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Report of the Comptroller and Auditor General of India on

Crude Oil Production Measurement and Reporting System in ONGC

Union Government (Commercial)
Ministry of Petroleum and Natural Gas

Report No. 21 of 2016

(Compliance Audit)

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Comptroller and Auditor General of India
on
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For the period ended 31 March 2016

Union Government (Commercial)
Ministry of Petroleum and Natural Gas
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Preface

This Report of the Comptroller & Auditor General of India has been prepared under the provisions of Section 19-A of the Comptroller and Auditor General's (Duties, Powers and Conditions of Service) Act, 1971, as amended in 1984 for submission to the Government for being laid before Parliament. The audit has been conducted in conformity with the Auditing Standards issued by the Comptroller and Auditor General of India.

The Report contains results of audit of the 'Crude oil production measurement and reporting system in ONGC'. Following a report on over-reporting of crude oil production in Ankleshwar Asset, an audit of the crude oil measurement and reporting system across Assets of ONGC was taken up.

The Report brings out deficiencies and anomalies in the crude oil production measurement and reporting system which resulted in overstatement of production figures of crude oil reported by the Company. This presented an inaccurate measure of the Company's performance and led to additional subsidy burden to the Company.

Audit wishes to acknowledge the cooperation extended by ONGC and Ministry of Petroleum and Natural Gas in providing records, information and clarification in completing the audit.

Executive Summary

Executive Summary

Introduction

Oil and Natural Gas Corporation (ONGC) Limited (the Company) is an integrated oil exploration and production company. The Company conducts its exploration activities through 'Basins' and production activities through 'Assets'. Presently, the Company has 13 crude oil producing Assets both in offshore and onshore areas.

Production of crude oil in Mumbai offshore

The well fluids from the offshore well head platforms are transported to the process platforms through subsea well fluid lines. At the process platform, the well fluids are separated into crude oil, gas and water. The separated, partially stabilized, crude oil is then pumped through the trunk lines to the onshore terminal (Uran) for further processing/stabilization before sale to consumers. The partially stabilised crude oil dispatched to Uran plant is measured using Turbine Meters (TM) at the outlet of the process platforms. This is the 'wet crude'. The water content in the crude is separately measured using Auto Samplers. The 'wet crude' is adjusted for the water content, so measured, to arrive at the 'dry crude' dispatched from the offshore terminal which is reported as the crude oil production from Mumbai offshore.

Production of crude oil in onshore areas

Emulsion along with associated gas produced from the wells is collected at Group Gathering Stations (GGS)/Early Production Systems (EPS) through flow lines/tankers. The liquid so received at GGS/EPS is processed through a separator where liquid and gas is separated. The separated liquid (emulsion) is stored in tanks and after stabilisation, free water is drained out. For GGS/EPS without processing facility, the emulsion is transported to the designated processing installation. The processing installations will process the emulsion through Heater Treater by adding demulsifier to separate water and crude oil. The separated crude oil is stored in oil tanks at the respective processing installation and after stabilisation, further free water, if any, is drained out and crude oil with desired quantum (0.2 per cent) of basic sediment and water (BSW) is dispatched to refineries through trunk pipelines.

The Base office of the Asset collates the information from all processing installations in the Asset and prepares the Daily Production Report (DPR) for the Asset. The quantum of crude oil recorded in the DPR is reported as the production of the onshore Asset.

Highlights

i. ONGC defines 'condensate' as liquid hydrocarbons produced with natural gas, separated by cooling and other means. 'Condensate' is distinct from crude oil, being produced from gas fields. Inclusion of 'condensate' quantity as crude oil production is neither in line with international reporting systems nor with the practice followed by domestic JVs, in which ONGC has participating interest. International consultants, M/s DeGolyer and McNaughton (D&M), appointed by ONGC in 2011-12, had pointed out that 'condensate' is reported as a separate stream wherever there is a gas processing plant. ONGC itself treats 'condensate' as natural gas while paying royalty to Government on its production yet reports it as crude oil production which overstates the crude oil production quantum.

(Paragraph 3.1.)

ii. The PNG Rules 1959 and the Oil Industry (Development) Act, 1974 define 'crude oil' as *"petroleum in its natural state before it has been refined or otherwise treated but from which water and foreign substances have been extracted".* The performance contract by which the Company internally sets crude oil production targets for individual assets, inter alia, defines crude oil production as 'the quantity after adjustment of Basic Sediment and Water (BS&W)'. The reported production in offshore areas is of partially stabilised crude oil, despatched from the offshore platforms before removal of off gas and Basic Sediment and Water. Inclusion of off-gas and BS&W, therefore, overstates the crude oil production of the Company.

(Paragraph 3.2. and 3.3.)

iii. Crude oil from the offshore platform is despatched to Uran through two pipelines, Mumbai-Uran Trunk line (MUT) and Heera Uran Trunk line (HUT). At both points, the crude oil is measured by Turbine Meters (TM). Test check of the measurement data (from August 2014 to August 2015) from Turbine Meters (at the offshore outlet and Uran inlet) indicates that for both MUT and HUT pipelines, the crude measured by TMs at offshore platform was consistently higher than that measured at Uran inlet; the average difference being 4.57 *percent* for MUT and 3.09 *percent* for HUT pipelines. Considering that the measurement by both meters were taken under the same conditions of temperature (15°C/60°F) and pressure, the volumes measured at both ends of the pipeline ought to be identical. This leaves open the likely possibility of human error in measurement/reporting at either or both ends.

(Paragraph 3.5.)

iv. Uran plant maintains electronic and physical logs of the measurements of receipt of crude oil. However, at the offshore platform, no logs (either electronic or physical) were maintained even though the flow computers have provisions for the same. In the absence of audit trail, the accuracy of this production data could not be verified. Considering the significant difference recorded in transit of crude oil by the MUT and HUT pipelines and no other justification for the same, the concern that the production recorded manually was inaccurate/over-stated could not be ruled out. The water content in the crude oil measured (Jan 2015 – August 2015) in offshore platform was consistently lower than that in the crude receipt at Uran, the average difference being 0.81 percent for MUT and 1.65 percent for HUT pipelines. In 2003, ONGC had appointed a consultant, M/s IHRDC regarding the reconciliation differences who had opined that the consistent trend of discrepancy points to un-representative sampling on part of ONGC. Audit analysis indicated that the situation has persisted for over a decade without being addressed by the Company.

(Paragraph 3.6.)

v. There was no standard operating procedure for measurement of crude oil in onshore assets. As such, different onshore assets measure production at different points of the value chain and use different set of measurement techniques for the purpose.

(Paragraph 4.1.)

vi. In Ankleshwar asset, the Daily Production Reports (DPRs) communicated to the base office of the Asset was much higher than the data maintained in the physical log books of the installation. In Ahmedabad asset, the quantity reported by the Asset office was much higher than the data communicated by the processing facilities to the Asset office. In Mehsana asset, the DPR reported a calculated production data which was higher than the actual production quantity recorded separately by the Asset. The net effect in all three assets was reporting of production that was higher than the actual/measured production.

(Paragraph 4.2.)

vii. Crude oil is used by the asset in work over operations for hot oil circulation/ squeezing jobs to improve productivity of sick wells. In such cases, a part of the crude oil is recoverable subsequently from the well. All Western onshore assets used to treat the entire quantity used for hot oil circulation/squeezing jobs as internal consumption. Recoverable crude oil thus treated as production led to possibility of double measurement.

(Paragraph 4.3.)

viii. Ahmedabad asset recognised significant quantity of pit oil as closing stock (accumulated from 2006-07 to 2009-10). While this increased the production quantum for crude oil, the asset did not value this stock in the books of accounts and the closing stock quantity pertaining to pit oil was gradually written off.

(Paragraph 4.4.)

ix. Ankleshwar, Rajahmundry and Cauvery assets have reported significant water drainage after processing and before custody transfer to the refinery. Such a high quantity of water drainage, post processing, raises doubt on the efficiency of the processing installations and contributed to overstatement of crude production.

(Paragraph 4.5.)

x. Ankleshwar asset had over-reported production significantly and to adjust this, it reported a much higher quantum of crude oil theft than actual theft of 550 litres. The asset showed a pipeline leakage of 3556 MT which the asset later accepted was to adjust the over-reporting of crude oil. The asset also over-stated the closing stock of crude oil at processing installations by introducing water/effluent in the closing stock taken at financial year end (31st March) and then drained the water in April. This was done to adjust the excess production reported by the asset. Similarly, it was noticed that the closing stock (31st March) in one of the processing installations of Assam asset had significant quantum of water which was drained in April for two years, 2013-14 and 2014-15, leading to an over-statement of closing stock, thereby over-stating the crude production.

(Paragraph 4.6. and 4.7.)

xi. Audit noticed various shortcomings in the measurement system of crude oil in ONGC. Tank calibration was not carried out every five years as mandated in ONGC. In fact, most of the 120 tanks in Assam asset had not been calibrated or cleaned after commissioning in 1970s. ONGC implemented the Supervisory Control and Data Acquisition (SCADA) system in March 2008 at a cost of ₹385 crore. Though SCADA system had been installed in most installations and tanks, the same is not being used for reporting. Manual tank dips continued to be resorted to. In Assam asset there were differences in log book and SAP data. SAP ERP has production revenue accounting (PRA) module capable of generating the DPR from the stock positions, liquid received and despatched at the processing installations. It was however noticed that in Western onshore assets, DPR was generated manually outside Production Revenue Accounting module of SAP.

(Paragraph 4.8.1. to 4.8.4.)

xii. ONGC signs a MoU with MoPNG regarding performance of the company in which crude oil production by the company is a key performance indicator. By including BS&W of 3.9 per cent, off-gas of 1 per cent, and recoverable internal consumption of 0.12 per cent, the production performance was over stated. If the actual crude oil production was reported, the company would not have met its crude oil production targets in any of the years (2010-11 to 2014-15). As performance related pay (PRP) of its employees is related to achievement of production targets, actual production reporting would have resulted in lesser pay-outs of ₹106.51 crore of PRP to the employees. Condensate was also included in the crude production incorrectly.

(Paragraph 5.1.)

xiii. The subsidy burden of up-stream companies since 2011-12 was determined as a function of reported production of crude oil. ONGC has borne a subsidy burden of 56 USD per barrel of its total production of crude oil. By over-reporting its production of crude oil, ONGC has borne additional burden of ₹18626.74 crore during the period from 2011-12 to 2014-15. Further, over reporting of production in Ankleshwar and Assam Assets (inflating closing stock) has resulted in additional subsidy burden of ₹160.69 crore.

(Paragraph 5.2.)

The following recommendations are suggested for improvement in the crude oil production measurement and reporting system.

- The loss/gain during transportation of crude oil through closed pipeline systems should be closely monitored to ensure that the variations are in normal range and identify abnormal loss/gain for corrective action. Such reconciliation and monitoring as well as corrective actions taken should be adequately documented.

- Asset-specific Standard Operating Procedures (SOPs) for measurement of crude oil production may be formulated and implemented in all onshore Assets in a time-bound manner to ensure that uniform measurement practices are followed across all production installations of the Company. Asset specific guidelines for segregating internal consumption of crude oil into 'recoverable' and 'non-recoverable' may be designed and 'recoverable' quantum may not be included as crude oil production. Norms for crude oil transit loss should be fixed and cases of abnormal transit loss should be investigated and remedial action taken to prevent revenue loss.

- The Company should strictly adhere to prescribed schedules laid down for calibration of all crude oil measuring devices, such as storage tanks and Mass Flow Meters, Turbine Meters, Auto Samplers, etc. in both offshore and onshore Assets to ensure accuracy of their measurement.

- Electronic and physical trails in support of measurement of crude oil at various stages of production should be maintained to derive assurance regarding their accuracy. SCADA installed in all production installations may be integrated with ICE-SAP ERP system for capturing data and to minimise manual intervention and improve accuracy of reported information. The production reports for onshore Assets should be generated through the SAP-PRA module, in line with the practice in offshore Assets, to preclude the possibility of their manual manipulation.

- The Company may report condensate as a separate stream as opined by the international consultant.

