CHAPTER I: MINISTRY OF PETROLEUM AND NATURAL GAS

Bharat Petroleum Corporation Limited

1.1 Extension of credit facility to a defaulter company without security

BPCL had been supplying fuel oil to KPCPL since June 2000. The fuel supply agreement did not have adequate safeguards to protect the financial interests of BPCL. BPCL did not ensure suitable security against credit sales to KPCPL, though the company defaulted on payment. This resulted in non-recovery of sales revenue amounting to ₹ 23.50 crore.

Bharat Petroleum Corporation Limited (BPCL) signed (24.06.2000) a Fuel Supply Agreement (FSA) with Kasargod Power Corporation Private Limited (KPCPL)[1] for supply of Fuel Oil (HSD and LSHS) to KPCPL's power plant at Mylatti in Kasargod District, Kerala State. The FSA, *inter-alia*, stipulated that the agreement period would be for 15 years (Article 2), that the bills would be paid on the 1st of every month along with interest for delay (Article 8) and that the agreement would be terminated if the buyer fails to make payment continuously for a period of three months (Article 16.02.1). The FSA did not have provisions for 'letter of credit' or 'liquidated damages & indemnity' to safeguard the financial interests of BPCL.

BPCL commenced supply as per the agreement and received timely payments upto March 2006. KPCPL defaulted and delayed the payments w.e.f April 2006. BPCL, however, continued credit sale of fuel oil to KPCPL.

Meanwhile, a credit policy was introduced in BPCL on 1st January 2009. This policy inter-alia stipulated customer categorisation, risk assessment, customer re-appraisal and setting credit limit accordingly. As per this policy, sales to very high risk customers were to be made either on pre-payment basis or secured with documents such as Letter of Credit, bank guarantee, parent performance guarantee or asset pledges. BPCL carried out the credit evaluation of KPCPL after one year. KPCPL was classified as "Medium Risk" customer[2] and sanctioned a credit limit of ₹ 10.50 crore in February 2010. The 'medium risk'categorisation was despite outstanding dues worth ₹ 27.40 crore against KPCPL which had accumulated from 2006-07 to 2009-10; more than twice the sanctioned credit limit.

Audit had commented (May 2010) on the accumulation of outstanding amount from KPCPL and up-liftment of products by KPCPL being more than payments made by it. Management had assured Audit that the case would be reviewed based on further receipts from the customer. After being flagged by Audit, BPCL raised (July 2010) the issue of

[1] ***KPCPL never used the word "Private" in their letter pad while corresponding with BPCL and even in FSA agreement the word "Private" was not printed however "Pvt" was manually incorporated and signed.***

[2] ***Credit policy permitted unsecured credit to medium risk customers.***

non-payment with KPCPL which was reiterated in August 2010. BPCL also asked (August 2010) KPCPL for a bank guarantee of ₹ 25 crore from a nationalized bank as security.

KPCPL neither paid the outstanding amount nor did it submit a bank guarantee. BPCL, however, continued to supply fuel on credit till July 2011. In July 2011, BPCL decided that future supplies to KPCPL would be drawn against advance payment till the overdue payments were cleared. At this point (June 2011), KPCPL had an outstanding balance of ₹22.06 crore.

KPCPL again defaulted in November 2012. BPCL continued its fuel supply till June 2013 after which fuel supply was stopped. As on March 2015, an amount of ₹ 23.50 crores[1] remained to be recovered from KPCPL. Meanwhile (in February 2014), BPCL has initiated arbitration proceedings against KPCPL which is presently under process (November 2015).

BPCL, thus, failed to secure its financial interest vis-à-vis KPCPL, *ab initio* through appropriate clauses in the FSA. Even after default by KPCPL, credit sales beyond the credit limit were continued to the company, without security, in contravention of the credit policy of BPCL. This has led to accumulation of outstanding dues of ₹ 23.50 crore (March 2015) and arbitration proceedings for its recovery.

Management replied (October 2015) that the terms of agreement with KPCPL were finalized as per the prevalent delegation considering then existing market conditions, business opportunity, availability of products etc. The credit extended was agreed to considering the payment receipt cycle of KPCPL from Kerala State Electricity Board (KSEB) and bank guarantee/ letter of credit was not considered necessary. Further, M/s. KSEB, being a utility company, unilateral stoppage could not be done due to critical nature of business. Both KPCPL and KSEB agreements, which were for supply of power to the State of Kerala, did not have any payment security through bank guarantee/LC. Management also stated that liquidated damages clause had been incorporated in both agreements. As such, there was no difference between these agreements. Management also stated that the recovery from KPCPL is presently under arbitration.

The Management response is not acceptable in view of the following:

(i) The statement that the agreement signed by BPCL with KPCPL had a 'liquidated damages' clause is incorrect. In fact, Audit noticed that clauses in the nature of 'letter of credit'/ 'liquidated damages and indemnity' to safeguard the financial interest of BPCL had indeed been incorporated in FSAs with three other customers[2] including KSEB[3] which had been entered into prior to FSA with M/s. KPCPL. The FSA with KPCPL, however, did not have the relevant clauses.

---

[1] ***₹ 11 crores plus ₹ 12.50 crore towards principal and interest respectively.***

[2] ***M/s Tanir Bavi Power Company Private Limited (Bangalore, Karnataka), M/s. Samalpatti Power Corporation (Coimbatore, Tamil Nadu) and M/s. Kerala State Electricity Board (Thiruvanamthapuram)***

[3] ***Article 11 LD and Indemnity of FSA with KSEB states that "it is mutually agreed that though the buyer and the seller being the Government bodies, no BG or indemnity bond shall be provided by either of the parties to cover liquidated damages against the default. It is further agreed that in the event of change of ownership of either of the parties from Government Body, BG or Indemnity Bond for invoking LD shall be provided".***

(ii) BPCL did not adhere to its own credit policy introduced in January 2009 and continued credit sales despite KPCPL accumulating outstanding amounts beyond credit limit. Had BPCL secured its financial interest in time, accumulation of outstanding dues as well as arbitration proceedings for their recovery could have been prevented.

(iii) The contention of BPCL that stopping of supply to KPCPL would affect electricity supply in the State of Kerala needs to be viewed in the context of stoppage of supply to KPCPL w.e.f June 2013.

Thus, non-inclusion of an indemnity clause in FSA and not insisting on bank guarantee/secured advance payment to cover risk of credit sales to a defaulter company led to non-recovery of ₹ 23.50 crore (towards sales revenue and interest thereon) from KPCPL.

The matter was reported to the Ministry (December 2015); their reply was awaited (March 2016).

GAIL (India) Limited and Indian Oil Corporation Limited

1.2 Safety Preparedness of Oil and Gas Transmission Pipelines

1.2.1 Introduction

Indian Oil Corporation Limited (IOCL) and GAIL (India) Limited (GAIL) own cross country network of oil & gas pipelines covering 24230 kms (IOCL-11221 kms. and GAIL-13009 kms) for transporting crude oil, Natural Gas (NG), Liquefied Petroleum Gas (LPG) and various other petroleum products **(*Annexure-I & II*).** These pipelines carry large quantities of inherently inflammable products; hence safety of pipelines and their periodical health assessment are of critical importance to ensure that they do not pose a risk to the public and environment.

1.2.2 Audit Objectives, Scope and Methodology

Audit of **'Safety preparedness of Oil and Gas Transmission Pipelines'** of Indian Oil Corporation Limited and GAIL (India) Limited was conducted to assess the safety preparedness of their pipeline operations. Audit covered operations from April 2012 to March 2015.

The criteria adopted for Audit consisted of the following:

1. Safety norms applicable to the pipelines;
2. Health, Safety and Environment (HSE) policy of the companies;
3. Safety requirements laid down by regulatory authorities;
4. Procedures / Guidelines adopted for maintenance & inspection of pipelines.

1.2.3 Safety Regulatory Framework

Safety aspects of oil & gas pipelines are governed by provisions of various Acts/ regulations/ standards and guidelines developed by the following agencies:

(i) **Oil Industry Safety Directorate (OISD):** OISD, a technical directorate, was constituted (1986) by the Ministry of Petroleum and Natural Gas (MoPNG) to formulate / standardize procedures and guidelines in the areas of design, operation and maintenance.

(ii) **Petroleum & Explosive Safety Organisation (PESO):** PESO, under the Department of Industrial Policy & Promotion (DIPP), Ministry of Commerce & Industry, is the statutory authority for implementation of Petroleum Act, 1934 and Rules thereof as well as Explosives Act, 1884.

(iii) **Petroleum and Natural Gas Regulatory Board (PNGRB):** PNGRB was constituted (2006) to protect the interests of consumers and entities engaged in specified activities relating to petroleum and natural gas. It has notified (2009) Technical Standards and Specifications including Safety Standard (T4S) Regulations for NG Pipelines.

Compliance with safety standards/guidelines is ensured by the companies through HSE departments which also conduct internal safety audit of various locations.

1.2.4 Audit findings

1.2.4.1 Non-compliance with safety norms

Non-compliance with safety regulations / guidelines issued by various regulators was observed in IOCL & GAIL as discussed below:

(I) Non-compliance with recommendations of External Safety Audit

OISD carries out External Safety Audits (ESA) of pipeline operators and gives its recommendations to ensure safe pipeline operations. It also monitors the implementation of ESA recommendations by way of quarterly reports. Generally it is expected that ESA recommendations are complied within two years of submission of report.

Audit observed that there were 149 recommendations pending compliance in IOCL as at September 2015 of which 11 were pending compliance for more than two years. In respect of GAIL, it was observed that 109 recommendations were pending compliance as at end of June 2015. Further, audit observed delay ranging from nine to 163 months in complying with ESA recommendations.

Whereas IOCL replied (November 2015) that compliance with recommendations was being reviewed on quarterly basis and compliance with 83 *per cent* recommendations was achieved, GAIL attributed (December 2015) the delay in compliance with ESA recommendations to non-feasibility of implementation, contractual issues, Govt. permissions etc.

Replies need to be viewed against the fact that timely compliance of ESA recommendations would strengthen safety preparedness.

(II) Non-compliance with regulations on Intelligent Pigging Survey

A. PNGRB T4S Regulations (2009):

Intelligent Pigging Survey (IPS) is conducted to assess health of a pipeline. Intelligent pigs are used to perform in-line inspections of active pipelines for signs of metal loss, corrosion or dents etc.

PNGRB, vide T4S Regulations (2009), identified certain critical infrastructure to be provided, activities and processes to be undertaken in existing NG pipeline network within stipulated period of six months to two years.

Test check of operations in respect of GAIL revealed the following:

- Intelligent Pigging Survey[1] (IPS) for piggable sections has to be carried out once in ten years from the date of commissioning, whereas for pipelines transporting sour gas, it has to be conducted within five years. However, delay ranging from one year to 17 years was noticed in carrying out IPS in 66 pipelines;
- IPS for Non-piggable Section (NPS) above 12” and length above 10 km. was to be conducted within two years from T4S notification (2009). However, audit observed a delay ranging from one to four years in IPS implementation in 46 pipelines;

GAIL replied (December 2015) that work for conducting IPS was under progress.

T4S regulations have not yet been complied with even after a lapse of more than six years.

B. OISD standards on IPS:

OISD-STD-141 on ‘Design, Construction and Inspection requirements for Cross Country Liquid Hydrocarbon Pipelines’ stipulates that the first IPS shall be carried out at the earliest but not later than 10 years of commissioning. Subsequent periodicity of IPS shall, in no case, be more than 10 years. Further, OISD-STD-139 on ‘Inspection for Offshore Pipelines’ stipulates conduct of IPS of Offshore pipelines once in five years.

Audit, however, observed that IOCL has not conducted IPS of eight pipelines and two offshore pipelines in violation of OISD-STD-141 and 139 respectively. Further, IOCL had planned to conduct IPS of 17 pipeline sections during the period 2013 to 2015 as per its IPS rolling plan; however, the same were either not conducted or conducted belatedly. (***Annexure-III***)

IOCL replied (November 2015) that the work for IPS is being awarded shortly and all the vendors of IPS are located outside India and their lining-up takes considerable time.

[1] ***A monitoring mechanism to ascertain pipeline health by accurately locating and defining the pipeline wall defects (internal / external).***

Reply needs to be seen in view of the fact that delay in conducting IPS is not only in violation of OISD standards but also indicative of improper planning. Further, five incidents of leakage had occurred due to corrosion / dents etc. at pipeline locations[1] where IPS was delayed.

(III) Failure to obtain of PESO approval - GAIL

As per amendment (2000) of Manufacture, Storage and Import of Hazardous Chemical Rules, 1989, PESO approval was required to be obtained for new as well as existing NG / LPG pipelines. However, the Company had not obtained the same for nine pipeline networks.

GAIL replied (December 2015) that applications have been made for obtaining PESO approval for all pipeline networks.

The delay is inordinate as GAIL has applied for PESO approval only in November 2014 even though the same was made mandatory in the year 2000.

(IV) Non-implementation of recommendations of MB Lal Committee – IOCL

MB Lal committee was constituted by MoPNG to enquire into the fire incident (October 2009) at Jaipur Terminal of IOCL. MoPNG accepted (April 2010) the committee's report which, *inter alia,* included remedial measures to prevent recurrence of such incidents. The committee had given 113 recommendations, implementation of which was to be completed by IOCL between July 2010 and November 2014 as per schedule agreed with MoPNG.

Audit, however, observed that despite lapse of more than five years, recommendations were yet to be implemented by IOCL in respect of its pipeline locations as installation of 26 Remote Operated Shut-off Valves (ROSOVs) at its pipeline locations, required by May 2012, were not completed upto November 2015.

IOCL replied (November 2015) that implementation of the recommendations was delayed due to slow progress by contractors, working in an operating installation, re-tendering etc.

Reply needs to be viewed in light of the fact that timely implementation of the recommendations would have strengthened the safety preparedness.

(V) Encroachment of Right of Use

For the purpose of laying of pipeline, Right of Use (RoU) is to be acquired from the land owners as per Petroleum and Minerals Pipeline Act, 1962 (PMP Act). The PMP Act imposes restrictions regarding construction of building/structure, excavation/construction of tank, well, reservoir, and plantation of trees on the land so acquired under RoU so as to avoid potential damage to pipelines.

---

[1] ***Three in Salaya Mathura Pipeline and one each at Mathura Tundla Pipeline and Paradip Haldia Barauni Pipeline***

Audit observed that there were 1116 cases of encroachment (August 2015) of which 647 cases pertained to installation of Electric Poles/transformers besides cases of construction of houses, boundary wall, bore wells and telephone towers inside the RoU area. However, IOCL has not yet been able to evict these encroachments despite the fact that some of these cases were pending for more than 40 years. MoPNG had also directed (September 2014) to ensure that the pipeline RoU remains free of encroachment.

It is also pertinent to mention that a fire took place (September 2011) on Allahabad-Mughalsarai section (BKPL[1]) due to fault in electric transformer installed in RoU area. OISD investigation highlighted threat to pipeline operations from number of electric poles/transformers in this RoU.

IOCL had no system to ensure periodical reporting of encroachment cases by Regional Offices to HO to enable timely action.

IOCL replied (November 2015) that it has been regularly taking action for removal of encroachment from RoU area from time to time. However, the fact remains that large number of encroachments still exist at RoU area and no system to ensure periodical reporting of encroachment by regional offices has been introduced.

In respect of GAIL, it was observed that:

- Out of total 527 encroachments noticed till September 2015, 201 were categorised as highly vulnerable viz. electrical transformer/tower, drilling activities, bore-wells, residential and commercial establishments *etc.*
- Seven encroachments in HVJ pipeline RoU were pending eviction since 1987 indicating ineffective eviction measures.
- Encroachments were reported also in Mumbai (48), Gujarat (19), NCR (15), HVJ pipeline (7), Pondicherry (5) and KG basin (2) pipeline networks.

GAIL replied (December 2015) that it has been taking follow-up action with encroachers as well as with District Administration for eviction.

The fact remains that GAIL has neither been able to evict existing encroachments nor prevent new encroachments in its pipelines RoU.

(VI) Non-compliance with OISD Standard-117 (Revised-Oct.2010) - IOCL

Rim Seal Fire Protection System (RSFPS) automatically detects and extinguishes fire at the petroleum storage tank roof at the incipient stage. In order to ensure safer oil & gas operations, OISD revised (October 2010) Standard-117 (OISD-STD-117) on "Fire Protection Facilities for Petroleum Depots, Terminals, Pipeline Installations and Lube Oil Installations" which stipulated that RSFPS shall be provided on all external floating roof tanks storing Class 'A' petroleum. Accordingly, Halon based RSFPS at 36 tanks at four locations viz. Vadinar, Viramgam, Chaksu and Haldia were to be replaced with Hollow metallic based RSFPS so as to comply with Revised OISD-STD-117.

[1] ***Barauni-Kanpur Pipeline***

Audit observed that:

- As per approval of the Board (June 2011) for augmentation/revamping of fire water network related facilities at Crude Oil Storage Tank, revamping work was to be completed within 21 months i.e. by March 2013. However, IOCL could not achieve this timeline despite concerns expressed (December 2012) by the MoPNG in this regard;
- In June 2013, major fire incident occurred at Vadinar Crude Oil Tank which was attributed to non-performance of Halon based RSFPS;
- Work orders for 22 tanks (Vadinar and Viramgam) were placed in August 2014 and for remaining 14 tanks (Chaksu and Haldia) in October 2014 for completion of work within 18 months. Thus, the work which was to be completed by March 2013 is scheduled to be completed only by March 2016.

IOCL replied (November 2015) that fire incident at Vadinar happened due to lightning and thunderstorm and the tank was already provided with Halon based RSFPS which could not extinguish the fire since the fire was intense.

The reply strengthens the audit observation that the existing Halon based RSFPS should have been replaced with Hollow metallic based RSFPS in compliance with revised OISD-STD-117 and further highlighted (June 2013) by OISD in its incident investigation report.

(VII) Unsafe location of Control Rooms in contravention of OISD Safety Standard-IOCL

IOCL's Guwahati-Siliguri Product Pipeline (GSPL) is having four pumping/tap-off-point stations (TOP) at Betkuchi, Bongaigaon, Hasimara and Madarihat. Betkuchi TOP, alongwith its control room located within marketing installation, is surrounded by nine Product Storage Tanks (Three each for Motor Spirit, Superior Kerosine Oil and High Speed Diesel) with total storage capacity of 25000 KL.

OISD-STD-118 on 'Layouts of Oil and Gas installations' stipulates that the distance of control room from storage tanks should not be less than 60 meters and 30 meters for MS and SKO respectively.

Review of records in audit revealed the following:

- Risk Analysis study got conducted (April 2011) by the Company highlighted that Betkuchi control room falls under zone where Incident Thermal Radiation Intensity is of very high magnitude;
- OISD, while conducting External Safety Audit of GSPL in November 2011, also observed that the distance between the Control Room and the Storage tanks was less than that stipulated and advised to carry out detailed risk analysis of the location apart from recommending relocation of control room. Similarly, Hazard and Operability Study (HAZOP) conducted by the Company in November 2012 also highlighted that the control room located at Betkuchi TOP was at a distance of 9 meters from MS storage tank dyke wall, 27 meters from MS storage tank

body and 24 meters from SKO tank. Considering the potential hazard, relocation of the control room was recommended;

- OISD in its ESA Report reiterated (March 2013) to address the issue on top priority.

Location of control room at Jalandhar Terminal was pointed out (July 2011) by OISD as violating OISD-STD-118.

IOCL has not relocated the Betkuchi and Jalandhar terminal control rooms even after lapse of four years.

IOCL replied (November 2015) that as Betkuchi and Jalandhar terminals were commissioned prior to formation of OISD, there was no violation of OISD-STD-118 which was published in 1988.

Reply is not tenable as OISD-STD-118 though published in 1988, became mandatory in 2002 for all terminals including existing terminals.

(VIII) Non-compliance with OISD Safety Standards resulting in frequent pipeline failures - IOCL

Mundra-Panipat Pipeline (MPPL) of IOCL transports mainly sour crude oil from Mundra Port to Panipat Refinery. Kandla-Panipat (KP) section of MPPL, commissioned (1996) for transporting petroleum products, was converted (August 2006) to crude oil service to meet the requirement of crude oil at Panipat Refinery.

IPS is conducted to assess pipeline health by Magnetic Flux Leakage (MFL) or Ultrasonic (UT) based special pigs to identify different types of anomalies in the pipelines. MFL based IPS is used for detecting corrosion type anomalies whereas UT based IPS is used for detection of cracks.

OISD-STD-188 stipulates that in case of pipelines carrying sour crude or sour gas, IPS having capability to detect cracks should be conducted once in five years.

An incident of pipeline failure (line burst) occurred in MPPL in September 2014 near Rewari pump station. This pipeline failure was third such incident in MPPL within nine months as two similar incidents had occurred earlier (January and March 2014) on account of anomalies in weld seam. As recommended by OISD in investigation report (October 2014), detailed metallurgical/ chemical/ mechanical analysis of the ruptured section was got conducted by IOCL through National Metallurgical Laboratory, Jamshedpur (NML).

Review of records revealed that:

- IOCL did not conduct IPS of MPPL with UT based pigs though MFL based IPS was conducted in 2012 wherein certain corrosion (metal loss) anomalies were detected but no cracks were reported due to inherent limitations of the technology used.

- Technical review was required to be carried out for conversion of product pipeline to crude service as per OISD-GDN-178. However, nothing was found on record to substantiate that such technical review was carried out in case of KP section of MPPL.

- After an earlier pipeline failure incident (January 2014), OISD highlighted that the weld seam quality of the pipes was not upto the desired level which should have been noticed at procurement stage itself. Further, it also raised concerns on poor quality of pipes and fatigue failure.

- NML concluded presence of iron oxides and iron sulphides and identified that the failure was caused by Hydrogen Sulphide[1] (H_2S) of crude oil and a combination of cyclic loading on pre-existing weld defects. Thus, it advised that concentration of H_2S in crude oil be kept under control to avoid recurrence of such failure. Moreover, it also recommended to identify the defective (weld defect) pipeline section to be removed from the service to avoid catastrophic failure.

IOCL replied (November 2015) that generally the first IPS is always done with MFL technology and UT based IPS is planned as soon as evidence of cracks is found. Further, all these failures were unusual and no visual sign of corrosion / other anomaly could be found during normal inspection.

Reply is not convincing as IPS, in case of MPPL being engaged in transportation of sour crude, was required to be conducted with UT based technology in line with OISD-STD-188.

(IX) Non-compliance with Safety norms in PJPL resulting in excessive corrosion - IOCL

Panipat-Jalandhar LPG Pipeline (PJPL) was commissioned (November 2008) for transportation of LPG from Panipat Refinery. IOCL noticed (September 2013) significant quantity of muck/contaminants and other harmful chemicals received at Nabha and Jalandhar stations, analysis of which indicated a high pH value[2] and high amount of water, iron and sulfur contents all of which are harmful for the pipeline health. High pH value leads to formation of Iron Sulfide (FeS) and Iron Oxide (Fe_2O_3) both being undesirable corrosion products. After cleaning pigging of PJPL in 2014, high presence of corrosive elements were again observed which resulted in continuous internal corrosion.

Audit observed that:

- Despite lapse of more than two years, IOCL has not yet taken corrective measures to prevent corrosive products in PJPL causing internal corrosion of the pipeline and Horton Spheres[3].

---

[1] ***A corrosive agent***

[2] ***A measure of acidity or alkalinity of water soluble substances (pH stands for 'potential of Hydrogen') on a scale of 1 to 14, pH of 1 being the most acidic and 14 being most alkaline and in pig residue pH is generally in the range of 6-8***

[3] ***A spherical pressure vessel used for storage of compressed gases such as Propane, Butane or LPG in Liquid gas stage***

- Pigging of LPG pipeline was required to be done at least once a year as per OISD-STD-214. However, first pigging of PJPL since inception was conducted in 2014 resulting in severe corrosion of PJPL due to consistent presence of corrosive elements.
- Presence of water in LPG was strictly prohibited by OISD-STD-214. However, presence of significant water was observed consistently in pipelines and Horton Spheres which may lead to failure of the pipeline and storage system on account of severe internal corrosion.

IOCL replied (November 2015) that Panipat Refinery has been sensitized for prevention of water and other contaminants in LPG. Further, delay in pigging was due to intermittent operations and development of expertise in pigging in LPG pipelines; however, regular pigging has been done since 2014.

Reply is not tenable as despite repeated requests Panipat Reinery has not yet been able to prevent and monitor the water contents in LPG. Further, prior to 2014, the Company failed to comply with mandatory requirement of annual pigging of LPG pipelines.

(X) Non-monitoring of R-LNG/NG specifications posing threat to DPPL - IOCL

Dadri-Panipat gas pipeline (DPPL) was commissioned (2010) for catering to the demand of Re-gasified Liquefied Natural Gas (R-LNG) at Panipat Refinery. IOCL has been procuring R-LNG from Petronet LNG Limited (PLL) at Dahej as per Gas Sale Purchase Agreement (GSPA). For transmission of gas from delivery point i.e. Dahej terminal to redelivery point i.e. Dadri, IOCL signed (April 2010) Gas Transmission Agreement (GTA) with GAIL.

In order to ensure the quality of gas, the GTA stipulated that the gas supplied at delivery point will have a specific composition. Further, Article 7 of GTA stipulated that IOCL will ensure measurement, analysis and testing of the gas and results therefrom be transmitted to GAIL in order to maintain the operating conditions and quality requirements for delivery into the transmission system.

