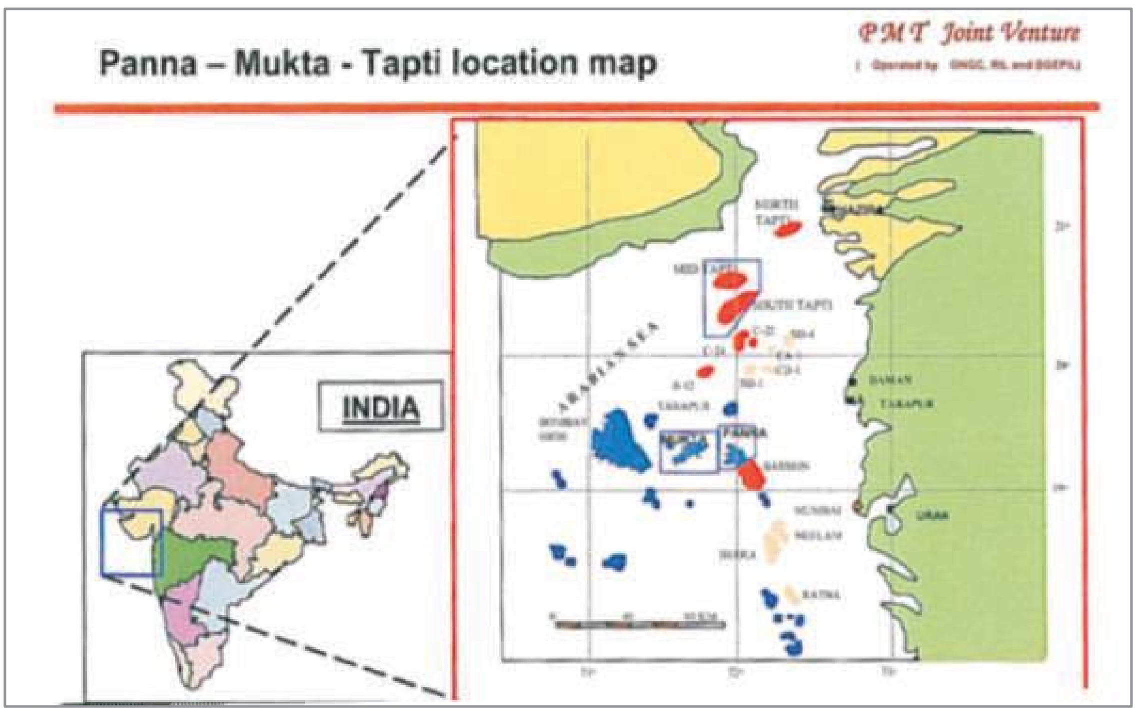
Chapter-3

Audit Findings in respect of Panna-Mukta and Mid & South Tapti Fields

Chapter 3 - Audit Findings in respect of Panna-Mukta and Mid & South Tapti Fields

3.1 Overview

3.1.1 Following the 1992 offering of small and medium sized oil and gas fields for development, GoI awarded (February 1994) the Panna-Mukta and Mid & South Tapti contract areas, which were discovered by ONGC, to a consortium comprising of ONGC (40 *per cent*), RIL (30 *per cent*) and Enron Oil & Gas India Ltd-ENRON (30 *per cent*) (together called Contractor) under a production sharing arrangement. The PSC was signed in December 1994 between the GoI and the Contractor. The Contractor formed an unincorporated joint venture (JV) called PMT JV. In February 2002, British Gas Exploration and Production India Limited (BGEPIL) acquired ENRON's 30 *per cent* stake in the JV and became a party to the PSC. Presently, the field is jointly operated by ONGC, RIL and BGEPIL.



3.2 JV operations in the Panna-Mukta and Mid & South Tapti Contract Area

3.2.1 Background

3.2.1.1. The Panna-Mukta (primarily an oil field) and Mid & South Tapti (gas field) are shallow water fields located in the offshore Bombay basin. At the time of bidding, the Panna-

Mukta contract area was a discovered and partially developed oil producing field of ONGC[74] and Mid & South Tapti contract area was a discovered gas field by ONGC. Both the Contract Areas were developed by the JV in two phases.

3.2.1.2. In Panna-Mukta, Initial Plan of Development (IPOD) project was executed between 1995-99 wherein three wellhead platforms (PC, PF and PG) were installed. In the second phase of development, i.e. Expanded Plan of Development (EPOD), executed between 2004 and 2007 two wellhead platforms (PH and PJ) were installed.

3.2.1.3. Similarly, Mid & South Tapti Contract Area was developed in two phases *viz*., IPOD and New Revised Plan of Development (NRPOD). The IPOD project was executed during 1995 to1997 wherein JV installed three wellhead platforms *viz*. STA, STB, STC in South Tapti field along with associated processing & transportation facilities. The NRPOD project was executed during March 2005 to August 2007 wherein JV installed one wellhead platform MTA in Mid Tapti field, and additional processing and transportation facilities for handling increased production. JV installed one wellhead platform STD in South Tapti field in August 2006 to maintain the plateau of production.

3.2.2 Physical and financial performance

3.2.2.1. The physical and financial performance of Panna-Mukta and Mid & South Tapti Contract Areas since inception till March 2012 is tabulated below.

Table 17 : Physical and financial performance of Panna-Mukta and Mid & South Tapti Contract Areas (as reported by the Operator)

Particulars	Panna-Mukta	Mid & South Tapti
Reserve as per PSC	Gas 10171 million M^3 Oil 145 .67 million Bbl	Gas 29134 million M^3 Condensate 12.35 million Bbl
Cumulative Production[75]	Gas 20967.59 million M^3 Oil 163.50 million Bbl	Gas 34908.39 million M^3 Condensate 15.42 million Bbl
Total Cumulative Revenue	US$ 11507.11 million	US$ 5891.48 million*
Cumulative Contract cost	US$ 4036.89 million	US$ 2219.23 million*
Total Cost Recovery (100%)	US$ 4036.89 million	US$ 2219.23 million*
Total PP	US$ 7478.98 million	US$ 3672.25 million*
Total Contractors PP	US$ 6613.42 million	US$ 2937.80 million*

[74] *ONGC installed 5 wellhead platforms (viz. PA, PB, PD, PE and MA wellhead platform) for production and handed over to PMT JV at the time of signing of PSC (December 1994).*

[75] *The PMT JV upgraded the reserves periodically and the reserves as of March 2012 were: Panna-Mukta – Crude oil 292.95 mmbbl, Gas - 38711 mmscm and Mid and South Tapti – Gas - 43035 mmscm and Condensate – 17.22 mmbbl.*

Total GoI PP	US$ 865.56 million	US$ 734.45 million*
Total Royalty paid to GoI	US$ 499.50 million	US$ 479.03 million*
Total Cess paid to GoI	US$ 439.20 million	US$ 24.59 million*

Note: * The financial figures are as claimed by the Operator and have been disputed by Government, presently under arbitration.

3.2.2.2. PMT JV has recovered 100 *per cent* of the cost incurred so far (March 2012) in the contract area. Out of total PP earned, JV's share was 88 *per cent* in respect of Panna-Mukta and 80 *per cent* in Mid & South Tapti.

3.2.2.3. The contract cost, revenue and PP to the GoI during the period under review, *as recorded by the Operator*, is detailed below.

Table 18 : Panna-Mukta Field

(In US$ million)

Year	Revenue	Capex	Operating Expenditure (Opex)	Levies	Total Contract Cost	GoI PP	GoI PP *per cent*
2008-09	1414.96	432.60	117.83	80.49	630.93	117.61	15
2009-10	1308.20	190.59	96.41	88.58	375.57	139.89	15
2010-11	1115.92	90.08	125.26	66.53	281.87	125.11	15
2011-12	1565.88	29.35	128.55	77.43	235.32	199.58	15
Total	**5404.96**	**742.62**	**468.05**	**313.03**	**1523.69**	**582.19**	

Table 19 : Mid & South Tapti Field

(In US$ million)

Year	Revenue	Capex	Opex	Levies	Total Contract Cost	GoI PP	GoI PP *per cent*
2008-09	1002.19	10.45	68.08	85.22	163.75	167.69	20
2009-10	698.83	56.83	50.48	61.91	169.22	105.92	20
2010-11	619.33	0.93	53.25	52.90	107.08	102.45	20
2011-12	500.77	3.10	55.84	40.47	99.41	80.27	20
Total	**2821.12**	**71.31**	**227.65**	**240.50**	**539.46**	**456.33**	

These have been disputed by GoI and arbitration proceedings are presently ongoing.

3.3 Execution of Committed Work Programme and Cost Recovery Limit under PSC

3.3.1. The Panna-Mukta and Mid & South Tapti PSCs stipulate execution of committed development work programme (Appendix-G of PSC) with a Cost Recovery Limit (CRL) of

US$ 577.5 million and US$ 545 million respectively. The JV is yet to execute the committed work programme of Mukta-B development in Panna-Mukta field and install 5 well platforms in Mid & South Tapti field.

3.3.2. The actual expenditure incurred till March 2012 as against the CRL for execution of committed work programme (Appendix-G of PSC) *as recorded by the Operator* is given below.

Table 20 : Actual expenditure incurred

Field/Contract Area	CRL	Total expenditure within Appendix-G of PSC till March 2012
Panna-Mukta	US$ 577.5 million	US$ 347.23 million
Mid & South Tapti	US$ 545 million	US$ 670.41 million

3.3.3. The actual expenditure of US$ 347.23 million (figures as claimed by the Operator) incurred in Panna-Mukta field till March 2012 within Appendix-G excluded the common expenditure of US$ 192.91 million which is required to be allocated between Appendix-G and outside Appendix-G. MoPNG disallowed excess cost over CRL. The actual expenditure of US$ 670.41 million (figures as claimed by the Operator) incurred in Tapti till March 2012 within Appendix-G excluded common expenditure of US$ 105.88 million which is required to be allocated between Appendix-G and outside Appendix-G. MoPNG / DGH in the MC Meeting disallowed excess expenditure of US$ 324.35 million over CRL, directed the JV to reverse the excess cost recovered over CRL and revised the calculation of cost and profit petroleum. The Operator took the matter to arbitration. The present status of arbitration is given below.

3.3.4. Issues relating to Arbitration

3.3.4.1. The partners RIL and BGEPIL served arbitration notice (December 2010) under PSC to GoI. The claims raised by RIL and BGEPIL pertain to i) Cost Recovery provisions under Panna-Mukta and Tapti PSC, ii) Calculation of IM, iii) Amount of royalty payable under PMT PSC, iv) Amount of cess payable by Contractor to GoI, v) Amount of service tax payable under PSC, and vi) Meaning and effect of Accounting and Audit provisions.

3.3.4.2. GoI also raised counter claim towards depressing expenditure allowance available under Section 42 of IT Act, accounting of inflated sales, accounting of Development Cost in excess of CRL, short accounting of sales revenue, income tax rate, non-completion of committed work programme as per Appendix-G, short accounting of sales, short accounting of marketing margin, short accounting under wrong PSC, excess cost recovery over CRL.

3.3.4.3. The Tribunal (by a majority) passed a final unanimous Partial Award of September 2012 on Preliminary Issues holding that the arbitral tribunal has the jurisdiction to adjudicate upon the preliminary issues *(viz. royalties, cess, service tax and C&AG Audit).*

3.3.4.4. The Tribunal also passed (December 2012) a final partial award in respect of Tapti PSC that

(i) the costs incurred after the Effective Date related to the construction and/or establishment of such facilities as are necessary to produce, process, store and transport petroleum from within Existing Discoveries in order to enable gas production above the Tapti IPOD Plateau Level are fully recoverable,

(ii) the determination of these costs should be made at the time approval for such work is sought or obtained from the MC,

(iii) where direct G&A and other Service Costs, are properly allocated as Development Costs, they would be recoverable in full by virtue of Article 13.1.1, 13.5 and 13.6 of the Tapti PSC unless they come within the CRL. All G&A costs and Service costs other than those which are attributable to Development Works fall outside the CRL and are recoverable in full,

(iv) indirect G&A and other Service Costs (head office and establishment expenses), where these costs are necessary for the production of gas at the IPOD Plateau Level, they would come within the CRL. If they are not, they do not come within the limit and are recoverable in full as head office and establishment expenses, and

(v) the CRL is lump sum.

The Arbitral Award also stated that these findings apply *mutatis mutandis*, to the Panna-Mukta PSC. The claimants had no obligation to complete the Appendix G works under either the Tapti or the Panna-Mukta PSC. The Tribunal also unanimously found that the timelines prescribed in Appendix C, Section 1, Paragraph 1.9 of the PSCs are not final and binding.

3.3.5. Present Status of Arbitration

- **Final unanimous Partial Award of September 2012:** Union of India (UoI) challenged the September 2012 award on issues of arbitrability in the High Court of Delhi. The High Court ruled (March 2013) in the UoI's favour, stating that the issues of cess, royalties, service and C&AG Audit are not arbitrable and that Part-I of the Arbitration and Conciliation Act, 1996 is not expressly or impliedly excluded in the PSCs by the parties. This order was challenged by the Claimants (BGEPIL and RIL) in the Supreme Court vide SLP (civil) 20041 of 2013. Supreme Court overruled and set aside the conclusion of the High Court and decided (May 2014) the case in favour of BGEPIL and RIL. UoI has filed a review petition with the Supreme Court of India.

- **Final Partial Award of December 2012**: The award dated 10 December 2012 on CRL issue was also challenged by UoI under section 34 of the Arbitration and Conciliation Act, 1996 in Delhi High Court on 02 January 2014.

- **Mandate of Mr. Peter Leaver:** Considering the conduct of Mr. Peter Leaver, arbitrator, appointed by the PMT JV to be partial, biased against GoI and that he interfered with the witness of GoI during the arbitration hearings and in correspondence with the parties, GoI challenged the mandate of Mr. Peter Leaver in the Permanent Court on Arbitration (PCA). The PCA rejected (June 2013) the challenge brought against Mr. Peter Leaver, QC under Article 10(1) of the UNCITRAL Arbitration Rules. The decision of PCA on Arbitration has been challenged by GoI in Delhi High Court (June 2013).

3.3.6. All the afore-mentioned issues are sub-judice as of July 2014.

3.4 Presentation of findings in this chapter

Para 3.5 of this report contains the sampling methodology adopted. Audit objections in respect of expenditure related issues noticed during the audit of Contractor's records are detailed in Para 3.6.1 and 3.6.2. Observations on Revenue and Accounting issues are contained in Para 3.6.3. Regulatory and monitoring issues observed during performance audit at MoPNG/DGH are in Para 3.6.5 and 3.6.6. Audit concerns regarding petroleum operations are in Para 3.6.4.

3.5 Sampling methodology

The current audit was conducted for the transactions pertaining to 2008-09 to 2011-12. Out of the 104 contracts (US$ 800.68 million), Audit selected 66 contracts (US$ 717.33 million) for scrutiny. In addition, Audit selected all the 10 projects for scrutiny which were at various stages of implementation during audit period. Apart from this, Audit also examined 22 contracts (US$ 267.44 million) pertaining to the period 2006-08. These contracts related to the previous audit period but since the records were made available at the end of the last audit exercise, it was agreed that they would be reviewed subsequently.

3.6 Audit Findings

The audit findings resulting from scrutiny of the records of the Operators and MoPNG/DGH have been grouped under six categories *viz*. (i) recoverable costs and cost recovery, (ii) deficiencies in contracting procedure, (iii) revenue (iv) petroleum operations (v) compliance to the PSC provisions, and (vi) issues relating to MoPNG/DGH. The findings under each category are discussed below.

3.6.1 Recoverable costs and cost recovery

As per Article 13 of the PSC, PMT JV is entitled to recover the Contract costs out of the total volume of petroleum produced and saved from the Contract area in each FY. The Contract costs include production, exploration and development costs.

PMT JV has recovered 100 *per cent* of the cost incurred so far (March 2012) in the Contract area. The issues relating to cost recovery are discussed below.

3.6.1.1 Improper allocation of rig mobilization/demobilization charges

3.6.1.1.1. PMT JV maintains a single account for both Panna-Mukta and Tapti fields. It books rig mobilization charges to the cost of the first well and demobilization charges to the cost of the last well drilled by the rig during its contract period instead of allocating the same between two fields either on the basis of number of days spent by the rig on each well drilled or numbers of wells drilled which would be a more realistic basis for allocating rig mobilization and demobilization charges. Audit observed that the major E&P Operators in India i.e. ONGC and RIL (KG-DWN-98/3 Block), are allocating rig mobilization and demobilization charges based on the actual number of days utilized in wells and number of wells drilled respectively. Since PP percentage to the GoI from Panna-Mukta and Mid & South Tapti fields are at different slabs, the unrealistic allocation of rig mobilization and demobilization charges on the basis of first and last well drilled by the rig may impact GoI PP.

3.6.1.1.2. PMT JV in its reply to Audit (January 2014) and to MoPNG (July 2014) stated that the *issue relates to PMTJV accounts since inception of the PSCs in December 1994 and therefore includes a period outside the audit period and hence, scope of audit. It is used for its practicality and simplicity, as drilling programs often change and rigs can be on site for longer than originally planned. It is not used with aim of reducing the GoI's share of profit petroleum as in principle this allocation could be either way. Any allocation method would be imperfect in some way. PMTJV does not consider it prudent to change its allocation methodology now. The result of PMTJVs allocation has not been very different from that sought by CAG.*

3.6.1.1.3. Reply of PMT JV is not convincing. The PMT JV is deploying the rig(s) in both Panna-Mukta and Tapti fields, therefore allocating the rig mobilization and de-mobilization to the first and last well drilled resulted in improper allocation of rig cost between these two fields.

3.6.1.1.4. MoPNG in its reply (July 2014) stated that *the impact on cumulative costs and cumulative Profit Petroleum also needs to be considered which may have an impact at variance from the percentage share under the two PSCs. The MoPNG added that issue is an accounting method followed by the Contractor in respect of which Audit should have taken clarification from Contractor only.*

3.6.1.1.5. Audit agrees with MoPNG that the impact would be cumulative. However, as different Operators follow different methodologies, Audit is of the view that MoPNG/DGH ought to address the issue to decide a common acceptable method which would protect the interest of the GoI.

3.6.1.2 Excess expenditure booking of US$ 0.52 million towards Mid & South Tapti field

3.6.1.2.1. The JV allocates the common expenditure between Panna-Mukta and Mid & South Tapti fields on 50:50 basis. Audit reviewed 809 common items of expenditure amounting to US$ 1.65 million incurred towards drilling activity relating to project personnel. It was noticed that US$ 1.37 million out of this (constituting 83 percent of the total common expenditure on personnel) was allocated between the Panna-Mukta and Tapti fields on a 50:50 basis even though the actual time bookings for each individual against the field/ project was easily identifiable from the monthly time writing sheets of each department. Since the GoIPP is different for Panna-Mukta and Tapti, a 50:50 allocation would distort the booking for each field.

3.6.1.2.2. The incorrect booking has resulted in an excess booking of US$ 0.52 million in Mid & South Tapti field and consequently under payment of GoI PP of US$ 0.026 million (*Annexure 11*).

3.6.1.2.3. PMT JV in its reply to Audit (January 2014) and to MoPNG (July 2014) stated that *allocation methodology which it had used consistently since inception, for its practicality and simplicity particularly as the relative costs involved do not justify the time involved in preparing a detailed allocation of all common costs. The common costs were not significant (3.3 per cent of total contract costs). The PMTJV does not consider it is appropriate for it to change its allocation methodology now.*

3.6.1.2.4. Reply of PMT JV is not tenable. As the expenditure incurred were easily identifiable to Panna-Mukta and Tapti contract areas, PMT JV should have booked them accordingly instead of allocating equally between Panna-Mukta and Tapti fields. Hence, PMT JV should pay the additional PP to the GoI along with penal interest as provided under Section 1.7 of Accounting Procedure (AP) of the PSC.

3.6.1.2.5. MoPNG in its reply (February 2014) stated that *any irregular allocation of expenditure between Mid-South Tapti & Panna-Mukta PSC reported by Audit would be taken up for remedial action for the amount identified by Audit.*

Audit Recommendation 11: The common expenditure should be appropriately allocated to Panna-Mukta and Tapti fields on a reasonable basis *viz.* actual expenditure identifiable to a particular contract area or in the ratio of expenditure on the primary activity.

3.6.1.3 Cost Recovery of unconsumed production inventory US$ 26.15 million in contravention to PSC

3.6.1.3.1. As per section 3.1.8(a) of AP of the PSC, the material and equipment held in inventory shall be charged to the accounts only when such material is removed from inventory and used in Petroleum Operations. *Contractor is allowed to recover interest at the LIBOR rate plus one per cent (1%) for reasonable inventories it carries. Costs shall be* *charged to the accounting records and books based on the average cost method'.*

3.6.1.3.2. However, contrary to the PSC provision, Contractor charges production inventory to cost recovery on date of purchase irrespective of its actual usage in Petroleum Operations. As on 31 March 2012, PMT JV was holding production inventory worth US$ 26.15 million (accumulated since Pre-SAP, i.e. before April 2005 – US$ 4.84 million) which was charged to cost recovery.

3.6.1.3.3. Out of total inventory of US$ 26.15 million as on 31 March 2012, inventory valuing US$ 11.03 million was not used for more than four years. The cost recovery of production inventory without its actual usage for petroleum operations had adversely impacted GoI share of PP.

3.6.1.3.4. Contractor needs to reverse production inventory charged from the respective FYs by recovering inventory carrying cost on reasonable inventory under section 3.1.8 (a) of Accounting Procedure to the PSC from date of purchase till its actual consumption for Petroleum Operations and remit the additional PP to the GoI along with interest @ LIBOR plus one (1) *per cent* as provided under section 1.7.3 of Accounting Procedure to the PSC.

3.6.1.3.5. PMT JV in its reply to Audit (February 2014) and to MoPNG (July 2014) stated:

1. *"Only controllable assets used for or in connection with Petroleum Operations such as drilling tangibles are inventory (see section 4.2.1(a) of Appendix C). In contrast, the items referred to by the CAG are small value items in the nature of consumables (i.e. chemicals, spare valves, maintenance spares required for various offshore equipment, nuts and bolts, etc.) used for operations and maintenance. Ever since inception, the PMTJV's accounting policy has been to charge the costs incurred in respect of these consumable items to the accounts as Production Costs and cost recover them on purchase rather than on consumption. Accordingly, the PMTJV has not recovered any inventory carrying cost on these items.*
2. *The PMTJV has endeavoured to ensure that such production consumable items are maintained at reasonable levels so as to avoid any production downtime due to non-availability of such items. An increase in project activities since 2005 resulted in a corresponding increase in consumable items of relevant specifications. The award of contracts to L1 bidders results in spares being purchased from different manufacturers. As a result, separate spares are often required for each make of equipment, which increases the number of spares being stored for ready use".*

3.6.1.3.6. The reply is not acceptable in view of the following:

(i) The PSC provides that inventory should be cost recovered as and when actually consumed and the cost recovery of the inventory on purchase is not correct.

(ii) Section 3.1.8 (a) of Appendix C of PSC did not differentiate material as consumable or small value items and reiterates that material or equipment held in inventory shall be charged only when used for petroleum operations.

(iii) The other PSCs, *viz*. KG-DWN-98/3 and Ravva, also provided for charging of inventory on use for petroleum operations.

3.6.1.3.7. MoPNG, in its reply (February/July 2014) agreed that *inventory not consumed should not form part of contract cost and is not allowed for cost recovery. The issue was raised by M/s Sharp & Tannon for the years 2005-06 and 2006-07 which was duly addressed in the revised computation of the auditor and agreed to remedy appropriately for subsequent years. Year wise inventory included by Operator in the Contract Cost if provided by Audit would be corrected in the account for subsequent years also.*

3.6.1.3.8. The PMT JV furnished the year-wise production inventory for the years 2008-12 while the data for the years 2006-08 though sought was not furnished by the Operator during last round of audit and, hence, the inventory movement for the year 2008-09 could not be worked out. The year-wise production inventory movement (as desired by the MoPNG) in respect of Panna-Mukta and Tapti Contract Area for the years 2009 to 2012 are tabulated below.

Table 21 : Production Inventory Movement of Panna-Mukta and Tapti Contract Area

(In US $ million)

Year	Inventory Movement	
	Panna-Mukta	Tapti
2009-10	2.64	1.59
2010-11	3.92	0.52
2011-12	1.49	1.22

Audit Recommendation 12: PMT JV may ensure that production inventory is charged to accounts only when such material is removed from inventory and used in petroleum operations as provided in the PSC.

3.6.1.4 Loss of revenue of US$ 0.09 million to GoI due to recovery of inventory carrying costs on sparable drilling inventory

3.6.1.4.1. Section 3.1.8 (a) of PMT-PSCs stipulates that *so far is practicable and consistent with efficient and economical operation only such material shall be purchased or furnished by the Contractor for use in the Petroleum Operations as may be required for use in the reasonable foreseeable future and the accumulation of surplus stocks shall be avoided to the extent possible. Material and equipment held in inventory shall only be charged to the accounts when such material is removed from inventory and used in Petroleum Operations.*

Contractor is allowed to recover interest at the LIBOR rate plus one per cent (1%) for reasonable inventories it carries. Costs shall be charged to the accounting records and books based on the average cost method.

3.6.1.4.2. PMT JV has recovered inventory carrying cost of US$ 549843 on the sparable drilling inventory till February 2009 impacting the GoI PP of US$ 90178 which needs to be paid along with interest amount due under Section 1.7.3 of AP to the PSC.

3.6.1.4.3. PMT JV in its reply to MoPNG (January / July 2014) stated that *subject to accounting verification of the figures; it would reverse the cost recovery and pay additional profit petroleum to the GoI accordingly. MoPNG in reply stated (July 2014) that the issue would be followed up with the Contractor.*

3.6.1.5 Infructuous expenditure of US$ 0.814 million on helideck and truss not used for Petroleum Operation

3.6.1.5.1. Under NRPOD project, Tapti JV awarded (March 2006) a contract to M/s Lamprel Energy Ltd, Dubai for Tapti Compression and Processing Platform (TCPP) deck fabrication. The contract included fabrication and installation of helideck and truss to the TCPP process platform. However, as the deck weight exceeded the derrick barge lifting capacity, the helideck and truss was cut off at the fabrication yard and was kept at ONGC's Nhava supply base from 29 May 2007 till 6 February 2009 with the intention to install it at a later date. In February 2009, the helideck and truss was relocated to Pipavav yard in Gujarat and since then it is lying idle at Pipavav yard. The total storage cost incurred for the helideck and truss was US$ 0.814 million (February 2009 to January 2014).

3.6.1.5.2. PMT JV in its reply to Audit (January 2014) and to MoPNG (July 2014) stated that *"after removal of the helideck and truss from the topside, it was kept in storage. Since alternative uses for the equipment were under consideration; the reinstallation of these facilities on the TCPP platform is not economical as a lifting barge would have to be hired specifically for this purpose. The PMT JV proposed to the Operating Board in May 2010 for disposal of the equipment. The Operator Board approved the disposal of the helideck on 26 April 2013. The PMT JV proposed a disposal methodology to the Operator Board on 19 August 2013, which the Operator Board approved on 29 May 2014. The helideck was offered to the GoI on 11 June 2014 and the GoI confirmed on 17 June 2014 that it does not require the helideck. The PMT JV will now dispose of the equipment in accordance with the PSCs, with the process estimated to be completed in the next 4-5 months. The PMTJV has made consistent efforts to dispose the equipment. When the helideck and truss are sold, proceeds of the sale will be remitted to the GoI as is the practice with respect to equipment and assets no longer required and sold".*

3.6.1.5.3. The fact remains that helideck and truss was not used by the PMT JV for almost seven (7) years from the date of its removal. From the reply of PMT JV it can be observed that the disposal was unduly delayed since the proposal of BGEPIL of May 2010 was approved by Operator Board only in April 2013 and disposal methodology was approved only in May 2014. With delay, the condition of the equipment would deteriorate and fetch lower realization value to the GoI besides adding to the storage expenditure.

3.6.1.5.4. MoPNG in its reply stated (June 2014) that *audit observation has been notified to the Contractor. Remedial measures would be initiated based on Contractor's reply.*

3.6.2 Deficiencies in Contracting procedures and execution of Contracts

3.6.2.1 Extra expenditure on hiring of costlier rig DD-4 on assignment basis from Reliance Industries Limited (RIL)

3.6.2.1.1. In June 2006, PMT JV extended the two existing contracts entered into with M/s Ensco Martime for hiring of drilling rig. While the contract for rig Ensco 53 was extended for one year upto December 2007, the contract for rig Ensco 50 was extended for two years upto December 2008. Both these contracts had an option for further extension by one more year at mutually agreed rate with same terms and conditions. On expiry of term, the contract for rig Ensco 53 was extended by PMT JV upto September 2008. For the requirement of subsequent period, PMT JV invited (March/April 2008) a tender wherein M/s Great Ship (L1 bidder) offered (September 2008) the rig 'HULL B294' at an operational day rate of US$ 185000 with rig deployment schedule of 31 March 2009. M/s Ensco Maritime offered the rig Ensco 50 (which was already deployed in PMT field with validity upto December 2008) at an operational day rate of US$ 162500 per day for short term requirement to bridge the gap till the deployment of L1 bidder's rig under the subject tender (i.e. till March 2009). Meanwhile, the JV partner RIL also offered (October 2008) the rig DD-4 which it had hired[76] from M/s Deep Drilling and was on standby. PMT JV hired (October 2008) rig DD-4 on assignment basis from RIL for a primary period of six months at an operational day rate of US$ 197000 per day to reduce the gap after demobilization of rig Ensco 53. During the contract period from October 2008 to April 2009, DD-4 drilled five infill wells in Panna-Mukta Contract area.

3.6.2.1.2. Audit observed that

(i) PMT JV drilled 5 infill wells in Panna-Mukta contract area in Oct 2008-April 2009, without having an approved drilling programme from the MC. The work programme was only subsequently approved by the MC in October 2010.

(ii) The charter hire rate paid by PMT JV for rig DD-4 was higher in comparison to prevailing market rate and higher than the rate offered in March/April 2008 tender.

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[76] *Hired for a firm period of 12 months effective from 26 November 2007 with options to extend the duration of contract in two instalments of 6 months each.*

The data download from the 'Rig Point Fixtures' revealed that most of the other E&P Operators hired similar type of rig in the range of US$ 85000 to US$ 146000 per day during the period starting from September to December 2008.

(iii) In the subsequent tender invited (December 2008) for drilling activities of 2009-10, M/s Premium Drilling (L2 bidder) offered DD-4 at lower charter hire rate of US$ 149000 per day (revised later to US$ 145000 per day). However, the contract was awarded (March 2009) to M/s Ensco (L1 bidder) for rig Ensco 53 @ US$ 105000 per day for a period of nine months.

(iv) In the Operator Board Meeting (02 December 2008), ONGC suggested that in the present market condition (falling oil prices), the rates of services and materials were expected to reduce. During 2008-09, there was substantial drop in the international crude oil price from US$ 103.4 (Dubai crude) and US$ 109.0 per barrel (Brent crude) in April 2008 to US$ 45.6 and US$ 46.5 per barrel respectively in March 2009.

(v) Thus, hiring of RIL rig on assignment basis at higher rate resulted in extra cost to JV Operations by US$ 6.49 million ($ 4.07 million-US$ 34500*118 days from 1 January 2009 to 28 April 2009 towards hire charges and US$ 2.42 million towards mobilization charges of rig DD-4) with a consequential adverse impact of GoI-PP by approximately US$ 1.00 million.

3.6.2.1.3. PMT JV in its response to Audit (January 2014) and to MoPNG (July 2014) stated that

(i) Hiring of rigs is often made based on reasonably anticipated drilling schedules prior to the approval of the drilling of specific wells in a work program in order to capture suitable rig, optimize drilling schedules and maximizes the production of hydrocarbons.

(ii) The budget revision for these wells was submitted vide OB resolution dated 10 October 2008, which DGH approved on 14 October 2008.

(iii) The PMTJV had tendered for two rig operation as there was a planned drilling program for two rigs. Therefore the rig DD-4 would have been hired even if the Ensco 50 was hired and DD-4 would always have drilled different wells to the Ensco 50. The PMTJV did attempt to obtain an extension to the rig Ensco 50 notwithstanding the deployment of the rig DD-4, however, decided against doing so as the Ensco 50 was not compliant with a circular of the Directorate General of Shipping. Further, Noble Denton and Associates (Marine Warranty Surveyor), at the time, did not qualify Ensco 50 or 53 for 2009 monsoon location.

(iv) By Q1 of 2008, it became apparent that an insufficient number of rigs would be on site to make use of pre-monsoon 2009 drilling window (October 2008-April 2009) as

one of the rigs on hire (Ensco-53) was scheduled for maintenance (dry docking) during that time. So as to utilize that drilling window, PMTJV invited tenders towards end of March 2008 to hire suitable rig for that period. No suitable rig was available before April 2009, which would have meant that the pre-monsoon drilling window would have been lost. The PMTJV therefore decided to hire the "Deep Driller 4" rig (DD-4), which was available from mid-October 2008, from RIL on an assignment basis. Had PMTJV waited until some other rig became available, approximately US $138 million in revenues generated from the infill wells drilled by DD-4 from November 2008 to June 2010 would have been deferred regardless of whether or not the wells were included in the relevant WP&B.

(v) The global prices began to decrease from September 2008. The market for rigs depends not only on oil prices, but on numerous factors such as the supply and demand of rigs particularly in a given region.

(vi) The agreed operating day rate for DD-4 rig of US $197,000 was comparable to the prevailing market conditions at the time, i.e. in October 2008, example, the rig offered by Great ship (HULL B294) in response to the invitation to tender, which was only available from April 2009, had an operating day rate of US$ 185,000 (24 month contract). It is therefore incorrect that the agreed rig rate was higher than the prevailing market rates as at October 2008. The lower rig rates referred to by Audit all relate to periods subsequent to October 2008 when global oil prices decreased dramatically'.

(vii) The Rig Point Data for jack-up rigs in and around the Indian Ocean for the period between September and December 2008 shows that the rig rate range was US$ 109,000 to US$ 225,000 per day. The data captures contracts of various durations for example a 4-year contract for US$ 165,068 per day to US$ 130,000 per day for a well contract. High rig rates for rigs in the region was not unexpected, especially those which were agreed before the global decline in rig became apparent, as the Indian rig market was expected to suffer from undersupply over the coming period (as reported by ODS Petrodata (the service provider for Rig Point Data) in an international rig report in May 2008. It is noted that the ODS Petrodata Rig Point Data does not indicate what contractual conditions resulted in the prices agreed and is not always entirely accurate (as shown by the DD-4 contract description).

(viii) The prevailing rates for rigs contained in the Rig Point Data do not include mobilization/demobilisation charges, which can be substantial. The PMTJV was not required to pay a mobilisation charge for the hire of rig DD-4. Rowan Mississippi quoted a mobilisation/demobilisation fee which was US$ 19.99 million more than that for DD-4 in its bid. This translates to an additional cost of US$ 61,233 per day for a one year contract. Meanwhile, the Greatship, which was found to be the L1 bidder, would have cost US$ 191,479 per day for a one year contract.

3.6.2.1.4. Reply of PMT JV is not convincing in view of the following:

(i) As per clause 6.8 (B) 1 of JOA, the procedure for capital contracts specifies that activities in respect of capital contracts commences only upon approval of WP&B. Therefore, hiring of the rig DD-4 on assignment basis without requisite approval from the MC (DGH) for drilling programme was not in accordance with the contracting procedure of PMT JV. It may be noted that in OB meeting held on 19 December 2008, the JV partner RIL had stated that henceforth all contracts for any JV program should be awarded only after MC approval of the work program and budget.

(ii) DGH vide letter dated 14 October 2008 had only approved these wells as techno-commercial viable and had suggested to include the same in the WP&B for 2009-10. The budget for these wells was not approved by DGH on 14 October 2008 as claimed by the Operator. The actual approval was accorded only in October 2010.

(iii) PMT JV did not have sufficient drilling program in 2008-09 for deployment of two rigs as is evident from the decision taken by the PMT JV in OB meeting of 2 December 2008 to de-hire Ensco 50 in view of limited amount of approved works remaining under WP&B for 2008-09.

(iv) The contention of the Operator that Ensco 50 was non-compliant to the circular issued by DGS (July 2008) and hence not considered for hiring in October 2008 needs to be viewed in the context of Operator considering hiring of Ensco 50 again later in November 2008. Besides, the DGS circular referred by Operator was a relaxation of conditions rather than stricter enforcement of the same. During the Exit Conference (July 2014), PMTJV had been requested to provide documentary evidence of disqualifying Ensco 50 which has not been made available. Further, the disqualification of Ensco 50 by Noble Denton and Associates for 2009 monsoon location as argued by the Operator was specific to drilling of PK locations. These locations had not been drilled by DD-4 and were only drilled from May 2009 to November 2009.

(v) The drilling of five infill wells at Panna was not included in the approved WP&B for 2008-09. Hence, the justification given by the PMT JV that hiring of rig DD-4 was necessary to prevent deferment of revenue in drilling of Panna infill wells is not acceptable.

(vi) The Rig Point Data for jack-up rigs in and around the Indian Ocean for the period between September and December 2008 furnished by the PMT JV revealed that rig rates for a hiring duration of 6 months (as that contracted for DD-4) was in the range of US$ 109000 to US$ 122000 per day. Further, ONGC also hired similar rigs in October 2008 and the day rates were ranging from US$162090 (Greatdrill Chetna) and US$ 162470 (Noble George Mcleod) and US$ 147501 (Greatdrill Chitra) hired in November 2008.

(vii) Extension of rig contract for Ensco 50 was without additional burden of rig mobilization and demobilization whereas PMT JV paid rig demobilization of US$ 2.42 million for DD-4. After loading of demobilization charges, the operating day rate of DD-4 works out to be higher at US$ 209284 per day in comparison to Ensco 50 offer of US$ 162500 per day.

3.6.2.1.5. Thus, hiring of the costlier rig DD-4 resulted in extra expenditure of US$ 6.49 million (US$ 4.07 million-US$ 34500*118 days from 1 January 2009 to 28 April 2009 towards hire charges and US$ 2.42 million towards mobilization charges of rig DD-4) and consequently adversely impacted GoI PP by US$ 1.00 million (approximately).

3.6.2.1.6. MoPNG stated in its reply (July 2014) that *audit exception has been notified to the Contractor. The CAG may recommend in its final report the amount to be disallowed from the Contract Costs after considering Contractors' reply, if any.*

3.6.2.1.7. The impact due to improper hiring of rig from an affiliate i.e. RIL has been commented. GoI may take a view on disallowing from the Contract Costs.

3.6.2.2 Award of contract on nomination basis

(A) Relocation of facilities

3.6.2.2.1. Following abandonment of SWP project (as discussed in para 3.6.4.1), PMT JV decided to shift its facilities to the PL location. PMT JV entered into a settlement agreement with M/s Swiber (the existing contractor for installation of PK and SWP platforms) for relocating these facilities on a nomination basis in March 2010. It was noticed that the actual cost for transportation and installation far exceeded the estimates.

3.6.2.2.1.1. The cost estimate prepared in August 2008 had indicated the total cost at US$ 15.8 million (including US$ 6.0 million for mobilization and de mobilization). Against this, the actual contracted price was more than double at US$ 35.98 million (including US$ 29 million for installation and US$ 6.98 million for transportation). Besides, the award was made on a settlement basis with M/s Swiber rather than a tender as mandated in the PSC.

3.6.2.2.1.2. PMT JV in its reply to Audit (February 2014) and to MoPNG (July 2014) stated that

- *The cost for transportation and installation as US$ 9.8 million is incorrect. This estimate comes from the PL POD which was merely an early estimate of the likely cost.*
- *PMTJV engaged Swiber to undertake the modifications to minimize the time for award of contract as the material was under care of Swiber; there was concern that there might be a dispute under the existing contract with Swiber regarding incomplete scope and there was no desire to incur extensive storage costs from Swiber.*

- *US$ 26.5 million would have been incurred had the PL installation been undertaken using the variation rates of the SWP-PK contract and the actual utilisation.*
- *The contract price of US$ 29 million is reasonable compared to US$ 26.5 million agreed for the installation of the SWP and PK platforms and pipeline under a prior contract.*

3.6.2.2.1.3. The reply is not acceptable since the estimates for PL platform had been prepared in August 2008 based on the quotes received in the tender for SWP and PK platform. The contract for SWP-PK was awarded in September 2008 to Swiber whose quotes were L1. The total installation cost of US$ 26.5 million was for two platforms (SWP and PK) and two pipelines hence is not comparable to US$ 29 million for the single PL platform and pipeline. The costs incurred for the transportation and installation of PL was, thus, comparatively very high.

3.6.2.2.1.4. MoPNG in its reply stated (July 2014) that *the audit exception has been notified to the Contractor. The CAG may recommend in its final report the amount to be disallowed from the Contract Costs after considering Contractors' reply, if any.* The non-adherence to the prescribed tendering procedure has been commented by Audit. The contract was awarded without competition and the rates are seen to be high on comparison with similar works. As there was no price discovery, Audit is unable to quantify the impact in the instant case.

(B) Detailed design and procurement assistance

3.6.2.2.2. As per Article 6.8 of the JOA under 'Procedure C' for contracts valuing more than US$ 3 million, the JV upon approval of WP&B and defining requirement of goods and services shall prepare tender documents and publish invitation to vendors not already pre-qualified for the proposed contract in a daily Indian newspaper and process the tender accordingly.

3.6.2.2.2.1. PMT JV issued a Letter of Intent (LOI) in December 2005 for detailed design and procurement assistance in implementation of the NRPOD for expansion of South Tapti field to M/s Ranhill Worley (RW) on nomination basis with a maximum value of US$ 3 million. Within six months, the contract value was revised to US$ 8.5 million with no justification for the upward revision on record. The Notification of Award (NOA) was issued in May 2006 for US$ 8.5 million.

3.6.2.2.2.2. As against the NOA of US$ 8.5 million, the contract signed on 30 August 2006 indicated a total compensation of US$ 8.63 million. No reasons for such deviation were found on record.

3.6.2.2.2.3. RW had, in April 2006, claimed a revision in the man hour rate @15% across the board effective 1 July 2006. This was not considered in the NOA issued in May 2006 but was approved unilaterally by BGEPIL (without being considered by the Group or OB) in

March 2007 with an increase in contract value effective retrospectively from 1 July 2006. This increased staff cost alone accounted for an increase of US$ 0.86 million.

3.6.2.2.2.4. BGEPIL also issued change orders for US$ 2.03 million which included US$ 0.66 million towards work not approved by OB. This was not in consonance with the terms of the JOA which provides that all change orders above a value of US$ 50,000 or 10% of the award value (whichever is lower) should be reported to the OB for approval.

3.6.2.2.2.5. Thus, as against the initial award value of US$ 3 million, RW was paid US$ 12.16 million. As the award was on a nomination basis there had been no price discovery. Besides, the process was not in conformity with the terms of the JOA.

3.6.2.2.2.6. PMT JV in its reply to Audit (February 2014) and to MoPNG (July 2014) stated that issues raised were on matters of operational performance of the PMT JV and are the obligations of the constituents of the PMT JV contained in the JOA; GoI is not a party to JOA and these issues did not fall in scope/review of C&AG Audit. However, the JV responded on the following lines:

- *"Engineering was a critical activity that needed to be completed by March 2006, and this schedule could only be met using RW, who was familiar with the design basis, fabrication drawings and procurement history given the FEED contract.*
- *Except for using a daily Indian national newspaper as a means of identifying bidders, the JOA procedures were otherwise followed. PMTJV added that although the LOI was issued ten days prior to the Operator Board approval, it was entered into with the knowledge of the members of the Operator Board as the cost estimates was intimated to the Operator Board on 8 December 2005. Moreover, the partners of the PMTJV have never disputed the issuance of this LOI.*
- *PMTJV disagrees that the contract value was not properly assessed. The contract with RW was based on an hourly rate and was not a lump sum contract. The hourly rate was based on the rate agreed in the FEED contract, which was determined following a competitive tender. The reference to US$ 3 million in the LOI was merely an early, low estimate intended to allow work to commence, which was always to be revised in the contract based on a more accurate scope of work. In the letter to OB members on 8 December 2005, the cost of work was contemplated around US$ 8.95 million to be incurred for the scope of work under discussion. It was not advisable to state this figure in the LOI since the detailed scope was not agreed at the time of issuing LOI.*
- *It is correct that RW claimed revisions in the agreed hourly rates in April and June 2006 on account of salary increases and increases in charge-out rates respectively. The PMTJV reviewed the documentation supplied by RW and considered the revisions to be reasonable as the pay of technical staff had increased in the market.*

- *While it is correct that BG issued change orders without approval from the Operator Board, the PMTJV partners have not disputed these amounts and they were only agreed following careful consideration as to their reasonableness.*
- *Although the Operator Board resolution dated 22 December 2005 approved a cost of US $8.5 million, the Note to the Operator Board of the same date noted that this was only an estimate of the costs that may be incurred based on an hourly rate. Eventually, RW exceeded this estimate and as per the PMTJV's records, RW was paid US$12,160,680.89. It is noteworthy, however, that as the PMTJV managed the project itself under the EPCM strategy, it often closely interacted with RW and therefore had good insight into the time being spent by RW".*

3.6.2.2.2.7. The reply is not acceptable in view of the following:

- As per JOA provisions, PMT JV was to invite a tender for contracts valuing more than US$ 3 million. In this case, PMT JV did not invite a tender in contravention of JOA provisions. Non invitation of tenders restricted the competition and the reasonableness of the rates could not be ensured.
- PMT JV was aware of the estimated cost of US$ 8-9 million as intimated (8 December 2005) by RW and should have taken it into consideration while issuing LOI on 12 December 2005 with the approval of the OB. Thus, placement of LOI with a maximum value of US$ 3 million was not justified. The statement of PMT JV that LOI of December 2005 for US$ 3.00 million was merely an early, low estimate intended to allow work to commence, which was always to be revised based on a more accurate scope of work is not correct since the LOI was awarded for the maximum value without any expressed intension for further revision. The increase/revisions in man hour rates were also intimated by RW before the placement of NOA in May 2006 and should have been considered while issuing the NOA.

3.6.2.2.2.8. MoPNG in its reply (July 2014) stated that *the audit exception has been notified to the Contractor. The CAG may recommend in its final report the amount to be disallowed from the Contract Costs after considering Contractors' reply, if any.*

3.6.2.2.2.9. The non-adherence to the prescribed procedure has been commented by Audit. The contract was awarded without competition and the rates are seen to be high on comparison with similar works. As there was no price discovery, Audit is unable to quantify the impact in the instant case.

3.6.3 Petroleum saved and sold

3.6.3.1. As per the terms of the PSCs, Panna-Mukta reached the revised ceiling price of US$ 5.73 / mmbtu in February 2005 and Tapti contract area reached US$ 5.57 / mmbtu in June 2004. However, GAIL, which was nominated by MoPNG to purchase the entire gas production, refused to honour the revised gas prices[77], and continued to pay the gas price at the earlier ceiling of $ 3.11 / mmbtu till March 2005. Consequently, MoPNG instructed (November 2004) PMT JV to supply 6 mmscmd[78] (out of the total gas production of 10.8 mmscmd) to GAIL at $ 3.86 / mmbtu for one year, and allowed PMT JV to market the balance gas (4.8 mmscmd) directly at a price higher than $ 3.11 / mmbtu or such price as may be offered by GAIL. The JV entered into contracts with private customers for the remaining 4.8 mmscmd at $ 3.96 / mmbtu for a three year period upto March 2008. In view of criticality of supply of PMT gas to the priority sector, GoI reviewed its earlier decision. At the request (March 2006) of GoI, PMT JV supplied 5 mmscmd of gas to GAIL for the period from 1.4.2006 to 31.3.2008 at a market driven price of US$ 4.75 / mmbtu. The additional gas in excess of 10.8 mmscmd produced by PMT JV was shared by the JV partners according to their PI and they entered into separate contracts at different prices ranging from US$ 4.60 per mmbtu to US$ 5.58 per mmbtu. MoPNG in October/November 2007 reviewed the PMT JV gas supplies and directed PMT JV to sell entire quantity of PMT JV gas to GAIL at revised PSC price with effect from April 2008.

3.6.3.1.1. In the previous Audit Report No. 19 of 2011-12, Audit had commented vide para 6.3.1 on the sale of entire JV gas during 2005-2008 at different prices to different parties. Audit concluded that the pre-determined PSC pricing formula has not been adhered to which severally affects the sanctity of the contract. This was highly undesirable from the long term perspective of all contracting parties. In the present report, Audit has discussed the issues regarding sale of additional production of gas (over and above 10.8 mmscmd of gas) from the additional production of PMTJV in contravention to MoPNG directives and GSPA which are discussed below:

3.6.3.2. Loss of US$ 9.92 million due to sale of gas in contravention to MoPNG directives and GSPA

3.6.3.2.1. **(A)** GoI had decided (March 2006) that a separate meeting would take place at an appropriate time for dispensation of additional gas production (over and above 10.8 mmscmd).

3.6.3.2.2. However, contrary to the GoI decision, ONGC (JV partner) entered into a long term contract for 12 years and signed GSPA in June 2006 with TPL for supply of 0.9 mmscmd of gas @ US$ 4.75 / mmbtu from its share of gas from PMT JV. BGEPIL and RIL (other JV partners) also sold their share of additional gas from Phase-II development plan to its affiliates and GSPC. Though this was contrary to GoI decision, the sale price of BGEPIL and RIL was US$ 5.58/ mmbtu (i.e. higher by US$ 0.01 per mmbtu of revised ceiling price of

[77] *On the ground that its gas was allocated to the priority sector – power and fertilizer plants – who had not been able to absorb the revised gas prices, as their output price was regulated.*

[78] *During April – May 2005, GAIL uplifted only 1.5 to 2.0 mmscmd against their agreed quantity of 6.0 mmscmd. The PMTJV had to shut in Tapti wells, as it had not entered into contracts with other buyers for the quantities committed to GAIL.*

Tapti field). As per contract entered with TPL, ONGC agreed to supply its share of gas of 0.90 mmscmd for a period of 12 years with a provision to review the price after expiry of 3 years from the date of first supply. ONGC also informed (December 2007) MoPNG that the contract with TPL was signed after following a tendering process and therefore, the contract should be honored by MoPNG / GAIL. Subsequently, MoPNG intimated (March 2008) ONGC that the contract entered with TPL would be assigned to GAIL. Supply to TPL commenced from 30 May 2008 and continued at the lower rate of US$ 4.75 per mmbtu till May 2011. Supply to TPL was made at PSC price only from June 2011.

3.6.3.2.3. The agreement for sale of gas entered in June 2006 to TPL was in contravention to MoPNG's direction of March 2006.

3.6.3.2.4. BGEPIL and RIL not being parties to the contract between ONGC and TPL, PMT JV forwarded (January 2014/July 2014) the response of ONGC. *ONGC invited attention to MoPNG letter dated 31 March 2008 on supply of gas from PMT fields to TPL which envisaged that the Price would be reviewed, as due under the contract and the then prevalent PSC price shall be applicable from the date of such review. As per the contract Daily Committed Quantity (DCQ) and Sales Gas Price were valid for a minimum period of three years. The supply to TPL commenced from 30 May 2008, and its revisions as per terms and conditions of the contract/contractual commitments was applicable after May 2011. Accordingly the PSC price was adopted for supply to TPL from June 2011 onwards. In view of the above it cannot be said that sale of gas to TPL by ONGC is in contravention of MoPNG directives.*

3.6.3.2.5. Reply is not acceptable. ONGC ignored MoPNG directives of March 2006 which had categorically stated that a separate meeting would take place at appropriate time regarding dispensation of additional production of gas and signed the GSPA with TPL in June 2006 for sale of its share of gas below the PSC price i.e. @ US$ 4.75 per MMTBU. Though the other two partners also ignored MoPNG directives, their share of additional gas was sold at US$ 5.58 per mmbtu, i.e. higher by US$ 0.01 per mmbtu of Tapti PSC ceiling price. MoPNG also expressed (November 2007) its displeasure for non-adherence to its directives and directed PMT JV to sell entire production to GAIL at PSC price with effect from April 2008 onwards. MoPNG had to honour the contract of ONGC with TPL (March 2008) as the contract has already been concluded. This led to loss of revenue of US$ 19.62 million to PMT JV (ONGC). This also adversely impacted GoI Take in form of PP, royalty and income tax by US$ 9.92 million.

3.6.3.2.6. MoPNG in its reply stated (July 2014) that *neither this report of the CAG nor the earlier report No. 19 of 2011 adversely commented on the PMTJV's supply of gas at prices lower than PSC price during period 2005 to 2008. In view of the CAG's adverse comment on ONGC's supply of gas to TPL at US$ 4.75 per mmbtu after 2008, it may to be appropriate to relook at the price charged by PMTJV for direct sale of gas (which has not been reported by CAG as having been sold through tendering process unlike in the case of*

ONGC) at prices less than price prior to 2008. This issue may be deliberated in the final report so that a uniform consistent stand is taken in respect of the different prices charged by the Contractors. In the previous Audit report for the year 2011-12, CAG commented adversely on GAIL's refusal to buy gas at PSC price but failed to express its views on direct sale by PMT JV at less than PSC price.

3.6.3.2.7. *CAG may be aware that the two Companies in PMTJV invoked arbitration against GAIL on the pricing issue and reached at a final settlement of partial enhancement of the price paid by GAIL. CAG may look at the appropriateness of enhancement of the price which was paid by the 'direct' buyers in line with the enhancement of price obtained from GAIL. As the customers of 'direct' sale happen to be either the Companies themselves or their affiliate, reopening the pricing of gas should not pose any commercial complication.*

3.6.3.2.8. *MoPNG also stated that one of the issues flagged by CAG is that the Contractor paid less income tax due to charging a price less than PSC price. This would be notified to the Income Tax Department for taking final view after audit issues its final report taking into consideration the reply of the contractor.*

3.6.3.2.9. *As the PSC stipulates GAIL as the buyer of gas and provides specific terms and conditions on the pricing formula to be adopted by the buyer of gas, MOP&NG communications may not be construed as amendment to such PSC provisions.*

3.6.3.2.10. *MOP&NG's communications referred by CAG are the fallout of a situation where as per PSC the PSU nominee GAIL was required to pay a higher price but failed to pay the higher price in the circumstances of GAIL's requirement to subsidize the gas price. Considering CAG's admission that the pricing by ONGC was through a tendering process, the issue before the CAG for consideration for final recommendation is whether any better option existed in the circumstances.*

3.6.3.2.11. The response of MoPNG may be viewed in context of the following:

(i) The Audit Report no. 19 of 2011-12 had pointed out the non-adherence to PSC price which affected the sanctity of the contract (which is to be maintained by all parties). The differential prices at which 10.8 mmscmd of gas was sold by PMTJV to GAIL *vis-à-vis* its affiliates and GSPC during 2005-08 had also been elaborated in the report (para 6.3.1). The present observation is regarding sale of additional 5.7 mmscmd of gas by the partners, the concern being sale of gas by ONGC at prices lower than the PSC price.

(ii) The PSC price had not been honored and hence the need for MoPNG intervention. Audit has commented on the non-adherence of all partners to MoPNG direction for sale of additional gas and its impact.

(iii) While it is not disputed that ONGC went through a tendering process, the point being made is that ONGC was not authorized to do so by MoPNG and that the price at which the transaction was concluded was much lower than the PSC price.

(iv) The other partners, RIL and BGEPL derived the PSC price through sale of their share of the gas at the same time. This points to existence of better option to ONGC.

3.6.3.2.12. (B) Audit further observed that, GoI also directed that supply be incumbent on present level of production of PMT fields and in the event of decrease in the same, there would be a *pro rata* reduction in supplies to all customers, including TPL. Article VIII of tripartite agreement also stated that *the parties agree that the supply of Gas to TPL under the Clause 2.3 of the Existing Contract shall be incumbent on present level of production from PMT fields (i.e. 17.3 mmscmd), as provided under Gas Supply Contract between GAIL and PMTJV and in the event of decline of the same, there would be pro rata reduction in supply to TPL in accordance with the Annexure 12. Accordingly, the quantity review envisaged every three years under clause 2.1.b of the Existing Contract or stated elsewhere in the Existing Contract, shall not be applicable.*

3.6.3.2.13. Though there was substantial drop in production in the Tapti and Panna-Mukta fields during the year 2008-09 to 2011-12, supply to TPL was not reduced proportionately by ONGC. On the contrary, ONGC sold more gas to TPL during 2009-10 to 2010-11vis-à-vis 2008-09. This resulted in a revenue loss (net of GoI-PP and Royalty) to ONGC by US$ 4.17 million (which is included in revenue loss of US$ 19.62 million commented at para 3.6.3.2.5).

3.6.3.2.14. BGEPIL and RIL not being parties to the contract between ONGC and TPL, PMT JV forwarded (January 2014/July 2014) the response of ONGC. ONGC argued that *"Article VIII of Tripartite Agreement was not applicable to ONGC. As per tripartite agreement, GAIL shall be fully responsible for the performance of the existing contract, including supply of gas, adhering to the terms and condition and ONGC shall have no obligations, liabilities whatsoever arising out of the same contract".*

3.6.3.2.15. Reply of ONGC is not convincing. As ONGC was selling its share of gas to TPL below the PSC price, it was obligatory on the part of ONGC to periodically inform GAIL about drop in level of production for making proportionate reduction in supply to TPL in accordance with Article VIII of Tripartite Agreement, so as to protect its financial interest. ONGC's failure on this account benefited the private party, i.e. TPL resulting in a loss of revenue of US$ 4.17 million to itself and adversely impacting GoI take by US$ 1.47 million.

3.6.3.2.16. MoPNG in its reply (July 2014) stated that *the audit exception has been notified to ONGC and CAG may like to consider ONGC's response. Specifically it needs to be seen whether GAIL could have reduced the supply to TPL by virtue of the provisions quoted by Audit, in the light of the fact that gas was actually available for supply to TPL at the entire agreed quantity.*

3.6.3.2.17. As already brought out in para Article VIII of tripartite agreement provided for *pro rata* reduction in supply to TPL in the event of decline in gas production. As ONGC suffered a loss in sale of excess gas to TPL, it ought to have protected its interests appropriately.

3.6.3.3. Loss of government revenue of US$ 0.52 million due to sale of Panna-Mukta gas in contravention to PSC

3.6.3.3.1. While ONGC sold its share of additional 5.7 mmscmd of gas at US$ 4.75 per mmbtu, the other two partners (RIL and BGEPIL) sold their share of additional gas from both Panna Mukta and Tapti fields at US$ 5.58 per mmbtu. Audit noticed that 14,767,436 mmbtu of gas sold was from Panna-Mukta field which was sold to private consumers at US$ 5.58 per mmbtu, the price being lower than the Panna Mukta PSC ceiling price of US$ 5.73 / mmbtu. This resulted in loss of revenue of US$ 2.22 million and resultantly loss of revenue to the GoI of US$ 0.52 million in the form of PP and royalty.

3.6.3.3.2. While stating that the *issue relates to pre date period being audited by C&AG and hence outside the scope* PMT JV in its reply to Audit (January 2014) and to MoPNG (July 2014) stated that *GoI had permitted PMTJV to market the surplus production of gas directly to consumers during {the Direct Gas Marketing (DGM) period)}. Accordingly, the gas price stipulated in the PSCs was not applicable during the DGM period. The gas price paid by GAIL and other buyers during the DGM period was a market driven price which was established on an arm's length basis with non-affiliated parties such as GSPC. As such, any loss in revenue to the GoI during the DGM period arose from the failure of GAIL and the GoI to comply with their respective obligations and not any failure on the part of the PMTJV. Upon the Government revoking its direction to the PMTJV to market gas directly, the gas price reverted to the PSC price with effect from 1 April 2008. The additional gas was allocated predominately from the Tapti field. Only a very minor proportion was supplied from Panna-Mukta (circa 1 % of sales) between December 2006 and September 2007 to maintain contractual commitments. From October 2007, additional volumes of gas from Panna-Mukta were supplied under the existing contracts which offered the highest price i.e. US$ 5.58/mmbtu.*

3.6.3.3.3. Reply of PMT JV is not convincing. The market driven gas price paid by GAIL and other buyers during DGM period was for sale of 10.8 mmscmd of gas. In addition to this, PMT JV produced approximately 5.7 mmscmd of gas during the period 2006-08 both from Panna-Mukta and Tapti contract areas. PMT JV partners contracted their share of additional quantity to private customers, mostly its affiliated parties at different prices. BGEPIL and RIL sold their share of gas @US$ 5.58 / mmbtu. During last round of audit (2006-08), in response to audit query, PMT JV stated that this additional gas production of 5.7 mmscmd (16.5 less 10.8 from Phase-I existing surface facilities) came from the Phase-II development of new surface facilities of the Tapti Contract area which was sold at a price of US$ 5.58 per mmbtu i.e. US$ 0.01 / mmbtu higher than the revised Tapti ceiling price.

Hence, there was no loss to the GoI in any form. However, Audit in the follow up audit of 2008-12, verified the reply of PMT JV to the Audit Exception notified by MoPNG for 2006-08 and found discrepancy and hence the argument of PMT JV that the issue falls outside of scope of audit is not tenable. Audit observed that PMT JV also produced additional gas (14,767,436 mmbtu) from Panna-Mukta field for which gas price of US$ 5.73/ mmbtu was applicable. Sale of Panna-Mukta gas at Tapti gas price led to loss of GoI PP and royalty of US$ 0.52 million that needs to be paid to GoI along with applicable interest. The contention of PMT JV that only a minor proportion was supplied from Panna-Mukta was not acceptable since there were different PSC prices for Panna-Mukta and Tapti gas and the quantum did not have any bearing as contested by PMT JV.

3.6.3.3.4. MoPNG in its reply (June 2014) stated that *notwithstanding the Contractor's reservation that the audit query relates to pre-date period being audited, CAG may like to give the financial impact of the two companies charging a price less than the PSC price for gas supplied to their affiliates during the entire period including for the years prior to period of audit. CAG may suggest the course of action that is available for MOP&NG, if any, as a remedial measure.*

3.6.3.3.5. The financial impact of GoI take (Royalty and GoI PP) due to sale of gas below PSC price by PMTJV and its partners over the period 2005-08 was US$ 107.66 million (*Annexure 12*). The financial impact for 2008-11 arising from sale of gas by ONGC to TPL at a price lower than PSC price has been worked out at para 3.6.3.2.5 above. GoI may take an appropriate view of short payment of GoI PP and royalty on this account under PSC provisions.

3.6.3.4 Non fixation of transportation losses of condensate

3.6.3.4.1. The PSC for Mid and South Tapti is silent on the disposal of condensate, i.e. whether it is gas or crude oil. PMT JV was treating the condensate as gas till December 2005. The transportation and processing of PMT gas was undertaken by ONGC through its South Bassein-Hazira offshore trunk pipeline and onshore Hazira facilities respectively and was governed by a settlement agreement of December 2005 between ONGC and PMT JV. In the settlement agreement, the condensate transportation losses from the Tapti delivery point to ONGC's Hazira Plant were to be determined by a condensate expert to be jointly appointed by ONGC and PMT JV. Pending determination of such losses, it was agreed to treat the Tapti condensate losses provisionally as 'zero'.

3.6.3.4.2. The non-determination of condensate losses during transportation was commented vide Paragraph 6.3.2 in C&AG of India (Union Government-Civil) Report No.19 of 2011-12-Performance Audit of Hydrocarbon PSCs. MoPNG in response stated that JV had already shortlisted international agencies for assessment of transportation losses. As a way forward, the JV and Institute of Oil and Gas Petroleum Technology (IOGPT) of ONGC were working on the simulation model to firm up the scope of work, results of which were to be validated by a third party expert. It was observed that the condensate transportation losses have not yet been determined (February 2014) even after a lapse of 8 years from the settlement agreement reached in 2005. The PMT JV and IOGPT-ONGC had only decided (August 2012) the scope for determination of Tapti Condensate Transportation losses and were to start the process of selection of 'Expert' for determination of Tapti Condensate Transportation losses.

3.6.3.4.3. The delay in determination of condensate transportation losses has been detrimental to ONGC.

3.6.3.4.4. PMT JV in its reply to Audit (February 2014) and to MoPNG (July 2014) stated that matters that arise under a settlement agreement between the PMT JV and ONGC are outside the scope of the present audit conducted under Section 1.9 of Appendix C of the Tapti PSC. Without prejudice to this, it is stated that *"the condensate loss expert has now been appointed and are hopeful that the matter will be resolved within the next few months. The transportation losses determined by the independent expert will be applied retrospectively from 1 April 2005, and excess amounts paid by ONGC, if any, will be refunded (clause 4.4 of the settlement agreement). As such, ONGC should suffer no detriment".*

3.6.3.4.5. MoPNG in reply (July 2014) stated that *CAG needs to consider whether condensate will be lost when it is transported in a closed circuit pipeline. MoPNG added that any transportation loss paid to ONGC will be detrimental to this PSC by reducing Profit Petroleum. Hence, this issue does not warrant reply under PSC audit. It may be appropriate to raise the issue to ONGC when ONGC's accounts are audited.*

3.6.3.4.6. The reply needs to be viewed in light of the fact that the non-fixation of transportation loss of condensate was brought out in the previous Audit Report No. 19 of 2011-12. While ONGC is considering internally 6 *per cent* as transportation and processing loss from condensate, the PMT JV is considering the loss as 'zero' from 2005 which was commented upon. It is also not out of place to mention that the ONGC was considered as a part of GoI while evaluating the bidding of PMT fields and the total revenue including the share of ONGC was considered as GoI share. In this context, the issue is appropriately raised under PSC audit in the last Audit Report and also in the current audit.

3.6.3.4.7. The fact, however, remains that the condensate transportation loss is yet to be determined even after a lapse of 8 years from Settlement Agreement.

Audit Recommendation 13: PMT JV may expedite the fixation of transportation losses of condensate pending for last 8 years that has impacted the interest of ONGC.

3.6.3.5 Short payment of royalty due to incorrect computation of wellhead value

3.6.3.5.1. Methodology adopted by the PMT JV for calculation of wellhead value in accordance with the notification of August 2007 was reviewed and the deficiencies observed in calculation of wellhead value of natural gas are discussed below.

3.6.3.6. Incorrect calculation of royalty on gas due to reckoning of facilities not used for post-wellhead activities

3.6.3.6.1. PMT JV laid two gas export pipelines; one an 18 inch TPP (Tapti Process Platform – April 1997) to ONGC's SBHT (South Bassein-Hazira Trunk line) pipeline (August 1997) and the other a 20 inch TCPP (Tapti Compression Process Platform-August 2007) to ONGC's SBHT pipeline (August 2007) for transportation of PMT JV gas from offshore to onshore for sale.

3.6.3.6.2. Audit observed that the dehydration system at TCPP is being bypassed and the field gas throughput is being routed *via* TCPP separators to TPP in an attempt to optimize the suction pressure and increase the production rates. In this process, the TCPP sales line is not being utilized from July 2011 and the entire gas is flowing through TPP sales line. However, JV has considered the value of TCPP dehydration facilities and TCPP 20 inch gas sales line for working out the ratio of wellhead and post-wellhead facilities and for calculation of wellhead value. As the TCPP dehydration facilities and TCPP gas sales lines (post-wellhead facilities) are presently not utilized for post well head activities, allocating the operating expenditure between wellhead activity and post-wellhead activity considering these facilities as post-wellhead facilities was improper and resulted in working out of lower wellhead value and consequently lower payment of royalty to GoI. In absence of separate operating cost of these facilities, Audit could not work out the impact on GoI take.

3.6.3.6.3. PMT JV in its reply to Audit (January 2014) and to MoPNG (July 2014) stated that *"it is irrelevant whether the equipment and facilities are being used at any particular point in time as long as the equipment and facilities have been created for the purpose of Petroleum Operations. The TCPP dehydration and TCPP 20 inch gas sales line was created for the purpose of Petroleum Operations, and attract a proportion of total operating expenditure even during periods their use is temporarily suspended. The equipment and facilities in question were utilised till June 2011 and since then have been on standby and used intermittently as and when required. PMTJV do not consider it would be practical to adopt the approach suggested by the CAG, nor do we consider there is any basis in the PSCs or otherwise for doing so".*

3.6.3.6.4. Reply is not convincing. The post-wellhead value should have been worked out considering the value of facilities actually used for petroleum operations and not based on value of facilities created for petroleum operations. Once a certain facility is not used for petroleum operations the same should have been excluded for working out ratio for allocation of opex between wellhead and post-wellhead expenditure. From the records produced up to March 2012, it was observed that TCPP dehydration and TCPP 20 inch gas sales lines was not utilised since July 2011. The TCPP dehydration is bypassed and production is routed through TPP in an attempt to optimize the line upto target lower suction pressure and increase production rates. Considering consistent drop in level of production in Tapti field, it is unlikely that PMT JV would utilise TCPP dehydration and TCPP pipeline in future. A similar issue on allocation of opex between wellhead cost and post-wellhead cost was pointed out in Audit Report No. 19 of 2011-12.

3.6.3.6.5. MoPNG in reply (July 2014) while agreeing with the Audit view on consideration of commissioned and used facilities only for the purpose of allocation of opex and payment of royalty stated that *the Government stand in the arbitration is that the royalty is payable on sale price as the gas sale price constitutes the wellhead value of gas. Hence, the issue flagged by Audit may not be relevant. The correct basis would be used to re-compute the royalty in the event that Government's case that royalty is payable on sale price does not become enforceable.*

3.6.3.7. *Exclusion of ONGC's facilities for working out ratio for allocation of opex between wellhead and post-wellhead activities*

3.6.3.7.1. While working out the ratio of cost of facilities incurred on wellhead activity and on post-wellhead activity, PMT JV has not considered the cost of five wellhead platforms *(viz. PA, PB, PD, PE and MA wellhead platform)* as wellhead activity which were installed by ONGC and handed over to PMT JV at the time of signing of PSC (December 1994) and presently being used by PMT JV for extraction and production of crude oil and natural gas. Since PMT JV is incurring the operating expenditure for all the facilities including the five wellhead platforms handed over by ONGC, the exclusion of ONGC's facilities for working out the ratio of post-wellhead operating expenditure is not correct and has resulted in lower payment of royalty to the GoI. The short payment of PP to GoI on this account worked out to US$ 0.47 million for the period 2008-09 to 2011-12.

3.6.3.7.2. While stating that the issue relates to PMT JVs accounts since inception and therefore includes a period outside the audit period and hence the scope of C&AG Audit, PMT JV in its reply to Audit (January 2014) and to MoPNG (July 2014) stated that

- *"Panna-Mukta PSC does not contemplate the transfer of costs incurred by ONGC before the PSC was entered into in respect of the 5 wellhead platforms and post wellhead interconnecting flowlines and pipelines into the PMT JV's books of accounts. For this reason, Appendix F of Panna-Mukta PSC expressly stipulates that 'All Equipment specified below including that not yet installed, shall be provided at ONGC's cost and risk'. In other words these platforms were transferred to PMT JV free of charge.*
- *Since capex in connection with the installation of the PA, PB, PD, PE and MA wellhead platforms and post-wellhead interconnecting flowlines and pipelines was not incurred by PMT JV or transferred to its books of accounts, these costs are not*

taken into account when calculating the ratio of pre-wellhead capex and post-wellhead capex for the purpose of calculating the WHV".

3.6.3.7.3. Reply of PMT JV is not acceptable in view of the following:

- Though it is a fact that these facilities were provided by ONGC free of cost, PMT JV is maintaining these facilities and thus cost of opex includes the cost towards maintaining these facilities.
- Non consideration of capex of these facilities for allocating the opex between wellhead facilities and post-wellhead activities would distort the allocation since the capex of both well head and post well head assets were not properly reflected for working out the opex and impacted the GoI PP.

3.6.3.7.4. MoPNG in reply (July 2014) stated that *without prejudice to the Government's stand that royalty is payable on sale price in the Contract Area, if capex is used as a basis for allocation of opex, then the cost of facilities handed over by ONGC should be considered for allocation of opex (as pointed out by CAG). In the absence of such data, the basis of allocation should be appropriately done based on the actual incidence of such opex. The proposed basis will be used to re-compute the royalty in the event that Government's case that royalty is payable on sale price does not become enforceable.*

3.6.3.8. Short payment of royalty due to amortization of capex not based on upgraded reserves

3.6.3.8.1. Pending determination of norms for computing post-wellhead costs in August 2007, Panna-Mukta and Tapti PSCs during the period from 1997 up to August 2007 reckoned capital cost for working out the value at wellhead. The capital cost was amortized during this period based on unit of production method. The amortization of capital cost was done considering PSC reserves instead of upgraded reserves subsequent to signing of PSC in December 1994. This was commented in Para 6.2.2 (Table 6.5) of C&AG report no. 19 of 2011-12 of Union Government (Civil) on PA of Hydrocarbon Production Sharing Contracts.

3.6.3.8.2. MoPNG agreed (July 2011) with the Audit view and stated that the *"quantification of the audit exception for the period prior to August 2007 would enable direct action on part of GoI. In the absence of such quantification, the JV would be advised to rectify the mistake and pay differential royalty, subject to arbitration proceedings".*

3.6.3.8.3. Based on C&AG report, MoPNG also notified (November 2011) this audit comment as audit exception to the PMT JV. In reply to audit exception, PMT JV stated (March 2012) to MoPNG/DGH that *"DGH/GoI did not object or raise any audit exception relating to the methodology and/or calculations of royalty submitted by the Contractor on a monthly basis in the period from 1997 up to August 2007. Further, the gas production from the upgraded reserves in Tapti commenced in August 2007, and to comply with the August 2007 notification the contractor has paid royalty on such gas production i.e. from August*

2007 without deducting post wellhead capital expenditure. Hence the basis for amortization as per Appendix H of the PSCs agreed amongst the Parties to the PSC and which has been consistently used each year".

3.6.3.8.4. However, review of the position of PSC production profile as of 22 December 1994 *vis-à-vis* reserves estimated by PMT JV during the period 1998 to 2007 for both Panna-Mukta and Tapti fields revealed that PMT JV had substantially upgraded the ultimate recoverable reserves (proved developed) in both the fields and extracted more production in comparison to PSC production profile. Thus, use of PSC reserves instead of upgraded reserves for calculation of payment of royalty resulted in short payment of royalty to the GoI.

3.6.3.8.5. In the absence of month-wise details of additional capex incurred, reserves position and royalty calculation statements Audit could not work out the exact impact on GoIPP. PMT JV should rework the royalty calculations for period from 1997 up to August 2007 considering the up-graded reserves and remit the short payment of royalty along with penal interest for delayed payment under Rule 23 of Petroleum and Natural Gas Rules, 1959 and subsequently under Petroleum and Natural Gas (amendment) Rules of 2003 to the GoI.

3.6.3.8.6. PMT JV in its reply to Audit (February 2014) and to MoPNG (July 2014) stated that *the audit issue relates to the period from 1997 to August 2007 and was therefore outside the scope of the C&AG Audit*. However the JV clarified that

(i) "Prior to August 2007, the PMT JV had been using the production profile set out in Appendix H of the PSCs for the purposes of calculating the amortized unit rate of capex. This methodology was first explained to the GoI when production from the Tapti and Panna-Mukta fields started in FY 1997-98 and reiterated on subsequent occasions.

(ii) Neither MoPNG nor the DGH has ever suggested that the production profile as per Appendix H of the PSCs used for the purposes of royalty calculations was incorrect. In PMT JV's view, the methodology used for these purposes was reasonable and it would be inappropriate to now impose retrospective changes to the PMT JV's accounts for the period FY 1997-98 to August 2007.

(iii) Further in any event, any revisions could only be based on the reserves that were proved and developed at the time the individual royalty calculations were originally made".

3.6.3.8.7. The reply is not acceptable in view of the following:

(i) The issue had been raised in the previous Audit Report and being a follow up audit is within the scope of the present audit exercise.

(ii) It has been verified that the reserves of both Panna-Mukta and Tapti fields were periodically upgraded right from 1998 onwards.

(iii) As the proved developed reserves of Panna-Mukta and Tapti fields were upgraded, the amortization of capex should have been worked out based on the upgraded reserves in order to arrive at the post-wellhead value. Non consideration of upgraded reserves in amortization of capex resulted in short payment of royalty to GoI.

3.6.3.8.8. MoPNG while agreeing with the Audit view stated (July 2014) that *the PMT JV's explanation is devoid of logic. It is clarified that the Government in the arbitral proceeding has pleaded that royalty is payable on gas sales price without any deductions. The entire deduction has been objected to by GOI under the arbitration. The correct basis as suggested by CAG will be used to re-compute the royalty in the event the Government's case that royalty is payable on sale price does not become enforceable.*

Audit Recommendation 14: All facilities used for petroleum operations (pre wellhead and post-wellhead activities) may be considered for computing the wellhead value while arriving at royalty payable to GoI. The PMT JV may also work out and remit the additional royalty to GoI by considering the upgraded reserves (1997 to August 2007) for amortization of capex.

3.6.4 Petroleum Operations

3.6.4.1 Preparation of Plan of Development for South West Panna without waiting for new seismic data resulted in abandoning of project

3.6.4.1.1. Article 7.3 (b) of PSC states that '*Contractor shall conduct all Petroleum operations within the contract area diligently, expeditiously, efficiently and in safe and workman like manner -------.*'

PMT JV in September 2007 submitted a draft Plan of Development (POD) for South West Panna (SWP) project to the MC. The MC approved (February 2008) the SWP POD involving installation of platform and pipeline. The POD envisaged recoverable reserves of 3.7 mmbbl of oil and 6.8 bcf of gas. During installation, the jackets of SWP platform fell (February 2009) into the sea which were recovered (April 2009) and stored in Pipavav. Meanwhile, in September 2009 the JV undertook a review of the reserves of SWP in light of the newly acquired 3D data and submitted (October 2009) to DGH a downward revision of SWP reserves at 1.76 mmbbl. With lowering of reserves the SWP project showed negative NPV. Hence MC/DGH decided (December 2009) that JV shift the SWP facilities to PL project which was approved in September 2009. The SWP pipeline already laid in March 2009 could not be used for PL location.

3.6.4.1.2. The SWP was designed for a 6 slot wellhead platform in 58.9 m water depth whereas PL was for 9 slots in 55.5 m water depth. Hence, modifications were necessary before relocating the SWP facilities to PL. The JV moved the SWP facilities to the fabrication yard of Gulf Piping Company at Abu Dhabi for modification. The facilities after modifications were installed at PL location in January 2011.

3.6.4.1.3. Audit observed that

- The MC approved the SWP POD in February 2008. It was known at that stage that there was 'reservoir uncertainty'. In fact, the shortcoming of 3D data shot in 1996 was acknowledged earlier leading to MC approving acquisition of a new high resolution 3D seismic data in September 2007. Yet at the same time the JV submitted the POD for SWP which was based on the old data of 1996.
- Consequently, PMT JV had to abandon the SWP project and on shifting the SWP facilities to PL incurred an additional expenditure of US$ 14.10[79] million.
- Though the facilities of SWP have been used for PL project, the SWP pipeline laid in March 2009 was rendered infructuous (US$ 20.80 million). Audit also noticed that during installation the pipeline got filled with untreated sea water. With the abandonment of SWP platform, the SWP pipeline was left with untreated sea water. Consequently, the SWP-PPA pipeline got corroded and the JV incurred a cost of US$ 0.86 million for carrying out preservation of the pipeline.

Thus, failure of DGH/MC and the JV to wait for new 3D data resulted in abandoning the project and consequent additional expenditure of US$ 35.76 million (US$ 14.10 million + US$ 20.80 million + US$ 0.86 million).

3.6.4.1.4. PMT JV in its reply to Audit (January 2014) and to MoPNG (July 2014) stated that *the issue raises matter whether PMT JV acted in accordance with its obligations under Article 7.3 of the PMT PSC with respect to SWP POD project and therefore was outside the scope of audit.* Without prejudice to this the PMT JV, responded as below:

The original 1995 3D seismic data in respect of Panna was of sufficient quality for the successful development of the whole of Panna field for several years and it was also vital in making discovery at SWP.

The SWP area was incorporated in new 3D seismic acquisition that was approved on 3 April 2007 on a contingent basis and 12 July 2007 on a firm basis to increase the confidence in SWP POD during the development phase.

The intention was to use the new high resolution seismic data to better place the wells only, as uncertainty in the porosity distribution affected the placement of wells targeting the sweet spots within the hydrocarbon pool. This did not prevent the JV from installing the SWP facilities and did not therefore require the PMT JV to wait for interpretation of new seismic data.

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[79] *1. Storage costs for SWP facilities: US$ 2.6 million, 2. