129.2%
BPCL	88.4%	101.4%	106.7%
CPCL	98.7%	99.0%	97.7%
MRPL	124.9%	129.4%	129.5%
BRPL	100.0%	87.7%	86.0%
NRL	71.1%	83.3%	85.7%
RPL	100.5%	116.3%	132.0%
Essar	0.0%	16.8%	63.1%
Wtd. Avg – India	87.4%	99.5%	109.2%

Source Industry Data and MoP&NG
Note: IOC – Indian Oil Corporation; HPCL – Hindustan Petroleum Corporation Ltd; BPCL – Bharat Petroleum Corporation Ltd; BRPL – Bongaigaon Refinery and Petrochemicals Ltd; CPCL – Chennai Petroleum Corporation Ltd; MRPL – Mangalore Refinery and Petrochemicals Ltd; NRL – Numaligarh Refinery Ltd; RPL – Reliance Petroleum Ltd.

Table 4 Gross refining margin of refineries

Refinery	2005/06	2006/07	2007/08
HPCL-Mumbai	3.2	4.8	6.0
HPCL-Vizag	2.6	3.5	7.0
BPCL	1.6	3.6	4.0
KRL	3.2	3.5	–
IOC refineries	4.6	4.2	9.0
CPCL	4.4	5.0	8.5
BRPL	3.3	5.2	7.6
MRPL	3.7	4.8	6.9
RIL (Reliance Industries Ltd)	10.3	11.7	15.0

Source Industry Data and MoP&NG
Note: IOC – Indian Oil Corporation; HPCL – Hindustan Petroleum Corporation Ltd; BPCL – Bharat Petroleum Corporation Ltd; BRPL – Bongaigaon Refinery and Petrochemicals Ltd; CPCL – Chennai Petroleum Corporation Ltd; KRL – Kochi Refineries Ltd; MRPL – Mangalore Refinery and Petrochemicals Ltd; NRL – Numaligarh Refinery Ltd; RIL – Reliance Industries Ltd.

by 2 MBD globally) since the recession started, this surplus refining capacity should set some alarm bells ringing with refinery managements. Economic theory suggests that in a truly competitive market and when supply capacity far outstrips the demand for a commodity, the weakest players are forced to exit the arena. Such a situation has occurred in the past in countries like Japan, US, and the UK, and has resulted in the closure of uneconomic and unviable refineries. In this context, some broad action plans for existing refineries are being suggested below.

- Installing crude blending facilities can be considered. In case, due to space constraints, this is not possible near the refinery, a remote location could be considered. Alternatively, rearrangement and reassessment of hardware needs in existing refineries can also be undertaken in order to generate additional space for blending facilities. Installation of blending facility is an important step towards diversifying crude oil sourcing and enabling the refinery to include lower cost heavy crudes as well as 'opportunity crudes'.

- Installation of more severe conversion capacities in the refineries such as cokers or solvent deasphalting units along with hydrotreaters and desulphurization units can be taken up. The additional distillate products available will not only boost refinery margin but also reduce the dependence on crude oil and will enhance energy security. The argument that since light heavy crude differentials are at an all time low, such investments are not viable can prove to be a shortsighted apprehension. What needs to be taken into account is the likely long-term trend and if historical developments are any guide (see Figures 1 and 2), we can expect a differential between light and heavy crude oil, which is more supportive of a heavy end conversion facility. In other words, a long-term view of prices and demand should be taken while deciding on such investments. Besides, the current economic environment provides an excellent opportunity for lowering capital costs, and therefore investments in facilities for upgradation and efficiency improvement should be seriously considered now. In the economic scenario, which may emerge by the time the current downturn is over, capital costs may tend to increase and such investments may become fairly capital intensive.

However, even if the downturn continues for longer, there may be all the more reason to quickly enhance competitiveness by upgrading refineries, since a supply glut can make the less sophisticated refineries uneconomic to operate. Therefore, in either case, whether there is an economic upturn or downturn, investments in refinery upgradation for higher conversion while processing more difficult crude oils, especially in the older refineries must immediately be considered. Indigenous crude production being considerably short of demand, it is all the more desirable that India has high conversion refineries which can extract the best value from the least expensive crude oil.