Audit observed that:

- IOCL did not install any mechanism to ensure the quality of supplied gas despite lapse of five years from its commissioning;
- IOCL had been receiving a large quantity of black dust, fines etc. in the filter cartridges of DPPL at Panipat necessitating its repetitive replacement due to choking by muck. The test reports of muck sample analysis (October/ December 2014) at Panipat confirmed the presence of significant quantity of Iron Oxide (Fe_2O_3) i.e. ranging from 41.80 *per cent* to 52.40 *per cent* which resulted in receipt of R-LNG with large quantity of fines/dust at Panipat Refinery;

IOCL replied (November 2015) that the gas quality in terms of GTA is to be monitored at source itself and the reconfirmation at redelivery point was not necessary. Further, the parameters were being monitored at Refinery end to ensure absence of any hazardous component.

Replies are not tenable as the monitoring of hazardous components at Panipat was not serving the purpose of ensuring safety of DPPL. The same should have been monitored at Dadri end to restrict the corrosive elements in DPPL at the entry point itself.

(XI) Non-adherence to PNGRB gas specifications and Ministry's directives resulting in pipeline deterioration and frequent accidents - GAIL

(A) Non Compliance with PNGRB Access Code for Common Carrier Natural Gas Pipelines, 2008

PNGRB Access Code for Common Carrier Natural Gas Pipelines, 2008 emphasize on gas quality conforming to pipeline health and stipulates maximum tolerable limits of corrosive constituents.

OISD also stipulates for evaluation of corrosive constituents in gaseous hydrocarbon. As per this, presence of H_2S, CO_2, salts etc. can cause stress corrosion. Further, OISD also stipulates for IPS of pipelines transporting sour gas once in every five years.

GAIL signed GSA (July 2006) with Oil & Natural Gas Corporation (ONGC) for 15 years for gas supply to Hazira-Vijaipur-Jagdishpur pipeline (HVJ) and other pipeline networks[1].

Audit observed that specifications of non-hydrocarbons were described[2] in GSA for HVJ network; however, no such specifications were mentioned in other pipeline networks. GAIL also contractually agreed to accept all types of gas (wet[3], dry[4] and sour gas[5]) despite being aware that presence of condensate[6] in gas is hazardous. Thus, GAIL had agreed to accept off-specification gas ignoring the likely safety hazards arising thereof. This was alarming as untreated wet and sour gas was being supplied from 60 out of 65 sources by ONGC thereby adversely impacting the pipeline health.

Similarly, such specifications were also not incorporated in GSAs signed with Hindustan Oil Exploration Company Limited (HOEC), OIL *etc.*; with the result that the suppliers were not obligated to supply gas in conformity with the specification prescribed by the safety regulators.

Further, PNGRB stipulated that in case of off-specification gas delivered by upstream supplier, the transporter (GAIL) may either refuse such gas or may provide additional treatment facilities and charge cost thereof from upstream supplier. Thus, GAIL was liable to ensure that off-specification gas did not adversely affect pipeline integrity and end-user specifications. However, GAIL continued to accept off-specification gas and transport the same to end users without treatment, thus exposing its pipeline network to

[1] Krishna Godavari (KG) basin, Agartala, Cauvery basin and Gujarat network
[2] H_2S: 4 ppm, Hydrocarbon dew point: ± 5 Centigrade, water dew point: 0 centigrade and no free water
[3] Unprocessed natural gas or partially processed gas containing condensable hydrocarbons and liquid hydrocarbons in solution.
[4] Gas with water content reduced by dehydration process.
[5] Natural gas which in its natural state, contains such amounts of sulphur as to make it impractical to use because of its corrosive effect.
[6] Mixture of hydrocarbon liquids present as gaseous components in raw natural gas which is hazardous for pipeline health

corrosion risk as well as unwarranted risk to end users. Audit observed that GAIL had paid (September 2015) ₹ 45 lakh as penalty to PNGRB on account of non-compliance with PNGRB specifications and that it has not yet taken corrective action and is liable to pay ₹1 lakh per day as penalty.

GAIL replied (December 2015) that ONGC had denied gas quality guarantee and the same was accepted by GAIL on 'as is where is' basis. However, GSA has a provision for compensating GAIL for condensate supplied with gas. Moreover, GAIL has installed slug catchers near source point.

Replies are not tenable as the fact remains that PNGRB explicitly stipulated that primary responsibility for safe transmission lies on the transporter. Thus, GAIL cannot overlook its responsibility of safe transmission while protecting its commercial interests. Further, GAIL has to ensure compliance with safety guidelines/ regulations notified from time to time. Moreover, despite the installation of slug catchers, condensate/ water continued to flow with gas, thus putting the pipeline safety at risk.

(B) Frequent incidents of accident, pipeline burst and corrosion in KG Basin pipeline network

Audit observed that though the 869 km long KG Basin pipeline network was designed for transmission of dry gas, gas supplied by ONGC was wet, sour and ingressed with water, condensate and sulphur thereby exposing the network to internal corrosion. Further, it was observed that quantity of condensate in gas reached alarming level of 13000-15000 Litres per day. Moreover, inadequate and unsatisfactory maintenance of pipelines by GAIL led to frequent pipeline accidents involving massive human casualties, incidents of pipeline burst and reduction of its useful life as follows:

(i) ***Ponnamada-Kadali NG pipline:*** Gas in this pipeline was being supplied from ONGC gas fields viz. Ponnamada, Kesanapalli (W) and Adavipalem. A fire accident occurred (November 2010) in this pipeline involving massive damage to agriculture, ecology and property due to supply of off-specification gas by ONGC resulting in extensive internal corrosion and reduction of pipeline thickness. Compensation of ₹51 lakh was paid by GAIL.

It was observed that GAIL conducted IPS in the pipeline only after the occurrence of incident. After carrying out IPS, severe internal corrosion was noticed which resulted in pipeline thickness reduction ranging from 20 *per cent* to 80 *per cent.*

GAIL replied (December 2015) that it has been conducting the cleaning pigging on yearly basis and has also installed slug catchers to prevent the condensate/ water in the gas.

Reply is not tenable as scrapper pigging instead of foam pigging was essential to prevent corrosion. Further, despite installation of slug catchers, condensate and water continued to flow with gas.

(ii) ***Tatipaka-Kondapalli Pipeline (TKPL):*** A major fire accident occurred (June 2014) in TKPL wherein 22 people were burnt alive and 18 people sustained serious injuries apart from damage to nearby property and agriculture for which GAIL paid compensation of ₹ 8.88 crore. MoPNG constituted a committee to inquire into the accident which held GAIL responsible for the incident on account of its various negligent and unsafe transmission practices. Audit further observed that:

- TKPL was commissioned (August 2001) for supply of gas to downstream consumers like power producers and City Gas Distribution entities. Though designed for transmission of dry gas, the pipeline was being used for wet gas transmission from ONGC fields which resulted in internal corrosion of pipeline. Further, GAIL had not developed separate policy for mitigating wet gas induced corrosion. Consequently, in a short period (April to June 2014), eight instances of leakage in the pipeline were reported, for which only make-shift/temporary arrangements were made. Temporary repairing of pipeline adversely impacted the pipeline integrity.
- OISD-STD-226 requires cleaning pigging annually and more frequently in case of significant liquid hold-up in the pipeline. GAIL, though commissioned TKPL in 2001, started cleaning pigging only after 2006 which led to significant accumulation of condensate, water and sulphur. IPS of the pipeline highlighted alarming metal loss to the extent of 50 *per cent*. However, GAIL did not replace corroded pipeline section. Further, GAIL was conducting pigging as per design of dry gas pipeline despite using it for wet gas which required pigging at a higher frequency. Moreover, scrapper pigging is essential to remove and mitigate condensate and muck, GAIL, however, relied upon foam pigging despite noticing huge supply of condensate associated gas from 2007 onwards which defeated the very purpose of pigging.
- Chemical examination of quality of deposits (pig residue) received after pigging was essential to assess pipeline health as per OISD and PNGRB. However, GAIL carried out pig residue analysis in KG basin network on two-three occasions only. Resultantly, deterioration of pipeline by significant amount of sulphur remained unnoticed.
- GAIL relied on contractors for repair/maintenance of pipelines without any inspection.
- GAIL did not install any Leak Detection System (LDS) despite mandatory safety regulations.
- Even after the disastrous incident, several long aged encroachments were noticed along pipelines. RoU boundary markers and Route marker were also found missing at various places.
- No Standard Operating Procedures (SOP) were developed for transportation of wet gas pipelines.
- Though GAIL has Regional Gas Management Centres (RGMC) to monitor various gas parameters like temperature, flow, gas compositions, the information and cause of TKPL failure could not be ascertained due to functionalities/configuration issues in RGMC of KG basin.

Audit further observed that incidents of pipeline failure due to off-specification gas were also noticed in Gujarat region. For example, Gas leakage occurred (July 2014) in Kadi GMS-SKCTF pipeline due to flow of sour gas, condensate/free water resulting in multiple leakages.

GAIL replied (December 2015) that condensates were prominently observed from 2007-08 onwards only and T4S Regulations do not define the pigging frequency for dry and wet gas separately. As regards LDS, GAIL replied that it has taken the initiative to install APPS software for leak detection.

Reply is not tenable because GAIL violated OISD stipulations in respect of installation of LDS and annual pigging despite using the pipeline for transmission of wet gas.

(C) Non-adherence to Ministry directives on gas specification resulting in damages/safety hazards in downstream consumers' equipment

MoPNG directed (June 2010) major oil companies including GAIL for adherence to gas specifications as the gas being produced and supplied contained liquid hydrocarbon and water carryover which could damage equipments of downstream consumers.

Audit observed that though downstream consumers reported matter of low quality gas, GAIL did not take remedial action by way of installation of Gas Dehydration Units which led to avoidable accidents / interruptions in downstream consumers' equipments as described below:

- Instances of fire in downstream consumers' furnaces were reported in Gujarat Region due to continuous transportation of condensate, posing a threat to life and property of consumers.
- CNG cylinder at CNG dispensing station of M/s Baghyanagar Gas Limited burst (January 2011) due to condensate, water, oily substances in the gas.
- Konaseema Gas Power Limited complained (March 2011/ January 2013) of damage to gas turbines due to off-specification gas.

Despite MoPNG directives (June, August and December 2010), GAIL failed to ensure adherence to gas specification and to prevent safety hazards in downstream consumers' equipment and public life. Audit observed that internal corrosion of the pipeline remained the root cause of all safety hazards which was due to non-incorporation of gas specifications in GSA and non-installation of GDU. Resultantly, various pipelines were corroded and needed replacement in short period of four to ten years against designed operational life of 20 years. Further, GAIL also assessed (October 2014) that 850 km pipeline was rendered unfit from safety point of view and needed replacement.

Moreover, issue of water/condensate between GAIL and gas suppliers remained inconclusive and resultantly GAIL continued to collect and hand over a large quantity of condensate to gas suppliers for reimbursement but could not address safety concerns. This may further be viewed against the fact that GSA signed (2000) with gas supplier CAIRN included gas specifications and hence, the supplier was contractually bound to deliver gas conforming to GSA and corrosive elements in the gas sample were found to be within specified limits, but such arrangements could not be made with other suppliers viz. ONGC, OIL and HOEC etc.

Though GAIL has a system in place for internal safety audit, the matter of pipeline corrosion due to condensate remained unaddressed. Unsafe gas transmission needed remedial action by the apex management in consultation with MoPNG.

(XII) Safety and Health Management of LPG pipelines - GAIL

Vizag-Secunderabad Pipeline (VSPL) was commissioned (2004) for transportation of LPG from HPCL, BPCL to various LPG bottling plants. A major accident occurred (April 2015) at Suryapet (Vijaywada–Suryapet section) causing two human fatalities. Review of records relating to the incident revealed that:

- GAIL did not conduct pigging for 10 years (since commissioning till July 2014) despite being recommended (February 2005 & September 2013) by OISD leading to accumulation of huge muck/debris in the pipeline. Consequently, during cleaning operations in April 2015 the pressurized pig ejected out violently and hit the workers.
- Improper design of scrapper barrel, type of pigging (magnetic pigging in spite of high iron content presence as indicated in pig residue analysis conducted in 2014), inadequate design of pig receiver and non-maintenance of minimum safe inter-distance were other factors responsible for accident.
- GAIL neither formulated SOP for pigging nor followed SOP for maintenance activities especially regarding availability of fire tender during pigging despite MoPNG directives (July 2014).
- GAIL did not ensure deployment of expert contractual manpower and deployed its own personnel who were not well versed with this type of job.
- Off-specification and moisture ingressed LPG supply in pipelines was noticed. However, the matter remained inconclusive due to disagreement on gas quality with HPCL. Moreover, GAIL was also not monitoring LPG quality as in-house/ third party quality checking facilities were not available.

Similarly, audit also noticed that cleaning pigging was being carried out in another pipeline JLPL (Loni section) once in five years against the requirement of annual pigging.

GAIL replied (December 2015) that though VSPL was commissioned in 2004, pigging was conducted only from 2008 onwards when substantial flow of LPG started. However, pigging of this section was not conducted till 2014 due to technical limitation of flow.

Reply is to be seen in view of the fact that safety aspects were compromised as delay in pigging of Vijaywada–Suryapet section resulted in huge muck/debris leading to two human fatalities.

(XIII) Monitoring mechanism of pipeline integrity - GAIL

PNGRB and OISD mandates monitoring and control of NG pipeline system using SCADA[1] to safeguard the pipeline against corrosive elements/ impurities (H_2S, moisture, CO_2 etc.)

Audit observed that though SCADA was installed and NGMC[2] was operational, various aspects of gas composition especially impurities at many regional gas grids were not being regularly monitored which led to transmission of gas in these grids with high level of impurities and corrosive substances; consequently, around 850 km pipeline was rendered unfit for safe operations forcing GAIL to replace the huge network as has been mentioned in para 1.2.4.1 (XI).

Further, PNGRB and OISD stipulate that gas should not contain H_2S, CO_2 and water etc. beyond a permissible limit to control corrosion. Hence, pipeline operators are obligated to install mechanism for evaluation and monitoring of H_2S and moisture.

Audit observed that GAIL was not carrying out gas analysis for monitoring H_2S and moisture regularly as analyzers for continuous monitoring were not available at many places. Presence of H_2S and moisture beyond threshold limit was reported in regional networks (Gujarat, Cauvery, KG and Agartala) underlining need of real-time monitoring.

GAIL replied (December 2015) that online analyzers at some additional locations were under commissioning.

The fact remains that requirements of OISD/PNGRB have not yet been complied with.

(XIV) Surveillance of gas transmission pipelines - GAIL

PNGRB mandates surveillance of pipelines RoU through improvised means like GPS, CCTV and satellite based monitoring to detect abnormal activities across pipeline RoU since third party damage contributes to highest number of incidents of pipeline integrity breach.

(a) Satellite/Remote sensing based RoU monitoring

Remote sensing based surveillance is about monitoring and detecting changes on pipeline networks RoU especially in remote and inaccessible areas. Traditional surveillance through aerial, vehicular and foot patrols have various shortcomings in terms of efficacy, accuracy, cost and safety.

Audit observed that though GAIL contemplated satellite based RoU surveillance project in June 2013, it has not been able to make use of this technology so far (December 2015).

---

[1] Supervisory Control and Data Acquisition is the technique for monitoring gas pipelines, remote operational abilities for controlling physical parameters viz. pressure, temperature, flow measurement and gas composition data without the need for onsite personnel control and supervision of the pipeline.

[2] National Gas Management Centre

GAIL replied (December 2015) that this project was taken up as an R&D project on pilot basis, it was not time bound.

Audit suggests that the project may be pursued for early completion and implementation as the same would strengthen the safety of its pipelines operations.

(b) GPS based surveillance

GPS based line patrolling enables effective monitoring of foot patrolling through real-time tracking and online alerts about movement of patrolling personnel.

Audit observed that a large network[1] of GAIL was not equipped with GPS technology.

GAIL replied that GPS based foot patrolling is in place for more than 80 *per cent* network of GAIL.

Fact remains that 20 *per cent* network is still devoid of GPS based patrolling.

(c) Pipeline RoU Surveillance

OISD as well as PNGRB mandate installation of pipeline markers and route markers. Report of third party inspection got conducted (August 2011) by GAIL through PNGRB empanelled agency revealed that RoU Boundary markers/ Route marker were not available at various places in KG pipeline network. Further, the pipeline markers were corroded at most of the places in Gandhar-Dabka pipeline section.

Another ESA conducted (September 2014) by OISD revealed that ground patrolling was not being carried out for Thulendi-Phulpur pipeline whereas the same was being carried out for only 17 *per cent* RoU of Auriaya-Jagdishpur and 45 *per cent* RoU of Suchendi-Kanpur pipelines.

(XV) Integrity management of non-piggable pipelines - GAIL

In view of significant increase in major incidents in non-piggable sections (NPS), OISD requires special focus on integrity of NPS. PNGRB also mandates that gas pipelines with diameter of 4” and above and length greater than 10 km. shall be provided with pigging facilities besides carrying out IPS to detect metal loss for the pipelines of 12" and above and length of 10 km. and above.

Audit observed that:

- Around 1000 km. pipeline was required to be provided with pigging and IPS facilities as per PNGRB stipulations. However, GAIL has so far (December 2015) converted only 100 km length of NPS to piggable. Majority of these were operational in KG Basin, Maharashtra Region, Gujarat Region and Cauvery Region which were prone to internal corrosion as gas being supplied was wet and sour.

[1] ***Tripura, Gujarat, Cauvery basin, Assam, Dabhol-Bangalore Pipeline, southern pipeline grid, Jaisalmer Region etc.***

- Further, corrosion monitoring was also not being done in Gandhar-Dabka and Vadodara Regions despite being highlighted by OISD.
- OISD stipulates dosing of Corrosion Inhibitors[1] (CI) for preservation of pipelines especially in sour gas pipelines. However, GAIL adopted CI dosing only after occurrence of a major accident (Tatipaka fire accident in June 2014), which was also not being regularly dosed by suppliers.

GAIL replied (December 2015) that conversion of NPS into piggable sections is in progress. GAIL further stated that it has also been relying upon other measures like bell hole inspection.

The non-conversion of NPS into piggable section is fraught with safety risk as is also evident from a number of pipeline failures in non-piggable sections due to sour gas.

1.2.4.2 Other instances of inadequate safety preparedness

Other instances of inadequate safety preparedness were also observed in IOCL & GAIL as discussed below:

(I) Inadequate safety measures leading to major fire incident - IOCL

SMPL crude oil pipeline has an originating pump station at Vadinar and intermediate stations at 12 locations[2]. Of them Vadinar, Viramgam and Chaksu installations also have crude oil storage facilities. Vadinar Crude Oil Terminal consists of 18 storage tanks.

On 18 February 2014, oil leakage was detected from ground outside the dyke wall of a tank. During repair/replacement work, a fire incident occurred (27 February 2014) due to flash fire from grinding operation in which three contract workmen sustained burn injuries; of them, two succumbed to their injuries. IOCL's Investigation Report highlighted various reasons/factors causing the incident. OISD also investigated the incident and issued recommendations for compliance.

Review of records relating to the incident revealed that:

- There was no structured system for maintaining history of pipeline health; drawings depicting corrosion prone locations, position of clamps/sleeves, timely compliance and its monitoring;
- SOP for undertaking repair works was not formulated and the Maintenance Manual was also not updated since July 2002;
- Job Safety Analysis for the work was also not carried out and the work was being executed during night hours despite the same being a critical work;
- Water flushing of the Header connecting the tank was not done for making it free from hydrocarbon vapour before execution of work;

---

[1] ***A chemical compound which when added to liquid or gas, decreases the corrosion rate of metal***

[2] ***Jamnagar, Gauridad, Surendernagar, Viramgam, Sidhpur, Abu Road, Kot, Rajola, Sendra, Ramsar, Chaksu and Rewari***

- Repair work was being carried out by operations group instead of by dedicated maintenance group;
- The officials issuing/receiving work permit had not undergone the mandatory minimum one-day training as stipulated vide OISD-STD-105;
- Fire fighting preparedness at the site was deficient as the fire tender engines were not kept 'ON' during repair work; further, second fire tender was not put into service;
- Coating survey of underground station piping, as stipulated in OISD-STD-130 had not been carried out as there was no written procedure available across the Pipelines Division.

IOCL, in its reply, stated (November 2015) that various procedures have been developed and implemented to ensure safe operations. However, the fact remains that IOCL has developed the requisite procedures only after the incident.

(II) Pipeline control and emergency preparedness system - GAIL

PNGRB and OISD prescribe installation of Sectionalising Valves (SVs) with remote shut-off provision. SVs are provided in the pipelines to isolate the pipeline section in case of leakage / incident. Remote operability is a vital component of emergency preparedness system especially in remote, inaccessible areas.

Test check of records, however, revealed that:

- Pan-India pipeline network of GAIL consists of 549 SVs, of which only 332 SVs were remote operated valves (ROVs).
- No time-bound plan was prepared for installation of RoVs despite recommended by HAZOP studies, MoPNG, OISD and MB Lal Committee. It was observed that only after occurrence (June 2014) of major pipeline incident in KG Basin, GAIL belatedly (June 2015) planned for conversion of manual operated valves into ROVs; however, action thereon was still pending (December 2015).

Though SCADA was in place, its objective of effective monitoring and control of the pipelines in these regions could not be fully achieved as 217 SVs were manually operated. Further, GAIL had belatedly assessed (February 2015) that remote operation with auto closure facilities could have been done for pan-India pipeline network without any additional facilities like land, power and building at a cost of ₹ 9.27 crore only.

GAIL replied (December 2015) that action for conversion of manual operated valves into RoVs was under advanced stage of execution at most of the locations.

1.2.4.3 Monitoring mechanism

Roles of Safety Regulators in Oil and Gas Industry

Regulatory environment of hydrocarbon industry in the country is mainly governed by OISD, PNGRB and PESO. However, these regulators are functioning under different administrative ministries.

OISD, a technical directorate under MoPNG, was formed with an objective to formulate and standardize procedures and guidelines to enhance safety in the oil and gas industry in India. PESO, on the other hand, is a statutory authority functioning under administrative control of Department of Industrial Policy & Promotion, Ministry of Commerce and Industry. Further, PNGRB was constituted by an act of Parliament to protect the interests of consumers and entities engaged in specified activities relating to petroleum and natural gas under MoPNG.

In this regard, Audit observed that:

- There were different and overlapping safety regulations by these regulators with multiple points of reporting without any coordination among these agencies.

- Though PNGRB empanels accredited external agencies for carrying out safety audits, nothing was found on record to substantiate that PNGRB takes any follow up action to ensure compliance with observations/recommendations contained in such reports.

- Safety standards, though formulated by OISD, implementation thereof is left unmonitored as OISD has no statutory powers to enforce the same. Further, though PESO administers six OISD standards over the oil and gas industry, it does not come under administrative control of MoPNG with the result that no legal action could be taken in case of violation.

- In the absence of any statutory powers, OISD could not enforce the companies to implement the ESA recommendations as the same was pending compliance in IOCL and GAIL even after lapse of 24 months and 168 months respectively.

Further, the Standing Committee on P&NG (2011-12) of the Parliament also suggested that OISD should be made the nodal agency to formulate, monitor and enforce the OISD standards and other applicable laws for the entire oil and gas sector. However, action in this regard has not yet been taken (August 2015).

Conclusion

Safety preparedness of IOCL & GAIL in respect of transmission pipelines was found inadequate in view of the following:

- There were instances of non-compliance with OISD safety standards and PNGRB regulations;

- Non-compliance with recommendations of ESA and MB Lal Committee was observed;

- There was lack of effective action on the part of management to evict RoU encroachments thereby posing threat to safety of pipeline operations

- Inadequate maintenance activities coupled with non-formulation of/ deviation from SOPs led to ineffective handling of several incidents.

As a result, the companies failed to protect pipeline network from accidents/ incidents leading to loss of lives, property and environment indicating inadequate safety preparedness. Further, in the scenario of global importance of HSE policy, there was no single nodal agency to ensure the requisite safety preparedness on the companies.

Recommendations

The following recommendations are made:

- ***Compliance with all applicable safety standards/regulations should be ensured;***
- ***ESA/ other recommendations relating to safety should be implemented in a time-bound manner;***
- ***There should be an empowered nodal agency to enforce compliance with safety norms;***
- ***Effective action should be taken to prevent encroachments and for eviction thereof immediately;***
- ***Companies should ensure regular maintenance activities to ensure pipeline integrity;***
- ***Mechanism for timely and regular review/monitoring of safety preparedness should be in place.***

The matter was reported to the Ministry (December 2015); their reply was awaited (March 2016).

1.3 Petrochemical Production and Project Management

1.3.1 Introduction

Petrochemicals are hydrocarbons derived from crude oil and Natural Gas (NG) and form a major segment of manufacturing industry. Petrochemical sector in India is deregulated and products are imported freely under Open General Licence[1]. Polymers *viz.* Polyethylene (PE)[2] and Polypropylene (PP) form a major part of petrochemicals.

GAIL (India) Limited (GAIL) commissioned a petrochemical plant at Pata, district Auraiya in 1999 (Uttar Pradesh Petrochemical Complex –UPPC) with an investment of ₹ 2327 crore and Indian Oil Corporation Limited (IOCL) established Panipat Naphtha Cracker Plant (PNCP) in 2010 with an investment of ₹ 14400 crore. Major products of UPPC and PNCP are different grades of High Density Poly Ethylene (HDPE) and Linear Low Density Poly Ethylene (LLDPE). PNCP also produces PP and Mono Ethylene Glycol (MEG). UPPC of GAIL consumes Natural Gas (NG) and PNCP of IOCL consumes Naphtha for producing basic raw material for petrochemicals. Financial performance of both the plants is given in ***Annexure-IV.***

[1] ***Open General License (OGL) is issued by the Government of India in pursuance of the Imports (Control) Order, 1955. It is the most liberalized type of license for imports for freely traded items for which no specific permission is required.***

[2] ***Includes LDPE, LLDPE & HDPE***

1.3.2 Audit objectives, scope & methodology

Audit Objectives were to ascertain whether:

- Sufficient feedstock was available to meet the production requirement;
- Consumption of feedstock and other inputs, including utilities, was as per industrial norms/standards; and
- Capacity enhancement projects and other projects were carried out effectively to achieve the production target.