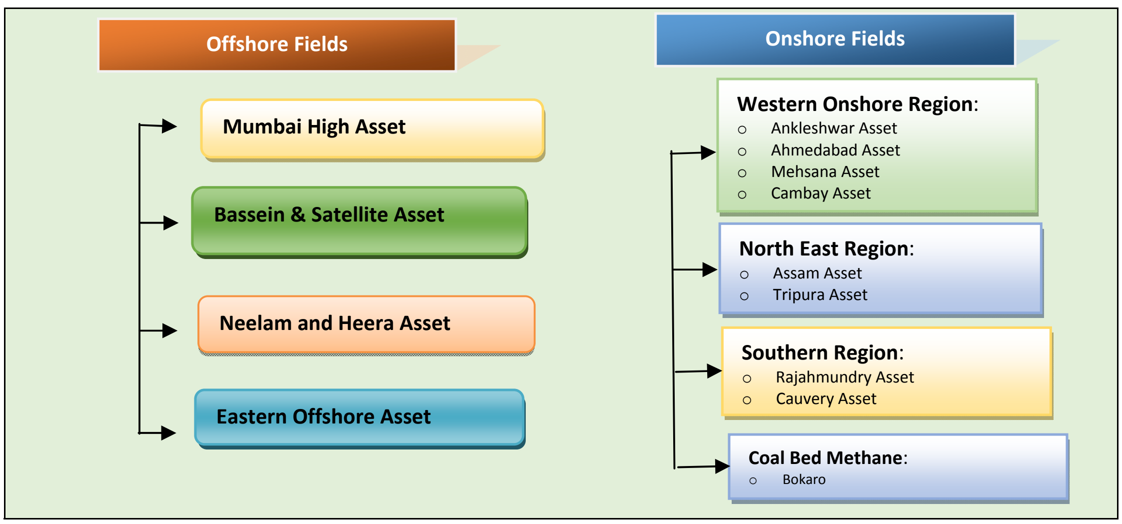
- The Company may ensure that items other than crude oil, namely, condensate, off-gas, basic sediment and water, etc., may not be reported as crude oil production. Considering the difficulties expressed by the Management/Ministry in accurately measuring the crude oil at the production point, there appears to be a case for shifting the production reporting point to a suitable location where stabilized crude (excluding BS&W, off-gas and condensate) can be accurately measured.

Chapter 1
Introduction

1.1. Introduction

Oil and Natural Gas Corporation (ONGC) Limited (the Company) is an integrated oil exploration and production company. The Company conducts its exploration activities through 'Basins' and production activities through 'Assets'. Presently, the Company has 13 crude oil producing Assets[1] in both offshore and onshore areas as indicated in Figure-1 below.

Figure-1: Crude oil Producing Assets



The production of crude oil reported by the Company for the last five years (2010-11 to 2014-15) including those from Joint Ventures and New Exploration Licensing Policy (NELP) is tabulated below.

[1] Asset: It refers to an entity in ONGC that is involved in production activities from existing wells and transportation of oil and gas on onshore plants. 13 Assets are Ahmedabad, Mehsana, Ankleshwar, Cambay, Assam, Tripura, Rajahmundry, Cauvery, Mumbai High, Neelam-Heera, Bassien-Satellite, Eastern Offshore Asset, Coal Bed Methane- Bokaro.

Table-1: Crude Oil Production Reported by ONGC

(Figures in MT)

Year	Onshore			Offshore		Production of Joint Ventures	Onshore NELP	Total Production of ONGC including NELP and JVs
	Western Onshore	North Eastern Onshore	Southern Region	Eastern Offshore	Western Offshore			
2010-11	5756676	1152021	537549	0	16972261	2859771	0	27278278
2011-12	5629262	1204507	550988	38458	16289179	3212953	0	26925347
2012-13	5186507	1224262	532950	44470	15572652	3564767	1506	26127114
2013-14	4916987	1264823	523424	25815	15514874	3747232	951	25994106
2014-15	4512939	1060798	494367	18191	16176615	3678874	986	25942770

Source: Corporate crude tally statement of the Company
Note: **Western Offshore includes Mumbai High, Bassein and Satellite, and Neelam and Heera Assets**

The total offshore crude oil production was around **65 *per cent*** of total reported production of the Company.

1.2. Audit Objectives

The objectives of the audit was to:

- Assess whether crude oil production has been accurately measured and reported
- Estimate the impact of inaccurate measurement and reporting of crude oil production, if any.

1.3. Scope of Audit

Audit examined the measurement and reporting system of crude oil production in nine out of the total thirteen Assets owned by the Company for the period 2010-11 to 2014-15. The Assets covered in the audit are:

- ***Offshore Assets***: Mumbai High, Bassein & Satellite, Neelam & Heera.
- ***Onshore Assets***: Ankleshwar, Ahmedabad, Mehsana, Assam, Cauvery, Rajahmundry.

1.4. Audit Criteria

The criteria for the audit was drawn from:

(i) The Oilfields (Development & Regulation) Act, 1948.

(ii) Oil Industry (Development) Act, 1974.

(iii) Petroleum & Natural Gas Rules (PNG Rules), 1959.

(iv) Internal Standard Operating Procedures/circulars/guidelines for measurement of production of crude oil, norms for transit loss.

(v) Domestic and international practices for reporting of crude oil production.

(vi) Industry norms for pipeline loss, permissible variations in meter readings.

(vii) The policy of the Company for calibration and maintenance of crude oil metering system.

1.5. Audit Methodology

The field audit commenced in August/ September 2015. Review of records was supplemented by field visits to selected field and processing installations. Discussions were also held with the Management at different levels during the course of the audit to understand the process and limitations of the audited asset. The preliminary audit findings were discussed with the Management and thereafter audit observations were issued to them for their response.

After incorporating the responses received, the draft audit report was issued to the Management of the Company. Replies to the draft audit report were received on 11 January 2016. After incorporating the Management response, the revised report was issued to Ministry in February 2016 and Ministry's response was received in April 2016. The responses of the Ministry have been incorporated in this report.

Chapter 2
Crude Oil Production Measurement and Reporting System

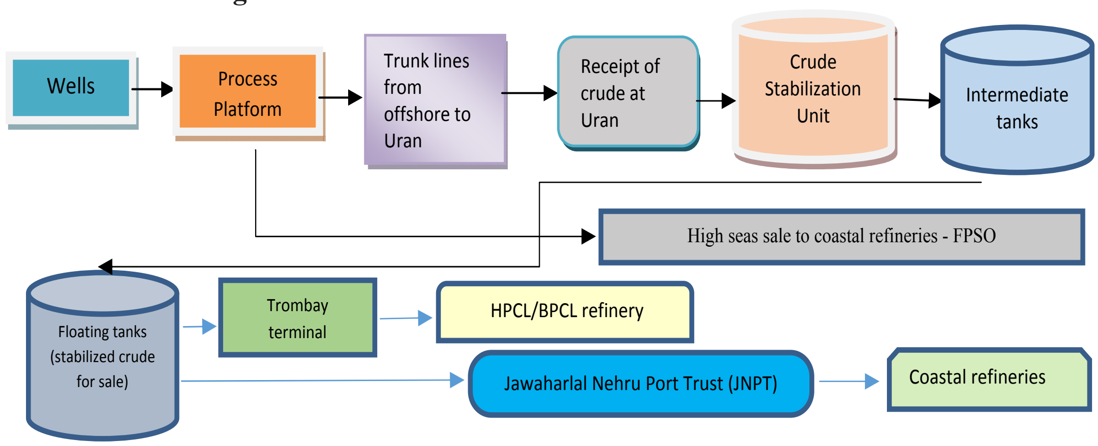
2.1. Offshore Assets

2.1.1 Production of crude oil in Mumbai offshore Assets

The Mumbai offshore field comprising of Mumbai High, Neelam Heera and Bassien & Satellite Assets is the Company's largest producer of crude oil. In contrast, Eastern offshore Asset is a minor contributor, accounting for 0.11 *per cent* of the offshore crude production.

The production facilities in Mumbai offshore field include well head platforms, process platforms, onshore terminal and pipelines linking them. The well fluids from the offshore well head platforms are transported to the process platforms through subsea well fluid lines. At the process platform, the well fluids are separated into crude oil, gas and water. The separated, partially stabilized, crude oil is then pumped through the trunk lines to the onshore terminal (Uran) for further processing/ stabilization before selling to the consumers. Processing facilities at Uran include Crude Stabilization Unit (CSU), where water is drained out and off-gas[2] is removed and added to gas stream. The stabilized crude from CSU is stored in intermediate tanks for further stabilization and then transferred to crude oil floating tanks. The crude oil from the floating tanks is dispatched to Trombay terminal and Jawaharlal Nehru Port Trust (JNPT) for sale to downstream refineries. Crude from isolated fields is produced through Floating Production Storage and Offloading vessel (FPSO) and transported through marine tankers to coastal refineries (around 7.90 *per cent* of total offshore crude oil production). The schematic diagram for production of offshore crude oil is depicted below:

Figure-2: Production of crude oil at Mumbai offshore



[2] Off gas is dissolved gas in partially stabilized crude oil dispatched from offshore to Uran. It is removed in Uran plant during processing and stabilization of crude oil and added to gas production.

2.1.2. Measurement of crude oil at Mumbai offshore

Measurement of crude oil produced at Mumbai offshore is carried out at the offshore process platform, the Uran plant and the custody transfer point - point of sales to refinery, e.g., Trombay terminal and JNPT. The process for measurement and the documents maintained at each of these locations are detailed below:

- **Process platforms:** The partially stabilised crude oil dispatched to Uran plant is measured using Turbine Meters[3] (TM) at the outlet of the process platforms. This is the 'wet crude'. The water content in the crude is separately measured using Auto Samplers[4]. The 'wet crude' is adjusted for the water content, so measured, to arrive at the 'dry crude' dispatched from the offshore process platform which is reported as the crude oil production from Mumbai offshore fields.

  The process platforms maintain the Daily production report (DPR) of crude oil dispatched in Microsoft Excel sheets. These documents (Excel sheets indicating DPR) are prepared manually by recording the production data displayed on the Human Machine Interface (HMI)[5] of the Turbine Meters on a real time basis. The laboratory report on the water content in the crude oil and its density is also separately maintained. No physical or electronic back-up of the production data is however taken. The details of the DPR, water cut and density are manually fed into the SAP system which calculates the dry crude production by adjusting the water content from the crude oil production reported in the DPR.

- **Uran Plant**: The Uran plant receives offshore crude oil dispatched by offshore platforms and measures the quantum of crude oil received at its inlet point using Turbine Meters and Auto Samplers. The crude oil is stabilised at Uran plant in three stages where off-gas, basic sediment and water (BS&W) and condensate are separated. At the outlet of Uran plant, the crude oil dispatched is also measured using Turbine Meters.

  Uran plant maintains logs of crude oil receipt and water content in it. The data regarding crude oil received is noted from the HMI of Turbine Meter at Uran and recorded daily in a log sheet, from which Excel sheets are prepared and entered into SAP system manually. Unlike the offshore platform, the Uran plant maintains electronic logs in the HMI system for previous three months. Apart from this, the physical log details are also maintained for previous three years. The lab register records manually the water cut and density of crude oil received. The crude oil receipt at Uran plant is calculated after adjusting the water cut from the crude oil

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3 Turbine Meter is a primary device of Electronic Liquid Measurement System. In operation rotating blades generate frequency signal proportion to liquid flow rate which is sensed by the magnetic pick up and transferred to real time indicator.

4 Auto Samplers are samplers installed inline in the downstream of Turbine Meters to collect samples of liquid at regular intervals. Samples so collected are tested at laboratory to determine the water content in crude oil.

5 HMI is the tertiary device forming part of Electronic Liquid measurement system. It is a flow computer receiving information from Primary device (Turbine Meter) and secondary devices measuring Temperature, Pressure and Density; Using the programme instructions it calculates the quantity of liquid flowing through the Turbine Meters.

measurement. The gas separated in CSU (off-gas) is calculated using a standard formula of Gas-Oil ratio of 13:1. The water drained in intermediate and main storage tanks are not metered, but measured based on dips. At Uran outlet, physical log sheets of stabilised crude pumped to Trombay Terminal and Jawaharlal Nehru Port Trust (JNPT) is maintained.

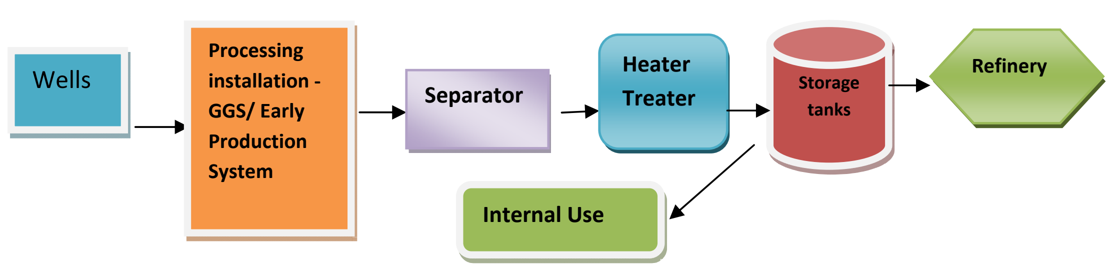
- **Trombay Terminal/JNPT (custody transfer point):** The sale of stabilised crude oil to refineries is measured at Trombay Terminal and JNPT using ultrasonic and Turbine Meters respectively for which electronic and physical logs are maintained.

