Management Discussion and Analysis

Review of 2017

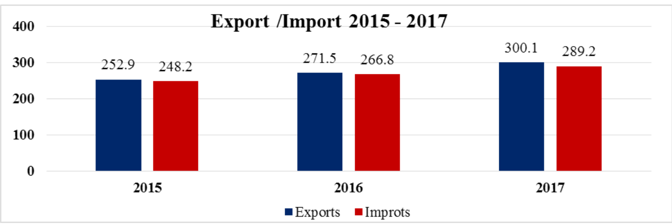
Belying expectations since 2015, the LNG glut which was expected to produce a significant surplus in the markets and lead to a transformational change in how LNG business will be conducted, has yet to make itself felt in a more significant manner. In 2017, LNG supply from Liquefaction Terminals worldwide rose by approximately 10.50% to about 300 MMT in 2017. This was 28.6 MMT more than in 2016, with imports on the other hand rising by 11.3% to 297 MMT from 266.8 MT in 2016 as shown in Table 1 below. This supply growth in 2017 set a new record for the fourth consecutive year. From 2012 to 2015, the average growth rate in supply was about 0.5%. **(Source: IGU 2017)**

Table 1: Import –Export 2015 to 2017

Year	Exports (MMT)	Increase (MMT)	Increase (%)	Imports (MMT)	Increase (MMT)	Increase (%)
2017	300.1	28.6	10.5	297.0	30.2	11.3
2016	271.5	18.6	7.4	266.8	18.6	7.5
2015	252.9	-	-	248.2	-	-

Source: Waterborne LNG data, IHS Markit

According to LNG market experts, the much anticipated LNG wave to hit the market due to supply increase from Australia and the US has been delayed, but is expected to eventually appear in the market. Due to supply disruptions in various countries like Yemen, Egypt and Angola, coupled with lower than expected production by new LNG projects that have recently come online, LNG volumes entering the market have been lower than projected. According to the International Association of Energy Economics (IAEE), the LNG trade rose by 27 MMTPA between 2014 and 2016, even though 65 MMTPA of nameplate production capacity was added. As shown in Chart 1 below, the oversupply of LNG rose from 1.9 MMT in 2016 to 8 MMT in 2017. This surplus was not excessive and did not impact the market significantly in 2017.



Source: Waterborne LNG data, IHS Markit

Uncertainly in the market

There is a great deal of uncertainty with regard to how long the LNG glut will last. Estimates range from early to the late 2020s. This wide range of time shows that there is basically no consensus in the industry on how long the buyer's market in LNG will last. This uncertainty in the market means that project developers are hesitant to advance their projects, as they do not want to commission their projects in the low LNG price environment. This lack of certainty becomes evident as one looks at the project development in 2016. Only 3 trains had reached financial closure in that year and they were incremental capacity additions in brownfield projects. 2017 was the worst year of project development since 1999, as only one LNG project reached FID, the Coral FLNG.

In the last few years the shift to a buyer's market in LNG has further strengthened buyers demand to have LNG SPAs with smaller volumes, shorter term contracts with greater flexibility on commercial terms like delivery destinations and lower slopes resulting in lower prices. This trend accelerated in 2017 and it was not just buyers who were keen on limiting contracts, but sellers were also reluctant to make long term commitments, as they want the current market conditions to improve and get better prices for their LNG volumes.

In addition to this, power and gas market liberalization in the large LNG importing markets like Japan have added to this uncertainty. Financiers of LNG projects have funded low risk LNG projects in which the buyers were public utilities which had regional monopolies with guaranteed markets and had a great deal of certainty when it came to their demand profile.

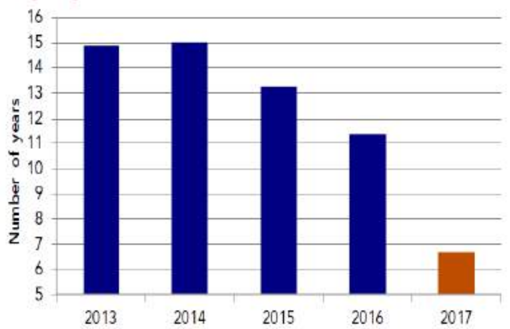
This is no longer the case with Japanese utilities, as they are having to compete for market share in Japan's newly-liberalized domestic gas and power sectors. This makes these utilities increasingly price sensitive and there is less demand certainty. These risks will have to be reflected in their upstream LNG SPAs. Japan and Korea, the two major LNG buyers in the World, also face uncertainty from the impact of nuclear restarts on LNG demand. Japan has five reactors in operation currently, but expects another four to start up in 2018. Korea also has issues with reactor startups and this make demand forecasting uncertain.

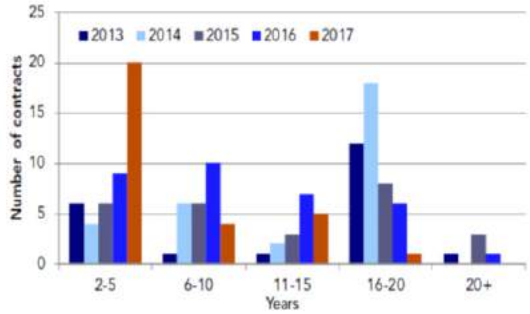
This general uncertainty about the timing of the LNG surplus has led to a change in contracting practices which has an impact on pricing and trade. They are 5 key developments in this regard in 2017 and the following section will throw some light on them.

1. Shrinking Term of Contracts

According to a study carried out on LNG contracts executed in 2017 by Poten and Partners, the tenure of the LNG SPA contracts executed from 2014 onwards has declined dramatically to about half from 15 years to about 6 to 7 years in 2017, as can be seen in Chart 2 below. Also Chart 3 shows the term of contract executed from 2013 to 2017. 2017 has 20 contracts executed with a term of just 2 to 5 years, which is more than double the number signed in 2016. In 2017 out of the total 30 contracts executed, more than 60% (20 numbers) were in the 2 to 5 year band. Out of the remaining 10 contracts, 4 were in the 6 to 10 year band, while 5 were in the 11 to 15 year band. Only one was in the 16 to 20 year band.