Audit examined records relating to operational performance of plants with reference to targets set by Ministry of Petroleum and Natural Gas (MoPNG), production capacity, industrial norms/standards on consumption of feedstock and chemicals, quality standards as per industrial practice and capacity augmentation along with other projects for petrochemicals for the period 2009-10 to 2014-15. Views of MoPNG and GAIL/IOCL have been obtained and incorporated.

1.3.3 Audit Findings

Audit findings emerging from review of performance of UPPC & PNCP and implementation of petrochemical projects by GAIL and IOCL are discussed in the succeeding paragraphs.

1.3.3.1 Petrochemical Production

(I) Capacity utilisation

A. Under utilisation of downstream capacity (GAIL)

UPPC has three units in upstream *ie.* Gas Sweetening Unit (GSU), Gas Processing Unit (GPU) & Gas Cracker Unit (GCU) and five units in downstream *ie.* Polymer units (HDPE I and II, SWING), Butene-1 & LPG unit.

As per the production process, impurities in NG is removed in GSU and heavier fractions[1] extracted in GPU. These fractions are subsequently cracked in GCU for producing ethylene. Ethylene is subsequently consumed in polymer units for production of polymers.

Capacity utilization of GCU (upstream) and polymer units (downstream) was above the installed capacity during the period of audit as indicated in ***Annexure-V***. Analysis, however, revealed that downstream units had capacity for achieving further production level but there was constraint in producing sufficient ethylene from the upstream (GCU) unit as discussed below.

The plant was commissioned (1999) with GCU[2] capacity of 3,00,000 MTPA[3] (ethylene) and polymer capacity of 2,60,000 MTPA. There were four furnaces in GCU with

[1] Ethane (C2), propane (C3) etc.

[2] Consisted four cracker furnaces, towers, vessels, drums, compressors, and pipelines as integral parts for gas cracking.

[3] Metric Tonne Per Annum

1,00,000 MTPA capacity each, with three furnaces in cracking mode and fourth one as standby. Under petrochemical expansion project, fifth furnace was installed (2005) and ethylene capacity was increased from 3,00,000 MTPA to 4,00,000 MTPA with four furnaces in cracking mode at a time. Polymer capacity was also increased from 2,60,000 MTPA to 4,10,000 MTPA by 2009-10 .

Polymer production units, with the installed capacity 4,10,000 MTPA, had the ability to produce over and above the installed capacity[1]. Considering this, achievable capacity in polymer units was assessed at 5,10,000 MTPA. This additional capacity, however, was not utilised due to non-availability of sufficient ethylene from GCU. Management, therefore, considered (2008) that if GCU capacity was not de-bottlenecked, the additional available capacity in downstream units would remain under-utilized. Accordingly, sixth furnace (1,00,000 MTPA) was installed in GCU and commissioned in December 2010 with a total capital expenditure of ₹ 73.89 crore.

Installation of sixth furnace was expected to give maximum flexibility for augmenting capacity of GCU, as it would make-up for the down time of furnaces for maintenance. In respect of availability of other infrastructure, it was noticed that GPU had sufficient capacity for providing feedstock for the additional capacity of GCU. Existing utility systems were also adequate to cater to the requirement of additional furnace.

Audit noticed that before commissioning of sixth furnace, GCU, had achieved ethylene production of 4,31,580 MTPA with the existing set of five furnaces including one furnace as standby for decoking[2]. With the addition of sixth furnace, furnace capacity was increased to 5,00,000 MTPA (excluding one furnace as standby). The actual maximum production of ethylene achieved so far was only 4,60,024 MTPA (2014-15). Resultantly, UPPC has been underutilizing the available ethylene capacity of 5,00,000 MTPA (after considering the spare capacity of 1,00,000 MTPA).

Management stated (April 2015) that sixth furnace was installed as an additional furnace to achieve sustained performance of existing five furnaces and to increase flexibility in operations. While admitting that with the addition of sixth furnace the ethylene production should have been 5,00,000 MTPA; it was stated that addition of furnace alone will not lead to proportionate increment in ethylene production. Certain de-bottlenecking of other integral parts of GCU was also required to be carried out to increase the production. It was also stated (July 2015) that for achieving 5,00,000 MTPA ethylene capacity, additional studies were required to be done by the licensor. Management also informed (October 2015) that additional sixth furnace was installed not in totality as debottlenecking of other parts was not considered economical.

Reply should be viewed against the fact that installation of sixth furnace was first step towards achieving 5,00,000 MTPA ethylene production. De-bottlenecking of integral parts such as Cracked Gas Compressor, ethane recovery unit, quench tower, de-propaniser, de-butaniser *etc*. were also carried out subsequently. As there was limitation

[1] ***SWING plant had the ability to achieve about 20 per cent over the design capacity. Similarly HDPE 1 and 2 plant was capable of achieving about 25 to 30 per cent over the design capacity.***

[2] ***Cracking takes place in furnaces at high temperature. At the time of cracking, coke formation takes place. Thus, the furnace needs to be decoked on regular intervals.***

in other integral parts like pipelines, no further debottlenecking could be taken up and intended enhancement in ethylene production could not be achieved. It may be noted that as per assessment of the Company (2008); before installation of sixth furnace in GCU, the polymer units were capable of achieving additional 1,00,000 MTPA (5,10,000 – 4,10,000) production provided sufficient ethylene is available from GCU. The constraint in increasing ethylene capacity, even after installation of sixth furnace hindered utilisation of additional capacity available in downstream polymer unit. This has resulted in operating downstream units at lesser load with resultant loss of opportunity to increase the polymer output by about 234593 MT[1]. Based on the prevailing price level of polymers the Company could have generated additional revenue and realised a margin of ₹ 630.70 crore from this additional polymer production during the period 2011-12 to 2014-15.

MoPNG/Management stated (October/November 2015) that in 2010 GAIL decided to go for doubling the polymer production capacity (Pata- II) and sufficient margin was kept therein so that upstream and downstream capacity gets matched which would rectify this mismatch.

Fact, however, remains that the downstream unit of existing plant was operating at lesser load for all these years and the intended benefit of adding sixth furnace could not be achieved fully.

B. Creation of capacity of utilities in excess of requirement (IOCL)

PNCP comprises Naphtha Cracker Unit (NCU) including associate units[2] in upstream, PP, HDPE, SWING, MEG, Butadiene Extraction Unit in downstream and power & steam generation units. Power and steam are critical requirement for operation of PNCP. Optimum utilization of facilities created for production of these utilities in combination with utilization of up and downstream units of the PNCP was essential for ideal absorption of fixed cost.

Audit analysis of monthly operation report revealed that maximum utilisation of power and steam in PNCP was 135 MW and 668 MT/hr respectively from April 2010 to March 2015 against the power and steam generation capacity of 241 MW and 1295 MT/hr respectively created at a total investment of ₹ 1217.26 crore. Maximum power and steam requirement for achieving 100 *per cent* up and downstream capacity after considering future expansion/projects at PNCP and Styrene Butadiene Rubber unit was 172 MW and 1000 MT/hr respectively.

It was also noticed that capacity configuration of power and steam production facilities were substantially increased from Detailed Feasibility Report (DFR) stage to investment approval/ installation stage (power from 130 to 241 MW and steam from 600 to 1295 MT/hr) without corresponding upward revision in the capacity configuration of PNCP except NCU (from 2170 to 2345 TMTPA) and MEG unit (from 250 to 300 TMTPA). This led to creation of capacity of utilities in excess of requirement of NCU and downstream units.

---

[1] ***(5,00,000 x 4 years = 20,00,000) – (1765407) = 234593 MT***

[2] ***C_4 hydrogenation unit, Benzene extraction unit and Pyrolysis hydrogenation unit***

Maximum capacity utilised in respect of power and steam was 54 *per cent* (2014-15) and 37 *per cent* (2012-13) respectively (***Annexure-VI***). It may be noted that during the year 2014-15, NCU and downstream units had achieved 100 *per cent* capacity utilisation.

Management stated (April/July 2015) that power and utility systems cannot be designed for average consumption. Sufficient cushion in margin of capacity was designed to cater to peak requirement of units based on combination of scenario such as requirement of spare capacity for periodic maintenance, increase in requirement during emergency situations *etc.* defined in feasibility study. Moreover, 25 *per cent* margin has also been kept for future capacity addition.

Statement made by the management may be viewed against the fact that audit observation was made after taking into consideration peak demand for power (135 MW) and steam (668 MT/hr) of the plant. Moreover, as per the practice, periodic maintenance is carried out during annual shut down, where all facilities including utility units were also taken off the production line for maintenance. Hence the argument of sufficient margin of spare capacity for utility systems for meeting the periodic maintenance is not acceptable. Further, regarding keeping of 25 *per cent* margin for future capacity addition, it may be noted that there is no immediate plan of IOCL for expansion of up and downstream capacities. Thus, the investment made in utility capacity to the extent of facilities underutilised as mentioned above remained idle since commissioning.

(II) Feedstock management (IOCL)

PNCP was conceptualized (2003) to give value addition by producing petrochemicals from the surplus naphtha available from Panipat, Mathura and Koyali refineries of IOCL. The estimated requirement of naphtha (3016 TMTPA) was expected to be obtained from Panipat (1280), Mathura (300) and Koyali (1436) refineries. Naphtha produced from refineries of IOCL is allocated as per the Industrial Logistic Plan of Refinery Headquarters (RHQ). Accordingly, PNCP receives naphtha from four more refineries (Barauni, Bongaigaon, Haldia of IOCL and HPCL Mittal Energy Limited- HMEL) in addition to Panipat, Mathura and Koyali refineries.

The plant has been receiving naphtha from Panipat and Mathura Refineries through pipelines as per the estimated availability. Availability of naphtha from Koyali, however, was in the range of 130 to 397 TMT which was less than the estimated availability of 1436 TMTPA. Non availability of estimated quantity of naphtha was made up from other refineries and using different feed mix.

Audit noticed that:

- During the period 2012-13 to 2014-15, 1683 TMT naphtha was procured from Barauni, Haldia, Bongaigaon, Koyali, Mathura[1] and HMEL through railway rakes. Out of this 17.90 TMT naphtha valuing ₹ 85.25 crore was lost in transit. Even in its fifth year of operation the plant is yet to set norms for permissible

[1] ***Some quantity of naphtha from Mathura refinery is transported through rail in addition to quantity transported through pipeline.***

limit for transit loss of naphtha. In absence of any norms, the extent of controllable loss of naphtha in transit could not be assessed.

- In addition to naphtha, PNCP uses 'hydrogenated C4' (C4H) as feedstock in NCU. C4 mix is a by-product from production of ethylene. It is a mixture of gaseous hydrocarbons[1]. C4 mix as such is unsuitable for blending in LPG or for sale. Therefore, C4 mix is first hydrogenated (C4H) and then blended with LPG and/or sold to industrial LPG consumers. In view of better marketability of C4H through blending with LPG, recycling of C4H in NCU was not commercially rewarding as discussed below.

NCU produced 10.59 lakh MT (LMT) C4 mix during 2012-13 to 2014-15, out of which 9.94 LMT was hydrogenated. From this quantity, 6.09 LMT was used for production of LPG. In absence of naphtha, 3.55 LMT was recycled in NCU as feedstock and remaining was consumed as internal fuel. It was noticed that LPG production was below the planned production by 70,089 MT and 63,675 MT during 2012-13 and 2013-14.

MoPNG/Management stated (April/July/November 2015) that PNCP is designed to crack naphtha along with C4H recycles. Mix of naphtha and C4H in the feed, however, is based on naphtha availability and is determined after working out economics of recycling based on prices of naphtha, LPG and polymer product. Audit, however, noticed that during the period 2012-13 to 2013-14, PNCP did not take the price advantage of LPG and opted for recycling C4H instead of producing LPG. Loss of margin on account of this worked out to ₹ 51.39 crore[2].

MoPNG/Management also stated (July/November 2015) that during the initial period naphtha allocation plan could not be implemented as envisaged. Also, sourcing of naphtha from different refineries resulted in wide variation in feed quality of naphtha which called for recycling of C4H to maximise polymer production. This points to the fact that there is a need for better coordination in allocation of naphtha by RHQ to obtain maximum value addition.

(III) Consumption of feedstock, chemicals and steam (IOCL)

For maximizing efficiency of plant it was essential for optimum utilisation of feedstock/chemicals/steam and to obtain the best yield out of it. It was, however, noticed that there were instances of excess consumption of feedstock, chemicals and steam as discussed in succeeding paragraphs.

A. Non-achievement of design yield in NCU

Naphtha and other recycle liquids[3] are cracked in NCU to produce polymer grade ethylene and polymer grade propylene. Operating manual of NCU specifies cracking yield of all feedstock for producing ethylene and propylene.

---

[1] ***Propane (C3), propylene, butane (C4), 1-3 butadiene etc.***
[2] ***Amount has been worked out after considering the cost benefit from production of LPG and Polymer.***
[3] ***Butane (C4), pentane (C5) and benzene (C6)***

Analysis, however, revealed that the plant was not achieving ethylene and propylene yield during the year 2012-13 to 2014-15 as per specifications of Operating Manual.

Management stated (October 2015) that yield varies with the quality of naphtha and depends on recycling of other liquids from NCU. Further, polymer units have different tendency to crack and give varying percentage of ethylene and propylene. Yield predictions from these recycles also change with the proportion of recycled streams in mixed feed. Therefore, to know the exact yield and monitoring benchmarking, software called PYPS is installed.

Audit further observed that the plant was not achieving even the benchmarking done by the PYPS. Non achievement of design yield of ethylene (2012-13 and 2014-15) and propylene (2012-13 and 2013-14) from cracking of naphtha and other inputs in NCU resulted in substantial increase in cost of polymers amounting to ₹ 90.52 crore as detailed in ***Annexure-VII.***

B. Excess consumption of Hexane in HDPE unit

Hexane is used as a solvent for keeping the polymer powder in slurry form in HDPE unit. As per the design standard 9.87 Kg of Hexane was required for producing one MT HDPE. Audit observed that actual consumption of hexane was between 11.20 Kg (2012-13) and 14.40 Kg (2014-15)[1].

MoPNG/Management stated (November 2015) that through optimisation of hexane recovery operation and reduction of hexane in wax, net consumption of hexane has been reduced over the period. Further, modifications in enhanced hexane recovery system have been envisaged to reduce the hexane consumption.

Management's reply may be viewed against the fact that since excess consumption is showing an increasing trend from 2012-13 the Company is required to limit the consumption within design standard to reduce its cost of production. Additional cost incurred on account of excess consumption of hexane worked out to ₹ 16.43 crore as detailed in ***Annexure-VIII.***

C. Consumption of steam in excess of design standards in NCU

Four different streams of steam namely Super High Pressure (SHP), High pressure (HP), Medium Pressure (MP) and Low Pressure (LP) are required in NCU. All four streams are generated in Captive Power Plant (CPP). In addition to this, SHP steam is generated during cracking process within NCU which is consumed internally by NCU. Therefore, SHP steam from CPP is required in NCU only during the start up of operations.

It was noticed that steam consumption by downstream units was within the prescribed limit during optimum operational activities. Review of data in respect of steam consumed in NCU (generated by CPP), however, revealed that there was excess consumption of steam over and above the design standard as indicated in ***Annexure-IX*** As against the design consumption standard of 85 MT/hr, the average steam consumption for the period

[1] ***Specific consumption prior to 2012-13 has not been considered being the stabilization period.***

2012-13 to 2014-15 was 191 MT/hr. Review of 'Management Information System report for Energy Conservation Meeting and Annual Operation Report ' revealed that NCU has been continuously consuming SHP steam from CPP in addition to HP, MP and LP. This has resulted in excess consumption of steam to the extent of 106 MT/hr with resultant increase in cost of production of polymers.

Management stated (October 2015) that out of 106 MT/hr. steam consumed in excess of design standard, 92 MT/hr. was due to lower severity operations, operational reasons, decoking requirement *etc*.

Reply needs to be viewed against the fact that no specific reason was attributed by the Management for excess consumption of steam to the extent of 14 MT/hr. Increase in cost of production during the period 2012-13 to 2014-15 on account of this excess consumption was about ₹ 138.85 crore. Further, no acceptable variation level in respect of excess consumption of steam due to lower severity conditions, decoking requirement and operational reasons was specified by the Management in absence of which financial impact on account of excess consumption due to these reasons could not be worked out by Audit. Thus, PNCP is required to limit consumption of steam within the design standard to reduce the production cost.

(IV) Implementation of energy saving measures in UPPC (GAIL)

During production process, certain amount of gas is flared due to technical reasons. For safety and operational reasons, a flare system is in place which continuously burns the vent gases. Company decided (2002-03) to provide a compressor arrangement to recover certain amount of flared gas and use the same as fuel gas in the complex. Accordingly, Company approved (2004) implementation of 'Compressor based Flare Gas Recovery System' (C-FGRS) at UPPC at a total cost of ₹ 10.72 crore. Implementation of the project was expected to save fuel to the extent of 132894 MKcal/year with corresponding cost savings of ₹ 6.50 crore per annum[1]. Accordingly, Lurgi India Company Limited (LICL) was awarded (February 2005) contract for Engineering, Procurement and Construction Management (EPCM) Consultancy for the project at an estimated cost of ₹ 57.30 lakh with scheduled completion by 21 May 2006.

LICL had carried out basic and detailed engineering of the project, prepared tender for procurement of flare gas compressor and composite work within the contractual period. Meanwhile, a committee was constituted (May 2006) for studying the feasibility of Ejector based Flare Gas Recovery System (E-FGRS) instead of C-FGRS. The Committee recommended (May 2006) for putting up E-FGRS on turnkey basis and to drop C-FGRS. Cost effectiveness, independence from the consequence of power failure *etc*. were the advantages expected from E-FGRS in comparison with C-FGRS. Accordingly, the Company abandoned (May 2006) the earlier EPCM contract with LICL after incurring an expenditure of ₹ 0.14 crore and decided (January 2007) to install E-FGRS at an estimated cost of ₹ 4.22 crore.

[1] ***Estimated based on the rate of recovery of gas at 3375 SCM/Hr at a normal flow rate of 2.5 MT/Hr. The calorific value of gas was considered at 4922 Kcal/SCM @ ₹ 2.44/SCM.***

Contract for procurement and commissioning of E-FGRS was awarded (December 2009) to Comm Engineering at ₹ 3.27 crore and work for piping and associated jobs were awarded[1] during 2011-12 at ₹ 2.27 crore. The system was installed in March 2013 at a total cost of ₹ 4.70 crore. The system after commissioning was expected to recover gas from flaring and to use the same to replace lean gas used for process heating.

Audit observed that E-FGRS system implemented in March 2013 at a total cost of ₹ 4.70 crore has not been commissioned so far resulting in the asset remaining inoperative. In addition to this, ₹ 0.14 crore spent on EPCM consultancy services on C-FGRS has become infructuous. Moreover, delay in implementing and utilising the system had resulted in non recovery of gas flared. During the period 2007-08 to 2013-14 the plant flared 12.43 MMSCM gas. Based on the average rate of gas[2] the cost of flared gas worked out to ₹ 18.66 crore. Based on the present assumption on recoverability of about 20 *per cent* flared gas, the total cost of recoverable gas works out to ₹ 4.06 crore during the same period.

MoPNG/Management stated (November 2015) that trial run of E-FGRS was taken in October 2013. Further, it is being explored to use E-FGRS outlet for boilers for Pata-II which was expected by December 2015. Fact remains that utilisation was yet to take place (November 2015) with resultant financial impact as discussed above.

(V) Procurement of liquid nitrogen and oxygen (IOCL)

IOCL and Air Liquide Industries, Belgium (ALB) entered (May 2007) into a contract for setting up oxygen and nitrogen plant on land leased to ALB within Naphtha Cracker Complex at Panipat. A license agreement for supply of oxygen and nitrogen was also entered (May 2007) between ALB and IOCL. Terms and conditions of contract *inter alia* stipulated that ALB was required to build, own and operate a plant capable of steady operation for at least 25 years for production and supply of gaseous oxygen and nitrogen to meet the quantity guaranteed to IOCL and market any surplus oxygen and nitrogen in the open market. After successful completion of construction of plant and distribution system, ALB assigned the scope of work to Air Liquid North India Private Limited (contractor).

IOCL was under contractual obligation to supply power as per the requirement of oxygen and nitrogen plant. Accordingly the price payable by IOCL to contractor for off-take of oxygen and nitrogen during each billing period was arrived at after adjusting amount receivable by IOCL from contractor for the power supplied during the same period.

Audit observed that:

- As per the billing trend, IOCL could not recover even the cost of power as the cost of power was more than the cost of oxygen & nitrogen and an amount of ₹ 39.90 crore (as per Haryana State Electricity Board -HSEB power rate) was pending from contractor as on December 2014. Yet IOCL did not take any security for recovery of its outstanding dues. As per the amendment to bidding document, bidders were required to

[1] ***To various contractors***
[2] ***Ranging between ₹ 11.98 / SCM and ₹ 23.50/SCM***

prepare their price bid considering the cost of power as ₹ 3.95 per unit (equivalent to HSEB power tariff). On the contrary, Article 8.3.1 of the contract states that rate of power to be charged by IOCL for supply of power to contractor is the cost of power generation of CPP which is higher than HSEB rates. This is disputed by contractor stating that ₹ 3.95 per unit was the base rate while bidding and is liable to pay power charges to IOCL as per HSEB rates only.

Thus, entering into an agreement with contradictory clauses in bidding document and agreement entered into with Contractor resulted in doubtful recovery of dues and created uncertainty in ensuring supply of oxygen and nitrogen for functioning of the plant.

Management stated (June 2015) that arbitration proceeding in this regard is in progress.

(VI) Non-maintenance of grade wise cost

A. GAIL

G-lex and G-lene are the brand name of polymers produced and marketed by GAIL. Over the period, GAIL has developed its own policy for pricing of its polymer products and has a well defined marketing mechanism. Price of polymer products in domestic market is indexed to the international prices of polymers (Import Parity Price – IPP).

Audit, however, observed that GAIL does not maintain grade-wise cost of polymers which would enable determining grade wise profitability.

MoPNG/Management stated (October /November 2015) that GAIL initially strived to have pan India presence in all downstream polymer sectors. After attaining market maturity, GAIL is trying to ascertain grade wise as well as location wise profitability. It was also stated that standard costing mechanism is maintained from 2005-06. Recently fine tuning has been done to the grade wise cost analysis and after commissioning of Pata-II it would be possible to effectively implement grade optimisation.

In this regard it may be noted that GAIL has been in the business since 1999 and was not able to implement grade wise cost effectively so far. In absence of this, margin from sale of different grades at different price levels could not be estimated for providing adequate managerial information.

B. IOCL

Under the umbrella brand 'PROPEL', IOCL offers wide range of petrochemicals[1] to cater to different applications. As per the pricing policy for its petrochemical products (2009), price in the domestic market is fixed on the basis of IPP.

Audit, however, observed that IOCL does not maintain grade-wise cost of polymers which would enable determining grade wise profitability.

Management stated (June/October 2015) that methodology for arriving grade wise cost of polymer is available for in-house purpose. IOCL has also carried out studies to maximize

[1] ***Linear Alkyl Benzene, Purified Terephthalic Acid, Paraxylene, MEG, PP, LLDPE and HDPE***

profitability and M/s. Mckinsey had been appointed to develop a model for assessing grade wise cost of polymers. Model developed by them is under testing and stabilization.

1.3.3.2 Petrochemical Project Management

(I) Capacity enhancement projects of UPPC (GAIL)

GAIL took up (August 2010) implementation of capacity expansion project of UPPC including ethane/propane recovery plant at Vijaipur. There was delay in execution of this project with resultant overshooting of target date for completion and non-achieving the targeted MoU production as discussed below.

The project envisaging expansion of polymer production capacity by 4.00 LMTPA at a capex of ₹ 8140 crore[1] was to come up at two locations *viz.* ethane/propane (C2/C3) recovery and enrichment plant at Vijaipur (Madhya Pradesh) and expansion of capacities at UPPC (Pata-II). The project was scheduled to be mechanically completed in 42 months from date of appointment of EPCM consultant.

Engineers India Limited (EIL) was appointed (11 August 2010) as EPCM consultant for the project on nomination basis. Considering the scheduled completion period of 42 months, the date of completion of project at Pata II and Vijaipur was scheduled as 10 February 2014. Financing portfolio for setting up of project was considered with debt component of ₹ 5258 crore in the Debt: Equity ratio of 60:40.

Plant at Vijaipur envisaged recovery of heavier fractions (ethane/propane - C2/C3) of NG available from HVJ pipeline. Ethane/propane recovered (about 1.25 MMSCMD) would be re-injected into pipeline to enrich the NG with ethane/propane component for subsequent consumption at UPPC. Plant at Vijaipur (GSU and GPU) was mechanically completed on 30 August 2014 against the target of February 2014 and commissioned in March 2015 with a delay of 12 months in commissioning.