2.2. Onshore areas

2.2.1. Production of crude oil in Onshore areas

Emulsion[6] along with associated gas produced from the wells is collected at processing installations - Group Gathering Stations (GGS)/Early Production systems (EPS) through flow lines/tankers. The liquid[7], so received at GGS/EPS, is processed through a separator where liquid and gas are separated. The separated liquid (emulsion) is stored in tanks and after stabilisation, free water is drained out. The emulsion is transported to the designated processing installation for GGS/EPS without processing facility. The processing installations will process the emulsion through Heater Treater[8] by adding demulsifier[9] to separate water and crude oil. The separated crude oil is stored in oil tanks at the respective processing installation and after stabilisation, further free water, if any, is drained out and crude oil with desired quantum (0.2 *per cent*) of basic sediment and water (BS&W) is dispatched to refineries through trunk pipelines.

Figure-3: Production of Onshore crude oil



[6] Emulsion is crude oil inclusive of water

[7] Water, Oil and Gas

[8] Heater Treater removes emulsified liquids and solids from crude and also use heat and pressure drop to flash volatile vapours.

[9] Demulsifier is a chemical used in the heater treater to separate water from oil.

2.2.2. Measurement of crude oil at onshore Assets

Crude oil is measured at the processing installations and collated at the base office of the respective Assets.

- **Processing installations:** The onshore processing installations, *viz.,* Group Gathering Station, Central Tank Facility and Desalter Plants maintain log books/ Daily production report (DPR). The measurement of crude is done through tank dips, Mass Flow Meters (MFM) and Supervisory Control and Data Acquisition (SCADA) at the processing facilities. For ascertaining the volume of liquid in a tank, calibration charts of tanks are used. The water cut is ascertained based on lab test. The crude measurement and water cut are recorded in physical logs which are then manually entered into the SAP system.

- **Base office:** The Base office of the Asset collates the information from all processing installations in the Asset and prepares the Daily Production Report for the Asset. The quantum of crude oil so recorded is reported as the production of the onshore Asset.

2.3. Audit findings

Audit findings are discussed in subsequent chapters under the following headings:

Chapter 3: Audit Findings on Measurement and Reporting in Offshore Assets

Chapter 4: Audit Findings on Measurement and Reporting in Onshore Assets

Chapter 5: Impact Assessment

Chapter 6: Conclusion and Recommendations

Chapter 3
Audit Findings on Measurement and Reporting in Offshore Assets

The three Western Offshore Assets of ONGC (Mumbai High, Neelam Heera, Bassein & Satellite) account for nearly the entire offshore production of crude oil. Audit observed the following issues in the crude oil measurement and reporting systems in the Western Offshore Assets:

3.1. Reporting of 'condensate' as crude

ONGC included 'condensate' production in 'crude oil' production. 'Condensate' constituted 7.07 *percent* of the reported 'crude oil' production during the period from 2010-11 to 2014-15.

Section 3(b) of the PNG Rules 1959 and Section 2(e) Oil Industry (Development) Act, 1974 define 'crude oil' as *"petroleum in its natural state before it has been refined or otherwise treated but from which water and foreign substances have been extracted"*. 'Condensate', as defined by ONGC[10] is "*liquid hydrocarbons produced with natural gas, separated by cooling and other means*". 'Condensate' is thus, distinct from 'crude oil', by definition.

Besides, 'condensate' is produced from gas fields unlike 'crude oil' produced from oil fields. Not only is the production process of 'condensate' different, its utilisation in ONGC is also different from that of crude oil. While 'crude' oil is sold to refineries, 'condensate' is not sold and is used internally by the Company for manufacture of value added products.

Audit also noticed that the domestic Joint Ventures (in which ONGC has a participating share, e.g., JV operating the Tapti field) reported 'condensate' production separately.

International consultants, M/s DeGolyer and McNaughton (D&M), appointed by ONGC in 2011-12, had pointed out that 'condensate' is reported as a separate stream wherever there is a gas processing plant. Considering that ONGC has separate gas processing plants at Uran, Hazira and Gandhar, where its 'condensate' is received and processed, 'condensate' ought to have been reported as a separate stream.

Audit also noticed that whereas ONGC treats 'condensate' as natural gas while paying royalty to Government on its production, it reports 'condensate' as 'crude oil' production. By inclusion of condensate in crude oil production, Company had to bear an additional subsidy burden of ₹16331.96 crore as discussed in Para 5.2 A.

By definition, condensate is separate from crude oil. Production and utilisation of both products are also distinctly different. Company itself had admitted (July 2012) to the

[10] Annual Report of ONGC.

Ministry that condensate is not crude oil nor is it sold and requested for exclusion of condensate quantity from crude oil production (reckoned for under recovery burden).

Management/Ministry in reply (January/April 2016) stated that natural gas condensate is included in the crude oil production target fixed for the Company in the annual MoU signed with the Ministry of Petroleum and Natural Gas (MoPNG). Therefore, reporting is being done on like to like basis. Further, MoU parameters are under the purview of Task Force (constituted by Department of Public Enterprises (DPE) for negotiating MoU) and have been evolving over the years.

The reply of the Management/Ministry is not acceptable in view of the following:

(i) The Company had been reporting condensate production as a separate stream till 1989-90 and reporting condensate as crude oil production commenced only later.

(ii) The reply is also silent regarding non adherence of the Company to international reporting practices as well as the divergence of the Company's reporting practices vis-à-vis other domestic oil and gas companies.

3.2. 'Off-gas' reported as crude

Partially stabilised crude oil dispatched from the offshore platforms is stabilised at the Uran plant. At Uran, it is stabilized at the Crude Stabilisation Unit (CSU) which, *inter alia*, separates the dissolved gas in crude oil. This separated gas is the 'off gas' which is then added to gas stream. Inclusion of 'off gas' in the reported crude production has resulted in over reporting of crude oil production by the Company. During the period from 2010 to 2015, 'off gas' production accounted for one *per cent* of the reported crude oil production of the Company.

Audit also noticed that the Company pays royalty to the Government on 'off-gas' production at rates applicable for natural gas even though the quantum of production is included under crude oil production. By inclusion of off-gas quantity in crude oil production Company had to bear an additional subsidy burden of ₹ 2294.78 crore as discussed in Para 5.2 A. The additional payment of Performance Related Pay (PRP) to Company's employees by inclusion of off-gas quantity in reported crude oil production is discussed in Para 5.1.

Ministry stated (April 2016) that, had the processing facilities been available at the platform for complete stabilization, this gas would have been liberated at the platform and would have formed part of gas production and accordingly royalty was paid as gas. Management has also requested (January 2016) Audit to take up the issue with the Government for exclusion of CSU off-gas for determination of Company's share of under recoveries.

Ministry's reply is not acceptable, as in the absence of sufficient processing facilities at offshore, the partially stabilized crude inclusive of dissolved gas is despatched to Uran plant where off-gas is liberated during stabilization and added to gas stream and royalty is paid as 'gas' for this quantity of off-gas. Including the same in crude production has resulted in over reporting of crude oil production. As off-gas is reported as crude oil production, it adds to the Company's liability for sharing under-recoveries leading to higher burden of under recovery to be borne by the Company.

3.3. 'Basic Sediment and Water (BS&W)' reported as crude

Partially stabilised crude dispatched from offshore platforms and measured for reporting production of crude oil includes BS&W which is removed during the stabilisation process at Uran plant. During the period from 2010 to 2015, BS&W included in crude oil production accounted for 3.9 *per cent* of the reported crude oil production of the Company.

Section 3(b) of PNG Rules, 1959 and Section 2(e) of the Oil Industry (Development) Act, 1974 define crude oil as *"petroleum in its natural state before it has been refined or otherwise treated but from which <u>water and foreign substances have been extracted</u>"*. The Performance Contract[11] by which the Company sets crude oil production targets for individual Assets defined crude oil production as '*crude oil would include the portion of recoverable oil reserve that is produced and <u>delivered at the custody transfer/delivery meter</u>. It includes the quantity <u>after adjustment of Basic Sediment and Water (BS&W)</u>*'. At the custody transfer point (point of sale to refineries), the crude oil should have less than 0.2 *percent* of BS&W as per Crude Oil Sales Agreement signed by the Company with the refineries. Thus, the actual quantum of crude oil would be <u>after</u> adjustment of BS&W which has not been done by the Company in reporting production. Audit also noticed that the domestic Joint Ventures (where ONGC has participating interest, e.g., PMT-JV, Rava-JV, RJ-ON-90/1 JV) report production of crude oil excluding BS&W. The additional payment of Performance Related Pay (PRP) to Company's employees by inclusion of BS&W quantity in reported crude oil production is discussed in detail in Para 5.1.

Management/Ministry in reply (January 2016/April 2016) stated that complete processing/ stabilisation of crude oil is not practically feasible at offshore platforms, primarily because of space constraints. The partially stabilised crude is transported to land terminal for final processing to meet customer specification. Deduction made in crude oil production based on samples to compensate for free water and BS&W are not very accurate and leads to additional BS&W draining at Uran end. The methodology followed for reporting of production is with the objective of reporting production exclusive of BS&W. It was also highlighted that the definition of crude oil as per PNG Rules under Oilfields Regulation and Development Act is from the point of view of payment of royalty and these statutory provisions do not pertain to reporting requirement.

[11] Performance Contract is an annual contract signed by the Chief of Strategic Business Units (SBU) with the concerned Director. The performance evaluation of SBU is done based on actual achievement vis-à-vis target set for Key Performance Indicators. The methodology followed for evaluation of MoU signed by the ONGC with MoPNG is adopted for this purpose.

The reply of the Management/Ministry is not acceptable in view of the following:

(i) Though the reply asserts that the objective of the reporting methodology is to report crude oil production exclusive of BS&W, a significant quantum of BS&W is reported as crude oil production (accounting for 51,69,136 MT of reported crude oil production during the period from 2010 to 2015) which has contributed to over-reporting.

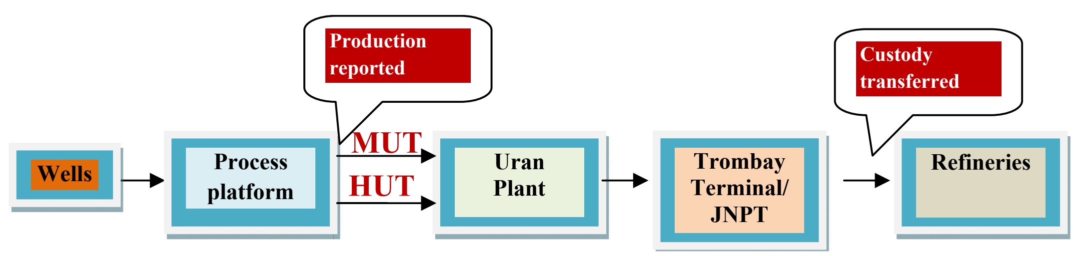
(ii) The crude oil production target fixed in the MoU signed with the Ministry does not indicate that crude production is inclusive of BS&W. In the absence of an alternate definition of crude oil for the purpose of reporting, the statutory definitions of crude oil (as per the OID Act and PNG Rules) ought to be applicable.

(iii) It is also pertinent to mention that the domestic JVs in which the Company is a partner, report crude oil production exclusive of BS&W. In fact, ONGC itself used to report crude oil production exclusive of BS&W till 1988-89 following which the process was changed. Even at present, crude oil production is reckoned excluding BS&W in the Company for high seas sale through FPSO. The reporting practice in the Company is thus inconsistent with its own practices as well as methodology followed by other oil and gas companies in the country.

3.4. Significant differences in reconciliation of crude oil

High seas sales of crude oil account for 7.90 *percent* of crude oil production from offshore areas with the balance transported through pipelines. Flow diagram of crude oil production and delivery in the pipeline sector of Mumbai offshore fields (with two major trunk lines, **MUT**: Mumbai Uran Trunk line and **HUT**: Heera Uran Trunk line) is depicted below:

Figure-4: Flow diagram of offshore crude oil production to sale point-pipeline sector



The difference in production quantity reported at the outlet of offshore platform and quantity sold at custody transfer point was examined in Audit. The results of analysis are given below:

Table-2: Reconciliation of pipeline sector of dry[12] crude oil at 15^{o}C

(in percent)

Sectors where differences were noticed	2010-11	2011-12	2012-13	2013-14	2014-15
Difference between quantity reported at outlet of offshore and receipt at Uran inlet	9.37	8.33	4.17	4.63	4.43
Difference between quantity reported at inlet of Uran and outlet at Uranrepresenting stabilization of crude oil	0.07	0.23	0.42	0.62	1.23
Difference between Uran outlet and custody transfer point	0.36	0.06	0.21	0.40	0.22
Total differences noticed	**9.80**	**8.62**	**4.80**	**5.65**	**5.88**

As seen from the table above, the overall differences which had reduced to 4.80 *per cent* in 2012-13 has since increased in 2013-14 and 2014-15. Audit also noticed that the differences in 2015-16 (upto August 2015) were 5.93 *per cent* which confirms the increasing trend. It is also seen that the most significant differences arise in the transport of crude oil from offshore platform to Uran plant through pipelines. In contrast, the processes at Uran plant lead to minor differences and transfer from Uran to custody transfer point results in insignificant differences in dry crude oil quantity.