Chart 2: Average length of bilateral contracts Chart 3: Tenure of Contracts Executed Year-wise





Source: Poten LNG in the World Market, January 2018

2. Decline in contract volumes

Traditionally, a large share of LNG volumes sold in the market has been underpinned by long-term contracts and no destination flexibility. Over the last decade, a growing number of cargoes have been sold under short term contracts or on the spot market. This is due to the proliferation of flexible-destination contracts and an emergence of portfolio players and traders. In 2017, it was noticed that the average volume committed under LNG SPAs was less than in the previous years. As shown in Chart 4 below, in 2017, contracts with terms between 2 to 5 years, had a decline in average volumes to about 0.6 MMTPA, in 2017, from 0.8 MMTPA in 2016. For contracts with longer terms between 6 to 10 years, in 2017 the average contract volumes was 0.2 MMTPA, declining from almost 0.8 MMTPA. From chart we can see that the biggest decline in average contracted volume in 2017 was in medium term contracts between 6 to 10 years.

Chart 4: LNG Volume per Contract Term

Source: Poten LNG in the World Market, January 2018

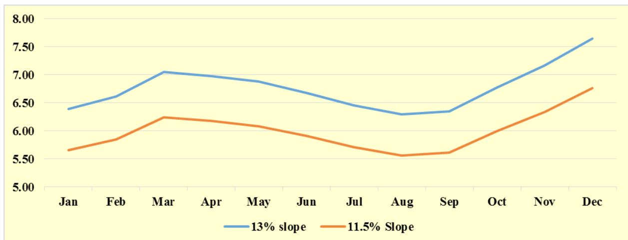
The total volume of LNG contracted in 2017 was about 22 MMT as compared to more than 30 MMT for 2016 and 22 MMT in 2015.

3. <u>LNG Pricing</u> - Contract Pricing Shifting back to Oil

For 30 contracts signed in 2017, 14 were oil linked with majority using dated Brent. 3 were linked to Europe Gas Hubs and 2 were Hybrid with a Brent / Henry Hub linkage. The slope to oil has declined in 2017 from 2016 for short term deals (2 to 5 years) due to surplus LNG available in the market. In 2017, the slopes for short term deals were within the low to mid 11% range, while in 2016, the slope ranged between mid-11% to above 13%. Japanese's Crude Cocktail has fallen out of favor with sellers as the JCC price is too low for their liking. Brent is a sweet crude, therefore, commands a premium as compared to JCC which is based on sour crudes imported from the Middle East. Also JCC prices are released after a few months of supplies and are not immediately available, so the LNG prices linked to JCC take long time to reflect actual market conditions. The reason for a shift back to oil linked pricing from gas hub, LNG indices and hybrid mechanism was due to the uncertainty in the market and no agreement in the market in general about what will be a benchmark alternative to oil linked pricing.

For the purposes of illustration, Chart 5 below shows the prices for 2017 linked to a 3 month Brent spot price average with a slope of 13% and 11.5%. The price difference between these two slopes would be between \$0.70 to \$0.80 /mmbtu.

Chart 5: LNG FoB price with Brent Linkage (3 Month Average)



Source: EIA, Poten

Spot LNG prices

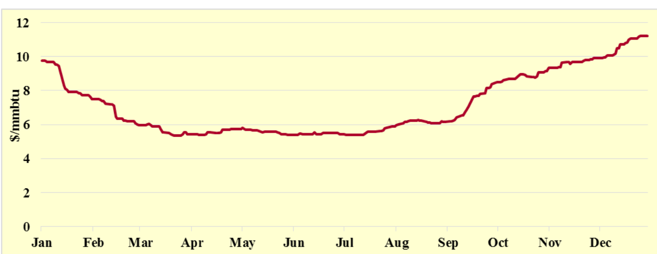
As far as spot prices are concerned, they are more based on the short term demand and supply dynamics, with factors like seasonal temperatures, immediate shortages in supply, shipping and unexpected spike in demand due unforeseen factors and, as China has shown, unexpected government policy measures.

In 2017, spot prices were recorded at their highest in the last 3 years. Spot prices in 2017 began in the high \$9/mmbtu range coming off from the peak winter demand of 2016. As spot prices seasonally drop after winter, the pricing assessments dropped to a low of \$5.25/mmbtu.

Chart 6 below shows that at the start of 2017, the LNG spot prices peaked due to the ongoing winter season in North East Asia and utilities in the region were procuring more LNG volumes for heating purposes. As winter comes to an end, temperatures become more moderate; so demand for heating in households and buildings declines. This means reduced demand for LNG spot cargoes and, as a consequence, LNG spot prices will decline as reflected in the pricing assessments from January onwards. During summer we would expect to see another spike in LNG spot prices as summer temperatures will lead to more demand for air conditioning. This summer price spike did not occur in 2017, as a few LNG trains were commissioned and they were ramping up LNG production in 2017, causing excess LNG supply in the market, which resulted in keeping LNG price for spot cargoes depressed during the summer. Additionally, large importer's like Japan went in for short term contracts in April 2017, as the slopes which determine LNG prices were very low during that time. This meant that they would not have to enter the spot market during peak summer time for spot purchases as they had already met their requirements through these short term contracts.

At the end of the year, as there was an onset of winter, a very sharp rise in prices took place. The key reason for this was unexpected strength of Chinese LNG demand. This increase in demand was because of three factors, firstly cold weather, secondly government policy directives encouraging coal-to-gas switching in power generation to combat air pollution, and lastly the replacement of coal-fired heating with gas-fired boilers in households in China this year. South Korea lost its position as the second largest importer of LNG in the World to China, with first position being held by Japan. This is despite South Korean LNG imports rising the highest since 2010 due to nuclear shutdown issues.

Chart 6: JKM Platts Pricing Assessment 2017



Source: Platts LNG Daily

4. Lack luster project development

In 2016, 5.9 MMTPA of new capacity was sanctioned, the lowest since 2008, but 2017 broke that record with only one FID for the Coral FLNG making it the lowest year since 1999 for new project sanctioning. But now due to the LNG surplus in the market and added uncertainty of the direction the market will head in and for how long, buyers now demand more flexibility in addition to shorter term contract and small volumes.