Expansion of existing capacity of UPPC was envisaged by setting up GCU (4.50 LMTPA) and downstream unit (4.00 LMTPA), butene-1 plant (20 TMTPA) along with required liquid hydrocarbon recovery facilities. Project was partially commissioned in March 2015 against the scheduled completion of February 2014.

Audit noticed that;

- Eleven major work contracts (plant at Vijaipur) awarded during the period February 2011 to September 2013 with scheduled completion between May 2012 and January 2014 were not completed within the scheduled time. These projects were subsequently completed with a delay ranging between 10 and 32 months. Details of major work orders, project schedule, physical progress where slippages noticed and reasons thereof are given in ***Annexure-X.***
- Nine major work contracts (Pata II) awarded during the period May 2011 to June 2012 with scheduled completion between August 2012 and December 2013 were not completed within the scheduled time. Out of the nine contracts, seven works were completed with a delay ranging between 11 and 20 months. Remaining two

[1] ***Including foreign exchange component of ₹1364 crore.***

works relating to water treatment plants were not completed by June 2015. Details of major work orders, project schedule, physical progress where slippages noticed are given in ***Annexure-XI.***

Parliamentary Standing Committee on Petroleum and Natural Gas also expressed (December 2014) concerns over delay in execution of Pata expansion project and held that project execution was hampered due to lapse on part of civil and structural contractors resulting in non-availability of work front to main contractors which had a cascading effect on the project completion. Besides, financial crunch of contractors at both sites affected the payment schedule to sub agencies. This called for a robust monitoring of project schedule by GAIL and especially by EPCM for streamlining the scheduled completion.

In respect of overall delay of project commissioning, Management stated (June 2015) that (i) effect of global recession affected fund flow for various composite and infrastructure contractors (ii) delay in starting civil works due to unprecedented monsoon in 2011 (iii) shortage of work force and their limited productivity (iv) local law and order issues (v) non-availability of specific steel sections (vi) shortfall in estimation of quantity of materials on account of difference in 3-D models developed by EPCM consultant and basic engineering details provided by licensors resulting in placement of late orders for procurement in the final stages (vii) delay in delivery of machines from BHEL, last minute shortage of materials, design faults *etc*. (viii) deficient design of cooling water system by EPCM (ix) delay in obtaining statutory clearances (x) failure of equipments such as relay problems in sub-station switches supplied by Siemens at Pata *etc*.

The prominent reasons such as shortage of work force, non-availability of material, deficient design *etc*. were associated with selection of contractor which was the responsibility of EPCM consultant. The EPCM consultant had failed in this respect as discussed above. Action in line with contractual stipulations against this failure is yet to be taken.

As a result of delay in commissioning of capacity expansion project, GAIL could not achieve the MoU target of production of 1,00,000 MT polymers from Pata expansion project for the year 2014-15 and thereby failed to avail the resultant profit margin of ₹ 32.10 crore. Various units of Pata-II were pending completion even as of October 2015.

(II) Non-synchronization of Butene-1 project with PNCP (IOCL)

A. Butene-1 is a critical chemical used in production of HDPE and LLDPE. At the conceptual stage of PNCP, it was envisaged (February 2004) that requirement of butene-1 would be met from butene-1 plant at Gujarat Refinery. Butene-1 plant at Gujarat Refinery though commissioned in 2001 was not functioning due to not meeting quality specification of butene-1. Subsequently, IOCL provided for impairment of assets (Butene-1 plant) in its accounts for the year 2004-05. No alternate source for butene-1, however, was considered while according investment approval (December 2006) for PNCP. IOCL continued its efforts to resolve the issue of butene-1 plant at Gujarat till January 2006. Since then plant was kept idle and finally written off in December 2009.

Since Butene-1 was not available, PNCP had no option but to import it for production of HDPE and LLDPE.

To avoid expenditure on import and storage facility, Board of Directors (BoD) accorded (22 December 2010) 'in-principle' approval for installation of Ethylene Dimerisation Unit for production of 20 KTA Butene-1 at Panipat at an estimated cost of ₹ 134 crore. Final investment approval was accorded (February 2012) at an estimated cost of ₹ 190 crore after a delay of 13 months from the date of 'in-principle' approval. The plant was subsequently commissioned on 19 May 2014 at a total cost of ₹ 172.38 crore.

Audit observed that:

- Butene-1 plant at Gujarat used feed from Gujarat Refinery. As per the quality requirement of feed for production of butene-1, the feedstock should have 'nil' level of sulphur (impurities). The feed received from Gujarat Refinery, however, was having sulphur content of 20 ppm[1] as the crude mix processed in Gujarat Refinery contains around 25 *per cent* to 30 *per cent* weight of imported high sulphur crude. Butene-1 plant remained inoperative since inception as there was no scope of getting the desired quality of crude for processing at Gujarat Refinery. This fact was known to the Management at the time of taking a decision for investment approval for PNCP in 2006. Still the Company considered sourcing of butene-1 from Gujarat Refinery for meeting the requirement of butene-1 in the proposed PNCP.
- To minimise the cost of import, in-principle approval (December 2010) for in-house production of Butene-1 at Panipat was taken after a lapse of one year from write off of Butene-1 plant at Gujarat. Subsequently, there was a further delay of 13 months in the pre-implementation and planning stage and a final decision to go ahead with the project was taken only in February 2012. The project was completed and production commenced in May 2014. Till commencement of production from Butene-1 plant, PNCP imported 40,793 MT butene-1 at a total cost of ₹ 420.02 crore for running the plant.
- As per the estimates of IOCL (August-2014), there was saving of ₹ 50,510 per MT by substitution of imported butene-1 with domestic production. Thus, due to delay in import substitution, IOCL had to forego savings of ₹ 189.24 crore[2].

B. For import of Butene-1, IOCL hired (January 2010) dedicated storage and handling facilities at port location with a capacity of 3,360 MT at a total contract value of ₹ 18 crore for a period of 24 months (upto 15 January 2012) from United Storage and Tank Terminals Limited (USTTL) through tendering process. Period of contract was further extended by one year (upto 15 January 2013) with revised contract value of ₹ 26.52 crore for three years. On expiry of the period, the contract was awarded to IMC Limited (erstwhile USTTL) on single tender basis at ₹ 13.50 crore for a period of 18 months from 23 January 2013.

---

[1] ***Parts per million***

[2] ***Cost of imported Butene-1 per MT (₹111926) / Cost of production per MT (₹61415) = 1.82***
Total cost of import of 40793 MT of Butene-1 for the period 2010-11 to 2014-15 = ₹420.02 crore
Pro-rata cost of production for import = (₹420.02 crore / 1.82) = ₹230.78 crore
Extra expenditure on import = (₹420.02 crore - ₹230.78 crore) = ₹189.24 crore

IOCL acquired storage and handling facility for parcel size of 2,500 MT to 3,000 MT at the time of floating the tender to avoid higher freight charges involved in transportation of lower parcel size. Import, however, was in a maximum parcel size of 2,000 MT. Resultantly the hired storage capacity of 3,360 MT was never utilized in full during the period. Also during the entire period of contract the total receipt of Butene-1 had never crossed 13,000 MT per annum.

Management stated (July 2015) that consumption of Butene-1 is grade dependent. Therefore monthly scheduling of grades in Petrochemical Production Logistics Plan (PPLP) decides parcel size of import taking into account the lead time of inland transportation. Further, to minimise the inventory and its cost, actual parcel sizes imported are optimised as per requirement.

Management's replies may be viewed in the backdrop that actual utilization of storage facility was only 50 *per cent*. Further, before hiring the facilities, analysis of historical data of PPLP regarding grade wise scheduling would have enlightened the management as to the actual size and requirement of storage capacity. Absence of such an analysis and non consideration of available storage capacity of 3360 MT at Panipat, led to underutilisation of hired facilities and rendered the expenditure of ₹ 15.58 crore[1] unfruitful.

Conclusion

UPPC, GAIL

- ***Mismatch between upstream and downstream production capacity in UPPC led to operation of downstream units at lesser load with resultant loss of opportunity for production.***
- ***Due to not maintaining grade-wise cost of polymer, margin from sale of different grades at different price levels is not estimated.***
- ***Delay in materializing capacity expansion of Pata- II due to failure on the part of EPCM consultant and contractors deprived GAIL the benefit from production of one lakh MT polymers during 2014-15.***

PNCP, IOCL

- ***Creation of power and steam generation capacity in excess of actual requirement led to under-utilisation of these utilities.***
- ***Recycling of C4H as feedstock in NCU instead of blending with LPG resulted in forgoing the price advantage available from sale of LPG.***
- ***Non achievement of design standards in respect of consumption of feedstock, chemicals and steam led to excess consumption and resultant increase in cost of production.***

[1] ***Facility hiring charges @ ₹71.25 lakh for 54 months (i.e. from Jan-10 to June-14) ₹38.50 crore x 1360 MT/3360 MT***

- ***Due to not maintaining grade-wise cost of polymers, margin from sale of different grades at different price levels is not estimated.***
- ***Due to delay in pre-implementation and planning stage of butene-1 project, production was delayed depriving IOCL the cost benefit advantage through import substitution.***

Recommendations

- ***GAIL and IOCL may maintain polymer grade wise cost so as to estimate margin from sale of different grades.***
- ***IOCL may take effective steps to avoid excess consumption of feedstock and other inputs.***
- ***GAIL and IOCL should develop a mechanism, with clearly defined responsibility centre, to ensure and assess timely completion of petrochemical projects and cut down delays.***

Hindustan Petroleum Corporation Limited

1.4 Avoidable expenditure on Diesel Hydro Treater Project in Mumbai Refinery

HPCL initiated the Diesel Hydro Treater (DHT) project in 2007 for meeting the statutory quality specifications of diesel at a cost of ₹ 1969.59 crore ignoring the existing DHDS plant, which was capable of producing similar quality of diesel since 2005 and could be upgraded to meet the statutory requirements. Subsequently, the DHDS project was taken up for upgradation (2009) to enhance its capacity and improve quality of its output. The revamped DHDS was capable of meeting the entire ULSD/Euro IV requirement of Mumbai Refinery of HPCL. This resulted in avoidable expenditure of ₹ 1969.59 crore as well as creation of excess capacity towards production of diesel.

The Auto Fuel Policy (2003) of GoI mandated supply of Euro-IV (sulphur content less than 50 ppm) quality diesel to 11 major cities of India from 1 April 2010.

HPCL had commissioned the Diesel Hydro De-Sulphurisation (DHDS) plant in Mumbai Refinery in 2000 which was subsequently revamped during 2005. An additional trickle bed reactor had been added during the revamp, which had increased the capacity of DHDS to 1.65 MMTPA[1] with the capability to produce hydro treated diesel product having 20 ppm[2] sulphur. Thus, Mumbai Refinery (MR) was capable of producing Euro-IV diesel (sulphur content less than 50 ppm) through its DHDS plant since 2005 itself. Ignoring the existing capability of producing the required quality of diesel, HPCL initiated (August 2007) establishment of Diesel Hydro Treater (DHT) plant for meeting the statutory quality specifications of diesel. In fact, the Management, while submitting the proposal of the DHT project to the Board in August 2007, had stated that the existing DHDS plant had been de-bottlenecked and there was no further possibility of enhancing its capacity. It was stressed that a separate DHT unit needs to be installed to ensure the

[1] *Million Metric Tonne Per Annum*
[2] *Parts Per Million*

mandatory Euro IV quality of diesel.The critical information that the DHDS plant had the capability to produce Euro IV grade of Diesel was not informed to the Board while proposing DHT Project in August 2007.

The estimated Net Present Value of the DHT project was (-) ₹ 2397.70 crore with a negative Internal Rate of Return.HPCL Board approved implementation of the project on 5 March 2009.The DHT project was commissioned in November 2013 and capitalized in June 2015 at a cost of ₹ 1969.59 crore.

While the DHT project was underway, HPCL took up a separate project (October 2009) using isotherming technology for revamping the existing DHDS plant. The revamped plant would be capable of producing diesel having sulphur content lower than 10 ppm[1] and at the same time maintain the Euro IV cetane number. The Committee of Functional Directors (CFD) approved (April 2011) the revamp project which was commissioned in July 2015 at a cost of ₹ 142.60 crore. The revamped DHDS plant had a capacity of 2.28 MMTPA and the ability to produce Ultra Low Sulphur Diesel (ULSD).

At present, thus, MR of HPCL has the capacity to produce 4.48 MMTPA (2.20 MMTPA capacity of DHT + 2.28 MMTPA capacity of DHDS) of Euro IV/ ULSD grade of diesel. The present crude processing capacity of MR is however only 6.50 MMTPA. Considering the crude throughput and diesel production in MR over the past six years (2009-10 to 2014-15), the average diesel production in MR has been approximately 30 *per cent* of the crude processed (***Annexure-XII***). Besides, Euro IV diesel accounted for 15 *per cent (*August 2014 to August 2015) of the diesel production by MR. Thus, the requirement of production of ULSD/EURO IV quality diesel is limited in MR and in no case more than 2.34 MMTPA as assumed by M/s EIL considering a higher crude refining capacity of 8 MMTPA in MR.The created capacity of production of 4.48 MMTPA of low sulphur diesel is thus, well above the MR requirement.

By implementing the DHT project without considering the existing capacity of DHDS and possibility of further revamping the same by using isotherming technology, HPCL has incurred an avoidable additional expenditure of ₹ 1969.59 crore as well as created excess capacity for production of ULSD/Euro IV quality diesel.

The Management replied (October 2015) that:-

(i) The DHT project was conceived to meet immediate requirement of Euro-IV grade fuel as well as Ultra Low Sulphur Diesel to meet the future stringent product specifications.

(ii) In order to produce 100 *per cent* Euro – IV diesel, the DHDS outlet cannot be blended with many high sulphur diesel streams downstream of DHDS. Hence, never in the past, prior to DHT, Mumbai Refinery has ever produced Euro-IV Diesel and the market requirement had been met through coastal inputs only. Considering these facts, it was informed to the Board that MR is not capable of producing Euro-IV grade diesel. Hence, there was no event of submission of imprecise information regarding Euro-IV diesel production to Board.

[1] ***Which is Ultra Low Sulphur Diesel superior to Euro IV (Sulphur contain not more than 50 ppm.) diesel.***

(iii) The DHDS unit post revamp in 2005 had the capability to produce Euro-IV diesel (50ppm sulphur) corresponding to 1.65 MMTPA feed of raw diesel. The DHDS process licensor M/s UOP in 2006-2007 suggested major changes in the equipment of existing DHDS unit for revamping the plant up to 1.8 MMTPA. Therefore, there could have been a gap of approximately 1.2 MMTPA of diesel. In view of the above, the additional capacity of diesel desulphurization to realize the full potential of diesel production of MR was required, irrespective of revamp of existing DHDS unit to its maximum capacity.

The reply is not acceptable due to the following:-

(i) The DHT project in MR was approved by the Board despite negative IRR and NPV merely to meet the GoI guidelines, to produce and supply Euro IV from April 2010. The existing DHDS had the capacity to produce Euro IV diesel as early as 2005. This option was not explored by the refinery when the proposal for DHT project was placed before the Board in 2007. The aspect of future stringent product specifications was not envisaged in the proposal submitted to the Board.

(ii) The contention of the Management that MR has a diesel potential higher than 3 MMTPA is not borne out by the present capacity of MR or its diesel production profile over the last six years. In fact, even considering a higher refinery capacity (8 MMTPA as against the present 6.5 MMTPA), M/s EIL had provided for a total diesel capacity of 2.34 MMTPA. Thus, by implementing both DHT project and DHDS revamp, MR has created nearly double the required facility for diesel.

(iii) The DHDS project not only had a lower capital cost (₹ 103.40 crore for DHDS as against ₹ 1969.59 crore for DHT), it would also result in lower hydrogen consumption and higher energy conservation. Thus, even in operation, DHDS would prove economical to DHT.

(iv) Had the entire facts been brought before the Board at the appropriate time, the revamp of DHDS project could have been completed in time to supply EURO IV products by April 2010 as envisaged in Auto Fuel Policy (2003).

The implementation of DHT project at a cost of ₹ 1969.59 crore without giving the Board the option of considering DHDS project, was thus, imprudent.

The matter was reported to the Ministry (December 2015); their reply was awaited (March 2016).

Indian Oil Corporation Limited

1.5 Irregular payment of Performance Related Pay

Indian Oil Corporation Limited made an irregular payment of ₹ 110.40 crore for the years 2012-13 and 2013-14 towards 'Performance Related Pay' due to non-adherence to the DPE guidelines

The Department of Public Enterprise (DPE) issued (November 2008) instructions for regulating pay and allowances, perquisites and performance related pay (PRP) to executives and non-unionized supervisors in Central Public Sector Enterprises (CPSEs).

The above instructions directly linked PRP to the profits of the CPSEs and performance of Executives. These instructions and further clarifications issued thereon in September 2013 and September 2014 *inter alia* laid down following condition for payment of PRP:

Profit Before Tax (PBT) for computation of PRP was expected to come out from the specified objective and core activities of CPSEs and that extraordinary items like valuation of stock, grants/waiver by Govt of India, sale of land, interest on idle cash/bank balances etc. (list of item is not exhaustive) was not to be included in calculation of PBT as far as PRP is concerned.

Indian Oil Corporation Limited (the company) included revenue of ₹ 1398.00 crore and ₹ 1400.12 crore arising out of non-core activities such as interest on loans and advances to employees, interest on fixed deposits with banks, sale of scrap, income from finance leases, profit on sale of investments etc. in the PBT for payment of PRP for the year 2012-13 and 2013-14 respectively. Accordingly, excess payment of PRP of ₹ 41.94 crore and ₹ 68.46 crore was made in these years in violation of DPE guidelines ***(Annexure-XIII)*.**

The Company replied (April/October 2015) that since it is a net borrower, there was no idle cash/ bank balance and thus no interest on the same which is to be deducted from PBT for PRP purposes. On the contrary, it is an oil marketing company and has incurred huge under recoveries on sale of petroleum products till 2013-14. These under recoveries were compensated by either Govt. of India or Upstream Companies but due to significant time gap between the announcement and actual receipt of such compensation from Govt. of India, the borrowing levels of the corporation were on very high side during 2012-13 and 2013-14. Further, the additional interest burden due to such delay in receipt of compensation has also adversely affected the financial result of the company. These two components were indeed related to core business activities of the Corporation and thus should have been be allowed to be added back while calculating PBT for the purpose of PRP in line with DPE letter dated 02 September 2014.

Audit observed that the Company had requested (December 2013 / July 2014) Ministry of Petroleum and Natural Gas (MoPNG) to approve exclusion of interest burden on the borrowings of the Company due to delayed release of compensation towards under recoveries by the Government as it dented profit arising from core activity of the Company. MoPNG took up this matter thrice with DPE i.e. in January 2014, June 2014 and July 2014. But DPE had categorically rejected (May 2014) the request of the Company to exclude interest burden for calculation of PBT as the existing guidelines on PRP clearly mention that it shall be based on PBT of the Company and there is no provision to add the interest paid by the Company on borrowed capital to the PBT. DPE further reiterated (September 2014) that PRP payable to the executives and non-unionised supervisors of CPSEs based on the profits of financial year 2012-13 onwards would be calculated as per DPE OM dated 18 September 2013 i.e interest on idle cash/bank balances may be deducted from PBT and PRP may be distributed based on profit accruing only from core business activities of the CPSEs.

Audit observed that despite clear instruction from DPE not to include income from non-core activities in the PBT for payment of PRP, the Company included such revenues arising out of non-core activities as has already been mentioned above.

Thus, due to non-adherence to the DPE guidelines with respect to payment of 'Performance related Pay', the company made an irregular payment of ₹110.40 crore for the years 2012-13 and 2013-14.

The matter was reported to the Ministry (November 2015); their reply was awaited (March 2016).

1.6 Undue benefit extended to the executives in the form of shift allowance

Indian Oil Corporation Limited extended undue benefit to the executives by paying shift allowance amounting to ₹ 56.27 crore in violation of DPE guidelines

Government of India formulated the policy for revision of pay and allowances of Board level and below Board level executives as well as non-unionized supervisors in Central Public Sector Enterprises (CPSEs) with effect from 1 January 2007 vide DPE O.M.[1] dated 26 November 2008. The said OM *inter-alia* provided that the Board of Directors of the CPSEs would decide on the allowances and perks admissible to the different categories of executives subject to a maximum ceiling of 50 *per cent* of the basic pay. CPSEs may follow 'Cafeteria Approach' allowing the executives to choose from a set of perks and allowances. Only four allowances viz North East allowance, Allowances for underground mines, Special Allowance for serving in difficult and far flung areas as approved by the Ministry and Non practicing allowance for Medical Practitioners were kept outside the purview of ceiling of 50 *per cent* of basic pay. It was also directed that infrastructure facilities created by CPSEs like hospitals, colleges, schools, clubs *etc*. should be monetized on the basis of recurring expenditure on maintaining and running the infrastructure for the purpose of computing the perks and allowances.

While implementing the revision of pay scales for Board level and below Board level executives, Indian Oil Corporation Limited (the Company) decided that available entitlement of the executives would be 44 *per cent* of their basic pay because six *per cent* of the basic pay has been considered as monetized value of the infrastructure facilities.

Audit observed that the Company was paying shift allowance to its executives and keeping the same outside the purview of ceiling of 50 *per cent* of basic pay. During 2010-11 to 2014-15, shift allowance of ₹ 56.27 crore was paid to executives of the Company. The Company stated (October 2015) that rotating shift duty was neither a normal duty nor its compensation was a routine payment; but it was purely a contingent/need based operational requirement. The compensation towards performing the difficult and hazardous duty was admissible on shift basis specifically for those job groups of employees who were transferred to work in the rotating shift involving eight hour continuous duty without any break in the morning, evening and night shift. Thus, rotating duty allowance was neither in the nature of perk/allowance to an officer nor it was universally payable to everyone *i.e.* it was not a perk or allowance in the manner it was generally envisaged under the DPE guidelines. Expenses towards rotating shift duty was incurred by the Company for discharging an hazardous/difficult assignment which was more in the nature of underground mining allowance or non-practicing allowance

[1] ***Department of Public Enterprise Office Memorandum No. 2(70) 108-DPE (WC)-GL-XVI/08 dated 26-11-2008***

allowed under the DPE guidelines. Further, if these executives were given a choice to choose from a set of perks and allowances under the cafeteria approach that includes shift allowance, then no executive would choose shift allowance as it led to hardship by way of rotating shift duty. As a result, the operations would suffer immensely.

The reply is not tenable as shift allowance is meant to ensure continuous round the clock production and is not meant to compensate for hazardous nature of duties performed by any employee. As regards the apprehension expressed by the Management that operations will suffer if executives do not choose shift allowance, it needs to be appreciated that in a cafeteria approach with the executives given the freedom to choose the allowance, enforcement of duties cannot be linked to choice of a particular allowance in preference to others. Moreover, DPE in this regard had categorically stated (June 2012 and June 2013) that except four allowances as mentioned in DPE OM dated 26 November 2008, no further allowance/benefit/perks was admissible outside the 50 *per cent* ceiling of basic pay under Cafeteria Approach.

Thus, payment of ₹ 56.27 crore made by the Company towards shift allowance was in violation of DPE guidelines and therefore, irregular.

The matter was reported to the Ministry (November 2015); their reply was awaited (March 2016).

Oil and Natural Gas Corporation Limited

1.7 Delay in appraisal and non-monetization of the discoveries in KG DWN 98/2 block

1.7.1 Introduction

Pattern of Participating Interest held by the JV Partners in KG-DWN-98/2				
Period	**Cairn Energy India Ltd**	**ONGC**	**Petrobras International**	**HOEI**[1]
April 2000	100 %			
March 2005	10 %	90 %		
August/ September 2007	10 %	65 %	15	10
December 2009	10 %	80 %	0	10 %
June 2010	10 %	90 %	0	0
September 2012 onwards	0	100 %		

KG DWN 98/2 is a deep-water block in Krishna Godavari basin which was awarded to M/s Cairn Energy India Private Limited (CEIL) with 100 *per cent* participating interest (PI) during the first NELP round in April 2000. The block has a total area of 9756.6 square kilometre (sq.kms) with water depths ranging from 300 metres in the north to 3000 metres in the south. CEIL with 100 *per cent* PI in the block was its operator.

In March 2005, ONGC acquired 90 *per cent* PI in the block from CEIL at a cost of ₹ 371.12 crore. To associate renowned and experienced companies with the block, ONGC farmed out its 10 *per cent* PI share to Hydro Oil and Energy Ltd. (HOEI) in August 2007 and another 15 *per cent* PI share to M/s Petrobras International Braspetro

[1] ***HOEI-Hydro Oil and Energy Limited***

(PIB BV) in September 2007. Subsequently, both the partners - PIB BV and M/s Statoil (on M/s HOEI merging with Statoil) – withdrew from the block in December 2009 and June 2010 respectively and re-assigned their PI share back to ONGC at no cost. Thus, by June 2010, ONGC had 90 *per cent* PI in the block with the balance 10 *per cent* being held by CEIL. In September 2012, CEIL also withdrew and ONGC acquired its share at a cost of ₹ 212.44 crore. Presently, ONGC is the sole operator of the block with 100 *per cent PI.*

The Contractor[1], after the block was awarded, completed the exploration during April 2000 to April 2008 and had drilled 14 exploratory wells and one appraisal well as against the Minimum Work Programme (MWP) of 6 exploratory wells and had made nine discoveries. The residual contract area of 7,294.6 sq. kms existing in September 2007 was declared as discovery area comprising of Northern Discovery Area (NDA) – 3,800 sq. kms and Southern Discovery Area (SDA) – 3,494.6 sq. kms on the basis of several discoveries made in northern part and lone discovery (UD-1) made in southern part respectively and was accepted by the Management Committee (MC).