Management/Ministry replied (January/April 2016) that the oil from offshore is not fully stabilized and also not free from emulsified water due to footprint constraints. De-emulsifiers get more retention time while oil travels from offshore to Uran via long subsea pipeline resulting in breakage of residual emulsion. Final phase of separation and stabilization is attained while processing at Uran. It was further stated that the reconciliation difference is a result of inaccuracies in water content measurement and metering and to overcome these inaccuracies Standard Operating Procedures (SOPs) on metering and measurement of crude oil has been prepared and issued to all offshore assets for implementation.

The reply of the Management/Ministry needs to be viewed in light of the following:

(i) The major quantity difference occurs during transport of crude oil from offshore platforms to Uran plant, in closed pipelines. In comparison, the quantity differences at Uran plant, where stabilization processes actually take place, are minor.

(ii) In view of the very significant reconciliation difference, Audit tried to ascertain efforts taken by the Management for review and corrective action. In response, Uran plant and Assets stated that such reconciliation meetings are held on need basis but minutes of such meetings are usually not issued

[12] In case of offshore crude oil production dry crude oil denotes wet crude oil dispatched from offshore to Uran adjusted for water count in wet crude oil based on laboratory test done at offshore.

and are not available. In the absence of records, Audit could not ascertain the reasons for differences nor draw assurance that adequate steps were being taken by the Company for corrective action.

(iii) Management has accepted that metering and measurement of crude oil and water content has been inaccurate and assured that SOPs have been prepared for corrective action. The action of the Management would be reviewed in future audits.

3.5. Differences in reconciliation for pipeline transfer between offshore fields and Uran

Audit carried out detailed analysis of reconciliation of differences in the light of significant differences during transfer of crude oil between offshore platforms and Uran plant. It was noticed that the offshore platforms and Uran inlet are connected through closed subsea pipelines, viz., Mumbai Uran Trunk line (MUT) and Heera Uran Trunk line (HUT) line. Since the transfer is through a closed pipeline system, it is expected that the quantity of fluid (Crude+water+dissolved gas) dispatched from offshore and that received at Uran should tally. The monthly dispatch through Mumbai Uran Trunk line (MUT) and Heera Uran Trunk line (HUT) for one-year period from August 2014 to August 2015 was analyzed in audit. The results of analysis are tabulated below:

Table-3: Differences in wet crude oil receipt and dispatch

(in cubic meters at temperature of 15^{o} Celsius)

Date	MUT				HUT			
	Offshore dispatch	Uran receipt	Difference		Offshore dispatch	Uran receipt	Difference	
	M^3	M^3	M^3	%	M^3	M^3	M^3	%
Aug-14	8,25,342	7,96,378	28,964	**3.51**	5,99,031	5,83,439	15,592	**2.60**
Sep-14	8,05,575	7,66,011	39,564	**4.91**	5,85,175	5,66,894	18,281	**3.12**
Oct-14	8,05,054	7,69,406	35,648	**4.43**	6,01,074	5,81,127	19,947	**3.32**
Nov-14	8,08,756	7,72,783	35,973	**4.45**	5,93,772	5,70,678	23,094	**3.89**
Dec-14	7,43,409	7,14,455	28,954	**3.89**	5,81,010	5,57,305	23,705	**4.08**
Jan-15	8,35,592	7,96,061	39,531	**4.73**	5,90,262	5,68,646	21,616	**3.66**
Feb-15	7,67,818	7,35,974	31,844	**4.15**	5,28,355	5,08,708	19,647	**3.72**
Mar-15	8,61,441	8,22,608	38,833	**4.51**	5,52,189	5,31,392	20,797	**3.77**
Apr. 15	8,23,367	7,91,660	31,707	**3.85**	4,67,987	4,57,361	10,626	**2.27**
May-15	8,49,233	8,09,459	39,774	**4.68**	5,44,778	5,23,463	21,315	**3.91**
Jun-15	8,55,317	8,11,114	44,203	**5.17**	5,13,798	5,06,394	7,404	**1.44**
Jul-15	10,46,719	9,96,539	50,180	**4.79**	3,77,988	3,66,974	11,014	**2.91**
Aug-15	10,40,076	9,79,540	60,536	**5.82**	3,88,857	3,87,779	1,078	**0.28**
Average	**1,10,67,699**	**1,05,61,988**	**5,05,711**	**4.57**	**69,24,276**	**67,10,160**	**2,14,116**	**3.09**

As seen from the table above, there was an average difference of 4.57 *per cent* (MUT) and 3.09 *per cent* (HUT) between quantity dispatched and quantity received. It was also seen that the quantity reported at the offshore process platform were consistently higher than that reported at Uran inlet. Considering that measurements at both ends (offshore outlet and Uran inlet) were done at identical conditions of temperature (15^{o}C), and the fluid travelled in a closed pipeline, such significant differences were not expected.

The American Petroleum Institute (API) standard 2560 on "Reconciliation of Liquid Pipeline Quantities" states that for pipeline systems, '*there is* ***no actual physical gain or loss,*** *just simply small measurement inaccuracies (a fraction of percentage) and is caused by small imperfections in a number of measurements in the system'*. The standard also states that '*most pipeline systems typically experience some degree of loss or gain over time representing normal loss/gain performance for a system. However, such loss/gain should be monitored for any given system at regular intervals to establish what is normal for that system and to identify any abnormal loss/ gain so that corrective action can be taken'*. The standard, thus, asserts that changes in quantity due to pipeline transfers are not expected and in case of differences, their cause ought to be analysed to identify whether it is abnormal and corrective action taken. In the instant case, the differences noticed are of the order of 3 to 4.5 *per cent* as against the fraction of a percentage difference expected as per the standard and hence abnormal. Considering the significant difference between the dispatch and receipt quantity, it is imperative that proper controls and monitoring is in place. API standards suggest that such differences in pipeline quantities could be due to *leakages, manual error in recording data or machine errors*.

Mumbai High and Neelam Heera Assets confirmed that there were no reported leakages of subsea trunk lines during the period of audit. The calibrations of meters were also checked by Audit and its impact was not found significant enough to explain the wide and consistent variations noticed. Human error is thus likely to be a reason for the un-explained differences in quantity.

Management in reply (January 2016) stated that:

(i) The API standard 2560 is not intended for non-liquid or mixed phase system. MUT and HUT pipelines are not single phase flow because of liberation of some gases between offshore and Uran over the 200 kms long pipeline. The API standard does not establish industry standards for loss/gain level because each system is unique and exhibits its own loss/gain level and/or patterns under normal operating conditions.

(ii) Minor meter imbalances or recurring hourly shortages/overages can be the result of pipeline pressure change, product interfaces, seasonal temperature changes, evaporation and volume shrinkage and thus, reasons for variation cannot be fully attributed to human error and machine error, as concluded by Audit.

The reply of Management needs to be viewed in the context of the following:

(i) The contention of the Management that transportation in MUT and HUT pipelines is not a single phase flow because of liberation of gases between offshore and Uran is not accurate. Management had appointed a consultant M/s IHRDC, Boston, USA (IHRDC) in October 2003 to study the reconciliation differences who had concluded that '*the crude oil in the offshore pipelines is above its bubble point at all times between the offshore and onshore meters. Break-out of gas cannot occur and therefore is not a factor in metering discrepancies and there is no product phase change between the meters'*.

(ii) Management has explained the reasons for minor differences between pipeline dispatch and receipt. However, the actual differences noticed are significant at 3 to 4.5 *percent*.

Ministry added (April 2016) that typical accuracy ranges for various metering purposes vary as per requirement and the metering at platform is mainly for production operations and not custody transfer grade. Ministry also pointed out that as per IHRDC, typical accuracy range for production purposes ranges at +/- 5 *per cent*.

The reply of the Ministry is not tenable. The typical accuracy range of +/- 5 *percent* quoted in the response, was suggested by IHRDC in its report of 2003, when the temperature at which measurement was recorded at both ends of the pipeline (offshore outlet and Uran inlet) was different. IHRDC had in fact recommended that, if temperature compensation is applied and meters were proved (calibrated), then differences ought to be within a percentage point or two. Presently volumes are measured at standard temperature (15^{o} C) at both ends (offshore despatch/Uran inlet) and thus the differences are expected to be much lower than the quoted +/- 5 *percent*. It is also pertinent to mention that for all days of the year (August 2014 to August 2015), there was a short receipt of crude oil at Uran when compared with the dispatch from offshore (not +/- scenario as suggested in the response).

The consistent losses, noticed during transportation of crude oil in a closed pipeline cannot be explained as typical inaccuracy of metering. Besides, the differences arising in the pipeline sector are significant; there being a difference of 7,19,827 cubic meters of reported crude oil production during transportation in the MUT and HUT pipelines for a year (August 2014-August 2015) alone.

3.6. Measurement of crude oil at offshore platforms

At the offshore platforms, measurement of quantity of crude oil dispatched is done using Turbine Meters and Auto Samplers. While Turbine Meters measure the quantity of partially stabilized crude (wet crude) pumped into the pipelines (MUT and HUT), the Auto Samplers measure the water content in the crude. To arrive at the actual quantity of crude oil dispatched (dry crude), the wet crude has to be adjusted for the water content. The cumulative quantity of dry crude dispatched from offshore platforms is reported as production of crude oil by the Company.

A. Non-availability of electronic/physical logs/records relating to measurement of wet crude by Turbine Meters at Offshore platforms

As already highlighted in Para 3.5, the wet crude measured at offshore platforms is consistently higher than the receipt at Uran inlet. Measurement at both ends is done using Turbine Meters (TMs). The measured quantity of wet crude by TMs is displayed by the Human Machine Interface (HMI) system on a real time basis. The readings from HMI is then read manually every day at 6.00 am and an Excel sheet containing the daily production details is prepared and manually entered in the SAP system. The standard volume[13] is taken from HMI and SAP uses a preset formula for final calculation of dry crude oil (based on water cut as measured by the Auto Samplers and density as reported by offshore lab) which is considered for reporting purposes.

Audit observed that electronic/physical logs/records of production data is not maintained at offshore and hence no audit trails were available to verify the correctness and integrity of data manually read from the HMI. While the flow computers have provision for storing logs for a period of 35 days, storing data for a longer period was possible by linking the flow computers with HMI with limited modifications. Audit observed that this was done at Uran plant where crude oil receipt data is maintained on hourly/daily/monthly basis for a minimum period of ninety days. Besides, the production data from HMIs is recorded in daily log sheets, maintained manually. Thus audit trails both electronic and physical, existed at Uran inlet. Audit test checked the records maintained at Uran end for the period January to August 2015 against electronic logs of HMI, physical daily log sheets, tank logs and SAP data and found them tallying. In the absence of logs/ audit trail for offshore dispatch quantity, reasonable assurance regarding accuracy of the recorded production figures at offshore could not be obtained by Audit.

Management in reply stated (January 2016) that subsequent to audit observations, necessary modifications and up-gradation of software in flow computers and HMI has been taken up at both Mumbai High and Neelam Heera Assets. Management also informed that post modification, back up of data would be available for over six months for Neelam Heera and longer periods for Mumbai High. Management also assured that post up-gradation, all the relevant audit trails will be available in the system. Ministry further stated (April 2016) that steps were being taken to integrate SCADA system with ICE SAP-ERP to address the issues brought out by Audit.

Audit has noted the corrective action taken by the Management and it will be verified during future audits.

[13] Volume at 15 degree Celsius /60 degreeFahrenheit

B. Differences in measurement of water content by Auto Samplers at offshore platforms

The water content in the partially stabilized 'wet' crude dispatched from the offshore platforms is measured by taking periodic samples of the 'wet' crude from the Auto Samplers and testing these samples chemically for water content at the offshore laboratory. An identical measurement process is followed at Uran plant where the water content at Uran inlet is measured based on Auto Samplers installed there. The net quantity, after adjusting the water cut is recorded as 'dry' crude dispatched and received at offshore and Uran respectively.

Audit noticed that the water content in the crude oil measured at receipt end (Uran inlet) has been **consistently higher** than that measured at the dispatch end (offshore platforms) during the period January 2015 to August 2015 as can be seen from the table below:

Table-4: Water cut in crude oil at offshore and Uran
Water Cut (WC) expressed as percentage of crude oil

Month, 2015	HUT pipeline (in per cent)				MUT pipeline (in per cent)			
	WC at Offshore	WC at Uran	Diff.	Diff. in %	WC at Offshore	WC at Uran	Diff.	Diff. in %
January	2.26	3.70	1.44	63.27	2.35	2.56	0.21	8.94
February	2.58	4.02	1.44	55.81	2.05	2.64	0.59	28.78
March	2.53	3.98	1.45	57.31	2.00	2.92	0.92	46.00
April	2.94	4.98	2.04	69.39	1.96	3.15	1.19	60.71
May	2.10	4.59	2.49	119.05	2.01	3.11	1.10	54.73
June	2.69	4.95	2.26	84.01	2.06	2.52	0.46	22.33
July	1.97	3.16	1.19	60.41	2.40	3.19	0.79	32.92
August	2.59	3.53	0.94	36.29	2.32	3.54	1.22	52.59
Average difference			**1.65**	**68.19**			**0.81**	**38.37**

As seen from the table, the discrepancy between the two measurements (at offshore and Uran) was as high as 68 *per cent* on an average for HUT pipeline (ranging between 36 to 119 per cent). The differences for MUT pipeline were slightly lower at an average of 38 *per cent* (ranging between 9 to 61 per cent).