- Since there is a tremendous shortage of power in the country, refineries can consider installing captive units with combined heat and power generating facilities based on heavy ends, which can achieve very high energy efficiencies.
- The recession and the resultant low-cost environment may also be an opportune time to acquire oil assets including refinery and marketing assets overseas. This can provide some leverage in getting access to the export market and possibly enable the country to get quality oil abroad at competitive rates.
- Though PSU refineries are looking at the overseas market to export products, it is more because of the surplus, which cannot be absorbed in the domestic market. A greater integration and a

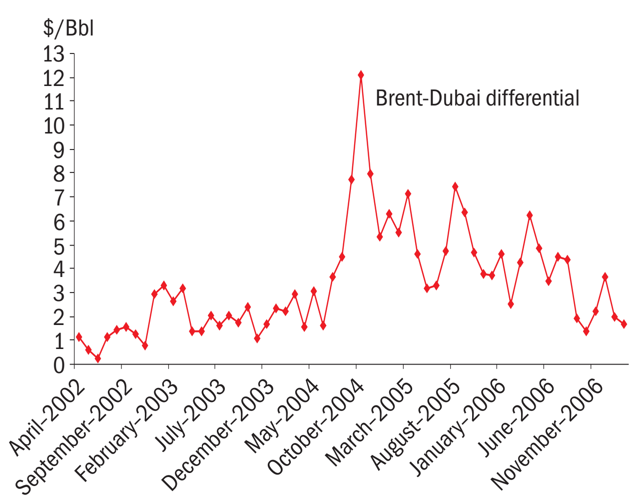

Figure 1 Sweet–sour crude price differential
Source International Energy Outlook

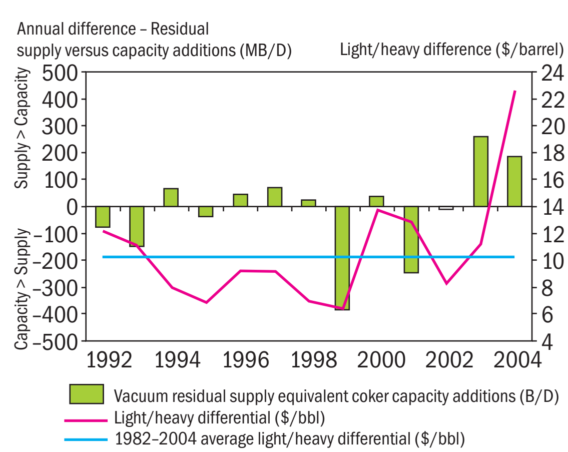

Figure 2 Trends in coker capacity additions and sweet-sour crude price differential
Source Purvin and Gertz

greater focus on the global oil market will enable refineries to spot opportunities both for crude oil/feedstock sourcing, as well as for product exports on a more regular basis.
- The older refineries especially those on the coast can also consider setting up infrastructure for exporting products on a larger scale, and upgrade the quality of products so as to get best value from the export market.

In India, administered/controlled price of key petroleum products has helped to insulate the consumer from volatile price changes and kept inflation under check. However, this has also prevented demand from being linked to market prices, and has prevented oil PSUs from adding due economic value through proper investment planning. The pricing system for refineries should enable them to earn the required return on their investments so that they can reinvest for enhancing competitiveness and pursue capital-intensive expansion.

A robust regulatory regime, which covers issues related to pricing and infrastructure can enhance the competitiveness of the refining sector, and provide greater value to the Indian consumer.

Conclusion

The greatest threat to Indian refiners would be of lack of capacity utilization in case of drying up of the export market primarily due to contracting demand and capacity addition in West Asian countries. The refineries there will have an advantage over Indian refineries due to proximate availability of crude oil. Also, they are closer to the export market as compared to a location in India. Under such circumstances, the refineries in India will be under tremendous pressure to market all their produce in the domestic market, which can result in lower capacity utilization as a result of heightened competition. Therefore, for the Indian refining system as a whole to remain healthy and competitive, export markets must continue to remain a viable and attractive option. To gear up for an alternative scenario, following few actions points may be considered for implementation.

- Today is the time for capital investments, so efforts need to be directed to upgrade facilities for improving distillate yield, building the capability to process heavier crude and enhancing product quality.
- Efforts should be made to acquire overseas refining and marketing assets, and overseas equity oil.
- Improvement in crude oil procurement and blending is key.
- There needs to be a focus on the global market with greater integration with global trading business.
- An advanced financial risk management policy should be implemented.
- Investments should be made based on long-term projections.
- Integration with power production is a possibility—combined heat and power for efficiency.
- Several bottom conversion technologies are available namely visbreaker, delayed coker, gasification, solvent deasphalting, fluidized bed boilers for power generation, resid hydrocracking, and resid FCC. These can be evaluated and the most economic (depending on specific refinery objectives) should be selected for implementation.

Current financial markets and impact on financing of energy infrastructure globally

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Building of energy infrastructure includes investments in ports, railways, coalmines, oil and gas fields and pipelines, power generation, transmission, distribution, and equipment for the power sector. Energy sector investments are also required for affecting alternative energy choices. Financing of energy infrastructure globally needs special attention because of two recent developments: the extraordinary volatility of crude oil prices, and the global meltdown in financial markets and institutions that have made funds for investment (equity or debt) and for short-term purposes, difficult and expensive. The recent rise in crude oil prices to $140 in less than a few months, and its collapse within a few months to $35 was accompanied by an almost concurrent rise in the prices of gas and coal. While gas prices have fallen with the prices of crude oil, coal has not fallen to the same extent.

The rise in prices resulted in a lot of activity in exploiting hitherto expensive energy sources. For example, tar sands in Alberta in Canada had become viable when crude oil prices were at $100. Many other oil fields that would produce expensive oil became viable and so did many gas fields. Many transnational pipeline projects also became viable and so did the possibilities of using LNG (liquefied natural gas), and demand for shipping capacity to transport it. Many of these new projects were suspended when crude oil prices collapsed. Drilling rigs, shipping capacity for oil and gas, have become much more easily available. Many renewable energy forms especially, wind, solar, and geothermal that witnessed investment interest have seen a setback. Attention to nuclear generation increased as nations decided to reduce their vulnerability to price-volatile imported oil and gas. In nations like India, which primarily have coal as fuel for electricity generation, the need for more options brought about fundamental changes in foreign policy as India looked to assure uranium supplies to increase its nuclear power generation in the long term.

India also faces the volatility of the foreign exchange value of the rupee caused by sharp falls in foreign investment into India, migration of foreign bank funds to bolster liquidity at their head offices, and rising deficits in the balance of payments as overseas demand fell.

Financing of energy infrastructure is thus affected by crude oil prices. Sudden price falls take the minds of consumers and governments away from finding alternatives to limited supply sources and to alternative energy. This restricts finance since the viability of such projects might seem weak. In addition, risk aversion in the time of global recession makes it difficult to raise fresh equity or long- and short-term debt. If new energy projects had not raised their funds or achieved financial closure when crude prices were high, it is difficult for them today to achieve financial closure when crude prices are falling.

In the last one year, the global meltdown of banks and financial institutions has made equity and credit more difficult to find. Arranging fresh funds is almost impossible. The sources of finance are domestic equity, domestic debt, insurance and pension funds, external commercial borrowings as debt and as optional convertible bonds, external commercial borrowings, and foreign equity funding from private sources, governments and from multilateral institutions. In recent months all these sources have become much more difficult to access. Liquidity is tight globally, and investors are reluctant to invest in other countries (even in their own countries) and borrowing is scarce as also more expensive. In countries like India, there is the additional problem caused by the declining foreign exchange value of the Rupee. This, within one year, reached a high of Rs 40 to the dollar and a low of Rs 50, hovering now at about Rs 48. India is not the only country so affected. The decline of the rupee and many other currencies of developing economies makes borrowings expensive both in interest payments when converted to domestic currencies for accounting purposes, and when the loans are marked to market in the balance sheets as required by accounting standards. This can also downgrade their credit rating, making it even more difficult to raise funds overseas.

Financing infrastructure for power projects requires many enabling conditions such as rising demand, lack of domestic fuel alternatives, payment security, remunerative prices, fuel availability, and transportation/transmission capacity. Clearly, any energy infrastructure projects that are taken up must be consistent with the economy's energy security and sustainable development objectives. For example, India is rich only in high ash coal and must depend on it for its soaring electricity needs till nuclear energy generation rises to more reasonable levels (20% or more of its needs), which is expected to be in the next 20 years. While India can expect rising quantities of domestic gas in the years to come, higher relative prices than coal and private sector control that maximizes profits will limit its use. However, electricity demand is rising, there are severe shortages, trading is increasing, and power exchanges make spot trades possible. Open access, and captive and merchant generation, will optimize availability. Payment security by buyers is more certain because central and state governments have ensured mechanisms for the purpose. All these developments enhance the financial viability of energy projects.

India and other economies wanting such investment, according to a document of the APEC (Asia–Pacific Economic Cooperation), 'should establish stable, transparent, independently administered, predictable and non-discriminatory legal, fiscal, regulatory, and trade regimes that support the enforceability of project contracts and consider the interests of all participants, including for projects of a cross-border nature'. A decade after the exit of Enron from India under inauspicious circumstances there are better drafted contracts, fiscal measures are in place to reduce tax incidence and offer incentives for capacity additions, the electricity regulatory regime with over 10 years of experience is much better developed despite some shortcomings, and trading has greatly expanded, though not to its potential.

However; fuel availability from domestic sources is not ensured in India because of nationalized coalmines, skewed government policies not encouraging use of gas for power generation, and a misguided attempt to relate gas prices to international prices than to adequate returns and user affordability. However, the ability of consumers to pay the cost of energy is low in India and in many other developing countries because of the poverty of many, and populist policies to benefit powerful vested voting groups. India, like others, has a complex system of subsidies and cross-subsidies as well as considerable theft of electricity. Despite this, an almost parallel market of viable customers has come about and payment security to investors especially in electricity is not as much of an issue today. The mega and ultra mega power projects also have built in safeguards to ensure payments. Other countries in similar situations may learn from this experience.

Notably, infrastructure projects are notorious for misuse of funds and padding of costs. Good governance and transparency in operating enterprises are essential if such projects are to raise funds and at reasonable costs. This is particularly important when tariffs are regulated. India has still to make progress in good corporate governance though there are some companies that are exemplary. Good governance also ensures that all risks are evaluated and monitored. Similarly, participation of overseas multilateral and international financial institutions, and private overseas investors, in energy infrastructure projects, gives credibility to projects. Currently, funds from them have become scarce. India, in addition, has many government-owned or controlled financing institutions that fund infrastructure—IDFC, PFC, IDBI, India Infrastructure Finance Company Ltd, and other banks and financial institutions. They have been encouraged by government, which in some cases has added to their capital to finance infrastructure and energy projects.

India has vast funds locked up in provident and pension funds, and in life insurance. The first two are not permitted to invest in energy projects. Insurance has low caps on how much can be invested. Clearly, in this time of financial shortage, the government must relax such restrictions. Investment in energy utilities gives guaranteed and good returns when they start production, and in developed countries is the natural outlet for investment of such funds.

It is important in a time of economic and oil price downturn that we prepare for future prosperity. Oil is a non-renewable resource and prices will resume tier rise. It is imperative that governments act to ensure that investment continues in developing alternatives to oil and gas. As in the revival package for the USA of President Obama, our economic revival packages must provide funds for this purpose.

Infrastructure projects require considerable funding; returns are slower because of long gestation of projects. Further, limitations of fuel availability, lower than cost sales to select customer groups and rising costs, affect project viability. The financial meltdown restricts availability of financing and raises its cost. However, well-designed projects by promoters with good track records have less difficulty in achieving financial closure.

The project developer must implement speedily so that the project begins to earn its way even before the expected dates. Government processes must not delay project execution; for example, on land acquisition, clearances when environment and forestlands are affected, inadequate planning of compensation to those who need relief and rehabilitation, and so on. These issues can delay project execution, thus raising costs. A project developer, who has planned for this and knows how to proceed without delays, will have little difficulty in raising the finances.

What this means in India (and other countries) is that a big project developer with track record may make progress. The smaller projects will come across many hurdles in raising finance. Government restrictions on investors like provident funds might ease their situation.

Aligning pipelines and politics: Russia, the West, and Caspian energy resources

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The geopolitics of Caspian oil and gas underwent a radical transformation in 1991 as a result of the disintegration of the USSR. During the Soviet era, the vast energy resources of its constituent republics reached the outside world exclusively through pipelines running through the territory of the Russian Federation. Thus, when the Soviet Union broke up, Russia became the sole transit state for Caspian oil and gas but, at the same time, new possibilities opened up denying Russia this monopoly by constructing pipelines bypassing its territory.

This was an attractive prospect for the Western allies concerned over the EU's (European Union) increasing dependence on Russia for energy supplies. In the 1960s, when West Europe drew up plans to import gas from Russia, the Western allies agreed, under US persuasion, to limit these imports to a maximum of 25% of the European Commission's total requirements. Currently, the EU's dependence on Russia for natural gas is closer to 30% and this dependence is likely to increase as a result of declining production in the North Sea. Thus, energy security considerations lead the West to seek direct access to overseas gas resources, bypassing Russia. Similar compulsions also explain Western initiatives to bring Caspian oil directly to global markets, without giving Russia the control and leverage it would have as a transit state. Furthermore, by directly linking the economies of the producer and transit states with the West, these countries might be drawn into closer political and strategic relations. Thus, conventional power politics calculations reinforce the energy security considerations underlying the search for new pipeline alignments.

As the US energy secretary, Bill Richardson, explained in October 1998, 'this is about America's energy security, which depends on diversifying our sources of energy worldwide. It is also about preventing strategic inroads by those who do not share our values. We're trying to move those newly independent countries toward the West. We would like to see them reliant on Western commercial and political interests than going the other way. We have made a very substantial political investment in the Caspian, and it's very important to us that both the pipeline map and the politics come out right'.

These were the driving objectives that explain the construction of the new 1768-km-long Baku–Tbilisi–Ceyhan pipeline, a vast energy infrastructure project to bring oil from the Baku fields in Azerbaijan to global markets, through the territories of Georgia and Turkey, bypassing Russia. The construction of the pipeline was a major political undertaking. Its alignment had to take into account deep-seated regional problems – the conflict between Azerbaijan and Armenia over the Nagorno-Karabakh enclave, and the historical animosities between Turkey and Armenia. A pipeline lying through Armenia would have been much shorter and more economical but the option was ruled out because of Armenia's strained relations with both terminal countries: Azerbaijan and Turkey.

If the alignment of the pipeline was shaped by existing political realities, it is also true that the pipeline alignment, in turn, helped to shape or strengthen new political realities. Thus, Georgia has developed close political and military ties with the Western allies. Georgia has expanded and re-equipped its army with US military assistance, contributed troops to peacekeeping operations in Iraq and Kosovo, and is a candidate for NATO membership. Conversely, its relations with Russia have deteriorated sharply as was witnessed during the recent armed conflict in Abkhazia and South Ossetia.

The first oil pumped from Baku reached the Turkish Mediterranean port of Ceyhan in May 2006, signalling a major success for the Western allies. The West has, however, been less successful in seeking new pipeline alignments to bring Caspian gas to EU markets. In 2002, a number of European energy companies, led by OMV of Austria, proposed the construction of a new gas pipeline, which like the Baku–Tbilisi–Ceyhan oil pipeline, would bypass Russia. Known as the Nabucco pipeline, it would connect Austria with Erzurum in Turkey, from where it would be linked to the Erzurum–Caspian Sea pipeline. The main sources of supply would be the Shah Deniz gas fields in Azerbaijan and the Daulatabad gas field in Turkmenistan. In 2006, a consortium of European companies signed an agreement to pursue the project.

The Russians swiftly responded with a new pipeline project called South Stream, while officially denying that it would have negative consequences for Nabucco. In June 2007, Gazprom and ENI of Italy concluded a Memorandum of Understanding to build a 900-km offshore pipeline connecting Dzhubga on Russia's Black Sea coast with Varna in Bulgaria, from where a northern pipeline would run to Austria, while a southern branch would terminate in Italy. In February 2008, Russia signed an agreement with Bulgaria, a NATO member, making it partner in the South Stream project—over the objections of the United States. Caspian gas would thus be supplied to central and southern Europe via pipelines running through Russia and Bulgaria. Passing under the Black Sea, the pipeline will bypass Ukraine, a difficult transit partner.

The readiness of EU companies to join Gazprom as partners in the South Stream project reflects an ambivalence in EU energy security policies. The EU does not as yet have a common grid and its member countries do not have a unified energy security policy. Some of Russia's neighbours – Poland and the Baltic republics, in particular – are deeply concerned about the risks of over dependence on Russia. These countries are strongly supported and encouraged by the United States. On the other hand, major importing countries such as Germany, recognizing Russia's need for oil and gas revenues, are less apprehensive about the possibility of Moscow holding up gas supplies for political reasons. The former Soviet Union had an unblemished record as an energy supplier throughout the Cold War period. The few blips in gas supplies in recent years were caused more by the failure of transit countries – Ukraine and, on one occasion, Belarus – to honour contracts than by political muscle-flexing on Moscow's part.

Thus, the western countries have different assessments about the risks and benefits of closer cooperation with Russia in the energy sphere. As a result, they are not always in agreement on the question of where to strike a balance between energy security and purely financial considerations.

Centre for Research on Energy Security

CeRES (Centre for Research on Energy Security) was set up on 31 May 2005. The objective of the Centre is to conduct research and provide analysis, information, and direction on issues related to energy security in India. It aims to track global energy demands, supply, prices, and technological research/breakthroughs – both in the present and for the future – and analyse their implications for global as well as India's energy security, and in relation to the energy needs of the poor. Its mission is also to engage in international, regional, and national dialogues on energy security issues, form strategic partnerships with various countries, and take initiatives that would be in India's and the region's long-term energy interest. *Energy Security Insights* is a quarterly bulletin of CeRES that seeks to establish a multistakeholder dialogue on these issues.

Previous issues of this newsletter are available at <http://www.teriin.org/div_inside.php?id=41&m=3>.

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