The Contractor availed 69 months extension (April 2008 to January 2014) for appraisal of discoveries. During appraisal period, the Contractor drilled 12 appraisal wells (eight in NDA and four wells in SDA) that resulted in two discoveries. The Contractor submitted (December 2013) Declaration of Commerciality (DOC) proposing to develop 10 discoveries in 3 clusters (**Cluster I**: D1 and E1, **Cluster II**: R-1; P-1; M-1; U-1; A-1; A2 & M3 and **Cluster III**: UD-1) from a total of 11 discoveries notified till that date in the Block. Cluster I and II developments were from the discoveries made in Northern Discovery Area and Cluster III was from the lone discovery of Southern Discovery Area. The Contractor also drilled (May 2013 to June 2014) two exploratory wells in NDA during appraisal period which did not result in any new discoveries.

The Company had incurred ₹ 8,402.56 crore towards exploration and appraisal of the block till March 2015. The present status of development in the three clusters of the block is as below:

- **Cluster 1:** The DOC for Cluster I has not been reviewed as the recoverable reserves could not be estimated and production profile could not be generated in the absence of surface flow data/ DST data for its discoveries.

- **Cluster II:** Management Committee (September 2014) reviewed the DOC for cluster II. The Concept Field Development Plan for this cluster has been submitted to DGH for approval in August 2015. It proposes to recover 23.53 MMt of Oil during the period 2019 to 2031 and 50.71 BCM during the period 2018 to 2034 with approx. Capital expenditure of US $ 6583.58 million (with option of fast track schedule for facility cost).

- **Cluster III:** The DOC for Cluster III was not reviewed for want of flow data/ DST data for the sole discovery in this cluster.

[1] ***Contractor- As per the PSC, the Partners of the PSC together are called as Contractor***

1.7.2 Viability of integrated development of cluster 1 along with Godavari PML area

1.7.2.1 The block (KG DWN-98/2) is contiguous to Godavari PML area (IG Nomination Block) operated by ONGC where three gas discoveries termed as "G-4" had been made during September 2003 to October 2006. To optimize cost, integrated development of Cluster I in KG-DWN-98/2 block and G4 discoveries was planned. Accordingly, the Company carried out (up to July 2013) detailed G&G interpretation of the seismic data of these two areas. The results of this study indicated extension of "G4" pools into the contiguous NELP Block KG-DWN- 98/3 (D6) operated by M/s Reliance Industries Limited (M/s RIL). ONGC sought (July 2013), data relating to D6 Block from DGH and Ministry to confirm continuity of G4 pools in D6 Block. Subsequently (November 2013), ONGC and M/s RIL shared data relating to these three contiguous Blocks. ONGC on basis of study of shared data concluded (December 2013), that G4 reservoir extended into M/s RIL operated D6 Block and four wells drilled by the M/s RIL in D6 was actually draining gas from this common reservoir. M/s RIL disagreed.

1.7.2.2 The disagreement could not be resolved and theCompany filed (May 2014) a writ petition in High Court of Delhi against (a) Union of India; (b) DGH and (c) M/s RIL alleging that M/s RIL had drained approximately 18 BCM of gas from the common reservoir shared between these contiguous blocks during the period 2009 to September 2013 and continued to do so. ONGC sought apportionment of gas produced from the common reservoir.

In July 2014, a third party expert, M/s DeGolyer & MacNaughton (D&M), was appointed at the request of ONGC and RIL under supervision of DGH with the following objectives:

- Comprehensive reservoir modelling and analysis to evaluate the continuity of channels and connectivity of reservoirs across the block boundaries operated by ONGC and RIL.

- If reservoir continuity and connectivity is established, then

  - To estimate gas volumes (in place volumes, estimated ultimate recovery (EUR) and reserves) of the respective blocks operated by ONGC and RIL.

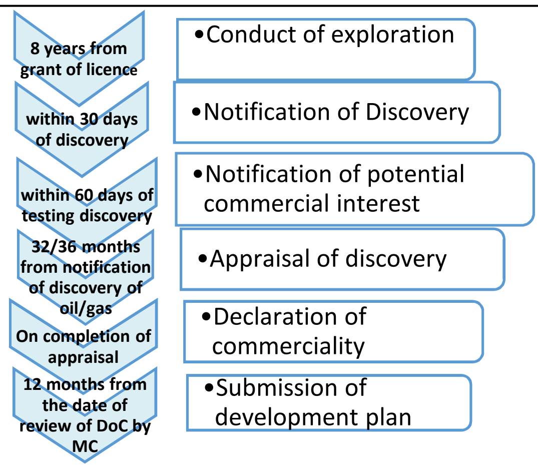
  - The allocation of connected/unconnected gas volumes (in-place volume, EUR, and reserves) to ONGC and RIL for the purpose of any commercial agreement/gas balancing, if applicable.

The scope of study included part of the Godavari PML area, D1 discovery of KG DWN 98/2 (both operated by ONGC), and D1 and D3 discoveries of KG DWN 98/3 (operated by RIL).

In its final report of November 2015, M/s D&M confirmed connectivity and continuity of the reservoirs across the blocks operated by ONGC and RIL. The report indicates that as on 31 March 2015, of the gas initially in place, 49.32 *per cent* in Godavari PML and 34.71 *per cent* in KG-DWN-98/2 (Cluster I) had migrated of which 85.15 *per cent* (pertaining to Godavari PML) and 73.25 *per cent* (pertaining to KG DWN98/2) was produced through DI, D3 fields of KG-DWN-98/3 block. The report projected a higher proportion of gas migration and its production through RIL operated KG DWN 98/3 block by end of 2019. The Company had intended (December 2013) integrated development of Godavari PML area and cluster 1 of KG DWN 98/2 block. The Revised DoC and FDP for the integrated development are yet to be submitted (November 2015) by the Company and as such the effect of the expert report projecting large scale migration of gas from both the areas on the commercial viability of such development remains unclear. Besides, it was noticed that the Company had considered a gas price of US$ 7 per mmbtu[1] (with a payback period of 5.89 years) while considering the viability in December 2013. Under the New Domestic Gas Pricing Guidelines (March 2015 and September 2015.), the gas price was fixed at US$ 4.66 per mmbtu between April 2015 to September 2015 and US$ 3.82 per mmbtu between October 2015 to March 2016, which would further adversely affect the financial viability of integrated development of cluster 1 (KG DWN 98/2) and Godavari PML area.

Delhi High court (September 2015) disposed the petition with directions that GOI shall take a decision on the action to be taken on the basis of the report of D&M, within a period of six months of submission of the report. On the basis of D&M report, Government has appointed (December 2015) a one member committee (Justice A P Shah) to consider the report and recommend future action of the Government considering the legal, financial and contractual provisions including those contained in the ORD[2] Act and the PSCs within a period of three months.

Process of exploration and appraisal as per PSC



1.7.3 Exploration and appraisal process as per PSC

PSC lays down different activities (exploration, appraisal, development, production) related to petroleum operations. The sequential activities involved in the exploration phase (including appraisal) leading up to submission of development plan for a field are indicated alongside. The search for hydrocarbons (exploration) leads to discovery. The commercial potential of such discovery is then assessed and notified. An appraisal plan is framed for appraising the discovery which is submitted for approval of the Management Committee. Thereafter appraisal of the discovery is carried out as per approved appraisal plan on completion of which, the document 'Declaration of Commerciality (DoC)' for the block is submitted to MC. On review of DoC, the development plan is formulated. Subsequently, development of the block is carried out as per the development plan. For each of these activities, the PSC prescribes specific timelines.

[1] *million British Thermal Units*
[2] *ORD: Oil fields (Regulation and Development) Act, 1948*

Ministry of Petroleum and Natural Gas (MoPNG), has, from time to time notified new policies allowing contractors certain relaxations to the above PSC provisions. Audit in respect of KG DWN 98/2 block was conducted with reference to the PSC provisions and the subsequent MoPNG notifications to obtain assurance that hydrocarbon operations in the field were carried out efficiently and effectively. The audit findings are discussed in the subsequent paragraphs.

1.7.4 Audit findings

1.7.4.1 Delays in exploration and appraisal due to lack of coordination among partners.

As per terms of the PSC, the exploration phase of the field was from April 2000 to April 2008. During the exploration phase, M/s CEIL, the operator of the block holding 100 *per cent* participating interest, decided to sell its assets. For two years (2003-05), M/s CEIL suspended exploration efforts and other petroleum operations in the field. Subsequently, in March 2005, 90 *per cent* of the participating interest was transferred to ONGC. In April 2005, ONGC became the operator of the block. In the process, two years of exploration phase was lost. DGH/ MoPNG did not penalize the erstwhile operator M/s CEIL for stalling exploration operations as the PSC does not provide for any penalization of the operator/ Contractor in case of voluntary suspension of work.

Subsequently, ONGC (operator since April 2005) declared (February 2008) the remaining area of the block as discovery area in two parts viz. Southern Discovery Area (SDA) and Northern Discovery Areas (NDA). ONGC was granted (April 2008) a 36-month extension as per Article 21 of the PSC, from the date of last discovery in NDA and SDA for appraisal (till July 2010 for NDA and till December 2009 for SDA). However, the new partners, M/s Statoil having 10 *per cent* PI (during August 2007 to June 2010) and M/s Petrobras having 15 *per cent* PI (during September 2007 to December 2009) did not support the appraisal programme for both discovery areas (NDA and SDA). Besides, M/s CEIL who had retained 10 *per cent* PI in the block, did not support the appraisal programme for SDA. The lack of consensus between the partners delayed implementation of the appraisal programme.

ONGC later agreed (April 2008) to bear sole risk of the appraisal programme in SDA and PI share of M/s Statoil and M/s Petrobras (additional 25 *per cent* risk) of appraisal programme in NDA. MC (December 2009) approved the appraisal programme with the additional risks of ONGC. The appraisal programme, however, could not be completed before expiry of the extension period (July 2010 for NDA and December 2009 for SDA) and ONGC, without completing the appraisal programme, submitted (December 2009 for SDA and July 2010 for NDA) the Declaration of Commerciality (DoC) to DGH for review by MC. However, MC did not review the DoC. In September 2010, ONGC sought extension in the appraisal period under Rig Holiday Policy (RHP).

Subsequently, MoPNG (June 2012), considering crunch in rig resources (January 2008 to December 2010), and excusable delay of 193 days[1]allowed further extension upto January 2014 for appraisal of discoveries. The appraisal programme could not be

[1] 166 days for delay in grant of license and 27 days force majeure

completed even within this extended period. The revised DoC was submitted (December 2013) based on appraisal conducted till then, for developing ten discoveries in three clusters (**Cluster I** : two discoveries, D1 and E1, **Cluster II**: seven discoveries, R-1; P-1; M-1; U-1; A-1; A2 & M3 and **Cluster III**: sole discovery, UD-1). Cluster I and II were in NDA while cluster III was in SDA.

Suspension of exploration work for two years by the erstwhile operator, M/s CEIL, and subsequent lack of consensus among the contractors, *inter alia*, delayed the exploration and appraisal process in the block.

1.7.4.2 Declaration of entire contract area as discovery area and non-compliance with PSC mandated phase-wise relinquishment

PSC[1], *inter-alia,* stipulated that the Contractor should relinquish contract areas in excess of 75 *per cent* of the original contract area at the end of the first exploration phase (four years from inception). Likewise, at the end of second exploration phase (seven years from inception), 50 *per cent* of the original contract area was to be surrendered. By the third exploration phase (completion of exploration period of eight years), only Development/ Discovery Area would be retained by the Contractor. In case, however, the Development/ Discovery areas exceed the limits set in the PSC, the Contractor can retain the entire Development/ Discovery areas. PSC defines 'discovery a*rea' as that part of the contract area about which, based on discovery and results obtained from a well or wells drilled in such part, the Contractor is of the opinion that petroleum exists and is likely to be produced in commercial quantities.*

M/s CEIL (the then Contractor), at the end of the first exploration phase (April 2004), relinquished 2,462 sq. kms representing 25.23 *per cent* of the original contract area of 9,756.6 sq. kms. However, ONGC (the present Contractor), at the end of the second exploration phase, resolved (September 2007) that the entire contract area of 7,294.6 sq. kms was "Discovery Area" and did not relinquish the 2,416 sq. kms (representing the balance area to be relinquished, i.e. 50 *per cent* - 25.23 *per cent* of the original contract area).

The third phase of exploration ended in April 2008. Even at the end of the third phase ONGC did not relinquish any further area as the entire area had already been designated as discovery area. For appraisal activities, ONGC divided the block (April 2008) into two distinct areas: Northern Discovery Area (NDA) with a discovery area of 3,800 sq.kms and Southern Discovery Area (SDA) with a discovery area of 3,494 sq.kms.

In this regard Audit observed the following:

(a) In the entire SDA of 3,494 sq.kms, a single well had been drilled which proved (December 2006) to be a discovery with a notified (February 2007) aerial extent of 566 sq. kms. Though aware of the limited aerial extent of the discovery in SDA, at the end of second phase of exploration (September 2007), ONGC proposed and MC approved (February 2008) retention of the entire 3,494 sq.kms as "Discovery Area" which was irregular.

[1]Articles 4.1, 4.2 and 4.3

(b) On appraisal of this discovery, the aerial extent of the discovery shrunk further and was notified by the Contractor as 141 sq. kms in the revised DOC submitted in December 2013. Even then, DGH did not seek relinquishment of balance area in SDA[1] though as per the PSC provisions, only discovery and development area was to be retained by the operator.

By retaining additional area in SDA, the Contractor incurred an additional expenditure of ₹ 161.39 crore[2] in API of 3D Q marine data (2007-09) and in payment of PEL fee of ₹ 4.59 crore (2007-14) for the additional area.

ONGC in its reply (February 2015) stated that (a) the "size of Discovery" and "Discovery Area" are two distinct things defined separately in PSC and hence based on the size of discovery it cannot be arithmetically concluded that the Discovery Area would be of equivalent size; and (b) Audit remarks on reduced aerial extent of the discovery have been made on hindsight after results of appraisal drilling are known and therefore retention of discovery area by Contractor was not irregular.

DGH in its reply (December 2015) stated that the Operator was able to map several independent channels and geo bodies spreading over the block, which enabled the Operator to establish the entire area of 7294.6 sq.kms. as 'discovery area'.

ONGC/DGH reply is not acceptable in view of the following:

(a) The "size of discovery" has not been separately defined in PSC as stated in the reply. The PSC enjoins upon the operator to surrender areas in excess of discovery/ development areas which has not been done in the instant case.

(b) By the end of the second exploration phase, only one of the several prospects identified in the SDA based on evaluation of 2D data had been drilled which proved a limited aerial extent of 566 sq. kms. Considering that other identified prospects were not based on results obtained from a well or wells drilled in such part 566 sq.kms only ought to have been retained in SDA as against the entire area of 3494 sq. kms.

(c) A similar matter of retention of excess area in contiguous NELP block had been highlighted in the AR 19 of 2011-12. Thereafter, MoP&NG directed[3] (October 2013) the Contractor to surrender the excess area beyond the discovery area which has since been complied with by the Contractor. In this context, DGH allowing ONGC to retain additional area in SDA even after being aware (December 2013) that the aerial extent of the discovery is only 141 sq.kms, is irregular.

---

[1] ***SDA area 3,494 Sq. kms– 2,416 sq. kms to be relinquished at the end of phase II = 1,078 sq. kms – 141 sq. kms Discovery Area in December 2013 =937 sq. kms to be surrendered in December 2013.***

[2] ***3,218 sq. kms of 3D Q Marine Data was acquired and processed during the period November 2007 to April 2008. at the cost of ₹214.96 crore through contract awarded to M/s Westerns Geeco. Proportionate cost of 2,416 sq. kms worked out to ₹161.39 crore.***

[3] ***Para No. 2.5.1.3 of Chapter 2 of Report No.24 of 2014 – Audit Report on Hydrocarbon Production Sharing Contracts.***

Thus, failure of the Contractor to relinquish contract area in excess of 50 *per cent* of the original contract area (2,416 sq. kms) at the end of II exploration phase and contract area in excess of discovery / development area (3,353 sq.kms) had resulted in the Contractor incurring avoidable expenditure of ₹165.98 crore[1] in API of 3D Q marine data and in payment of PEL fee for the additional area retained.

ONGC retained the entire 3,494 sq.kms of SDAas 'discovery area' though the aerial extent of the sole discovery in the area was 141 sq.kms as per notification made of ONGC in DOC submitted in December 2013. Besides being irregular, retention of higher area led to additional avoidable expenses on acquisition and interpretation of data and payment for exploration license.

1.7.4.3 Extension of appraisal period

A. Northern Discovery Area (NDA)

Notification of discoveries in NDA		
Sl. No	NDA 3800 sq. kms (10)	Date of notification
1)	R-1 gas	18.7.2001
2)	P-1 oil	12.10.2001
3)	M-1 oil	16.11.2001
4)	U-1 gas	25.1.2006
5)	A-1 gas	25.1.2006
6)	W-1 gas	12.4.2006
7)	E-1 gas	2.5.2006
8)	D-1 gas	17.5.2006
9)	A-2	28.3.2013
10)	M-3	22.1.2014

By the end of the exploration period, the Contractor had made eight discoveries in NDA. Two more discoveries were made in the NDA during the appraisal phase bringing the total number of discoveries in NDA to ten. Appraisal wells were drilled for only five of these ten discoveries (R-l, P-l, M-l, U-l& A-l). Though a location for drilling an appraisal well for A2 discovery had been approved, the well could not be drilled within the extended period allowed for appraisal (December 2013). Finally, the Contractor submitted (December 2013) DOC covering nine of the ten discoveries (R-l, P-l, M-l, D-l, U-l, A-l, E-l, A-2, and M-3).

In this regard Audit observed the following:

i) As per the PSC provision (10.5 and 21.5.4.), the Contractor had to appraise each discovery within 32 (oil discovery)/36 (gas discovery) months from notification of discovery.The Contractor requested DGH for permission to pool the discoveries in NDA as it was not economical to appraise them on stand-alone basis. MC allowed the Contractor (April 2008) to pool the then existing discoveries in NDA even though such pooling was not provided for in the PSC. MC also allowed reckoning of appraisal period from the last discovery made in NDA (July 2007). Thus pooling of discoveries led to individual discoveries in NDA being allowed 4 to 7 years (as against a maximum of three years provided in the PSC) to complete appraisal as detailed in the ***Annexure-XIV***.

ii) Even with the additional time made available for appraisal through pooling of discoveries, the Contractor could not complete the appraisal programme by July 2010 and the appraisal period had to be extended till January 2014. As per the PSC, the DoC was to be prepared based on appraisal of the discoveries. Audit noticed that even after the extensions, DoC for NDA was submitted without an

[1] ***₹ 161.39 crore plus ₹4.59 crore.***

approved appraisal programme for three discoveries (D-l, E-l, M-3) and appraisal well not having been drilled for A2 discovery.

ONGC in its reply stated (February 2015) the following:

(i) 2 ½ years was lost due to non-availability of deep water rigs and 1 ½ years was lost due to delay in re-structuring of exploration phase by MoPNG (January 2011 to June 2012). The New Policy Framework (November 2014) also allows additional time for appraisal.

(ii) It would be incorrect to state that discoveries were not appraised as G&G study was carried out under an appraisal programme. Appraisal programme need not always culminate in appraisal drilling. Besides, discoveries D-1 and E-1 being quite small/ marginal, did not warrant appraisal drilling.

(iii) In the interest of bringing the block on production at the earliest, Contractor did not seek any additional time to appraise A2 and M3 discoveries as sufficient data had already been collected from the wells based on which DOC was submitted for MC review and FDP is under formulation.

The reply is not acceptable in view of the following:

(i) The reply does not explain the reasons for delay in submission of appraisal programme. The delay (in the range 3 to 8 years vide ***Annexure-XIV***) is far greater than condoning the period of three months provided for in the New Policy Framework (November 2014).

(ii) The Contractor did not have a comprehensive appraisal programme and the G&G study referred to in the reply was preparatory to submission of appraisal programme;

(iii) Incompleteness of appraisal of NDA discoveries is further highlighted by the fact that E1 discovery notification was not accepted by MC, recoverable reserves of D1 and E1 discoveries were not estimated nor could the production profile for these discoveries be generated. A proper appraisal programme would have adequately tested these aspects before submission of DoC. Thus, while the Contractor availed of additional time for appraisal through pooling of discoveries in NDA, it failed to complete the appraisal satisfactorily leading to inadequate DoC which would further delay monetisation of these discoveries.

B. Southern Discovery Area (SDA)

In the SDA, a single well was drilled (December 2006) which was designated as a discovery (UD 1). The Contractor submitted an appraisal programme for SDA (the entire area of 3,494 sq. kms. having been retained in SDA)in April 2008. MC, considering that there was insufficient time to appraise the discovery, granted extension for completion of appraisal by December 2009 (considering 36 months appraisal period from the date of discovery as per PSC provisions). The appraisal programme for SDA comprised API (acquisition, processing and interpretation) of 3D data and Geological and Geophysical (G&G) studies.

Meanwhile, GoI notified (July 2010) Rig Holiday Policy (RHP)for deep water blocks which, *inter alia,* declared a rig moratorium for three years (1st January 2008 to 31st December 2010) for deep water block PSCs signed upto NELP V. RHP, inter alia stipulated that:

(a) Blocks with existing drilling commitment as on 1st January 2009 could be extended upto 31st December 2010 or till their completion, whichever was earlier.

(b) Thereafter, the Contractor will have the option to avail balance exploration period, if any.

The Contractor applied (September 2010) for RHP and requested extension of appraisal phase in SDA upto December 2012. It also sought (June 2011) excusable delay of 5.5 months that occurred at the beginning of exploration phase due to delay in grant of PEL from April 2000 to September 2000. Ministry acceded to the request and granted (June 2012) extension up to December2013 for the entire block.

In this regard, Audit observed that:

(a) SDA was ineligible for grant of extension under RHP as it did not have any drilling commitment as on 1st January 2009. In fact, Contractor did not have any approved drilling commitment by the end of the appraisal period in December 2009.Hence, grant of extension of 43 months (January 2010 to July 2013) under RHP for SDA was irregular.

(b) After the expiry of appraisal period (December 2009 for SDA) the Contractor drilled two appraisal wells (UD2 & UD3) during July 2010 to January 2011. Grant of ineligible extension (January 2010 to July 2013) had the effect of regularising the unauthorised drilling of these two appraisal wells at a cost of ₹ 834.24 crore. Subsequently, two more appraisal wells were drilled in SDA (November 2012 to February 2013) at a cost of ₹ 594.14crore.

(c) The effectiveness of the appraisal done by the Contractor through drilling of four appraisal wells was also in doubt. The DoC for SDA (Cluster III) submitted by the Contractor in December 2013 could not be reviewed by the MC as recoverable reserves were not estimated and production profile could not be generated in the absence of surface flow data / DST data for these discoveries. Besides, the Contractor claimed that there was no demonstrable technology implementation analogues available anywhere in the world in such ultra-deep waters of 2800 metres and beyond and thus further development of this area remains in doubt.

ONGC in its reply (February 2015) stated that the Ministry had granted Rig Moratorium Period under RHP which also gave option to the Contractor to avail the balance Exploration period after the end of rig moratorium period. The Contractor lost more than 2 ½ years due to non-availability of deep water rigs and 1 ½ years due to late issuance of order by Ministry in June 2012.DGH in its reply (December 2015) stated that Operator applied for RHP with respect to entire block KG-DWN-98/2 (not for NDA or SDA) and MOP&NG granted it in June 2012.

The reply is not acceptable in view of the following:

(a) As there was no drilling commitment either for exploration or appraisal activities in SDA as on 1st Janaury 2009, RHP was not applicable to SDA. It was also noticed that the Contractor did not wait for grant of extension but took up appraisal drilling in SDA (where it did not have technology for further development) before grant of formal extension.

(b) ONGC in September 2010 had sought restructuring of exploration phase of two distinct areas of the Block, NDA and SDA, upto July 2013 and December 2012 respectively and not as one entire Block as stated in the reply. With the Block already divided (April 2008) into two distinct discoveries areas - NDA and SDA having two different appraisal periods, it was inappropriate to consider the entire area as one Block.

1.7.4.4 Exploratory well drilled during appraisal in NDA

The Contractor had identified deeper 'Cretaceous' prospects in NDA during exploration. It sought to probe these prospects through additional drilling during the appraisal phase. MC approved drilling of two exploration wells KT-2 (in September 2012) and J-AA (in August 2013) in NDA to explore the cretaceous prospect. The wells were spudded in January 2014 (at the end of the restructured appraisal phase) and completed by May/ June 2014 after the appraisal period. While the well KT 2 achieved the exploratory objective and found gas, the well J-AA could not be explored due to technical constraints. Both the wells were permanently abandoned after incurring an expenditure of ₹ 1,905.41 crore[1].

Audit observed that the PSC does not provide for exploration during appraisal period. Continuance of exploration activities during appraisal phase has been commented upon by Audit[2] earlier. In case of NDA, the appraisal activities had not been completed on time and the Contractor had been allowed extension to complete these activities. While the appraisal of NDA remained incomplete (para 3.3.A), additional exploration activities were carried out with substantial investment and no tangible benefit.

The effect of additional exploration done during the appraisal period in NDA was to increase the expenditure and hence cost recovery on the block by ₹ 1,905.41crore without any tangible benefit. There appears to be a case for ring-fencing such additional exploration efforts, as has been mandated by MoPNG (vide notification dated February 2013) for exploration in ML area after expiry of exploration period. This would ensure that cost recovery of the original block is not unduly increased to the detriment of profit petroleum and Government take.

---

[1] ***₹1,244.18 crore plus ₹661.23 crore.***

[2] ***Reports of the Comptroller and Auditor General of India - No.19 of 2011-12 and No. 24 of 2014.***

Management in its reply (August 2015) stated that the location was approved based on the merit of prospectivity for adding value and reserve accretion.

DGH in its reply (December 2015) stated that:

(i) The GOI restructured (June 2012) exploration period upto December 2013. Further, GoI's policy (November 2014) allows contractors to do extended appraisal activities to enable Operator to submit robust FDP; and

(ii) In ML area revenue is being generated so to protect the GOI share of 'profit petroleum', safeguard measures has been taken in ML policy. However, GOI policy (November 2014) allows extended appraisal activities, where appraisal wells are to drill to evaluate extension of the reservoir and in the initial stage of exploration no revenue is being generated in the Block. The basic idea is that the Operator may submit a robust FDP.

Reply of Management/ DGH is not acceptable in view of the following:

(i) The reply of management is not specific to the audit observation which has highlighted the substantial investment made on such exploration with no tangible benefits.

(ii) As per the notification of June 2012, re-structuring of the exploration period was allowed only to carry out appraisal program. This is in line with the provisions of Article 3.8 of PSC which allows such restructuring when there is insufficient time to carry out appraisal program.

(iii) The contention of DGH that safeguards are not required during exploration phase as no revenues are generated then is not acceptable as such expenses would add to the cost recovery and impact adversely profit petroleum from the block once the block commences production.

1.7.4.5 Non adherence to testing processes mandated by PSC

As per the PSC provisions (Articles 10 and 21), when a discovery is made within the contract area, the Contractor should:

(i) Forthwith inform the MC and Government of the Discovery and furnish particulars in writing within 30 days of the discovery;

(ii) Notify the Government at least 48 hours in advance of any drill stem test (DST)/ product test with government having the right to have a representative present during the test.

Subsequently, GoI vide its Notification (November 2014) allowed acceptance of discoveries for which advance notification had not been given, provided the Contractor undertakes to carry out fresh tests after giving due advance notification. GoI also provided (vide Notification dated 13May 2015) after approval by CCEA on 29 April 2015, three specific options to the defaulting Contractors who had not met the testing requirement of PSC:

<u>Option -1:</u> relinquish the contract area related to discoveries;

Option – 2: conduct fresh test and submit revised DoC within one year from approval of CCEA in April 2015 with a stipulation that only 50 *per cent* of cost incurred for testing will be allowed for cost recovery with a cap of US 15 million; and

Option -3: proceed for development of discovery without conducting DST, but cost recovery of such development would be ring fenced.

The Contractor had to select the option within two months from date of CCEA approval of the notification (i. e., by end June 2015). The notification also laid down that the cost of MDT incurred by the contractors earlier in respect of such discoveries would not be allowed for cost recovery.

The Contractor did not follow the laid down procedure of the PSC and notified three discoveries - D1, E1 and UD-1 based on MDT. It also failed to give advance notification before conducting MDT at D1 and E1. Hence, initially D1 and E1 discoveries were not accepted. Later, D1 prospect was tested through another well KT—1 by MDT, based on which D1 discovery was accepted by DGH.

The Contractor submitted DoC in December 2013 for these discoveries (D-1 and E-1 in Cluster-1 and UD-1, the lone discovery in Cluster III). DGH did not agree to review the DoC for these two clusters in the absence of surface flow data/ DST.

The Contractor subsequently (March – May 2015) carried out DST for D-1 discovery through drilling a new well D1-sub and incurred an expenditure of ₹ 365.97 crore (US$ 58.07million). In respect of E-1 and UD-1 discoveries, the Contractor has exercised (24 June 2015) the option of carrying out DST (as per option 2 of May 2015 notification). The test is yet to be carried out (June 2015).

In this regard, Audit observed the following:

(i) DGH had accepted UD-1 and D-1 as 'discoveries' even though the testing requirement of PSC had not been fulfilled. Subsequently, DGH did not review the DoC for these discoveries citing need for surface flow data/ DST.

(ii) As per the 'Policy for testing requirement', by exercising Option 2, the Contractor will be ineligible to claim cost recovery of ₹ 17.28 crore which it has incurred in conducting MDT for the three discoveries (D-1 – ₹ 10.93 crore and E-1 – ₹ 3.10 crore and UD-1 ₹ 3.25 crore) rendering this expenditure avoidable and wasteful.

(iii) The fresh DST done in respect of D1 by the Contractor resulted in additional expenditure of ₹ 271.44 crore (US $ 43.07 million) towards fresh DST test conducted for D-1 discovery. In case of fresh DST for E1 and UD-1 discoveries, the Company would only be eligible for recovery of 50 *per cent* of the cost with a cap of US$ 15 million as per the 'Policy for testing requirement'.

Thus, the Contractor's non-compliance with PSC provisions by not carrying out the prescribed DST has resulted in delayed monetization of these discoveries and irrecoverable costs of ₹ 17.28 crore on MDT and ₹ 271.44 crore on fresh DST for D-1 discovery with the future prospect of further irrecoverable costs on DST for E-1 and UD-1 discoveries.

Management in its reply (August 2015) stated that inconsistent stand of DGH had resulted in additional costs and avoidable delays but it on its part would endeavour to bring the field on production without much loss of time by dovetailing the proposed development scheme for other oil / gas fields in the block.

Management's contention is not acceptable as DGH in its reply (December 2015) stated that they had been consistent in their stand that DST is required to validate flow rates and as the Contractor failed to conduct it, DoC was not reviewed.

1.7.4.6 Compliance issues

(I) Delays in submission and approval of the Work Programme& Budget (WP&B)

PSC stipulated that the Contractor should submit Annual WP & B not later than 31st December of the preceding year for review of exploration operations and approval of development and production operations. PSC also provides for submission of revised WP&B if the circumstances so justify, for either review / approval of the MC. The "New Policy Framework" (November 2014) has allowed condonation of delays upto three months in this regard.

Audit observed that MC had not reviewed the WP&B prior to the PSC stipulated date (31st December) in any year over the decade (2005-06 to 2014-15). Even considering the condonation period of three months, the WP & B was reviewed late by 2 months to 23 months in six years (2005-06, 06-07, 08-09, 09-10, 12-13 and 14-15) and has not been reviewed yet for another three years (2010-11, 2011-12, 2013-14).

In the years, 2010-11 and 2011-12, the budget approval was not sought as the extended appraisal period had expired in August 2010 and the Contractors' request for extension of appraisal period had been rejected by DGH (October 2010). However, the Contractor, without waiting for formal approval for extension, incurred an expenditure of ₹ 1,127.80 crore during the years 2010-11 and 2011-12. The budget proposal for the year 2013-14 was also submitted late and its approval was still awaited (June 2015) though an expenditure of ₹ 2,503.90 crore was incurred in the year on appraisal/exploratory drilling of six wells.

The Contractor has claimed the entire expenditure of ₹ 3,631.7 crore for the years 2010-11, 2011-12 and 2013-14 under Cost Recovery though such expenditure was not authorised.

MC needs to expeditiously review this expenditure and regulate cost recovery accordingly. Management (August 2015) and DGH (December 2015) in their reply attributed the delays till 2012-13 to delays in getting Operating Committee approval from JV partners. Contractor also assured to make sincere efforts to comply with PSC provisions in this regard. Their replies are not acceptable as approval of WP&B for the three years 2010-11, 2011-12 and 2013-14 are still awaited (August 2015).

(II) Delay in approval / adoption of Annual Audited Accounts

PSC stipulates that the Contractor should submit a copy of the audited accounts to GoI within 30 days of the receipt thereof and such audited accounts should be adopted by the

MC[1]. Audit observed that though the Contractor had submitted the annual audited accounts of the 10 years from 2005-06 to 2014-15 within 30 days of its receipt, their adoption in MC is pending for up to 9 years.

Inordinate delay in adoption of accounts is against the spirit of PSC. Hence Audit recommends timely approval and adoption of audited accounts for confirmation of transactions and for taking appropriate corrective measures.

Management in its reply (August 2015) accepted the delays but attributed it to delay in receipt of Operating Committee approval from Joint Venture partners for appointment of Auditors. It also stated that these have since been received and have been submitted to DGH in July 2013. Thereafter the audited accounts were once again submitted by the contractor to DGH in June 2015 for adoption which is in progress.

Management has accepted that there had been delay of 2 years to submit accounts even after obtaining approval of JV partners in July 2013. Moreover, the delay of 9 to 10 years in obtaining approval for appointment of auditors and adoption shows that neither the Operator (ONGC) as Convenor of Management Committee Meeting nor the two Government nominees as Chairman/Deputy Chairman had ensured compliance with PSC provisions in this regard.Such non–compliance had perpetuated violation of PSC stipulated procurement procedure as brought out in succeeding paragraph.

DGH in its reply (December 2015) also stated that audited accounts for the year 2005-06 was pending due to cost recovery issue pertaining to wells D1 & A1 drilled during the financial year 2005-06.

Reply is not acceptable as action required to be taken in respect of wells AI & D1 were taken by the Contractor in January 2006 & July 2007 respectively and DGH had recommended to Ministry to allow cost recovery of expenditure incurred on these wells in February 2008 itself.

(III) Violation of PSC stipulated Procurement Procedure

PSC prescribed[2] procedures for acquisition of goods and services. As per these provisions, the Contractor can procure goods and services worth more than or equal to US $ 0.5 million on following due process of tender viz., to have a pre-qualifying criteria, to publish invitations for parties to pre-qualify, to select qualified parties as per pre-qualification criteria and invite bids, and award contracts after due bid analysis and approval of Operating Committee. However, PSC also provided that the Contractor may, when the circumstances so justify, modify the above laid down procedure with the approval of MC.

[1] ***Article 6.6.(d)***

[2] ***Appendix - F***

The Contractor had taken three Rigs - Discoverer Seven Seas, DDKG-1[1] and GSF Explorer with Contract value of ₹ 2,953.27 crore, ₹ 3,914.39 crore and ₹ 899.49 crore respectively on Assignment/ Nomination basis citing urgency of work commitment across various blocks of the Contractor. Though this was in deviation from PSC prescribed procurement procedure, Contractor utilized their services in the Block without obtaining approval of MC.

Management in its reply (August 2015) stated that the feasibility of separate procurement procedures for each ONGC operated NELP block, will not provide the scope of economic/cost advantage in presence of existing stringent Material Management (MM) set procedures/ guidelines in line with Article 23.2 of PSC and that the procurement policy of ONGC is being constantly reviewed and upgraded as per CVC guidelines. Management further added that ONGC does not have any JV in the KG-DWN-98/2 block and is currently (August 2014) holding 100 *per cent* PI.

Management reply is not acceptable as it had neither followed the procurement procedure it had agreed with the Government viz., PSC nor it could claim to have derived any cost advantage when it had awarded contracts on nomination basis without calling for competitive bids. Moreover, PSC clearly stipulates[2] that it can deviate from bidding process only in case of emergency and that too with approval of MC. The contractor had taken the three rigs on nomination basis citing urgency of work but utilized their services without obtaining approval of MC which was a clear deviation from the PSC prescribed procurement procedure.

DGH in its reply (December 2015) also accepted that no proposal has been received at DGH for MC approval.

Conclusion

The KG-DWN-98/2 block was awarded by the GoI under first round of NELP in 2000. The Company acquired ninety *per cent* stake in 2005 and balance in 2012. The Company availed several extensions under various PSC provisions, policies of the Government, and concessions allowed, to explore and appraise its discoveries at a cost of ₹ 8402.56 crore (March 2015). Till date (August 2015) Company has notified total 11 discoveries in the block (10 in NDA and 1in SDA). The Company had submitted (December 2013) DOC to develop 10 discoveries in 3 clusters (Clusters I and II in NDA and Cluster III in SDA). However, the Management Committee reviewed (September 2014) the DOC for Cluster II alone and did not review Cluster I and III as the recoverable reserves could not be estimated and production profile could not be generated in the absence of surface flow data/DST data for these discoveries. The Feasibility Development Plan for monetization of discoveries in Cluster II is yet to be approved by the DGH/MoPNG. The monetization of Cluster III (SDA) is not planned by the Company since there is no suitable technology

---

[1] ***The irregular hiring of ultra deep water rig from Reliance Industries Limited was commented vide Para 11.10 of Union Report (Commercial) 8 of 2012-13. ONGC deviated from standard tendering procedure and hired DDKG1 from RIL without calling for competitive bids for period of four years on untenable grounds and incurred an extra expenditure of ₹9.36 crore due to deviation from standard norms and ₹29.32 crore due to frequent breakdowns of the rig***

[2] ***Artcle 23.2***

available to develop the discoveries in such deepwater areas. The integrated development of discoveries of Cluster I and nomination block of PML Godavari had also suffered a major setback in view of the expert confirmation regarding substantial migration of reserves from this area and their exploitation by RIL through its KG-DWN-98/3 block. Besides, the Company had considered a gas price of US$ 7 per mmbtu (with a payback period of 5.89 years) while considering the viability of in December 2013. Under the New Domestic Gas Pricing Guidelines (March 2015 and September 2015), the gas price was fixed at US$ 4.66 per mmbtu between April 2015 to September 2015 @ US$ 3.82 per mmbtu between October 2015 to March 2016, which would further adversely affect the financial viability of integrated development of Cluster 1 and Godavari PML area.

The matter was reported to the Ministry (September 2015); their reply was awaited (March 2016).

1.8 Non achievement of objective of acquiring Coal Bed Methane blocks

Land acquisition was critical for commencement of exploration activities in Coal Bed Methane (CBM) blocks acquired by Oil and Natural Gas Corporation Limited (ONGC). There appeared to be lack of mechanism at pre bid stage between the Ministry of Petroleum and Natural Gas, the Ministry of Coal and the State Governments to facilitate acquisition of land and statutory clearances for exploration activities in CBM blocks identified for bidding. Besides, delayed action by ONGC for acquiring land after the blocks were awarded to it and delay in completing the committed minimum work programme further affected Exploration Phase of the blocks. As a result, ONGC had to seek repeated extensions, due to which not only the Company had to pay liquidated damages of ₹ 6.81 crore to the Government of India, but Development Phase of five years of each of the four blocks in hand was also reduced drastically. Failure to obtain Mining Leases and Environmental Clearances from the respective agencies in time due to delayed action on the part of ONGC led to a situation where commencement of development operations to put any of the blocks into production in near future appeared unlikely. This rendered the objective of acquiring CBM blocks unachievable and an aggregate expenditure of ₹ 1,217.86 crore from February 2003 to March 2015 incurred in exploration of CBM blocks unfruitful as of August 2015.

1.8.1 Introduction

Coal Bed Methane (CBM), is natural gas (methane) absorbed in coal and lignite seams and is an eco-friendly non-conventional source of energy. Coal is both the source and reservoir rock for CBM. CBM is pipeline-quality gas requiring no or minimal processing prior to sale. CBM gas is similar to other sources of natural gas and can be sold into any market for uses similar to conventional natural gas. It is considered to be more environmentally friendly than oil, coal or even conventional natural gas being a “sweet gas” as it generally does not contain hydrogen sulphide.

1.8.1.1 CBM exploration in India

India, having the third largest proven coal reserves and being the fourth largest coal producer in the world, holds significant prospects for commercial recovery of CBM. CBM blocks are carved out by the Directorate General of Hydrocarbons (DGH) in close interaction with the Ministry of Coal and Central Mine Planning and Design Institute, Ranchi under the CBM policy formulated by the Government of India (GoI) in July 1997. For exploration and production of CBM in the country, technically and financially competent Foreign and Indian companies are invited through International Competitive Bidding (ICB) to bid either singly or in association with other companies for allotment of CBM blocks.

The winning bid is selected based on technical capability, financial strength, work programme and fiscal package, including production linked payments to GoI. Each of these four criteria has a fixed weightage and a CBM block is awarded to the bidder having highest score. Four rounds of bidding were held between 2001 and 2009.The weightages given for the individual criteria were as under:

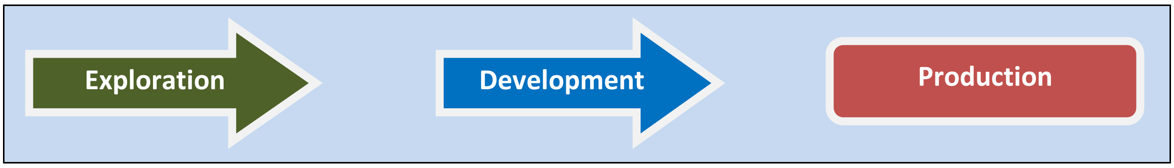
Table 1

Bidding Criteria in CBM rounds I to IV

Bidding Criteria	Weightage on a scale of 100 points			
	CBM I	CBM II	CBM III	CBM IV
Technical capability	20	20	20	30
Financial strength	10	10	--	--
Work programme	50	50	45	35
Fiscal Package	20	20	35	35

Source: Notices Inviting Offers of CBM blocks – Ist to IVth round

The successful bidder enters into a contract with GoI which, *inter alia,* provides that CBM resources in India should be assessed and exploited in commercial quantities with utmost expedition in accordance with modern industry practices. The contract envisages essentially the following activities:



- **Exploration Operations:** These are conducted in the contract area in search of commercially exploitable CBM accumulation and include seismic surveys and drilling of pilot wells for assessment of CBM potential. Exploration operations are carried out in two[1] Phases, Phase-I and Phase-II. The total duration of the two Exploration Phases is 6 to 7 years.

- **Development Operations:** Development operations commence after completion of the exploration operations. The activities in this Phase are as per the approved development plan and include drilling of development wells, laying of gathering lines, tankage, other producing and injection facilities required to produce, process and transport CBM into main gas storage or gas

[1] ***Phase-I (two to three years from the effective date) and Phase -II (4 years after Phase-I). Effective date means date of grant of Petroleum Exploration License (PEL) and is generally taken as the date of commencement of activities in the block.***

processing facilities. The Development Phase has a duration of 5 years immediately following exploration operations.

- **Production Operations:** The production operations constitute final Phase of CBM exploitation. The Production Phase has a duration of 22 to 25 years.

1.8.1.2 Award of CBM Blocks

DGH carved out several prospective CBM blocks in different coalfields of the country. The first round of CBM bidding took place in May 2001. In all, four rounds of CBM bidding were held by GoI from 2001 to 2009 in which 36 CBM blocks were offered. During all the four rounds, 30 blocks were awarded to both public and private sector companies, as indicated in Table 2:

Table 2

Blocks awarded in four rounds to various companies

ONGC	Reliance Industries Limited (RIL)	Essar Oil Limited (Essar)	Geopetrol International Inc	Arrow	Dart	Coal gas	Great Eastern Energy Corporation Limited (GEECL)	BP Exploration Alpha Limited
7	5	5	4	3	2	2	1	1

ONGC was successful to acquire 7 blocks in 1st and 2nd bidding rounds held in 2001 and 2003. In addition, GoI also awarded one block to GEECL and two blocks to ONGC on nomination basis in 2001 and 2003, respectively.

1.8.1.3 Status of CBM blocks awarded by the Government

(I) Of the 33 blocks awarded, 16 had since been relinquished or were under relinquishment (August 2015) owing to poor prospects. The balance 17 blocks were under various stages of execution, the details of which are given in the Table 3 below.

Table 3

Details of blocks in various stages of execution

Particulars	ONGC	Private parties						Total	
		RIL	Essar	GEECL	Coal gas	Geo	Dart		
Blocks in Exploration Phase	0	0	4	1	2	1	1	9	17
Blocks in Development Phase	#4	2	1	1	0	0	0	8	
Production of CBM **(mmscm)** till March 2015	^13.89	0	156.80	525.34	0	0	0	682.14	
Royalty on the above production (**₹ in crore**) paid to State Governments	^1.21	0	17.63	46.36	0	0	0	63.99	
Production linked Payment (**₹ in crore**) to GOI based on above production	^0.30	0	0	11.59	0	0	0	11.59	

 # In Jharkand: Three blocks viz. Bokaro, North Karanpura and Jharia). In West Bengal: One block viz. Raniganj North.

^Relates to incidental production from Jharia block and is not included in totals.

(II) It may be seen from the above Table that whereas private parties (Essar and GEECL) derived production of 682.14 million metric standard cubic metres (mmscm) of CBM till March 2015 from their two blocks operated by them, paid royalty of ₹ 63.99 crores to the State Governments and contributed a production linked payment of ₹ 11.59 crores to GoI, ONGC had not yet (August 2015) commenced development operations in four blocks operated by it and, hence, did not contribute any revenue to any State Government or GOI, except that relating to incidental production.

(III) The details of CBM blocks acquired and surrendered by ONGC till 31.3.2015 are given below in Table 4. ONGC relinquished five blocks after incurring an expenditure of ₹ 147.68 crores.

Table 4

Blocks relinquished by ONGC

Round	**No. of Blocks**	**Name of blocks acquired**	**Effective date**	**Date of surrender, if surrendered**	**Expenditure (₹ in crore) on surrendered blocks**	**Remaining number of blocks**
I	2	Bokaro	21.02.2003	NA	NA	2
		North Karanpura	21.02.2003	NA		
II	5	Barmer-Sanchor	10.09.2004	09.03.2008	32.02	0
		Satpura	23.02.2005	20.07.2007	3.41	
		Wardha	13.04.2005	12.04.2007	2.80	
		South Karanpura	12.05.2006	05.07.2011	91.18	
		North Karanpura West	12.05.2006	23.06.2011	18.27	
Nomination	1	Jharia	28.08.2003	NA	NA	1
	1	Raniganj	09.06.2004	NA	NA	1
Total	**9**				**147.68**	**4**

NA ~ Not Applicable.

As on March 2015, ONGC had spent ₹ 1,070.18 crores on the four blocks operated by it and ₹ 147.68 crore on the five blocks surrendered subsequent to acquiring the same. The specific reasons for unsatisfactory performance of ONGC in CBM blocks are discussed below.

1.8.2 Audit Findings

CBM activities carried out by ONGC since inception (2003–15) in all nine blocks were examined in Audit with a focus on the four active blocks as shown in Table 4 above. Audit findings are summarised in the succeeding paragraphs:

1.8.2.1 Delays in completion of exploration activities

ONGC could not complete exploration activities in CBM blocks within the time allotted in the contract. As against the contractual time frame of six to seven years, ONGC took more than seven to eight years for completion of exploration activities. The delay in

Exploration Phase was loaded on to the Development Phase and would eventually shorten the time allowed for production of CBM. Delays in completing exploration were on account of delays in land acquisition, non-availability of ready for drilling sites, non-availability of logistics etc. as discussed in succeeding paragraphs:

(I) Delays in land acquisition

After award of a CBM block, the Contractor (viz. ONGC) applies for Petroleum Exploration Licence (PEL) to the State Government concerned for the contract area. On receipt of PEL, ONGC collects data by drilling core holes in the contract area of each block to facilitate identification of potential locations for drilling of wells. Once the locations are firmed up for drilling exploration/pilot wells[1], it is ONGC's responsibility to apply for the land to the concerned district authorities, following which the district authorities acquire the land and hand it over to ONGC. The responsibility of ONGC in land acquisition involves, staking[2] of released locations and joint inspection, collection of ownership documents and demarcation and drawing of the drilling site. Following this, the application for land acquisition is submitted to the district authorities. Thus, the responsibility of land acquisition rests partly with ONGC and partly with the district authorities of the State Government concerned.

Audit observed that both ONGC and district authorities of the State Government concerned took inordinately long in completing the land acquisition process ***(Annexure- XV).***

The delay on the part of the concerned State Governments appeared to stem from lack of a mechanism for active coordination, at pre bid stage and after allotment of blocks, and lack of coordination among MoPNG, the Ministry of Coal (MoC) and the concerned State Governments which was noticed in (i) identifying the actual geographical stretch of the CBM blocks proposed to be offered to the bidders, (ii) assessing the problems, if any, in facilitating availability of land to the successful bidders and (iii) taking steps in advance to mitigate the issues that may be faced by the successful bidders in commencing operations due to non-acquisition of land and other statutory clearances such as Environmental Clearance (EC), Mining Lease (ML) etc. so that such issues causing avoidable delay could be addressed in time. Subsequent to allotment of blocks, delays in taking timely action by ONGC for acquisition of land and for EC and ML further aggravated the position.

While the delays on the part of the State Governmentswere beyond the control of ONGC, submission of application for land acquisition was entirely within its control and the delays could have been avoided.

Of the 23 locations[3] **(*Annexure-XV*)** spread over four blocks in hand with ONGC (refer Table 4) for which details were furnished to audit, it was noticed that in 12 cases (52 *per cent*), ONGC took 145-600 days in submitting applications to the district authorities for land acquisition after the locations had been identified. The delay on the part of ONGC

[1] Pilot well is drilled for determining the potential CBM accumulations in the Contract Area.

[2] Staking means ground checking of geological position of the released location for drilling of well whereas released location signify a surface point within PEL/ML boundary of the CBM block where a CBM well is proposed to be drilled and had been agreed upon by the Competent Authority.

[3] Locations are the specific points in the blocks where wells are drilled

contributed to the overall delay in land acquisition, loss of time scheduled for Exploration Phase and entering into the time scheduled for development of the four blocks as illustrated:

- **Bokaro block:** For twelve pilot wells to be drilled in Exploration Phase-II during the four year period (21February 2005 to 20 February 2009), application for land acquisition was made as late as September-December 2006, *i.e*. after more than a year when Phase II of exploration was due for commencement. The actual land acquisition took place during May 2007 to August 2010. Consequently, actual drilling of wells could take place in June/July 2009 after obtaining extension of time from GoI against scheduled completion by February 2009.
- **North Karanpura:** Land acquisition for five pilot wells to be drilled during Exploration Phase-II (21August 2005 to 20 August 2009) started between January 2008-July 2008 after more than two years (over 28 months) when Phase II of exploration was due for commencement. The actual land acquisition took place in July 2009. As a result, wells could be drilled only during March 2010 to January 2011 against their scheduled completion by August 2009.
- **Raniganj:** Land acquisition for two pilot wells during Exploration Phase-II (09 June 2007 to 08 June 2011) started late in August 2009 and June 2010 respectively, more than two years after commencement of Phase II. The land was actually acquired only in November 2010 and May 2011 respectively. Drilling of wells took place from April 2011 to April 2012 against scheduled completion by June 2011.
- **Jharia:** Land acquisition for two exploratory well in Exploration Phase-I (28 August 2003 to 27 August 2006) started in June 2005 and August 2005 nearly two years after commencement of Phase-I. Land was actually acquired in March 2006 and June 2006, respectively. The wells were actually drilled between July 2006 to May 2007 after the scheduled completion of Phase-I.

ONGC stated (January 2015) that:

- Land acquisition was always one of the primary causes of delay as most of the areas fall in 'Gair mazrua'[1] or Tribal land marked by poor availability/maintenance of revenue records.
- Since land acquisition involved the local authorities and populace, the process of acquiring land and the pace of such acquisition was hardly in the control of the ONGC.
- Overlapping issues in CBM acreages (coal mining operations by different companies in CBM Blocks on being awarded coal mining license by Ministry of Coal) further aggravated the land acquisition scenario.

The reply is not acceptable in view of the following:

- The audit observation focuses on the delays in land acquisition on the part of ONGC which could have been avoided with efficient planning and coordination among its various sections i.e. Land Acquisition Section (LAQ), Civil Section,

[1] ***Gair mazrua: Uncultivated waste land***

Drilling Section *etc*. Audit noticed that a Task Force constituted (June 2010) by ONGC for expediting development and production of CBM blocks had, *inter alia,* observed (June 2010) that land acquisition manpower was grossly inadequate in terms of numbers, skill and constitution and recommended association of full time legal officers and outside legal experts besides dedicated finance discipline officer. These issues were deliberated in the meeting (July 2010) of Executive Committee though no evidence of affirmative action taken in this regard was available in records reviewed in audit. In fact, the manpower posted in LAQ section reduced from eleven in 2008-09 to five in 2014-15.

- Audit recognizes the issue of overlapping. However, on the basis of information made available to Audit by ONGC, it was seen this issue was not as significant as pointed out by the Company. In Bokaro, North Karanpura and Raniganj blocks, overlap affected only one location each. The problem was more pronounced in Jharia block where six locations had been affected by overlap as shown in the following Table 5:

Table 5
Status of overlapping in CBM blocks

Name of block	Total Area (sq. Km)	Present area	Overlapped Area (sq. Km)	Names of locations falling in Overlapped area
Bokaro	95.00	75.00	3.50	BKAL
North Karanpura	340.00	271.50	30.00	NKAB
Jharia	84.55	65.10	08.00	JH1, 1A, 2, 3, 14, 15
Raniganj	350.00	311.79	28.95	RNAA

However, GoI allowed dispensation of 14 months (28 February 2007 to 27 April 2008) to ONGC for delay on account of overlapping issues in Jharia block.

(II) Failure to handover sites for drilling to a contractor[1] entailing a claim of ₹312 crore

ONGC awarded (May 2006) an integrated turnkey contract (ITC) for drilling 36 wells (14 development wells in central Parbatpur area of Jharia block and 22 pilot wells: 3 horizontal and 19 vertical in Bokaro, North Karanpura and Jharia block) by 18 December 2008. As per the contract, ONGC was to make available land for drill sites (locations) and an approach road to the contractor, at least three months before start of drilling activities. In case of ONGC failing to provide the drill sites and approach road beyond this period, ONGC would be required to pay non-operating day rate (NODR) charges at the rate of USD 50000 and ₹ 50,000 for horizontal wells and USD 35,000 and ₹ 35,000 for vertical wells to the contractor. The contractor drilled 3 horizontal and 16 vertical wells.

Audit noticed that though the work was awarded to the contractor in May 2006, no ready locations were available with ONGC for handing over to the contractor at that time. The first location was handed over to the Contractor in February 2007 viz. nine months after award of contract. Over the period 2007 to 2012, ONGC could hand over 19 locations

[1] ***'contractor' ~ A contractor appointed by ONGC, whereas 'Contractor' refers to a party/parties (in the present case ONGC) with whom GOI has signed the CBM contract.***

(out of 36 contracted) to the contractor which were drilled. The contractor claimed standby charges (NODR) of ₹ 312 crore on account of non-availability of contract site. An Outside Expert Committee (OEC) was constituted (March 2014) for foreclosure of contract (December 2011).

ONGC stated (January 2015) that with trouble-free acquisition of land in the initial stages of CBM project Bokaro, it was envisaged that identified/released locations would be acquired in time to be handed over to ITC contractor on regular basis. However, unexpected changes completely jeopardized the envisaged plans. ONGC stated (December 2015) that despite several communications and persuasions, the contractor failed to comply with pre-conditions for OEC to start its functioning and consequently, proposal for closure of OEC was initiated (November 2015) and final decision was awaited (December 2015).

The reply is not acceptable as ONGC had entered into an ITC contract without having any location ready for handing over to the contractor. Subsequently, the Company failed to ensure timely acquisition of land for the proposed locations which led to contractor invoking NODR clause. Considering that the contract had provided a NODR clause in case of delay in handing over sites by ONGC, adequate seriousness on the part of ONGC for expediting the land acquisition process was needed as has been commented upon at para 2.1.1 above.

(III) Delay and avoidable expenditure of ₹21.04 crore due to idling of rig even after land has been acquired

Land for drilling locations in four blocks (Bokaro, North Karanpura, Jharia and Raniganj) under CBM Project Bokaro had been acquired between April 2004 and May 2011. ONGC deployed a departmental rig (M-750-I) to drill wells on the selected locations in the four blocks from 5 January 2005 to 19 February 2014 *i.e.* 2770 days and incurred an expenditure of ₹ 134.59 crore thereon. During this period, the rig remained idle for 552 days, of which 428 days were attributable to non-availability of ready for drilling locations due to non-completion of civil works and 124 days to non-availability of logistics. The idling time constituted approximately 24 *per cent* of total period for which the rig was deployed and cost the Company ₹ 21.04 crore ***(Annexure-XVI).***

ONGC stated (January 2015) that hurdles like limited availability of contractors, lack of their professional competence, shortage of quality suppliers for civil materials and non-cooperation/hostilities between contractor and their suppliers which affected efficient, seamless functioning and execution of operations were experienced. The Company assured that with the past experience, every effort would be made in future to ensure timely completion of civil works and arrangement of transportation/logistics.

While Audit takes note of the assurance given by ONGC, the fact remains that given the prohibitive cost of departmental rig, being in the range of ₹ 2.7 lakh to ₹ 6.6 lakh per day during the above mentioned period, and the fact that ONGC had been working in similar environments from a very long time, it ought to have made efforts and better co-ordination and management among its various functional sections *viz.* drilling section, civil section, logistics etc. so that drilling operations could be carried out as planned without time and cost overruns. Further, failure of the Company in selecting professionally competent contractors/suppliers for civil works/material etc. shows the need for improvement in the bidding/tendering process and better contract management in ONGC in so far it relates to exploration of CBM blocks.

(IV) Delays in exploration leading to payment of liquidated damages

The Exploration Phase of four blocks *viz*. Bokaro, North Karanpura, Jharia and Raniganj was scheduled to be completed between February 2009 and June 2011. ONGC, however, could not complete the exploration within the scheduled period on account of delayed land acquisition (refer paragraph 2.1.1), non-availability of ready locations due to delayed civil works and logistical problems etc. (refer paragraph No.2.1.3). Consequently, ONGC sought repeated extensions for completing the committed Minimum Work Programme (MWP) in these blocks and had to pay ₹ 6.81 crore as liquidated damages to GoI for the delays. As a result, the exploration of these four blocks could be completed only between January 2011 and December 2012 with delays ranging from 368 to 549 days (***Annexure-XVII***) which in turn reduced the time available for development activities in the blocks for production.

ONGC stated (January 2015) that CBM blocks were in such areas where infrastructure for Oil and Gas industry did not exist. Consequently, availability and their mobilization of resources was a major challenge. Land acquisition was another major stumbling block. ONGC was, therefore, forced to seek extensions which were granted by GoI after examining their merit.

The reply needs to be viewed against the following:

(i) GoI granted extensions of time to ONGC subject to payment of liquidated damages by the latter. This indicated that the delays were not considered excusable by GoI.

(ii) Further, ONGC was obligated by CBM contractsto ensure timely and effective management of resources and execution of committed activities. However, it could not ensure timely acquisition of land which could have been managed by better coordination with GoI and the State Government agencies. Even after availability of land, there were delays on the part of ONGC in timely completion of civil works, availability of logistics and adequate manpower, as discussed above and these factors were controllable while carrying out exploration activities in CBM blocks.

1.8.2.2 Factors leading to constricted Development Phase with no activity

(I) Excess time consumed in Exploration Phases

Article 10 of CBM contract provided that Development Phase would commence, after the end of Exploration Phase-II, for five consecutive years during which the Contractor would carry out development operations in accordance with the development plan. GOI's policy (December 2007) for extension of Exploration Phases provided that where MWP of the relevant Phase has not been completed within the stipulated period of that Phase and extension is sought to complete MWP (excluding excusable delay), the period of extension would be set off from next Phase.

CBM contract provided that if the Contractor was unable to fulfil the development operations within the Development Phase, GoI may, at the request of Contractor, consider extension of Development Phase, not exceeding one year, to complete the development operations and the period so extended would be deducted from the Production Phase.

Audit observed that in view of the additional time consumed in Exploration Phase, the Development Phase of each of the four blocks had been constricted significantly to less than five years as shown in ***Annexure-XVII***.

In case of Bokaro block, the Development Phase was over on 27 July 2014. The window of seeking one year extension had also expired on 27 July 2015. Thus, the Development Phase elapsed with no development activities having been undertaken. Similarly, in case of North Karanpura block, no development activities had been undertaken. Though the Development Phase expired on 26 March 2015, Audit observed that as of July 2015 ONGC had not sought one year extension. In case of other two blocks, viz. Raniganj and Jharia, though the Development Phase would expire in June 2016 and October 2016, ONGC had not undertaken any development activities in these blocks too from commencement of their Development Phases (December 2012 and October 2012, respectively) till August 2015.

ONGC did not respond specifically to the issue of delayed Development Phase.

(II) Delay in seeking Mining Lease

Article 11.1 of CBM contract provides that after completion of Exploration Phase-II and on submission of a development plan pursuant to Article 5.6(d) of the contract, the Contractor would submit an application to the State Government for lease in respect of the then producing and producible areas held by the Contractor in the contract area.

Audit observed that ONGC submitted applications for grant of Mining Lease (ML) in respect of four CBM blocks, mentioned above, about 7 to 29 months after completion of Exploration Phase-II as shown in ***Annexure-XVIII***. ML had not been received for two blocks (Bokaro and Raniganj) till August 2015 whereas the same for the remaining two blocks (North Karanpura and Jharia) had been received in July 2015.

ONGC stated (January 2015) that applications for ML were submitted to the respective State Governments in July 2013 itself after receipt of communication from DGH regarding effective date of approval of Field Development Plan (FDP). However, the process got held up (in case of Bokaro, North Karanpura and Jharia blocks) in view of elections held in Jharkhand State. The same was now being pursued by the project.

Reply of ONGC is not acceptable as ML applications ought to have been submitted immediately after completion of Exploration Phase II and on submission of Development Plans in terms of Article 11.1 of CBM contract. The Exploration Phases of four blocks completed between January 2011 and December 2012. However, the applications for ML were made in July 2013. The Company, thus, lost more than seven months to two years, squeezing further the already shortened time for development.

(III) Delay in commencement of Environmental Impact Assessment

Article 14.5(b) of CBM contract required, *inter alia*, the Contractor to carry out Environmental Impact Assessment (EIA) studies to establish the likely effects on the environment, human beings and local communities, flora and fauna in the contract area and adjoining areas as a consequence of CBM operations and submit methods and measures for minimizing environmental damage and carrying out site restoration activities. Article 14.5.2 provided that EIA studies should be completed before commencement of development operations and shall be submitted by the Contractor as part of the development plan, and specific approval of the Government obtained before commencement of development operations. It also provided that such approval would not be unreasonably withheld.

Audit noted that ONGC did not submit EIA studies along with development plans of the four blocks. In fact, ONGC delayed engagement of agencies for conducting EIA studies even after the Terms of Reference (TOR) for the same had been made available to the Company by the Ministry of Environment and Forests (MoEF). TOR had been received between November 2011 and March 2014 while the engagement of agencies for conducting the studies was done by ONGC only between November 2013 and December 2014. There was, thus, a time lag of more than four months to two years ***(Annexure-XIX)*** which led to delay in Environmental Clearance (EC) for the Development Phase. Till August 2015, ONGC had received EC for only one block (North Karanpura), while the same for the remaining three blocks was awaited.

ONGC stated (January 2015) that it was not feasible to conduct the EIA studies without approval of FDP. In case, EIA report was to be submitted along with FDP, EIA process needed to be initiated at least one and half years ahead, *i.e.* at a time when the potential of the block was still under assessment and FDP area was yet to be defined. It would not be a prudent thing to do, especially in light of the fact that EIA studies had substantial financial implication of around ₹ 30 to 40 lakh each.

The reply may be viewed against the following:

- The contract required two EIA studies to be undertaken; one, before commencement of operations during Exploration Phase and the second before commencement of Development Phase. Therefore, before commencement of the development operations, ONGC was required to complete and submit the EIA studies as part of the Development Plan as per Article 14.5.2 of CBM contract.
- After receipt of the proposal for EIA studies from the block-manager office of ONGC, identification and engagement of agencies for EIA studies took an unduly long time with the consequence that EC was still awaited (August 2015) for three blocks *viz.* Bokaro, Jharia and Raniganj which would delay commencement of development operations.

Conclusion

ONGC acquired seven CBM blocks in the first two rounds of bidding held in 2001 and 2003. In 2003, GoI had also allotted it two blocks on nomination basis. Between April 2007 to July 2011, ONGC relinquished all the five CBM blocks, acquired by it in the second bidding round, on the ground of poor prospects and after having incurred an expenditure of ₹ 147.68 crore. With the remaining two blocks acquired through bidding and two nomination blocks, ONGC was operating four CBM blocks as on August 2015. Lack of mechanism among MoPNG, MoC and the state governments agencies to facilitate acquisition of land and statutory clearances for timely commencement of exploration activities in the blocks awarded to the successful bidders, and delay in requisite action on the part of ONGC subsequent to allotment of blocks led to delayed acquisition of land. Because of this factor coupled with ONGC's failure in completing the committed MWP in the remaining blocks, Exploration Phase of these blocks was affected badly and ONGC had to seek repeated extensions of time from GoI to complete MWP, albeit after paying liquidated damages in some cases. Repeated extension had the effect of squeezing the Development Phase of five years drastically. At the end of August 2015, the remaining period of Development Phase had already expired in case of two blocks. For the remaining two blocks, the time left was only 9 months (Raniganj block) and 14 months (Jharia block). Aggravating the position, ONGC failed to apply and obtain Mining Leases (ML) and Environmental Clearances (EC) from the respective agencies in time with the result that ML and EC which are pre-requisite for commencement of development operations, had not been received. The only block (North Karanpura) where ML and EC had been received, the scheduled Development Phase had expired in March 2015. However, ONGC had not made any application to GoI to obtain the permissible extension of one year to carry out development operations in that block too. The Company had incurred an expenditure of ₹ 1,070.18 crore in the four blocks in hand. In such a scenario, with no development activities yet (August 2015) having been commenced in any of the four blocks, it seems unlikely that ONGC would be able to put these blocks into production in the near future. Thus, the objective of acquiring CBM blocks and incurring an aggregate expenditure of ₹ 1,217.86 crore in exploration thereof remained unachieved.

The matter was reported to the Ministry of Petroleum and Natural Gas in February 2015 and a reminder was issued on 11 December 2015 to seek the views of the Ministry, reply was awaited (March 2016).

1.9 Loss of returns to ONGC due to adoption of financing mechanism to maintain the status of ONGC Petro additions Limited (OPaL) as a non public sector undertaking

ONGC made advances against equity to OPaL during April 2007 to May 2013. OPaL delayed the conversion of the advances into equity shares. OPaL also offered rights issue (March 2015) to ONGC. However, subsequently it did not issue the shares with the intention of avoiding the status of the Company as CPSU. ONGC again paid (June 2015) money towards instalment against convertible warrants which is yet to be issued. Thus, ONGC made available interest free funds to OPaL without any commensurate benefit. This resulted in loss of interest of ₹ 408.15 crore to ONGC. The financing mechanism employed by ONGC had the sole intent of retaining the character of OPaL as a non PSU entity.

Oil and Natural Gas Corporation Limited (ONGC) approved (August 2006) implementation of a petrochemicals complex through Special Purpose Vehicle (SPV) route with ONGC's investment in the SPV limited to 26 *per cent*. Accordingly, ONGC Petro additions Limited (OPaL), a Joint Venture Company (JVC) was incorporated (November 2006) with 26 *per cent* stake of ONGC and five *per cent* stake of Gujarat State Petroleum Corporation (GSPC). OPaL was to be a private company, with balance equity expected to be contributed by strategic partners and Financial Institutions.

Subsequently (May 2009), GAIL (India) Limited (GAIL) agreed to invest in OPaL (19 *per cent* equity stake). Thus, the public entities would have 50 *per cent* share in OPaL with the balance 50 *per cent* to be contributed by private partners. Thus, OPaL would continue to retain its private/ non-PSU character.

The ONGC Board had approved (February 2008) ONGC's equity contribution as ₹ 970 crore (considering a project cost of ₹ 12,440 crore at a debt equity ratio of 2.33:1 with equity contribution of ONGC at 26 *per cent*). ONGC, however, made available much higher quantum of funds to OPaL through a financing mechanism designed to maintain OPaL's non CPSU character, as discussed below:

(a) During the period from April 2007 to March 2011, ONGC contributed ₹ 970.29 crore as advances against equity to OPaL. The entire amount remained categorized as 'application money pending allotment' or as 'advances against equity' by OPaL. Due to amendment of Unlisted Public Companies (Preferential allotment) Rules 2003 (in December 2011) stipulating mandatory allotment of shares within 60 days of receipt of application money, OPaL was forced to issue (September 2012) equity shares against the advances. OPaL issued equity shares for ₹ 637.43 crore to ONGC, for ₹ 634.44 crore to GAIL and for ₹ 29 crore to GSPC. With issue of equity shares, OPaL became a deemed Government Company under the Companies Act, 1956. The delay in allotment allowed OPaL to utilize these funds of public sector entities (ONGC, GAIL, GSPC) without any cost during the period April 2007 to September 2012, while retaining its status as a private company.

(b) While equity shares worth ₹ 637.43 crore had been issued to ONGC in September 2012, OPaL had retained the balance ₹ 332.86 crore (₹ 970.29 crore – ₹ 637.43 crore) as advances against equity. In addition, ONGC contributed ₹ 27.64 crore on 15 May 2013 to OPaL, also towards advance against equity. The equity shares for total ₹ 360.50 crore was allotted by OPaL only on 16 May 2013, i.e. after 775 to 1168 days (two to three years) from date of receipt of ₹ 332.86 crore. GAIL was also issued additional equity shares in May 2013 against funds made available by them. With allotment of shares in May 2013, the capital structure of OPaL was ONGC: 49.36 *per cent*, GAIL: 49.21 *per cent* and GSPC: 1.43 *per cent.* OpaL continued to be a deemed Government Company under Companies Act, 2013. The delay in allotment of equity shares by OPaL led to continued use of funds of Government companies without any cost for prolonged periods.

(c) Subsequently, ONGC continued to finance OPaL by employing different financing mechanisms to ensure that OPaL does not become a public sector entity, as discussed below:

    (i) Just two days after the issue of last tranche of equity shares, OPaL offered (18 May 2013) a rights issue to its equity shareholders. ONGC subscribed to the rights issue for ₹ 670.92 crore on 21 May 2013. The other stakeholders (namely GAIL and GSPC) did not subscribe to the rights issue. OPaL did not issue the shares to ONGC. Had the shares been issued, OPaL would have become a subsidiary of ONGC and a public sector enterprise bound by the prudent Government guidelines for PSUs.

(ii) With implementation of Companies Act 2013, the funds received by OPaL against rights shares qualified as ‘deposit’ accepted before the commencement of the Companies Act 2013 and OPaL was statutorily mandated to make requisite filings in terms of the said provision or repay the deposits to ONGC by 31 March 2015. OPaL (in its Financial Management Committee (FMC) meeting held in March 2015), decided, that it is desirable that the non-PSU structure and character of OPaL be maintained. To comply with the statutory provisions of Companies Act 2013, OPaL refunded the funds received against rights issue (₹ 670.92 crore) to ONGC on 30 March 2015. Thus, the amount remained locked up with OPaL for a year and ten months, benefitting OPaL through interest free funds.

(iii) A day after receiving the refund (31 March 2015) of ₹ 670.92 crore from OPaL against non-issue of rights shares, ONGC paid ₹ 750.55 crore as application money for a new rights share. The Board of OPaL noted (May 2015) that ONGC was the only shareholder that had participated in the rights issue and that allotment of shares against the said application money would change the nature of the Company (OPaL). It was therefore decided to refund the amount to ONGC. However, OPaL kept the funds for the maximum period of 75 days, allowed under the Companies Act, 2013 before refund (Acceptance of Deposit Rules, 2014[1]).

A fortnight after receiving the refund of ₹ 750.55 crore, a call notice was received for subscription to share warrants from OPaL. Though the options of issuance of convertible debt instruments and subordinated loans were also considered by OPaL, it could not proceed due to restrictions placed by the Companies Act 2013; share warrants were neither defined in the Act nor the procedure for issue defined thereon. ONGC subscribed (30 June 2015) an amount of ₹ 961 crore (First instalment of ₹ 5 per warrant) and ₹ 480.50 crore (second instalment of ₹ 2.50 per warrant during November 2015) for warrants against issue of equity shares. The warrants were convertible to equity shares within a period of 12 months from the date of issue. The warrant exercise period has been extended (October 2015) from 12 months to 18 months. The amount paid by ONGC against the warrants also amount to interest free funds extended to OPaL for 18 months period.

If on completion of eighteen months, equity shares are issued against these warrants, OPaL would be a subsidiary of ONGC and a public sector undertaking. However, ONGC has the option to have the warrants converted to share. In the event of non-exercise of warrant conversion by ONGC, warrant subscription price already paid would stand forfeited.

The financing mechanism employed by ONGC, thus, had the sole intent of retaining the character of OPaL as a non PSU entity. Such funding was to its own detriment as it made available a large quantum of interest free funds to OPaL without any commensurate

[1] ***Acceptance of Deposit Rules, 2014 stipulates that shares would have to be issued within 60 days of receipt of application money with a 15 day grace period for refund in case the company fails to issue the shares***

benefit. The loss of interest to ONGC on account of the improper financing mechanism is ₹ 408.15 crore[1] as indicated in the ***Annexure-XX***.

Management replied (November 15) that:

(a) It was a conscious decision of the Board of Directors of ONGC, comprising of Executive, Non-executive/Independent and Government nominee directors, to keep the structure of OPaL as non-PSU SPV so that the projects could be implemented through induction of professionals from the industry and offering the company a platform with flexibility of faster, transparent and objective decision making.

(b) It is pertinent to add that ONGC is spearheading OPaL project as promoter because this is a Downstream Integration Project and Value Addition Project aligned to its future plans. So by infusing capital as 'Advance against Equity' matching with the Cash-flow requirement in OPaL, ONGC is ensuring timely cash flow for execution of the projects and at the same time it is giving a comfort to the prospective lenders regarding its commitment as the lead Promoter. Hence, in order to preserve the envisaged structure of OPaL and at the same time to fulfill the condition of upfront equity infusion by promoters for drawl of long-term debt, the option of 'Advance against equity' was resorted to for implementation of the project.

(c) It may be appreciated that in case promoters were to insist on interest against its commitment towards equity (i.e. Advance against Equity) such fund infusion would not be treated as promoters' commitment to the project and as such no lender would extend any fund on project finance basis thereby jeopardizing the whole project itself. In other words, interest bearing advances to be extended by promoters ranking *paripassu* with the long-term debt would not be acceptable to Lenders or meet the requirement of upfront fund infusion by promoters.

(d) The infusion of funds towards equity by ONGC may be seen as commitment of ONGC for implementing the Project as per its Board decision, rather than a lost opportunity for earning interest on funds infused in OPaL.

Reply of Management needs to be viewed in context of the following:

(a) It needs to be emphasized that the funds with OPaL were funds of Government companies even though its structure remained as a non-PSU SPV. OPaL, thus, was given access to public funds without the responsibilities enforced on PSUs.

(b) While ONGC made efforts at preserving the non PSU status of OPaL (at its own cost), it needs to be appreciated that private strategic investors have not been identified so far even after nine years of incorporation of OPaL (Nov 2006 to December 2015). Through the financing mechanism employed, ONGC has made available large sum of interest free funds to OPaL without any commensurate benefits to ONGC and thus acted against its own interest.

(c) Induction of professionals from industry or flexibility of faster, transparent and objective decision making is not precluded for PSUs. The response of ONGC also

[1] ***Calculated on the basis of interest earned on short term deposits of ONGC during the relevant periods***

needs to be viewed in the context of it being a PSU itself. Besides, it is also noted that there has been abnormal delay in completion of the project by OPaL. As against original scheduled completion of January 2014, the project is yet to be completed (as on December 2015) resulting in time over run of more than 24 months and cost overrun of 117 *percent* (the estimated project cost ₹ 12,440 crore in February 2008 had increased to ₹ 27,011 crore in July 2014). In fact, on account of time and cost overrun, the project economics are no longer viable. This raises doubt on the professionalism and efficiency of the present structure of the company which has been sought to be preserved.

(d) Audit has not suggested that interest be charged on funds made available to OPaL but has pointed out that the funding mechanism of ONGC is imprudent. ONGC had made interest free funds available to OPaL without any commensurate benefit to ONGC or responsibility on the part of OPaL. Out of the total amount of ₹ 3860.92 crore invested in OPaL, ONGC received allotment of only 997955639 number of shares against the initial investment of ₹ 997.95 crore. ONGC neither received any return nor any further benefit in the form of equity that can be sold at a future date on the funds of ₹ 1421.47 crore which was refunded by OPaL without allotment of shares. Allotment of shares against the balance investment of ₹ 961.00 crore and ₹ 480.50 crore, by ONGC towards purchase of share warrants, is subject to exercise of warrant conversion after a period of 18 months from the date of allotment. It may also be noted that other PSU investors (GAIL, GSPC) have not followed the financing mechanisms employed by ONGC.

Non-conversion/delayed conversion of advances into equity by OPAL, subscription to rights shares by ONGC and subsequent refund to circumvent statutory provisions and issue of warrants against equity shares by ONGC have enabled OPAL to use funds of Government companies without paying any dividend or interest and continue to retain the character of a non PSU SPV.

The matter was reported to the Ministry (February 2015); their reply was awaited (March 2016).

1.10 Loss of interest due to inordinate delay in receipt of share of gas transportation charges

Due to dispute between the seller Panna Mukta Tapti Joint Venture (PMTJV) and buyer GAIL (India) Ltd. (GAIL) on delivery point, Oil & Natural Gas Corporation (ONGC) (transporter) did not get its legitimate claim towards gas transportation charges. ONGC allowed release of the withheld funds to private partners Reliance Industries Ltd. (RIL) and BG Exploration and Production India Limited (BGEPIL), without realising its dues, which led to inordinate deferment of its dues (US$ 21.54 million) and consequent loss of interest thereon (US$ 24.93 million) from 1998-2005. The full realisability is also doubtful due to acceptance of conditional comfort letter from the private partners.

The Panna Mukta (PM) field is operated by the Panna Mukta Tapti Joint Venture (PMTJV) with participating interest in the PMTJV distributed between RIL (30 *per cent*), BGEPIL (30 *per cent*) and ONGC (40 *per cent*). The gas produced in the PM field (offshore) is transported through ONGC's trunk pipeline to ONGC's Hazira terminal where it is processed. For providing transportation and processing services, ONGC is eligible for compensation.

The Government nominated buyer of PM gas was GAIL. Since inception of production from PM field (February 1998), PMTJV and GAIL (Government nominated buyer) differed on 'delivery point' of the gas. While PMTJV maintained that 'delivery point' was offshore, MoP&NG/ GAIL held that it was on-shore, at Hazira. As per the production sharing contract, the seller (PMTJV) is responsible for all costs upto the 'delivery point' after which it would be the responsibility of the buyer (GAIL). As ONGC transports the gas between offshore and Hazira, it would receive compensation from seller (PM-JV) or buyer (GAIL) depending on the location of the 'delivery point'. With the dispute on 'delivery point', ONGC did not receive transportation charges from either seller or buyer (February 1998 to March 2005). Pending resolution of the dispute regarding delivery point, MoPNG directed (January 1998) GAIL to withhold 10 *per cent* of sale proceeds of PM gas in a separate escrow account.

This situation continued till April 2005 when PMTJV was allowed direct marketing rights as GAIL did not agree to the revised price of the PM gas. Having received direct marketing rights from the Ministry, PMTJV started selling (from April 2005) the gas to private parties and shifted the delivery point to Hazira. Meanwhile, the Government of Gujarat, under the contention that the delivery point is onshore, demanded sales tax (Jan 2004) for sale of gas by PMTJV. The demand was disputed by the PMTJV and the matter reached the High Court of Gujarat. After shifting the delivery point to on-shore in April 2005, the PMTJV paid sales tax prospectively though the dispute continued for the past period (February 1998 to March 2005).

ONGC proposed (in a meeting among PMTJV partners in July 2005) that the JV partners should approach the Government for release of revenues withheld by GAIL, 50 *per cent* of which, would be kept in an escrow account to be released after verdict of the High Court on sales tax and the balance shared amongst the partners as per their participating interest. Accordingly, this arrangement was included in the 'settlement agreement' entered into between PMTJV and ONGC (December 2005). PMTJV started paying ONGC, transportation charges from April 2005 as per rates agreed in the settlement agreement.

On being approached for release of withheld revenues, MoPNG sought (September 2007) a joint indemnity from PMTJV indicating that the PMTJV shall deliver all the gas from Panna-Mukta at Hazira in accordance with the provisions of the Production Sharing Contract (PSC) and incur all costs for delivering up to Hazira eg. sales tax, processing charges, environment aspects etc., from the effective date of the contract. Accordingly, PMTJV indemnified MoPNG (December 2007) and GAIL (April 2008) separately, stating that *"Contractor undertakes to incur all costs and liabilities relating to the transportation charges, processing charges and environmental aspects from the time of inception of gas sales and shall have no claim on this account against the Government"*. The indemnity bond, thus, clarified that the JV would pay for transportation charges for the prior period to ONGC.

GAIL released the withheld amount (₹ 388.84 crore) in November 2008. 50 *per cent* of the released amount was distributed among the partners in their participating interest and balance (equivalent to gas transportation charges payable to ONGC) kept by the partners in separate escrow accounts. In May 2015, High Court of Gujarat passed its judgment that delivery point for gas was offshore and therefore PMTJV is not liable for payment of sales tax for the period February 1998 to March 2005. The decision has been challenged by the State Government in Hon'ble Supreme Court of India (SC) and the matter is presently pending before the SC.

In this context, Audit observed the following:

- ONGC voluntarily allowed deferment of realisation of its legitimate dues on transportation and allowed distribution of 50 *per cent* of withheld amount (along with interest accrued thereon) among the PMTJV partners rather than ensuring payment of its dues as a service provider. It was also noticed that the present amount (US$ 25.80 million) in the escrow account of the private JV partners (including interest) is insufficient to cover the transportation dues of ONGC amounting to US$ 46.47 million[1] (principal US$ 21.54 million and interest of US$ 24.93 million).

- MoPNG advised (December 2004) ONGC to take recourse to dispute resolution mechanism provided under the PSC to get its transportation charges claims from the PMTJV. However, ONGC failed to take recourse to dispute resolution mechanism provided under the PSC to protect its own financial interest, despite advice of MoPNG.

- With PMTJV indemnifying Government and GAIL, and undertaking to pay transportation charges since inception, it was clear that ONGC would receive the transportation charges from the JV regardless of the outcome of the court case. However, ONGC had sought a comfort letter (August 2007) from the private PMTJV partners (BGEPIL and RIL) to assure payment of compensation of transportation services, in the event that the judgment of High Court is in favour of the JV. In the comfort letter, the private partners *inter alia* stated that, if the court decides that the delivery point is at offshore, BGEPIL and RIL will negotiate then in good faith with ONGC, the amount of transportation cost to be paid to ONGC. As per the settlement agreement, ONGC had already agreed to charge the JV for transportation services on actual cost basis. By agreeing for further negotiation on rates, ONGC placed itself at a disadvantage.

- The Gujarat High Court, in its judgment (May 2015), has held that the delivery point for Panna Mukta gas was offshore for the period 1998-2005. In view of the conditional comfort letter, the quantum of reimbursement to be received for transportation of crude by ONGC remained uncertain.

Management in reply, stated (December 2015) that an omnibus settlement for all the outstanding issues including money held in escrow account by GAIL was arrived at in

[1] ***Interest rate of nine per cent is adopted for the period February 1998 to March 2005 (rate as adopted in the High Court judgment on the Sales tax issue)***

the meeting held (July 2005) by the Chairman & Managing Director (CMD), ONGC with the representatives of RIL and BGEPIL. This was later formalized through 'settlement agreement' (December 2005). The amount parked in escrow account of the PMTJV partners is interest bearing and the issue of accrued interest shall be dealt with after obtaining the verdict of Supreme Court.

Management's reply needs to be viewed in light of the following:

(i) ONGC failed to take recourse to dispute resolution mechanism provided under the PSC to protect its own financial interest, despite advice of MoPNG.

(ii) ONGC, on its own, proposed parking 50 *per cent* of released amount (equivalent to gas transportation charges receivable) in an escrow account, linking it with the sales tax issue. Thus, ONGC had allowed benefit to the private partners in deferring realization of its legitimate dues on transportation voluntarily.

(iii) The private partner (RIL and BGEPIL) share of US$ 25.80 million including interest held in escrow account as on March 2015 is not sufficient to repay ONGC dues of US$ 46.47 million (principal US$ 21.54 million and interest of US$ 24.93 million).

(iv) The 'settlement agreement' is also silent on the payment of interest due to the ONGC on its outstanding amount.

Thus ONGC extended undue benefit to the private partners (RIL and BGEPIL) which had resulted in inordinate deferment of its transportation revenue of US$ 21.54 million accrued over 1998-2005. Due to delay, the Company has suffered an interest loss of US$ 24.93 million (₹157.05 crore) (PMTJV private partner's share). The full realisability of these dues is doubtful considering the fact that the escrow account does not have sufficient funds to meet ONGC's claims and the conditional comfort letter accepted by ONGC providing for further negotiation of the amount to be paid to ONGC.

The matter was reported to the Ministry (December 2015); their reply was awaited (March 2016).

1.11 Improper decision of procuring intelligent well completion equipment led to idling of equipment

The Company planned implementation of Intelligent Well Completion (IWC) technology in eighteen wells in Mumbai Offshore. The finalisation of tender was delayed. By the time the contract was placed, the majority of the intended wells were already completed. The other wells where IWC technology was to be employed were not suitable. This led to improper use of two IWC sets and idling of 12 IWC sets for nearly four years. Placing the procurement contract without proper assessment of the actual requirement was an imprudent commercial decision. The value of the idling equipment was ₹ 46.24 crore.

ONGC (Company) planned (December 2008) implementation of Intelligent/smart Well Completion[1] (IWC) technology which precludes deployment of rigs for well completion

[1] ***Intelligent well completion in Horizontal Open Hole is a technology to combat increased water production, presence of intermediate shale, isolate fault and facilitate selective stimulation of individual segments. In this type of completion horizontal open hole is divided into segments using open hole packers, surface controlled ICVs are used for selective production/stimulation/shut in and measurement devices are used to have productivity and control.***

while ensuring productivity of the well. IWC was to be employed in thirteen wells in RS-15 and RS- 16 platforms in 2009-10 and in five wells of B-193 cluster in 2010-11. Indent for the same was placed in October 2009.

The Company floated a global tender (19.02.2010) for designing IWC, supplying downhole equipment and provisioning tools and experts for carrying out IWC in the 18 planned wells. Though the indent for IWC was placed in October 2009, the contract was awarded to M/s Schlumberger Asia services Limited (Contractor) in May 2011 for duration of 30 months from the date of mobilisation. Thus, the Company took more than one and a half years to finalise the contract from the date of indent, as against 140 days stipulated in the Material Management manual of the Company.

The Contractor mobilised 18 sets of IWC equipment at Company's Nhava Supply Base (NSB) in January 2012 (on 09.01.2012).

The Company had planned to utilise 13 IWC equipments in wells of RS-15 and RS- 16 platforms during 2009-10. With the delay in finalisation of the IWC contract, all the wells in RS-15 and RS-16 platforms had been drilled and completed before scheduled mobilisation of IWC equipment. Thus, 13 of the 18 IWC equipments could not be utilised for completion of the intended wells.

The balance five IWC equipments were envisaged for wells in B-193 cluster. The drilling of these wells was taken up only in 2013-14 when IWC equipment was available with the Company. However, the Company did not utilise IWC equipment in these wells citing high ppm of H_2S and CO_2 in the B-193 cluster. Thus, even these five IWC equipments were not utilised for the intended wells.

Over the next 30 months (the contract duration), the Company could use only four sets of IWC equipment in offshore wells and transferred another two sets to Mehsana onshore asset. The utilisation of IWC equipment at Mehsana asset was not as intended by the Company. Besides, only 50 *per cent* of the equipment has been utilised by Mehsana asset and the balance 50 *per cent* remained unutilised. Audit did not find any plan for utilisation of these balance items of IWC units (costing ₹4.73 crore) in the near future.The remaining twelve sets of IWC lie unused at NSB (December 2015).

As per the contract terms, 60 *per cent* of cost of equipment was payable within 15 working days from the date of successful completion of mobilisation of equipment at NSB. The balance 40 *per cent* of equipment cost along with cost of services was payable after satisfactory and successful completion of each job.The Company paid US$ 6.36 million (₹ 32.53 crore), i.e. sixty *per cent* of the equipment cost after successful mobilisation and balance US$ 3.53 million (₹ 21.73 crore), i.e. forty *per cent* on completion of contractual period.

For nearly four years after their mobilisation (Jan 2012 to Dec 2015), twelve sets of IWC equipment have idled with the Company. Considering that the contract term was 30 months within which installation of all IWC sets were envisaged and for which warranty was provided, the idling of majority of the sets points to poor planning on part of ONGC. Besides, the condition of the equipment after idling for such a long period remains in doubt.

Management replied (November 2015) that:

- As the IWC equipment and services were being procured for the first time in ONGC and the nature being complex, firming up of BEC took considerable time. Large number of queries in pre-bid conference, incorporation of additional clauses, extension of Technical Bid Offer (TBO) and two rounds of clarifications took considerable time.
- All the wells drilled with intelligent well completion were planned in consultation with service provider and equipment supplier. Though the planning of wells by the Asset was not inappropriate, the performance of the wells was mixed.
- B-193 cluster wells were highly sour in nature having high H_2S and CO_2 content except in one gas field. Based on recommendation of IEOT and international consultant expert a decision was taken by B&S Asset to complete the wells with liner of Corrosion Resistant Alloy (CRA) metallurgy, liner hanger of sour resistant, CS metallurgy, production tubing of sour resistant CS metallurgy and well completion packer of CRA metallurgy.
- The Mumbai High (MH) Asset has identified four wells for intelligent completion, three wells in 2015-16 and one well in 2016-17. The Bassein & Satellite asset has identified four wells for intelligent completion, two each in 2016-17 and 2017-18. The remaining four IWC sets would be used in phase III wells of MH Asset. The contract for hiring services is likely to be in place by January 2016 with the same rates and terms and conditions.

Management reply is not tenable in view of following.

- By the time the contract for IWC was awarded (May 2011), 16 wells out of total 19 wells in these platforms had already been completed and two more wells were under drilling. Thus, even at the time of award of the contract, the Company was aware that the IWC sets being procured could not be utilised for completion of the intended 13 wells in RS-15 and RS-16 platforms.
- The study on selection of casing metallurgy for B-193 development project wells had been carried out through Institute of Engineering & Ocean Technology (IEOT) as early as 2009. The IEOT report (May 2009) had observed that all the formations (Bassein, Mukta and Panna formation) of B-193 cluster wells are very sour with high H_2S and CO_2 content. IEOT had suggested to have preferably CRA metallurgy for B-193 wells. Thus, the Company was well aware of the requirement of completion of B-193 wells with CRA metallurgy even before placement of indent for IWC sets in October 2009. While selecting the five wells in B-193 cluster for IWC, the IEOT report ought to have been considered by the Company.
- The Company has assured in reply that IWC sets would be utilised in six wells over 2015-16 and 2016-17. Review of Rig Deployment Plans for 2015-16 and 2016-17 revealed that only four out of the six wells has actually been planned for drilling during the period from 2015 to 2017. The future utilisation of the IWC sets therefore remains doubtful.

Thus, the decision of the Company to procure IWC equipment without assessing their actual requirement was an imprudent commercial decision and resulted in idling of equipment valuing ₹46.24 crore.

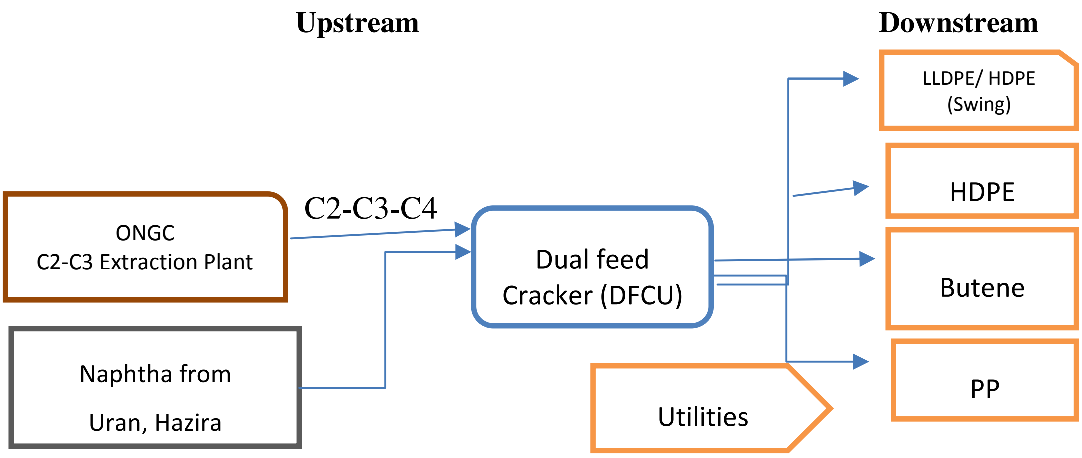
The matter was reported to the Ministry (December 2015); their reply was awaited (March 2016).

ONGC Petro additions Limited

1.12 Non–synchronization of construction of downstream units and other utilities with the Cracker Plant led to avoidable expenditure on Preservation and plant check of Cracker Plant

OPaL's failure to freeze the configurations of downstream units with cracker plant and to synchronize the award and completion of all the packages resulted in avoidable expenditure of ₹ 13.19 crore towards preservation charges and payment of ₹ 73.36 crore towards plant check of Cracker plant.

The Oil and Natural Gas Corporation Limited (ONGC) Board had approved (October 2006) setting up of an integrated Gas and Liquid based Petrochemical Complex in Special Economic Zone, Dahej through a separate Special Purpose Vehicle (SPV) ONGC Petro additions Limited (OPaL). It was envisaged that the feedstock of naphtha (from ONGC's Hazira and Uran plant) and C2-C3, C4 (from ONGC's unit in Dahej) would be processed in the upstream Dual Feed Cracker Unit (DFCU) and associated utilities to produce ethylene and propylene which then would be utilised in downstream polymer units to produce polymers like LLDPE, HDPE, Polypropylene, SBR[1], etc.



Process Flow diagram of Petro Complex

[1] *LLDPE-Linear Low Density Polyethylene, HDPE – High Density Polyethylene and SBR-Styrene Butadiene Rubber*

The detailed feasibility report (DFR) of the project prepared by M/s. Engineers India Limited (EIL) in April 2005, had provided for synchronised completion of upstream and downstream units. The contract for the upstream units (DFCU and associated units) was awarded in December 2008 to a consortium[1] with the scheduled completion by September 2012 and commissioning by December 2012. As per the schedule drawn up in the DFR, the contract for all downstream units and utilities ought to have been awarded within two months of award of upstream contract (February 2009). It was, however, noticed that the contracts for downstream units were delayed and awarded piecemeal to different contractors (15 contracts[2]) from November 2010 to May 2012.

As per the awarded contracts, the downstream units and utilities were to be completed by October 2013. However, these are yet to be completed (November 2015). The upstream facilities were mechanically complete by September 2012, as envisaged and have not yet been commissioned in the absence of downstream facilities and utilities.

Meanwhile the warranty on DFCU expired and OPaL had to maintain the unit under preservation mode since February 2014. OPaL employed EIL from February 2014 to March 2015 for preservation and maintenance of the DFCU at a cost of ₹13.19[3] crore. Subsequently, in March 2015, OPaL awarded a contract for plant check for pre-commissioning to the consortium of M/s. Samsung and M/s. Linde. Till November 2015, OPaL has paid ₹ 73.36 crore to this consortium.

Audit has the following observations in this context:

- The delay in award of the downstream contract was on account of frequent changes in project specifications by OPaL. The project specifications were changed in February 2008, bringing down the project cost to ₹12,440 crore (from ₹19486 crore estimated in 2007) involving an investment of ₹ 992 crore by ONGC at 26 *per cent* participation with management control. The project cost had to be reduced so that the contribution of ONGC to the project would fall within its financial autonomy for investment (₹ 1000 crore as a Navratna company). Subsequently, in March 2009, OPaL again revised the project specifications to revert to the original configuration of the swing units and included a dedicated HDPE in the project scope. This increased the project cost to ₹ 19846 crore. This revised cost was further discussed with SBI Caps (debt adviser cum arranger for OPaL). SBI Caps worked out revised project cost as ₹ 19535 crore, which was approved by the OPaL Board in June 2010, only after ONGC attained Maharatna status (May 2010) which enhanced the financial autonomy of ONGC.
- Following approval of the project specifications in March 2009, OPaL selected the licensor for downstream units in September 2009. It was noticed that OPaL did not plan for obtaining Secretariat of Industrial Assistance (SIA) clearance for the license which took five months. The licensor took another six months to make available the design data (September 2010). Thus, there was a delay of nearly two years in receipt of process package (as against scheduled date of November 2008

[1] ***M/s. Linde A.G., Germany & M/s. Samsung Engineering Co. Limited, Korea***
[2] ***Engineering Procurement Construction (EPC) contracts***
[3] ***₹10.97 crore to M/s EIL and ₹2.22 crore towards other expenses.***

it was received in September 2010) which contributed to delay in initiation of the downstream facilities.

- The scope for Captive power plant, Product warehouse, Laboratory, living quarters and water packages were added late to the original scope of project specifications.
- OPaL had awarded 15 EPC contracts to different contractors. As per their scheduled completion, all downstream facilities (units and utilities) were to be completed by February 2014. The execution of these contracts was delayed. In particular, the utility contracts (cooling water systems; effluent treatment plant and balance utilities and off-sites) were badly delayed. The work of these utilities was yet to be completed (November 2015).
- Even with completion of all downstream units and utilities, the project cannot be commissioned in absence of feedstock arrangement for operation. The upstream facility, DFCU, is designed to operate on dual feed, naphtha and C2, C3, C4. It had been envisaged that naphtha would be supplied from Hazira plant of ONGC through a pipeline to Dahej. However, on account of ROU problems, the pipeline could not be laid. An alternate arrangement of bringing the naphtha from GCPTCL to Dahej has been initiated. However, though the pipeline between GCPTCL and Dahej has been laid, the terminal facilities at both ends are yet to be completed.

Management in reply stated (November 2015) that:

(i) Such a mega petrochemical complex, with the DFCU and associated units as the core unit has intricate interdependencies even at the design stage with various other downstream units. The downstream and utilities design/load could only be conceived with the firming up of design output of the DFCU and AU. With feed quality related supply issue (rich feed changed to comingled R-LNG feed), specification for output streams took time to finalize.

(ii) The delay in award of EPC work for downstream unit of LLDPE/HDPE swing unit is because of waiting on having the process design package (PDP) from the licensors.

(iii) The cost of the project increased by ₹ 7095 crore (₹ 19535 crore – ₹ 12440 crore) due to the changes and also due to addition of captive power plant with steam generation facility necessitating approval of OPaL board for additional expenditure envisaged. Also, change in scope/configuration led to increased utilities requirement, which had to be re-worked, before tie up of utility packages;

Management's reply is not tenable in view of the following:

(i) The change in feed quality supply on account of comingled R-LNG being available for C2C3 plant instead of the originally envisaged rich feed of ONGC has no relevance as OPaL decided to procure the balance C2+fractions from market (June 2010) to make up and maintain the design feed of 973 KTPA in the

DFCU. Thus, the output of DFCU would not change and consequently the design of downstream units would also not require change.

(ii) The delay in award of EPC work was on account of changes made in project specifications to maintain project cost within the financial autonomy of ONGC and also due to delay in selection of licensor due to changes in project specifications and not planning for SIA clearance.

(iii) The increase in project cost pointed out by OPaL in reply was on account of intermittent changes in project scope to keep the contribution of ONGC within its financial autonomy limits. It needs to be noted that the project cost (2007) was ₹19486 crore which was deliberately reduced by OPaL to ₹ 12440 crore in February 2008 and then raised again to ₹19535 crore (June 2010). The frequent change in scope points to poor planning. It is noted that Central Lab – Optical control system package was awarded as late as October 2012 while the upstream DFCU unit has already been completed in September 2012.

Thus, non-synchronisation of the upstream and downstream facilities in the petrochemical project led to additional expenditure of ₹ 86.55 crore towards preservation and plant check for pre-commissioning of upstream unit (DFCU) till November 2015. As the downstream units, utilities and the terminalling facilities for obtaining feedstock are yet to be completed (Nov 2015), the idling of facilities already created is likely to continue with additional expenditure being incurred on its preservation.

The matter was reported the Ministry (December 2015); their reply was awaited (March 2016).