Audit also noticed that there were problems in the functioning of Auto Samplers at both Mumbai High and Neelam Heera offshore Assets. The Mumbai High Asset (in 2012) cited frequent malfunctioning of Auto Samplers. Auto Sampler in Neelam platform did not function from September 2014 to October 2014 while the Auto Sampler in Heera platform was non-functional from November 2014 to January 2015. In the absence of Auto Sampler, the Asset resorts to manual sampling as the Company does not have a standby philosophy for Auto Samplers (unlike Turbine Meters). The consistent differences between the water cut measured at both ends of the closed pipeline point to problems in the functioning of the Auto Sampler.

Management in reply (January 2016) stated the following:

(i) The fields are ageing ones and water cut in the well fluid has increased considerably with present average water cut being more than 70 *per cent*. The partially stabilised crude contains water in emulsion and the average residence time may not be sufficient to completely break the oil-water emulsion, reducing water content to refinery standards before dispatch from offshore. During transportation of crude oil from offshore platform to Uran, crude oil gets high residence time in the pipeline because of its large volume (200 KM pipeline) and consequent large reaction time for emulsion to break and free water to segregate in the pipeline. Hence there is compositional difference in the form of pure oil-free water at receiving end at Uran when compared to offshore end.

(ii) The Auto Sampler, though the best way of collecting representative samples, has some limitations, especially in cases where there is a sharp variation in the fluid composition on account of plant/ processing disturbance.

(iii) In spite of having the most advanced technology for capturing representative sample both at offshore and Uran end for determination of water cut, the differences in water cut have arisen due to inevitable technical reasons.

Ministry further added (April 2016) that SOP on metering and measurementof crude oil have been prepared and issued by all offshore assets.

The reply of the Management needs to be viewed in the following context:

(i) The discrepancy in water cut recorded at offshore and Uran, had been noticed earlier when the Company had appointed a consultant, M/s IHRDC in 2003 to study these differences. The external consultant (M/s IHRDC) in its report (October 2003), had concluded that "*if representative samples are taken both at offshore and onshore locations,* ***their readings must be very close to each other regardless of flow velocities and length of these lines****. The consistent trend of discrepancy points to unrepresentative sampling"*.

(ii) The report (of M/s IHRDC) had also concluded that *"****regardless of the type of water (free or emulsified) present, the water measurement at the end of the closed pipeline should match over longer period of time****. The consistent discrepancy between these two measurements makes us question the sampling points and techniques used both at offshore and onshore facilities"*.

(iii) The Mumbai High Asset had pointed to malfunctioning of Auto Sampler at offshore end as contributing to incorrect reporting of water cut in crude dispatched from the Asset.

As admitted by the Management, the present measuring system has limitations/ inaccuracies. The implementation of the Standard Operating Procedures for metering and measurement, assured by Management in reply, would be reviewed in future audits.

C. Non-adherence to calibration schedule of Turbine Meters

The correctness of the measurement is dependent on the accuracy of the measuring equipment. Audit examined the steps taken to ensure accuracy of the Turbine Meters (TMs) installed at offshore platforms (dispatch) and at Uran (receipt). The Neelam Heera and Mumbai High Assets informed that OEM[14] does not prescribe any calibration schedule for TMs but a calibration frequency of two years is followed by the Asset. Uran plant management also informed that the same calibration frequency of two years is adhered to. Management of the Assets further informed that OEM had recommended Turbine Meters to be inspected every three to five years unless measurement anomalies occur and assured Audit that OEM's recommendations were being followed.

Audit observed that while Mumbai High Asset carried out calibration on a regular basis, Neelam Heera Asset has not followed the laid down frequency of two years for calibration of TMs. Out of four TMs installed in the Asset, three had been calibrated after a gap of 4 to 5 years and the balance TM installed in Neelam process complex in November 2008 is yet to be calibrated (January 2016).

Management in reply (January 2016) stated that the execution of Neelam Heera Reconstruction Project led to delay in calibration of meters in Neelam Heera Asset. Ministry also assured (April 2016) that action for calibration of the balance meter has since been initiated.

The assurance of Management/ Ministry will be verified in future audits. It is also stressed that timely calibration of Turbine Meters is necessary for accurate measurement of crude oil.

[14] OEM - Original Equipment Manufacturer

Chapter 4
Audit Findings on Measurement and Reporting in Onshore Assets

4.1. Inconsistency in measurement procedures

Measurement and reporting system of six onshore Assets were reviewed in Audit (Ankleshwar, Ahmedabad, Mehsana, Assam, Rajahmundry and Cauvery). The Assets accounted for nearly the entire onshore oil production in ONGC. During the period of Audit (2010-2015), there was no standard operating procedure for measurement of crude oil in onshore Assets. As such, different Assets measured production at different points of the value chain using different measurement techniques for the purpose.

Audit observed the following disparities in Western onshore region:

In Ankleshwar Asset, crude oil production was measured through tank-dip at the storage tanks from which crude oil is dispatched to the refineries. Thus measurement of crude oil production was after completion of all processing activities in Ankleshwar. In Mehsana Asset, however, crude oil production was measured using mass flow meters at the inlet of the Central Tank Farm (CTF), before the crude oil was processed in the CTF.

The point of measurement was important as the quantity of liquid would necessarily measure higher before processing than after removal of water and impurities. The method of measurement and the equipment used for the purpose was also important for standard measurement of production quantity. Audit observed need for standardising the measurement process in this regard in ONGC.

Management/Ministry stated in reply (January/April 2016) that a corporate standard operating procedure (SOP) for crude oil measurement at onshore Assets have been issued and Asset specific SOPs based on corporate SOPs have been prepared and issued.

Implementation of SOPs for crude oil measurement in onshore Assets would be verified in future Audits.

4.2. Mismatch between reported and measured quantity of crude oil in Western Onshore Assets

The processing installations of an Asset maintain log books and daily production records for crude oil production which are sent to the base office of the Asset. The base office of the Asset collates the production data of all processing installations to generate the Daily Production Report (DPR) of the entire Asset. The Asset DPRs are consolidated at the corporate level. Audit checked the different sets of crude production records at three Western onshore Assets (physical logs maintained at processing installations, production data communicated by processing installations to base office, production data reported by the base office of the Asset and the production data of the Asset as recorded in the corporate level statement) and noticed the following discrepancies:

A. **Ankleshwar Asset:** In Ankleshwar Asset, the processing installations maintained physical logbooks recording the production data which were used for preparation of DPR at the processing installations. These installation DPRs are communicated to the base office of the Asset, daily before 8.00 AM. Audit noticed that the DPR of the processing installations (transmitted to base office and incorporated in the corporate level production data) was much higher compared to the data maintained in the physical log books recording actual production. The difference between the reported production (as per DPR of the asset) and the actual production recorded in the log books maintained at the processing installations, over the period 2010-11 to 2014-15 was **6,63,406 MT** (10.66 *percent* of the reported production of the Asset). The specific details are at Annexure I.

B. **Ahmedabad Asset:** The production figures reported by the base office of the Asset (incorporated in the corporate level production data) were much higher than the production data that was communicated by processing facilities to the base office. Audit noticed that the data communicated by the processing facilities tallied with the physical log books maintained at these facilities. However, there were differences between the figures pertaining to the facilities reported by the base office to the corporate office. The difference between the reported production (as reported by base office to corporate level) and the actual production as seen from the log books maintained at the processing installations, over the period 2010-11 to 2014-15 was **3,75,765 MT** (5.02 *percent* of the reported production of the Asset). The specific details are at Annexure I.

C. **Mehsana Asset:** In Mehsana Asset, the technical cell at the Asset base reported calculated production data to corporate office. The calculation was done on the basis of fluid received at Mehsana Central Tank Farm. Mehsana Asset also worked out the actual production based on processed crude obtained at the outlet of the processing facility, adjusted for actual water drained. Audit noticed that the calculated production data reported by the Asset (and incorporated in the corporate level production data) was higher than the actual production quantity recorded by the Asset. The difference between the reported production (as reported by base office to corporate level) and the actual production over the period 2010-11 to 2014-15 was **2,62,810 MT** (2.29 *percent* of the reported production of the Asset). The specific details are at Annexure I.

Management/Ministry in reply (January/April 2016) accepted the audit observations and assured that a host of corrective measures have been set in motion with all stringency. Management also stated that these actions namely forward reporting, withdrawal of authorization at the base stations, uniformity of reporting time, strict monitoring and total reporting based on SAP system (legacy system has been done away) are yielding desired results.

Audit has noted the Management/Ministry reply and will verify the position in the course of future audits.

4.3. Lack of asset specific norms to determine recoverable crude oil used for internal consumption

Producing wells may become sick over a period and need to be repaired through work over operations. The process of work over operation require hot oil circulation (HOC)/ squeezing job in the well. Crude oil produced is used for the HOC/squeezing job. A significant portion of this crude is recoverable and would form part of future production from the repaired well.

Audit however noted that production installations accounted the crude oil used for HOC/squeezing jobs as "internal consumption" without indicating the possibility of future recovery of the oil, thus over-stating production.

Review of the records of onshore Assets revealed that Ankleshwar, Ahmedabad and Assam Assets depict the entire usage of crude oil for HOC/squeezing jobs as internal consumption and do not provide for any 'recoverable' component (details in **Annexure II**). Besides, no Asset specific norms have been prescribed to determine 'recoverable' component of the crude oil used for HOC/ squeezing jobs.

Management in reply (January 2016) stated that though theoretically, most of crude oil used for HOC should return back to the installation where that well is flowing, this is not practically the case. Amount of crude oil returned depends on a number of factors (permeability and pressure of reservoir, distance of well from installation, depth, revival, type of wells, etc.) and hence it is difficult to anticipate quantity of recoverable crude oil, being a field specific phenomenon. Ministry assured (April 2016) that the Asset specific SOPs now implemented, will be addressing the issue.

Ministry has accepted the audit observation and initiated corrective action. The actual implementation of corrective action will be reviewed in future audits.

4.4. Accounting of Pit oil stock as crude oil production

Ahmedabad Asset had recognised **1,34,794 MT** of crude oil as pit oil[15] stock in the closing stock of crude oil for the year 2009-10 (which had accumulated over the period, 2006-07 to 2009-10). The Asset, however, did not consider this pit oil stock for stock valuation in its books of accounts. Subsequently, the Asset accounted a loss of 14,183

[15] In an effort to realise production from exploratory wells expeditiously such wells are often flogged to make shift pits at well sites during initial testing. Oil recovered from effluents was also often stored in wash tanks prior to being recovered. Also during period of high stock due to less evacuation of refineries excess oil is stored in available storage like wash tanks /effluent tanks. The oil which is not stored in crude oil tanks and does not appear in tank stock statement of the Asset is referred to as pit oil.

MT and 10,615 MT during the years 2010-11 and 2011-12 respectively due to bio-remediation[16] and reduced it from the pit stock of those years. Later, the Asset reduced a further quantity of 39,000 MT in 2012-13 from the closing stock of pit oil stating that the said quantity had already been recovered from the pit stock at the Desalter Plant, wash tanks and CTF Nawagam during the years 2009-10 to 2012-13. The Asset has finally written off the balance quantity of 70,746 MT in the year 2014-15.

Management/Ministry in reply (January/ April 2016) stated that the matter has already been intimated to Audit & Ethics Committee and ONGC Board on 14 February 2015 and that pit stock has been corrected as per the Board decision. Management also assured that, at present, there is no pit stock in Ahmedabad Asset.

The corrective action would be verified during future audits.

4.5. BS&W and free water drained after reporting crude oil production

Audit noticed that during the period from 2010-11 to 2014-15, 523,338 MT of BS&W and free water had been removed from crude oil in Ankleshwar and Mehsana Assets, after production had been measured and before custody transfer of crude to refinery. It was noticed that a significant quantum of BS&W and free water had to be removed at the refinery end before custody transfer. In onshore Assets, crude oil production is mostly measured after processing and before its dispatch to refineries. Such quantity was expected to contain less than 0.2 *percent* of BS&W. It was however seen that Ankleshwar, Rajahmundry and Cauvery Assets have reported high water drainage at the refinery end as shown in the table below:

Table-5: Free water and BS&W drained at refinery end

Asset	Free water and BS&W drained at refinery end	Percentage of free water and BS&W in the dispatch quantity
Ankleshwar	49,835 MT	0.92 %
Cauvery	11,195 MT	0.95 %
Rajahmundry	15,385 MT	1.30 %

Such a high quantity of drainage of free water and BS&W, post reporting of production quantity of crude oil from these Assets has contributed to overstatement of crude production of these Assets.

Management/Ministry in reply (January/April 2016) stated that high BS&W losses were partially on account of higher water cut, due to lack of adequate processing facilities/ handling facilities at all the installations resulting in dispatch of high BS&W crude oil to the refinery where it is given some more retention time to drain excess/free water before custody transfer. In case of Rajahmundry Asset, Management stated that the BS&W

[16] Bio remediation is the process of naturally/deliberately introducing micro-organisms to consume and break down environmental pollutants in order to clean a polluted site.

figures included transit losses and assured that corrective action to report BS&W and transit losses separately would be taken in 2015-16.

Management also stated that the high BS&W was partially reported to adjust wrongly reported production in Ankleshwar. Management assured that the matter has been considered by the Audit & Ethics Committee and Board of ONGC and subsequently, control mechanism has been put in place to avoid occurrence of such incidents in future.

Ministry added (April 2016) that 0.20 *per cent* BS&W is excluding free water and accordingly it is maintained in the supply to refineries and steps have been taken to increase retention time at tanks by adding new tanks (by 2017) which will reduce considerably the water draining at refinery end.

The reply of the Management needs to be viewed in the following context:

(i) It is noted that the Management has initiated corrective action to avoid recurrence of over reporting in future by adjusting BS&W quantity, implementation of which will be reviewed in future audits.

(ii) It is however stressed that corrective SOPs would not address the inadequacy of processing facilities which lead to higher water content in processed crude or operational constraints in determining accurate water cut in reported crude oil production. Hence, a high quantum of BS&W may continue in the crude oil after the production reporting stage even with revised SOPs. Audit is of the opinion that this concern could be addressed by appropriately shifting the production reporting point to ensure that production of crude oil is reported after adjustment of BS&W.

4.6. Reporting water in closing stock of Assam and Ankleshwar Assets

A. **Ankleshwar Asset:** Audit observed that the Ankleshwar Asset over reported the crude oil production from 2007-08 onwards by filling the crude oil tanks with the effluent or water at the end of the year so as to match the actual closing stock of crude oil in different product tanks with the reported closing stock of crude oil. During the period from 2010-11 to 2014-15, the Ankleshwar Asset overstated the closing stock of crude to adjust a part of the over reported production of the Asset by **81,800 MT**.

Management accepted (January 2016) the observation and assured that appropriate action has been taken to prevent future cases of this nature.

B. **Assam Asset:** Test check of log books/DPR of Group Gathering Station-II of Rudrasagar field in Assam Asset, for the years 2013-14 and 2014-15, revealed that the closing stock (as on 31st March) was increased by 2699.54 MT (3139 M^3) during the period January to March and was subsequently decreased by draining water during the month of April. As a result the production of crude oil from this field was over reported by **2699.54 MT**.

By over reporting of closing stock, Company had to bear additional subsidy burden of ₹ 160.69 crore as discussed in Para 5.2.B.

Management in reply (January 2016) accepted the audit observation and assured that due care would be taken to avoid such incidents in future.

Ministry stated (April 2016) in reply that post audit observation, Assets have been sensitized of the issue and close monitoring of closingstock is being done to avoid recurrence of such incidents.

The assurance of Management/ Ministry would be watched in future audits.

4.7. Incorrect reporting of theft of crude oil in Ankleshwar for reconciliation

Crude oil from various fields in Ankleshwar Asset is collected at Central Tank Farm (CTF), Ankleshwar and further transported to IOCL Refinery, Koyali through a trunk pipeline. It was observed that on 18 February 2013, the said trunk pipeline was punctured by miscreants to steal crude. The security team of the Asset reached the site on the same day and seized the filled and empty barrels and cans and filed an FIR with the police for theft of 550 liters of crude oil. However, in the crude oil tally statement as on 31March 2013, the Asset indicated pipeline leakage of 3556 MT as against the reported theft of 550 litres. The excess reporting was done to reconcile the differences between reported production and sale of crude oil by the Asset.

Management accepted (January 2016) that the crude oil theft of 3556 MT was not a correct figure and the same was reported to adjust the over reported production of crude oil. Management/ Ministry (January/April 2016) also accepted the observation and stated that the Asset has been advised to avoid recurrence of such incidents.

4.8. Shortcomings in the measurement system of crude oil in onshore Assets

The measurement of crude oil in onshore systems is mainly carried out through tank dips in storage tanks of the Asset. The Company had also installed Supervisory Control and Data Acquisition (SCADA) system to allow for measurement of the crude oil quantity through electronic instruments without manual intervention and tampering as well as integration of acquired data with the IT system of the Company and SAP. Audit noticed a set of infirmities and shortcomings in the on land crude measurement system as detailed below.

4.8.1. Non-calibration of storage tanks in onshore Assets: Tank calibration is the process of accurately determining the capacity of a tank and expressing this capacity as a volume for a given linear increment or height of liquid. Tank calibration, tank inspection and certification of storage tanks at least once every five years was made mandatory by the Directorate of Legal Metrology. However, the calibration of the storage tanks was not carried out at the required frequency of five years. In cases where calibration was done, deficiencies were noticed as discussed below:

(A) Assam Asset: Audit noticed that most of the tanks in Assam Asset were commissioned during1970s and re-calibration of these storage tanks have not been carried out since their commissioning, i.e., even after 40 years. Cleaning of tanks was also not regular (with the exception of 14 tanks out of 120 in the Asset).

The Management replied (September 2015) that the contract for calibration of 63 tanks had been awarded in September 2015 to be executed for a period of three years. The reply has to be viewed in the context of non-adherence to the mandatory calibration schedule by the Asset.

(B) Southern Assets: Audit test checked calibration charts in four installations out of 36 in Rajahmundry Asset and Cauvery Asset. It was noticed that the tanks had not been re-calibrated since their commissioning.

(C) Western Onshore Assets: In Western onshore, Audit noticed that the re-calibration of tanks was not carried out every five years as per the prescribed norms.

Non-adherence to the scheduled calibration may result in incorrect reporting of crude oil quantity and reduce the credibility of measurement and reporting.

Management in reply (January 2016), accepted the audit observation and assured that steps had already been taken to increase the tankage, as well as repair and maintenance of out of service tanks and that annual rate contract/one time contract has been placed for repair and maintenance of tanks in Mehsana, Ankleshwar, Ahmedabad and Assam. Action taken by the Management would be examined during future audits.

4.8.2. Poor utilization of SCADA system:

The Company implemented the Supervisory Control and Data Acquisition (SCADA) system in March 2008 at a cost of ₹385 crore for measuring production and drilling parameters. SCADA system in onshore Assets was installed at Group Gathering Station (GGS), Early Production System (EPS), Crude Tank Farm (CTF) and Central Processing Facility (CPF).

Audit observed that though the Company had installed SCADA system in most onshore installations and gross volume of crude oil in tanks were being captured by the SCADA system, the same was not used in reporting production. Production continued to be measured by tank readings based on manual dips. In the case of Ankleshwar, even though the SCADA system was integrated with SAP, the Asset did not generate production reports based on SCADA readings.

Management/ Ministry accepted (January 2016/April 2016) the audit observation and stated that steps are being taken to integrate SCADA system with ICE SAP-ERP[17] to

[17] Information Consolidation for Efficiency through implementation of Enterprise Resource Planning, i.e., SAP Systems and other IT efforts.

address the issues brought out by Audit. The actual implementation of Management assurance will be verified in future audits.

4.8.3. Mismatch between data recorded in log book and SAP in Assam Asset

Crude oil production was manually measured by the Assam Asset (by tank dips) and entered in the log books of the processing installations. The same data was subsequently entered in the SAP-ERP system. A test check of the log books of production installations, and the SAP-ERP data revealed mismatches which raises doubts on the reliability of the crude oil production reported through the SAP system.

Management in reply (January 2016) stated that guidelines have been issued in September 2014 and corporate level SOPs for onshore Assets on metering and measurement of crude oil have also been issued. Besides, Assets have been advised to formulate Asset specific SOPs based on the corporate level SOPs. Managemental also assured that the measurement and reporting system had some identified inefficiencies which are being addressed in a continuous manner. Ministry stated (April 2016) that all the Onshore Assets have prepared Asset specific SOPs on crude oil measurement. The action taken would be verified during future audits.

4.8.4. Deficiency in using Production Revenue Accounting (PRA) system

The Company had implemented the PRA module in SAP-ERP system w.e.f. February 2010. The PRA system generates daily crude oil production reports (DPR) for a processing installation, based on data (quantity along with density, temperature and water cut) pertaining to closing stock of crude oil and crude oil dispatch from the installation. This forms the basis for the daily, monthly and annual production records in SAP. However, in Western onshore Assets, the data was not correctly fed into the PRA system. The DPR was generated manually, outside the PRA system, by the Asset Technical Cell. A test check of the SAP-DPR figures noticed variation with those reported in the manual DPR data. In Assam Asset and Southern Region, discrepancies were noticed among different reports generated in SAP which indicated different crude production figures.

Audit noticed that Director (Onshore) of the Company had directed (September 2011) that correct production figures should be entered in PRA system on daily basis within stipulated time, so that representative figures can be available to ONGC management through Business Intelligence (BI) module. However, the Production and Development Directorate (P&DD) of ONGC observed differences in the Asset reported figures and BI module figures for the first quarter of 2015-16.

Management in reply (January 2016) stated that the non-matching of data among different reports in Assam Asset was on account of wrong methodology adopted by the Asset and that corrective actions are being taken. Management/Ministry also stated (April 2016) that all Assets have been sensitized to report production data in PRA module. The corrective action taken by Management would be verified during future audits.

Chapter 5
Impact Assessment

5.1. Over payment of Performance Related Pay (PRP) due to over reporting crude oil production

Department of Public Enterprise (DPE) introduced (November 2008) payment of PRP as a variable pay directly linked to the profits of the CPSEs, the performance of the CPSE as well as that of the employees[18]**.** The performance of the CPSE is measured by its MoU (Memorandum of Understanding signed with the respective Ministry) rating. For a CPSE having 'excellent' rating, 100 *percent* of PRP is payable to its employees as against 80 *percent* for 'very good', 60 *percent* for 'good' and 40 *percent* for 'fair' rating.

Audit noticed that the Company was awarded 'excellent' rating during 2011-12 to 2013-14 and was awarded 'very good' in 2014-15. Crude oil production by the Company is a parameter for assessing its performance. It was seen that the Company failed to achieve the MoU target for crude oil production consistently during this period even though the reported crude oil production had been over-stated during these years by inclusion of BS&W and off-gas quantity (as mentioned at paras 3.1 and 3.2 of the report).

Audit reworked the MoU rating of the Company (**Annexure III**) considering the actual crude oil production (i.e. excluding BS&W and off-gas quantity) and observed that during the year, 2013-14, the score of the Company changed from 1.476 (Excellent rating) to 1.508 (Very Good rating). Hence, for 2013-14, the PRP applicable to employees should have been 80 *per cent* instead of the 100 per cent received by them. Considering Company's estimates of PRP payment under excellent rating of ₹854.67 crore, and the eligible amount of ₹748.16 crore (@ 80 per cent) under Very Good rating, the excess payment works out to ₹106.51 crore (approximately) on PRP payments for the financial year 2013-14.

Management replied (January 2016) that the actual production data is reported against target exactly in the same line and with same assumptions as are made while formulating the target. Management pointed out that in the MoU target, no adjustments of BS&W and off-gas was made in formulating the crude oil production targets. The same practice was followed in actual reporting too. Hence PRP has been paid by ONGC for the FY 2013-14 as per DPE guidelines.

The reply of the Management is not convincing in view of following:

(i) Crude oil production target for 2013-14 was fixed in the Task Force meeting held in February 2013. Audit noticed that the crude oil production target did not indicate

[18] Annual PRP amount = Component of PRP (60% from current profit and 40% from incremental profit)*Annual Basic Pay* **MoU Rating** (Excellent-100%, Very Good-80%, Good-60%, Fair-40%)*Grade Incentive (E0 to E3-40%, E4 to E5-50%, E6 to E7-60%, E8 to E9-70% and E-10-10%, Directors-150%, CMD-200%)* Executive Performance Rating*Ratio of required amount available to available amount.

that it was inclusive of BS&W and off-gas quantity. The MoU (2013-14) signed by the Company with the MoPNG on 25th March 2013 is also silent regarding inclusion of BS&W and off-gas in the crude oil production target. Audit noticed that the signed MoU indicated 'Annual Report 2013-14' as documentary evidence and source/origin of document for evaluation of performance of crude oil production target. There was no mention regarding BS&W and off-gas quantity being a part of crude oil production quantity in the Annual report of 2013-14.

(ii) Besides, with ageing of the Company's fields, BS&W quantity is progressively increasing. Inclusion of BS&W quantity in the crude oil production target or achievement would lead to erroneous target setting and reporting, with the quantum of error increasing consistently over time as BS&W quantity increases.

(iii) The MoU targets of the Company for crude oil production are distributed among the offshore and onshore Assets. The production targets of the individual Assets were fixed in the Performance Contracts signed by them with the Management. Audit noticed that these performance contracts defined crude oil production as *"crude oil would include the portion of recoverable oil reserve that is produced and delivered at the custody transfer/delivery meter. It includes the quantity after adjustment of Basic Sediment and Water (BS&W)"*. The JVs (in which the Company had a participating interest) also reported crude oil production exclusive of BS&W and off-gas quantity. This indicates that BS&W and off-gas is not intended for consideration as crude oil production within the Company as well as other domestic JVs.

(iv) Off-gas is a dissolved gas in partially stabilized crude oil dispatched from offshore and same is removed in Uran plant during processing and stabilization of crude oil and added to the gas production and sold as natural gas. As such, it should not have been reported as crude oil production.

5.2. Additional subsidy burden borne by the Company

A. Additional subsidy burden of ₹18626.74 crore due to over-statement of Crude Oil production by inclusion of condensate and off-gas

The upstream National Oil Companies (NOCs, viz., ONGC and OIL) shared the under-recovery of the Oil Marketing Companies (OMCs) arising from sale of refined petroleum products at subsidized rates since October 2003. The methodology for determination of subsidy share of upstream NOCs during the period from 2003 to 2011, did not refer to the actual production of crude oil by these companies. MoPNG, by its order dated 9 January 2012, revised the subsidy sharing methodology. As per the revised system, the subsidy burden of an NOC would be based on its crude oil production (less basic sediment and water, internal consumption and transit loss). Subsidy share of ONGC for the period 2011-12 to 2014-15 (upto September 2014) has been worked out based on the following formula:

USD56 per barrel x Reported crude oil production measured in barrels

For the third quarter of 2014-15 (October to December 2014), the subsidy rate was revised to USD 37.50 per barrel which further reduced to 'nil' in the last quarter (January to March 2015) in view of the falling international crude oil prices.

The Company had to bear a larger share of subsidy due to overstatement of reported crude oil production by inclusion of condensate and off-gas (7.06 *per cent* of condensate and 1 *per cent* of off-gas). The additional subsidy burden borne by the Company was ₹18626.74 crore (*i.e.*, ₹16331.96 crore on account of inclusion of condensate and ₹2294.78 crore on account of inclusion of off-gas in crude oil production) during the period from 2011-12 to 2014-15 (**Annexure-IV**).

Management/Ministry replied (January/April 2016) as follows:

(i) The significant implication of inclusion of condensate for determination of ONGC's share of under-recoveries has been taken up with the Government. ONGC had appealed to Government that in future only crude oil quantity be considered for determination of ONGC's share of under-recoveries and quantity of gas condensate may not be included, as it is neither crude oil nor is it sold. It has also been informed that the issue of exclusion of condensate has been taken up by ONGC with MoP&NG/MoF at various level/forums over the period from October 2012 to May 2014.

(ii) The information regarding off-gas was provided by the Company as per the format made available by MoPNG/Petroleum Planning Analysis Cell. Since the off-gas quantity (though removed subsequently from the crude oil and added to gas stream) is included and reported in gross production of crude oil, the same is considered by Government for determination of ONGC's share of under-recoveries. Since Q3 of 2015-16 quantity of off gas has been shown separatelyin the crude tally statement submitted to MoPNG.

(iii) Government Audit may take up the issue with Government for exclusion of condensate and off-gas for determination of ONGC's share of under-recoveries.

The reply of the Management/Ministry only strengthens the Audit contention that 'condensate' and 'off-gas' ought not to be reported as 'crude oil' production.

(i) The Company had itself stated to the Government (July 2012) that 'condensate' is '*neither crude oil nor is it sold*'. Yet, the Company has been '*reporting production of crude oil inclusive of condensate right from 1990 onwards*'. It is this incorrect practice of reporting condensate as crude oil, even as the Company was aware of the difference of the two, that has led to the present situation of additional subsidy share on this account.

(ii) As the Company itself points out in reply, 'off-gas' is removed subsequently from the crude oil and added to gas stream. It is later sold as natural gas. As such, reporting 'off-gas' as crude production is incorrect. It is noticed that while the Company had taken up the matter regarding exclusion of 'condensate' for working out subsidy share, the issue regarding exclusion of 'off-gas' had not been raised with the Government (except showing it separately after the issue has been flagged in Audit).

The additional subsidy burden on condensate and off-gas quantity has arisen on account of reporting both items (which are not crude as acknowledged by the Company) as crude oil production.

B. **Excess sharing of subsidy burden of ₹160.69 crore due to over reporting of crude oil production**

The impact of excess subsidy borne by the Company in onshore areas due to over reporting of closing stock is detailed below:

- As discussed at Para 4.6-A, the Company over reported crude oil production in Ankleshwar Asset by way of reporting excess closing stock vis-a-vis actual, which resulted in avoidable payment of share of subsidy of ₹153.48 crore (**Annexure V**).

- As discussed at Para 4.6-B, the Assam Asset over reported crude oil production by 2699.54 MT (3139 M^3) which resulted in avoidable payment of share of subsidy of ₹7.21 crore. (**Annexure-V**)

Management agreed (January 2016) with the audit observation on over reporting of closing stock crude oil production and stated that closing stock was corrected in January 2015. In respect of Assam Asset, Management has accepted the audit observation and assured that due care would be taken to avoid such incidents in future. Ministry added (April 2016) that post audit observation, Assets have been sensitized of the issue and close monitoring of closing stock is being done to avoid recurrence of such incidence.

Audit has noted the corrective action taken by the Management subsequently.

Chapter 6
Conclusion and Recommendations

6.1. Conclusion

ONGC is the largest producer of crude oil, accounting for 69 *per cent* of the country's production. Significant efforts and resources of the Company are deployed for augmenting production of crude oil from its offshore and onshore Assets. Accurate measurement and reporting of crude oil production by the Company is of critical importance to assess and monitor its performance.

Audit of the crude oil measurement and reporting system indicated that the Company was reporting partially stabilized crude oil as its crude oil production. This led to over-reporting of crude production by including items other than crude oil, *namely*, off-gas, BS&W and recoverable internal consumption. At the same time, the Company has reported 'condensate' production inappropriately as crude oil production, though both products were distinct and treated differently by the Company. A summary of the over-reporting and incorrect reporting in onshore and offshore areas is given below:

Table-6: Reported crude oil production *vis-à-vis* actual production

FY	Unit	Crude Production reported by the Company (including Condensate) as per MoU (R)	Quantity of BS&W in R	Quantity of off-gas in R	Quantity of recoverable internal consumption in R	Over-statement of R	Quantity of Condensate incorrectly included in production - R
		1	2	3	4	5= 2+3+4	6
2010-11	MT	27282278	1455148	268103	29073	1752324	1955360
2011-12	MT	26925347	1373034	263813	26302	1663149	2008340
2012-13	MT	26127115	655562	259128	39507	954197	2109810
2013-14	MT	25994106	843520	263717	32122	1139359	1828311
2014-15	MT	25942270	841871	271136	29671	1142678	1446798
Total	**MT**	**132271116**	**5169135**	**1325897**	**156675**	**6651707**	**9348619**
Other items reported as crude expressed as a percentage of reported crude oil production			**3.91%**	**1%**	**0.12%**	**5.03%**	**7.07%**

As seen from the table above, 12.1 *per cent* of reported crude oil production consists of items other than crude oil. Of this, basic sediment and water (3.91 *per cent*) has no financial value at all. The over-reporting and incorrect reporting of crude oil production has presented an inaccurate picture of performance of the Company on crude oil production and has led to the Company sharing an additional subsidy burden of ₹18,787.43 crore during the year from 2012 to 2015. Besides, over-reporting of crude oil production (inclusion of BS&W and off-gas) resulted in over payment of performance related pay (PRP) to the executive and staff of the Company as the MoU ranking of the Company for 2013-14 had improved from an actual 'Very Good' (where eligibility of PRP was 80 *per cent*) to 'Excellent' (where eligibility of PRP was 100 *per cent*) through over-reporting of crude oil production.

With ageing of fields (majority being more than 30 years old), there has been an increase in water cut. This coupled with lack of adequate handling/processing facilities at the production installations resulted in higher proportion of BS&W and off gas in the crude oil. The Company, however, reported crude oil production without adjusting these elements fully. Considering the fact that with progressive ageing of fields, the BS&W proportion is likely to increase, there is a need for adopting a suitable measurement system for crude oil so that these elements are suitably adjusted before crude oil production is reported.

Anomalies were also noticed in the measurement practices. In Western offshore, the reported production quantity measured at offshore platforms were higher than the actual sale quantity with the bulk of the differences in volume arising during transportation of crude oil in a closed pipeline. Where measurements have been taken at both ends of the pipeline under identical conditions of temperature, such differences are not expected to arise. Reasons for the differences should have been investigated and corrective action taken. No record of such action taken by the Company was provided to Audit. Besides, audit trail (either in electronic or in physical form) of reported production quantum from offshore Assets was not maintained by the Company and hence Audit could not verify the accuracy of these reported quantities. In onshore areas, it was noticed that to reconcile over-reported production, fictitious inflating of closing stock of crude oil, erroneous reporting of theft of crude oil and reporting non-existent pit oil as stock were adopted. The Company assured that corrective steps have been/ are being taken in this regard.

The measurement and metering system as well as the reporting system for crude oil production in the Company also had several infirmities. Audit noticed that the Company did not have a Standard Operating Procedure (SOP) for metering and measurement system and different Assets (particularly in Western onshore) followed different measurement practices. Though SCADA system was installed in all onshore production installations since 2010 with the objective of single point measurement through electronic instruments without manual intervention/changes and integration of acquired data with ICE-SAP ERP data, measurement continued to be carried out on the basis of manual dips of crude oil tanks. The accuracy of the manual dips could not be ensured on account of the Company's non-adherence to the calibration schedule. In fact, instances were noticed where crude oil tanks installed in 1970 had not been cleaned yet or re-calibrated against the prescribed calibration schedule of five years. On being pointed out in Audit, the Company initiated corrective measures by formulating SOPs, operationalizing SCADA and integrating it with ICE-SAP ERP, and initiating repair, maintenance, cleaning and re-calibration of crude oil tanks.

6.2. Recommendations

- The loss/gain during transportation of crude oil through closed pipeline systems should be closely monitored to ensure that the variations are in normal range and identify abnormal loss/gain for corrective action. Such reconciliation and monitoring as well as corrective actions taken should be adequately documented.

- Asset-specific Standard Operating Procedures (SOPs) for measurement of crude oil production may be formulated and implemented in all onshore Assets in a time-bound manner to ensure that uniform measurement practices are followed across all production installations of the Company. Asset specific guidelines for segregating internal consumption of crude oil into 'recoverable' and 'non-recoverable' may be designed and 'recoverable' quantum may not be included as crude oil production. Norms for crude oil transit loss should be fixed and cases of abnormal transit loss should be investigated and remedial action taken to prevent revenue loss.

- The Company should strictly adhere to prescribed schedules laid down for calibration of all crude oil measuring devices, such as storage tanks and Mass Flow Meters, Turbine Meters, Auto Samplers, etc. in both offshore and onshore Assets to ensure accuracy of their measurement.

- Electronic and physical trails in support of measurement of crude oil at various stages of production should be maintained to derive assurance regarding their accuracy. SCADA installed in all production installations may be integrated with ICE-SAP ERP system for capturing data and to minimise manual intervention and improve accuracy of reported information. The production reports for onshore Assets should be generated through the SAP-PRA module, in line with the practice in offshore Assets, to preclude the possibility of their manual manipulation.

- The Company may report condensate as a separate stream as opined by the international consultant.

- The Company may ensure that items other than crude oil, namely, condensate, off-gas, basic sediment and water, etc., may not be reported as crude oil production. Considering the difficulties expressed by the Management/Ministry in accurately measuring the crude oil at the production point, there appears to be a case for shifting the production reporting point to a suitable location where stabilized crude (excluding BS&W, off-gas and condensate) can be accurately measured.

(H. PRADEEP RAO)

Deputy Comptroller and Auditor General and
Chairman, Audit Board

New Delhi
Dated 19 July 2016

Countersigned

(SHASHI KANT SHARMA)
Comptroller and Auditor General of India

New Delhi
Dated 19 July 2016

Annexure

Annexure-I

(Referred to in paragraph 4.2.)

Statement showing over-reported production of Western Onshore Assets during the period from 2010-11 to 2014-15

(Figures in MT)

Year	Crude Oil Production reported at Corporate Level	Crude Oil Production as per Log Books of Processing Installations	Over-reported Crude Oil Production
Ankleshwar Asset			
2010-11	16,41,827	15,07,365	1,34,462
2011-12	14,99,747	13,21,831	1,77,916
2012-13	12,73,328	11,27,530	1,45,798
2013-14	10,49,607	8,78,969	1,70,638
2014-15	7,56,486	7,21,894	34,592
Total	**62,20,995**	**55,57,589**	**6,63,406**
Ahmedabad Asset			
2010-11	16,71,932	15,82,164	89,768
2011-12	16,27,900	14,83,560	1,44,340
2012-13	14,62,921	14,08,457	54,464
2013-14	13,95,535	13,28,385	67,150
2014-15	13,17,626	12,97,583	20,043
Total	**74,75,914**	**71,00,149**	**3,75,765**
Mehsana Asset			
2010-11	22,62,862	22,30,716	32,146
2011-12	23,21,590	22,33,842	87,748
2012-13	22,79,541	22,42,370	37,171
2013-14	23,10,380	22,71,007	39,373
2014-15	22,88,771	22,22,399	66,372
Total	**1,14,63,144**	**1,12,00,334**	**2,62,810**

Note: Base Office of Mehsana Asset maintains two sets of production data in its DPR (1) Production based on the liquid received at processing installations and Mehsana CTF and its water cut which is further refined by using trend analysis of actual water drained during previous periods. This calculated production is reported as Asset Crude Oil Production. (2) Production based on overall Asset dispatch and stock variation w.r.t. previous day, which however, is not reported. Production figures used in above table is as per these calculations.

Annexure-II

Details of crude oil used for HOC/squeezing jobs accounted as "internal consumption"

(Referred to in paragraph 4.3.)

(Figures in MT)

Year	Total recoverable internal consumption in SAP (ZPRAMPVL)			
	Ahmedabad	**Ankleshwar**	**Assam**	**Total**
2010-11	6,167	19,133	3,773	29,073
2011-12	9,411	13,567	3,323	26,301
2012-13	17,547	17,427	4,533	39,507
2013-14	12,837	14,520	4,765	32,122
2014-15	11,491	13,892	4,289	29,672
Total	**57,453**	**78,539**	**20,683**	**156,675**

Annexure-III

(Referred to in paragraph 5.1.)

Statement indicating awarded score/rating and revised score/rating for crude oil parameter as well as overall score/rating in MoU during 2011-12 to 2014-15

Year	Weightage for crude oil production	Target	Actual	Crude oil parameter Score	Overall Score	Rating	BS&W	Off-gas	Actual Production.	% of BS&W in reported qty.	% of Off-gas in reported	% of BS&W and Off-gas	Revised MoU Score	Added to Overall score	Revised Overall score	Revised rating
2011-12	3	27.00	26.925	0.062	1.222	Excellent	1.373	0.263	25.289	5.10	0.98	6.08	0.128	0.066	1.288	Excellent
2012-13	4	27.54	26.127	0.121	1.32	Excellent	0.655	0.259	25.213	2.51	0.99	3.50	0.148	0.027	1.347	Excellent
2013-14	4	27.24	25.994	0.117	1.476	Excellent	0.843	0.263	24.888	3.24	1.01	4.25	0.149	0.032	1.508	Very Good
2014-15	7	24.88	23.94	0.19		Very Good										
	2	2.26	2.003	0.09												
	9	27.14	25.943	0.28	2.22		0.841	0.271	24.831	3.24	1.04	4.29	0.331	0.051	2.271	Very Good

Crude Oil MoU target (very good) and raw score and MoU score achieved considering actual production excluding BS&W and off-gas quantity from reported production

Year	Excellent	Very Good	Good	Fair	Poor	Actual excl. BS&W and Off gas	Raw Score	MoU Score
2011-12	27.54	27.00	25.65	24.3	22.95	25.289	4.2674	0.128
2012-13	28.03	27.54	26.16	24.79	23.41	25.213	3.6912	0.148
2013-14	28.60	27.24	25.878	24.516	23.154	24.888	3.7269	0.149
2014-15	26.12	24.88	23.63	22.339	21.14	24.831		
	2.34	2.26	2.15	2.03	1.92			
	28.46	27.14	25.78	24.369	23.06		3.6726	0.331

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Annexure-IV
(Referred to in paragraph 5.2.A)

Additional subsidy burden due to overstatement of reported crude oil production (offshore)

Subsidy burden due to inclusion of condensate in crude oil production						
Year	**Condensate Qty. in bbl (Offshore)**	**Condensate Qty. in bbl (Ankleshwar)**	**Subsidy per bbl (in USD)**	**Exchange rate (₹)**	**Subsidy burden shared by ONGC (₹in crore)**	**Excess sharing subsidy burden (₹ in crore)**
2011-12	14893467	426280.47	56	47.95	44465	4113.66
2012-13	15830546	257443.83	56	54.44	49502	4904.65
2013-14	13787191	172666.90	56	60.48	56384	4728.04
2014-15 (Apr-Sept.)	5702312	37005.50	56	60.79	26842	1953.80
2014-15 (Oct- Dec.)	2753046	18502.50	37.5	60.79	9459	631.81
2014-15 (Jan-March)	2530705	18502.50	-	-	-	0
Total						**16331.96**

Note: Figures of 2014-15 have been shown separately in three phases, since subsidy discount for the 1st & 2nd quarter is USD 56; for the 3rd quarter it was reduced to USD 37.5. Further, for the 4th quarter subsidy details are not available.

Source: Offshore data for condensate has been taken from crude tally statements. In respect of Ankleshwar condensate data has been taken from Asset tally statement.

Subsidy burden due to inclusion of off-gas in crude oil production					
Year	**Off-gas Qty. in MT**	**Off-gas Qty. in bbl (1MT=7.63bbl)**	**Subsidy per bbl (in USD)**	**Exchange rate (in ₹)**	**Excess sharing subsidy burden (₹ in crore)**
2011-12	263813.00	2012893.19	56.00	47.95	**540.50**
2012-13	259128.00	1977146.64	56.00	54.44	**602.76**
2013-14	263717.00	2012160.71	56.00	60.48	**681.49**
2014-15 (Apr-Sept.)	135567.33	1034378.73	56.00	60.79	**352.13**
2014-15 (Oct- Dec.)	67783.67	517189.402	37.50	60.79	**117.90**
2014-15 (Jan- Mar)	67783.67	517189.402	-	-	**-**
Total					**2294.78**

Annexure-V
(Referred to in paragraph 5.2.B)

Additional subsidy burden due to overstatement of reported crude oil production (Onshore)

Year	Quantity of over reported closing stock of crude oil		Discount per bbl	Exchange rate	Total amount
	(in MT)	(in BBL)	(in USD)	(in ₹)	(₹ in crore)
Ankleshwar					
2011-12	23,033	181,431	56	47.95	48,71,77,758
2012-13	20,852	164,251	56	54.44	50,07,42,169
2013-14	19,574	154,184	56	60.48	52,22,02,706
2014-15	920	7,247	56	60.79	2,46,70,527
Total	**64,379**	**507,113**			**153,47,93,160**
Assam					
2013-14 & 2014-15	2,699.54	21,245.38	56	60.63	**7,21,34,013**

List of Abbreviations

Sl. No.	Term used	Description of Abbreviated Term
1	API	American Petroleum Institute
2	AS	Auto Sampler
3	BI	Business Intelligence
4	BS&W	Basic Sediment and Water
5	CPSEs	Central Public Sector Enterprises
6	CSU	Crude Stabilization Unit
7	CTF	Central Tank Farm
8	D&M	M/s DeGolyer and McNaughton
9	DPE	Department of Public Enterprise
10	DPR	Daily Production Report
11	EPS	Early Production System
12	FIR	First Information Report
13	FPSO	Floating Production Storage and Offloading vessel
14	GGS	Group Gathering Station
15	HMI	Human Machine Interface
16	HOC	Hot Oil Circulation
17	HUT	Heera Uran Trunk line
18	JNPT	Jawaharlal Nehru Port Trust
19	JV	Joint Venture
20	KPI	Key Performance Indicator
21	M^3	Cubic Meters
22	MFM	Mass Flow Meters
23	MoF	Ministry of Finance
24	MoPNG	Ministry of Petroleum & Natural Gas
25	MoU	Memorandum of Understanding
26	MT	Metric Tonne
27	MUT	Mumbai Uran Trunk line
28	NELP	New Exploration Licensing Policy
29	NOC	National Oil Company
30	OEM	Original Equipment Manufacturer
31	OID Act	Oil Industry (Development) Act, 1974
32	OMC	Oil Marketing Companies
33	ONGC	Oil & Natural Gas Corporation Ltd.
34	ORD Act	Oil fields (Development & Regulation) Act, 1948
35	P&DD	Production and Development Directorate
36	PNG Rules	Petroleum & Natural Gas Rules, 1959
37	PRA	Production Revenue Accounting
38	PRP	Performance Related Pay

39	SBU	Strategic Business Unit
40	SCADA	Supervisory Control and Data Acquisition (SCADA)
41	SOP	Standard Operating Procedure
42	TM	Turbine Meter
43	WC	Water Cut

Glossary of Technical Terms

Sl. No	Technical Term	Meaning
1	Auto Sampler	Auto Samplers are samplers installed inline in the downstream of Turbine Meters to collect samples of liquid at regular intervals. Samples so collected are tested at laboratory to determine the water content in crude oil.
2	BS&W	Abbreviation for basic sediment and water. BS&W is measured from a liquid sample of the production stream. It includes free water, sediment and emulsion and is measured as a volume percentage of the production stream.
3	Condensate	Liquid hydrocarbons produced with natural gas, separated by cooling and other means
4	Demulsifier	Demulsifier is a chemical used in the heater treater to separate water from oil
5	Effluent Treatment Plant	To process the effluent received from GGS/CTF installation before disposal of effluents as per pollution control norms. The critical equipment are Pumps and Tanks.
6	Emulsion	Emulsion is crude oil inclusive of water
7	Free Water	Water produced with oil which is usually settles once the well fluids become stationary.
8	Heater Treater	Heater Treater remove emulsified liquids and solids from crude and also use heat and pressure drop to flash volatile vapours
9	Human Machine Interface (HMI)	HMI is the tertiary device forming part of Electronic Liquid measurement system. It is a flow computer receiving information from Primary device (Turbine Meter) and secondary devices measuring Temperature, Pressure and Density; Using the programme instructions it calculates the quantity of liquid flowing through the Turbine Meters
10	Hydrocarbon	Organic chemical compounds of hydrogen and carbon atoms. There are a vast number of these compounds and they form the basis of all petroleum products. They may exist as gases, liquids or solids. An example of each is methane, hexane and asphalt.
11	ICE SAP-ERP	Information Consolidation for Efficiency through implementation of Enterprise Resource Planning, i.e., SAP Systems and other IT efforts
12	New Exploration Licensing Policy (NELP)	NELP was formulated by the Government of India in 1997-98 to provide a level playing field in which all the parties may compete on equal terms for the award of exploration acreage. This was for accelerating the pace of hydrocarbon exploration in the country through which various blocks including deep-water acreages were offered for competitive bidding.
13	Off-gas	Off-gas is a dissolved gas in crude oil which is separated during stabilisation process of crude oil

14	Performance Contract	Performance Contract is annual contract signed by the Chief of Strategic Business Units (SBU) with the concerned director. The performance evaluation of SBU is done based on actual achievement vis-à-vis target set for Key Performance Indicators. The methodology followed for evaluation of MoU signed by the ONGC with MoPNG is adopted for this purpose.
15	Petroleum	Crude Oil and/or Natural Gas existing in their natural condition but excluding helium occurring in association with Petroleum or shale.
16	Pit Oil	In an effort to realise production from exploratory wells expeditiously such wells are often flogged to make shift pits at well sites during initial testing. Oil recovered from effluents was also often stored in wash tanks prior to being recovered. Also during period of high stock, due to less evacuation of refineries excess oil is stored in available storage like wash tanks /effluent tanks. The oil which is not stored in crude oil tanks and does not appear in tank stock statement of the Asset is referred to as pit oil
17	Reserve Accretion	Addition of hydrocarbon reserves to the existing reserves
18	Reservoir	A naturally occurring discrete accumulation of Petroleum
19	Rigs	It was an equipment used for drilling a well bore. There are various types of offshore rigs like jack-up rigs, floaters, Modular rigs, etc. In onland, there are two types of rigs, viz., mobile rigs and High Floor Mast / Sub structure types of rigs
20	Turbine Meter	Turbine Meter is a primary device of Electronic Liquid Measurement System. In operation rotating blades generate frequency signal proportion to liquid flow rate which is sensed by the magnetic pick up and transferred to real time indicator
21	Well	A borehole, made by drilling in the course of Petroleum Operations, but does not include a seismic shot hole.
22	Wet Crude	Wet crude is the partially stabilized crude containing crude, water and dissolved gas.