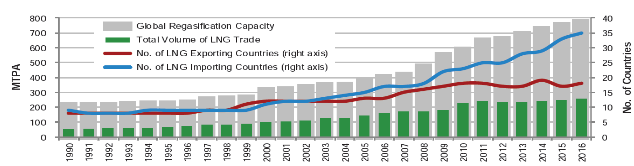
This new commercial paradigm for contracting LNG has put developers under great pressure as banks naturally prefer the more secure long term contracts, which guarantee cash flow for the life of the project. As the market has changed, the financiers of the projects have suggested that project developers at least secure some volumes under term contracts and the remaining volumes can be contracted out under shorter tenure contracts, allowing there to be a portfolio of contracts with varying terms and volumes. So far, no project has achieved financial closure under this commercial structure. Therefore, the portion of volumes of LNG that need to be contracted under term contracts and what will be the tenure of the contract itself, is not clear. As the commercial terms change of the new projects with the percent of longer-term contracts going down out of the total volume of LNG marketed, the risk level of these projects rises, so the debt-to-equity ratio will go down as financial institutions lend less to these projects and expect the promoters to share a bigger burden of the total financing cost. This change in financing structure will lead to a higher price of LNG as the project margins charged will go up to support the higher equity participation. Therefore, new project financing structures will have to emerge and even financial institutions backing these projects will have to accept more risk and new innovative pricing formulas and contract terms like destination flexibility.

5. Buyer's strategy for SPAs

In a new development in LNG contracting, of all the SPAs executed by buyers in 2017, with a term more than 2 years, approximately 8 SPAs were done through the tender route. Volume wise this method of LNG contracting accounted for only 10% of the total volume of LNG sold under new contracts in 2017. Out of the 8 SPAs, 6 had a term between 3 to 5 years, while 2 SPAs were of 15 years each. Two countries that were the main drivers for this method of LNG contracting were India and Pakistan. All these tenders were issued by buyers only. Traditionally tenders were generally used for spot trades or for fulfilling seasonal demand, but in 2017, tenders were used for LNG contracting and even for one contract with a term up to 15 years. Though the average term for contracts executed via the buy tender route was slightly more than 6 years, they were all delivered ex-ship and had oil price linkages, according to the study carried by Poten and Partners.

LNG Trade

Chart 7: LNG Trade and Buyers & Sellers



(Source IGU Edition 2017- 2016 in review)

The above chart shows the rise in LNG trade from 1990 to 2016, as well as the rising number of buyer and seller countries joining the LNG market, boosting liquidity. In 2017 there was no new addition to the LNG buyers or sellers club, which is a first since 2002.

In 2017, LNG trade faced some tense times. One critical episode was the diplomatic crisis which Qatar faced with some Middle East countries and passed without having a major adverse impact on the market. Also the Australian government's decision to regulate LNG exports to protect the domestic market prices also caused some jitters in the market. On the flip side, there is gradually slowing demand from major North East countries and some major term contracts with large volumes coming to an end of the tenure. This will release more LNG in the market and put further pressure on the market.

There was also an impact of government regulation on the LNG market, as the Japanese government declared that clauses that restrict destination in LNG SPAs are anticompetitive. In response to this, European Union also agreed to corporate with Japan and end destination restrictions on re-sales of LNG from Europe.

The growth of short term and spot trade accelerated in 2011 because of the Japanese Fukushima nuclear crisis, coupled with the massive increase in gas from the shale gas exploration in the United States. However, the share of LNG traded without a long-term contract as a percentage of the global market has tapered off since 2013. According to the International Gas Union (IGU), short-term trade is defined as agreements of less than 2 years and accounts for the vast majority of all volumes traded without a long-term contract in 2016. In 2016, short-term trade was 67.6 MT, or 25.8% of total gross traded LNG. The decline in short term trade in 2016 was due to several emerging markets like Pakistan and Malaysia importing LNG under new long-term contracts, while other markets that typically rely very heavily on spot and short-term volumes, like Brazil, measured large drops in LNG imports. Further, the majority of new liquefaction projects that started operations in 2015 and 2016 in the Asia-Pacific region are supported by long-term contracts that are starting, so these projects will to be able to offer much LNG volumes into the spot market or short term market.

International Group of Liquefied Natural Gas Importers (GIIGNL) defines spot trades as trades whereby cargoes are delivered within 3 months from the transaction date and GIIGNL estimated that for 2016, approximately 18% of total LNG volumes were under spot trade, which is about 47 MMT. This was an increase from the previous year 2015, of 15%, which is 37 MMT. The reason for this growth in spot trade was countries like China, India and Egypt, accounting together for 30% or about 15 MMT of the total spot LNG volumes in 2016. In 2017, China set a new record of increasing its imports by 12 MMT, which is the largest ever by a single country in a year. China also overtook South Korea to become second largest LNG importer, despite Korean imports increasing by the greatest amount since 2010.

Despite recording breaking demand by North East Asian Countries in 2017, no new buyers were added in the year and the recent buyers that have entered the market in the last few years will gradually continue to transit from spot and short term volumes to term volumes.

LNG outlook 2018 and beyond

According to Platts Analytics, global supply capacity growth is expected to outpace demand growth in 2018, with 31.8 MMTPA of new capacity due to come online, versus a forecast global demand growth of 23.3 MMTPA on year. Demand for LNG is forecast to grow by 7.9% from 2017 to a total of 317.4 MMT. The main driver for this demand growth will be the Asia Pacific region with demand rising by 11% in 2018 to 231.2 MMT.

In Northeast Asia, the total imports from Japan, South Korea, China and Taiwan are expected to increase 4.6% in 2018 from 2017 to 181 MMT. That growth is supported solely by China's demand growth, with the other three key importers to have declining imports. China's imports are expected to grow by 32.1% or by nearly 12 MMT to reach nearly 49 MMT in 2018. The impact of government policy promoting coal-to-gas switching is expected to be significant in 2018. While in Japan, the world's largest LNG consumer, LNG imports are expected to decline by 4.1% year on year to 78.9 MT, as the country pushes to restart its nuclear reactor fleet. In South Korea, LNG imports for 2018 are expected to decline by 1.1% to 36.7 MMT. This is because in 2017 LNG imports were supported by nuclear outages in the first quarter of 2017 and the commissioning of three new storage tanks. In Taiwan, LNG imports for 2018 are expected to decline by 1.6% to 16.1 MMT because of newly commissioned coal-fired power generation capacity that is expected to reduce demand for gas-fired power generation. Additional demand from India, Pakistan, Bangladesh, Singapore, Thailand, Malaysia and Indonesia could hit 50 MMT in 2018, up 41% from 35.4 MMT in 2017.

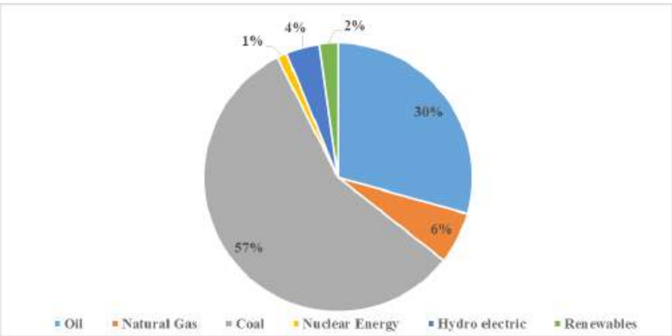
According to some industry experts, 100 MMTPA of new capacity will be starting up between 2017-2020, out of which 85 MMTPA will be commissioned in 2019. This supply boost will come mainly from 2 countries, USA and Australia, with 50% of it coming from Australia alone. Some expected that the LNG market may achieve balance between demand and supply before the mid-2020s, but by Qatar's July, 2017, announcement that it would expand LNG liquefaction capacity by 30% to 100 MMTPA by 2023, this LNG glut may last now well into the late 2020s. In conclusion, it seems the LNG market will be entering a period of long term structural oversupply, with more liquidity and flexibility in LNG procurement. This augers well for developing LNG markets like India which are price sensitive and lack a gas rich geology.

Indian Gas Scenario 2017: Year in Review

According to the International Energy Agency's (IEA) World Energy Outlook, India's economy is expected to grow more than five times its current size by 2040, leading to a massive increase in energy demand. In addition to this, India's population is expected to exceed 1.6 billion, overtaking China in the early 2020s.

India's current share of global energy consumption, according to the BP Statistical Review of World Energy 2017 is 5.5%, compared to 30% to that of China. Coal and oil will have the biggest shares of India's energy basket, contributing heavily towards emissions. Therefore, with a view to control emissions the government is targeting an increase in the share of natural gas. The emissions target India has under the Intended Nationally Determined Contributions (INDCs) of the United Nations Framework Convention on Climate Change (UNFCCC) for reductions in greenhouse gases is the reduction of emissions intensity of its GDP by 33 to 35 per cent by 2030 from 2005 level and to create an additional carbon sink of 2.5 to 3 billion tonnes of CO2 equivalent through additional forest and tree cover by 2030. Chart 8 below shows coal and oil in 2016 accounted for 87% of the total energy consumed in India.

Chart 8: Fuel share in India's Energy Consumption in 2016



Source: BP Statistics 2017

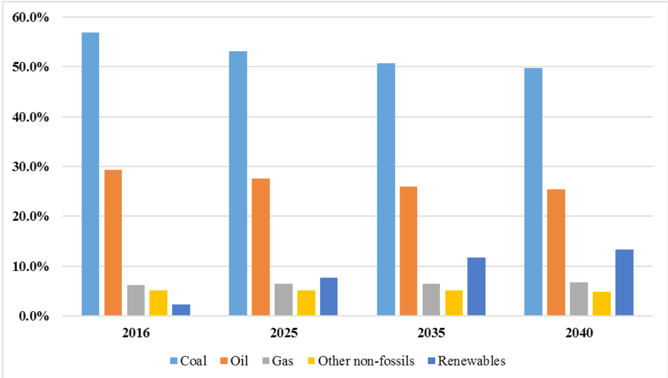
According to the BP Energy Outlook 2035, the usage of coal and oil in India's primary energy consumption will continue to be high, despite a drop in their respective shares from 57% and 29% in 2016 to 49% and 25% in 2040. Natural gas's share in India's energy consumption on the other hand, rises marginally from 6.2% to 6.7% throughout the projected period, while demand for gas is expected to expand by 286% as against 230% and 232% for oil and coal respectively, from 2016 to 2040. Non-Fossil and Renewables will have the highest growth as in 2016 they have relatively a smaller base to start from, as compared to other fuels. Despite their high growth, they will still account for a small percentage of the total energy consumption by 2040 in India.

Table 2: India's Energy Consumption growth from 2016 – 2040 (MTOE)

Fuel Type	2016	Share 2016	2040	Share 2040	Growth in % 2016-2040	CAGR
Oil	212.7	29.38%	489.50	25.4%	230.16	3.53
Natural Gas	45.1	6.23%	129.00	6.7%	286.13	4.48
Coal	411.9	56.91%	959.13	49.7%	232.83	3.58
Non-Fossil Fuel	37.7	5.21%	257.06	13.3%	681.85	8.33
Renewables	16.5	2.27%	94.43	4.9%	573.51	7.55
Total	723.9	100.0%	1,929	100.0%	266.49	4.17

Source: BP energy Statistic 2017, BP Energy Outlook 2035

Chart 9: Fuel share in India's Energy Consumption 2016-2040



Source: BP energy Statistic 2017, BP Energy Outlook 2035

Thus, while these trends signify that natural gas usage in India will remain marginal as compared to oil and coal, it then begs the question of how the government's ambitious target to more than double the share of natural gas to 15% in India's energy consumption is going to be achieved. Given the need for India to curb its emissions coupled with projections for marginal increase in gas use till 2040, the current liquefied natural gas glut, India's push towards natural gas to fuel its economy, is well timed.

Push For Gas

Even though the BP projections paint a very bleak picture for gas in India, it must be remembered that these are forecasts and do not accurately predict the future. They are based on the current scenario existing in India and are not taking into account changes in government policy or market conditions and other disruptive changes that may take place, like in renewables.

The new government's plans to more than double the share of natural gas in the energy mix to 15 per cent by 2022 will require a huge increase in imports of LNG and the construction of more LNG terminals, as domestic gas production is not expected to grow significantly. India has four terminals to receive LNG and over the next seven years there are plans to build another 10 terminals. India plans to electrify millions of households that still burn wood for light, heat and cooking and also plans to reduce its heavy reliance on coal, the biggest polluter.

Upstream Push

From NELP to HELP

Since the advent of New Exploration Licensing Policy (NELP), over 250 blocks were awarded under nine rounds of bidding held over a period between 1990 and 2010. The government in order to boost Exploration and Production (E&P) activity in India and make the E&P sector more attractive, has shifted from NELP to Hydrocarbon Exploration Licensing Policy (HELP).

Chart 9: Architecture of HELP

Source: Director General Hydrocarbon

Under HELP, each block on offer has been carved out by prospective bidders under the open acreage licensing (OAL) policy and a total of 55 fields were offered under the first auction. Now contractors will themselves identify blocks for which they want to bid, unlike in NELP, wherein they bid for blocks offered by the government under different NELP rounds. Contractors can submit Expression of Interest (EoIs) throughout the year which will be then be evaluated together every six months. Six Indian companies have submitted bids for 55 blocks, covering 59,000 sq. km, which are now being opened to bids by others. Profit-sharing model of NELP has been replaced with a revenue-sharing system to avoid possible dispute and litigation over capital expenditure claims by contractors. Besides this, there is now a unified license that would allow harnessing of both conventional and non-conventional hydrocarbon resources and contractors of the blocks have also been given marketing and pricing freedom.

Despite the best efforts by the government to encourage as much interest in the oil and gas sector, the response was disheartening. No foreign oil company had submitted any bid and there were only six domestic companies. ONGC had bid for 41 blocks and Vedanta's Cairn India for 15 blocks, with four smaller domestic oil companies. Reliance did not participate in the bidding process. According to some, due to this lackluster response, the government's goal of reducing oil imports by 10% in 2022 will be very hard to achieve.

Discovered Small and Marginal Fields (DSF)

In addition to the above, the government successfully auctioned out 44 discovered marginal fields (28 onland and 16 offshore) in February, 2016 under the Discovered Small and Marginal Fields (DSF) round of auction. The government's expectation is that about 40 million tons of oil and 22 BCF over a 15 year period can be produced from these fields. These fields which were offered in the first DSF round were originally discovered by ONGC and Oil India and not developed as they were considered to be economically unviable at that time.

The government after evaluating the response and bids results from the first DSF auction have also decided to launch a second round of DSF. The 60 discovered marginal fields to be put on offer for the second round are estimated to have 194.65 mtoe oil and gas reserves in place and this is a bigger offering than the round 1.

Coal Bed Methane (CBM) pricing policy

To further encourage gas production in the country, the government approved pricing and marketing freedom to producers of natural gas from coal seams (CBM). To discover the arm's length sales, a contractor has to ensure a fully transparent and competitive bidding process from among users of the CBM gas with the objective that the best possible price is realized for the gas. Of the 33 CBM bearing blocks awarded so far in four auction rounds and on a nomination basis, gas is being produced from only 4, so the government is hoping that this new pricing and marketing policy will incentivise further production. The 4 CBM blocks in production have a combined output of 1.17 MMSCMD. As many as 18 blocks have either been relinquished or are in the process of being relinquished, as operators found that it did not make economic sense to produce gas at the prevailing rates. According to the Directorate General of Hydrocarbons (DGH), India has the 5th largest proven coal reserves in the world and holds significant prospects for exploration and exploitation of CBM. The estimated CBM resources in the country are about 92 TCF. The 33 CBM blocks awarded so far hold a total of 62.4 Tcf of the estimated CBM resource, of which so far, 9.9 Tcf has been established as Gas in Place.

Shale- An opportunity lost?

In October, 2013, government granted permission for Shale gas and oil exploration and exploitation initially only by National Oil Companies (NOCs) i.e. ONGC & OIL for on-land nomination blocks i.e. blocks awarded to the NOCs on nomination basis before the advent of Pre-NELP and NELP PSCs. The policy was announced with exclusive purpose of promoting Shale Gas & Oil operations in the existing on-land areas under Nomination.

As per the policy, the NOCs have been permitted three Assessment Phases for exploration (Phase I, II & III) of 3 years. Each Phase will culminate in a development and production phase depending on the results of the Assessment Phase.

By November 2016, ONGC stated that they were having limited success in shale oil and gas fracking. Shale gas exploration are not conducive in India as the availability of huge water resources, needed for shale gas operations, remains a major challenge. Shale gas exploration not only involves the use of fresh water, but land acquisition, which also is a potential issue due to the large tracts of land required for fracking that may lead to displacement of people. India is a densely populated country and the legal and logistical issues for acquiring land required for shale oil and gas pose serious problems for companies.

Downstream Push

In tandem with the push by government in the upstream sector, there is also a push by government in the downstream gas consumption sector. The government is trying to build up gas demand in the country through various downstream initiatives. They include infrastructure development of LNG import terminals, gas pipelines and other policy and regulatory measures like uniform tariffs of gas pipelines.

LNG Import Terminals

There is a push in India to develop more LNG Import Terminals. The nameplate capacity of the 4 operating terminals is about 30 MMTPA. Two Terminals are under construction and are of 5 MMTPA each, while one is an expansion of 2.5 MMTPA at the Dahej Terminal of PLL. The rest are under planning stage.

Table 3: LNG Import Terminal Status

No.	TERMINAL	DEVELOPERS	CAPACITY (MMTPA)
	Existing Terminal		
1	Dahej	Petronet LNG Limited	15.0
2	Hazira	Royal Dutch Shell, Total Gaz Electricite	5.0
3	Dabhol	GAIL,NTPC	5.0
4	Kochi	Petronet LNG Limited	5.0
	TOTAL EXISTING		**30.0**
	UNDER CONSTRUCTION		
1A	Dahej Expansion Phase III B	Petronet LNG Limited	2.5
5	Mundra	GSPC, Adani	5.0
6	Ennore	Indian Oil Corp, TIDCO	5.0
	TOTAL UNDER-CONSTRUCTION		**12.5**
	PLANNED		
7	Dhamra	Adani	5.0
8	Jafrabad (FSRU)	Swan, Exmar	5.0
9	Jaigarh	H Energy	5.0
	TOTAL PLANNED		**15.0**
	PROPOSED		
10	Gangavaram	Petronet LNG Limited	5.0
11	Kakinada	GAIL, APGDC, Shell **or** VGS	2.5
12	Kolkata Port	H Energy	2.5
13	Chhara	HPCL & Shapoorji Pallonji	5.0
14	Krishnapatnam	LNG Bharat	2.5
	TOTAL PROPOSED		**17.5**
	GRAND TOTAL		**75.0**

Source: PPAC; PLL analysis

Pipeline connectivity is a major issue in the gas markets as a LNG Import Terminal with limited pipeline access cannot have market penetration. The last mile connection to the industrial and residential users is essential, as without that the gas market cannot develop. Petronet LNG Ltd's Kochi Terminal, is one such facility facing a challenge in reaching consumers as it does not have sufficient gas pipeline connectivity. The gross capacity is expected to be 75 MMTPA in the best case scenario of all terminals listed here getting commissioned, but the actual number to be commissioned will be lower as all projects may not reach financial closure.

Gas Pipeline Network

To tap into a bigger gas market and increase the last mile connectivity for gas, the government's National Gas Grid Plan (Pradhan Mantri Urja Ganga) envisages developing additional 15,000 km of gas pipeline network. At present, the natural gas grid in the country predominantly connects the western, northern and south-eastern gas markets with major gas sources. As a commitment to provide clean energy in the Eastern part of the country, the Government has approved a capital grant of Rs. 5,176 Crore (40 per cent of the estimated capital cost of Rs. 12,940 Crore of the entire gas pipeline project).When it comes to gas pipelines, India currently has 16,470 Km of gas pipelines with 387 MMSCMD of capacity. Another 13,489 Km is under construction with an estimated capacity of 548 MMSCMD.

City Gas Distribution

The PNGRB, has put these 86 geographical areas (GAs) on offer under the ninth bid round, expects to attract investment of around Rs70,000 crore.

The contracts entail supplying piped cooking gas and compressed natural gas (CNG) to 174 districts across 22 states and Union territories and the licenses will be awarded by October 2018. This is in support of the government policy of developing a gas-based economy. The plan is to connect 10 million households to piped natural gas by 2020.

So far, India has CGD networks in 91 GAs operated by 36 firms. With 16,500km of pipelines in operation, 42 lakh domestic consumers and 33,000 industrial and commercial consumers, 19% of India's population has been covered by the CGD network.

The 86 new GAs on offer will cover 24% of the country's area and 29% of its population.

Indian government is planning to reduce its carbon emissions by 33-35% from its 2005 levels by 2030, as part of its commitments to the United Nations Framework Convention on Climate Change adopted by 195 countries in Paris in 2015.

In the current bid round regulations have been relaxed to increase marketing exclusivity from five to eight years, with infrastructure exclusivity provided for 25 years.

Regulatory and Policy Impact

Uniform Gas Pipeline Tariff

The Petroleum and Natural Gas Regulatory Board (PNGRB) has recently issued a Public Discussion Document inviting opinions on the proposal. This is due to a massive investment program by GAIL of Rs 12,940 Crore on constructing a pipeline for eastern India, as part of the National Gas Grid. GAIL is of the view that the transmission tariff for carrying gas through new pipelines may be too high for customers connected to it and has proposed a scheme to pool the tariff across seven existing pipelines. The impact of this will be the reduction in gas transmission tariff for new lines and increasing tariff on existing gas pipelines lines. The main pipeline of 1,836 kms will be from Jagdishpur in UP to Haldia in West Bengal, near Kolkata. It will interconnect with a second line that connects Bokaro in Jharkhand to Dhamra on the Odisha coast. The combined pipeline will be 2,539 km long, with capacity to transport 16 mmscmd of Natural Gas. GAIL has also estimated the Unified Tariff to be Rs.57/mmbtu. But there are pros and cons to this tariff structure and in a pooled tariff system certain parties, due to lower charges benefit, while other parties will lose as their charges will rise to compensate for the lower charge. This may lead to majority of the consumers protesting the implementation of the Uniform Tariff. The Table 4 below shows the net impact on GAIL's revenue, which will be a positive of Rs. 1009 crores.

Table 4: Gas Pipeline Tariffs vs Uniform Tariff

	Pipeline name	Current tariff	Unified tariff
		Rs/mmbtu	Rs/mmbtu
1	Dadri Bawana Nangal DBNPL	73.36	57
2	Chhainsa Chhajjar Hissar CJHPL	67.17	57
3	Dabhol Bangalore DBPL	40.83	57
4	Dahej Uran Panvel Dabhol DUPL-DPPL	24.49	57

Source: InfralinePlus

The Uniform Tariff will be beneficial for a growing industry as many new gas pipeline projects need to be implemented in the future, as the government tries to increase the penetration of gas in the country. To encourage industries to connect to these pipelines and use gas instead of liquid fuels it is critical that gas prices be as competitive and that means minimizing cost across the gas supply chain. Therefore a Unified Tariff is one way to ensure that new users connecting to newly built pipelines do not pay higher tariffs than consumer who are connect to older infrastructure.

Unbundling

In order to stimulate gas market development, the government is also considering the unbundling of GAIL India Ltd., as it is the largest gas pipeline owner in the country and is also a gas marketer which is in direct conflict of interest with its gas transmission business. In order to provide a fair and an open access system for gas transmission in the country, the government is now considering unbundling of GAIL. In 2017, GAIL earned over 70% revenue from marketing operations, while over 40% of the profit came from natural gas transmission.

A sole company dedicated to building gas pipelines will have an incentive to build as quickly as possible as many gas pipelines it can in the country and will want to encourage as many shippers to transmit gas through the gas pipeline network. This ease of gas transmission on a transparent capacity booking system will encourage a more liquid market.

LNG/Gas Hub in India

In order to have a market determined price discovery of gas in India, the government is also putting together a plan to set up a domestic gas hub, where both imported natural gas (LNG) and domestically produced gas will be traded. An electronic trading platform is expected to be ready sometime in 2018, which will allow only physical trading. This project, if successful, will be a major development for the gas industry, as market prices will be determined by bids by buyers and offers by sellers. Demand and supply dynamics in India will start to determine the actual price of gas in the market rather than any form of government control or formula based on other gas markets.

LNG in India Review 2017

The balance between domestic gas and R-LNG consumption was evenly divided with R-LNG accounting for 51% of the gas consumed in the country and 49% by domestic gas. The sector wise consumption for domestic gas and R-LNG is shown in Table 5 below

Table 5: Domestic and R-LNG consumption for 2017 MMSCM

Sectors	Domestic gas consumption	R-LNG consumption	Total Consumption (Domestic gas +RLNG)
Fertilizer	19.28	20.60	39.87
Power	25.87	7.03	32.89
City Gas	12.48	10.01	22.49
Other Industries	12.47	33.92	46.39
Total	70.10	71.56	141.65

* Petrochemicals/ Refineries/Internal consumption/LPG Shrinkage/ Manufacture/Sponge Iron

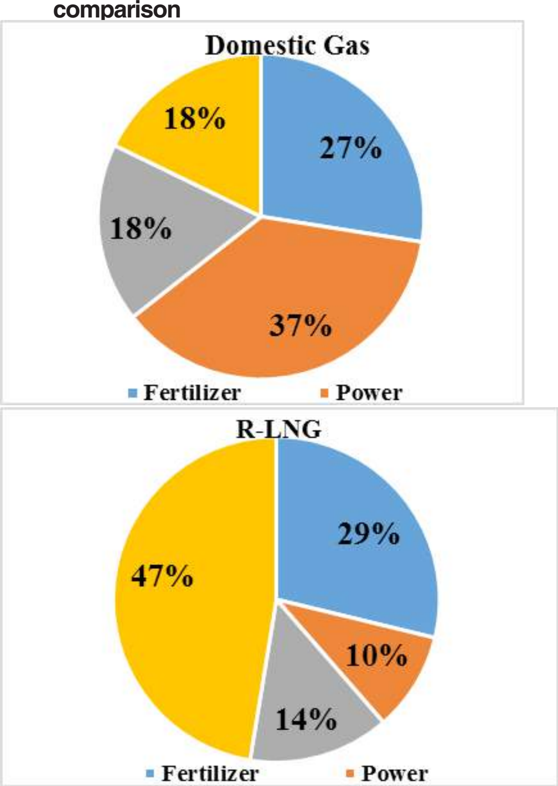
Source: PPAC

It can be seen from the above table that in the power sector, domestic gas constitutes about 80% of the gas consumed and R-LNG only 20%. This is because the power consumers are very price sensitive and power produced with only R-LNG will prove to be too expensive to sell. City Gas Distribution has higher affordability, while in fertilizer, the cost of production is a pass through with government subsidizing the difference between the cost price and the selling price of Urea. The sector called Other Industries includes Manufacturing, Petrochemicals, Refineries, Sponge Iron etc. They have higher affordability so they can absorb more R-LNG.

Chart 10 below shows the sector wise break up for domestic gas and R-LNG consumption in the country. For domestic gas it can be seen that 64% of the gas consumed in 2017 was by the power and fertilizer sector. Power and Fertilizer are generally the biggest consumers of gas, but they are regulated industries, as fertilizer prices are regulated by government and power tariff are also regulated by state and central regulatory authorities. Due to this, they are more price sensitive than other industries which are not subject any government price controls. Domestic Gas being cheaper has to be sold to them as per the governments Gas Utilization Policy.

As far as R-LNG is concerned, as the price is market determined and no government policy regulates R-LNG's price, its affordability for the Fertilizer and Power drops significantly and is consumed more by industries like refineries, sponge iron, manufacturing, petrochemicals, etc. Chart 10 below shows that power and fertilizer consumer a total of 39% for R-LNG consumed, while consumers classified as Other Industries consumes 47%. The Other Industries also do not have their selling price like power and fertilizer regulated and can afford to pass on any cost increase to the consumer.

Chart 10: Domestic Gas vs R-LNG Sector-wise consumption comparison

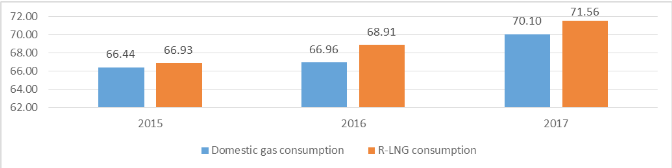


Source: PPAC

India's LNG Imports in 2017

Table 5 shows the LNG consumption of India as compared to domestic gas consumption from 2015 to 2017. From 2015 to 2017 gas consumption rose incrementally by about 8 MMSCMD and the R-LNG's share of the gas market in India was hovering around 50%.

Chart 11: 2015 to 2017 LNG and Domestic Gas consumption (MMSCMD)



Source: PPAC

LNG industry in India started on a somber note in 2017 as in January, 2017, the imports declined by 14.7% from December, 2016, due to the economic impact of demonetization coupled with high spot prices during that period caused by peak winter heating demand. Spot prices during that period reached about \$10/mmbtu. This made term contract prices in India cheaper and Indian buyers were put off buying spot LNG from the market. In 2016-2017 cumulative imports were higher than 2015-16, as there was a subsidy given by government to gas based power producers, lower LNG prices internationally which encouraged more buying by Indian importers and a 1 MMTPA CFR contract with Qatar Gas and Petronet LNG Ltd, which led to increased imports under a long term contract. According to the government, gas demand in the country is at least double the current consumption level, but is constrained due to lack of gas pipeline infrastructure. Chart 12 below shows the domestic consumption vs R-LNG in 2017. On an average, for every month, they are almost evenly split.

Chart 12: Domestic vs R-LNG Consumption (MMSCMD)

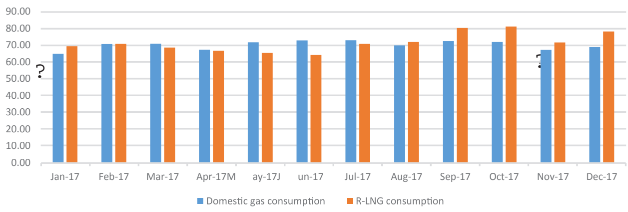


Chart 13: R-LNG Import (MMSCMD)

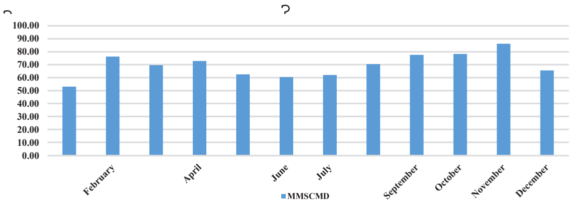


Chart 13 above shows the monthly LNG imports into the country. In February, LNG imports went up sharply to 76 MMSCMD from 53 MMSCMD in January, which was an increase of more than 40%, while consumption remained at January levels. This was because LNG importers in India were stock building. This was due to oil prices rising and as a consequence LNG became comparatively cheaper. Domestic gas demand in February was also gradually recovering as the demonetization impact was slowly wearing off, but the first preference would be to consume the cheaper domestic gas. Domestic gas consumption rose from 65 MMSCMD to 70 MMSCMD. At the same time spot LNG prices dropped from $10 to $6/mmbtu.

For March and April there was a minor variance in LNG imports from 70 to 72 MMSCMD. During this period spot prices continued their steady decline to $5.50/mmbtu. In May, imports fell by 14%. This was due to slow down in manufacturing growth as aggregate demand in the country was slowing, due to sluggish GDP growth. In June there was further decline in LNG imports. Though at the beginning of the year there a sharp recovery in LNG imports, the impact of demonetization was still being felt and economic growth was struggling. In June a smaller fall in LNG imports was recorded of about 3%.

In July there was a reversal in the decline of LNG imports, since March, though it was an incremental increase of 2% from June to 62 MMSCMD. In August LNG imports continued to rise and was 8% higher than last July. In April to Jun 2017, economic growth slowed to a three year low due to the impact of demonization which was implemented in late 2016. Also the implementation of GST in July, 2017, also impacted small to medium businesses in manufacturing as they adjusted to the new taxation code.

In September, LNG imports rose to 77 MMSCMD. This was because as coal stockpiles were declining and coal inventory was very low, which would result in coal based thermal power plants reducing generation and gas based power plants would have to fill the gap. This would lead to additional LNG imports to meet increased gas based power sector demand. In October the LNG import story was the same as more gas was needed to support increase gas based power generation.

For November, LNG imports went up by 8% from October to 86 MMSCMD and the majority of the LNG cargos were bought from Angola LNG. This was due to destination restrictions placed by Angola LNG as they wanted the LNG Vessels back quickly from trade runs back to their load port. In December a sharp decline took place in LNG imports of 20% from November. This was due to rising spot prices which depressed demand and an increase in coal stocks which reduced demand for gas based power. December is the winter month and demand by North East Asian countries rises as they require additional LNG to meet rising heating demand, which pushes up LNG spot prices.

Outlook for gas in India

Gas is a fuel which will be an essential component of the Indian energy mix. Though there is much emphasis on the renewable sector, one has to be realistic about the expectations one has about how much this sector can contribute. There are issues of variability for wind and solar and the additional issue of storage. These technologies, specially for storage will take time to develop and till then fossil fuels will continue to play a vital role in India. Gas will have to be a bridge fuel which has to be used increasingly to offset the impact of fossil fuel emissions. Fossil fuels are here to stay for the long term, but with new technologies and better emission controls reduces their negative impact on the environment. As far as energy independence is concerned from the point of view of fossil fuel imports, it does not seem to be possible for India to achieve energy independence, as the geology of India is not very rich in hydrocarbon resources. As India is expected to be increasingly dependent on imports of oil in the future, gas will also face the same demand supply imbalance. It seems LNG will have to play an increasingly major role in India's environmentally sustainable growth story for a long time to come.

Threat from Competition

All the major players in the Indian hydrocarbon business and many new players, including foreign entities, have plans to enter the natural gas business. Competition is expected across the gas value chain.PLL is prepared to face the competition in the market through long term tie-up of LNG/ Regas capacity.

In India, gas competes primarily with Coal (in Power sector) and with liquid fuels (in Industrial and Fertilizer sectors). As a result, gas demand is fairly price- sensitive for the Power sector. However, gas demand has a fairly low elasticity for the Fertilizer sector due to the existing Fertilizer policy.The city gas distribution segment, where the competition is mainly with high- priced petroleum fuels (HSD, Petrol, LPG, etc.) faces challenges in terms of infrastructure and conversion costs.

Many new players are in the process of setting up LNG terminals – land based and / or FSRUs at various locations in the Country. LNG terminals at Mundra and Ennore are expected to be commissioned in the next few months. Being in the same market, the LNG terminal at Mundra is expected to compete with the Dahej LNG terminal.

Segment wise or Product wise Performance

Presently, PLL primarily deals only in one segment, i.e. Import and Re-gasification of Liquefied Natural Gas (LNG).

Risk and Concerns

PLL considers good corporate governance to be a pre-requisite to meet the needs and aspirations of shareholders and other stake shareholders alike. As part of the company's efforts to strengthen corporate governance, the Board of Directors has formulated a Risk Management Policy. This policy puts a risk management structure in place that clearly defines roles and responsibilities. It also provides a risk portfolio that involves a continuous process of risk identification, assessment and monitoring, review and communication. The company aims to:

- Identify, assess and manage existing and new risks in a planned manner.
- Increase the effectiveness of PLL's internal and external reporting structure.
- Develop and foster a 'risk' culture within the organization to encourage all employees to identify risk and associated opportunities and respond to them with appropriate actions**.**

Risk of Competition

LNG competes with naphtha, coal, fuel oil and similar hydrocarbons. These alternate fuels are currently widely used by end-user industries like fertilizers and power. In addition to the above- mentioned fuels, LNG also competes with the domestic natural gas. LNG offers several advantages over the above-mentioned fuels.

PLL LNG sourced under long-term contract linked to crude oil prices, is currently facing price challenge from alternate fuels. Further, spot LNG prices moving away from crude linkage also puts the Long Terms crude linked contracts under threat. This may have an impact in the near growth of PLL.

Currently, the company does not produce or market any products other than LNG/R-LNG. The sole activity is the import and re-gasification of LNG. PLL has sourced LNG under long-term contract from RasGas of Qatar and has sold re-gasified LNG mainly to three intermediate off-takers, namely, GAIL (India) Ltd., Bharat Petroleum Corporation Ltd., and Indian Oil Corporation Ltd. PLL has long-term gas sale and purchase agreements with these reputed companies. Even though this assures market for the entire product, there are risks involved due to limited customers base.

In addition to the contracts with RasGas of 8.50 MMTPA, PLL also has another long-term contract with the Australian entity of Exxon Mobil for supply of around 1.44 MMTPA of LNG from its Gorgon project. Similar arrangements of offtake have been made with BPCL, GAIL and Indian Oil.

PLL also provide regas services to third parties who import LNG directly. PLL has executed 8.25 MMTPA equivalent contracts to provide long- term regas services to GAIL, IOCL, BPCL, GSPC and Torrent from existing and expansion plans of Dahej. PLL entered into an Agreement with ONGC for extraction of C2-C3 which is extracted at ONGC's Plant located near to Dahej Terminal.

Internal Control Systems and their Adequacy

The company has developed adequate internal control systems commensurate to its size and business. PLL has appointed Ernst & Young as Internal Auditors, who conduct regular audits for various activities. The reports of the Internal Auditors are submitted to the Management and the Board's Audit Committee. There is a thorough review of the adequacy of internal control system.

Financial Performance

The turnover during the financial year ended 31st March, 2018, was Rs. 30916.02 Crore including other income as against Rs. 24962.67 Crore in FY 2016-17. The net profit during the financial year ended 31st March, 2018, was Rs. 2077.85 Crore as against Rs. 1705.67 Crore in 2016-17.

Disclosure by Senior Management Personnel, i.e. One Level below the Board including all HODs

None of the senior management personnel has financial and/or commercial transactions with the company. They do not have any personal interest that would have a potential conflict with the interest of PLL at large.

Cautionary Statement

Statements in the Management's Discussion & Analysis describing the Company's objectives, expectations or anticipations may be forward looking within the meaning of applicable securities, laws and regulations. Actual results may differ materially from the expectations. Critical factors that could influence the Company's operations include global and domestic demand and supply conditions affecting selling prices of products, input availability and prices, changes in Government regulations/tax laws, economic developments within the country and factors such as litigation and industrial relations.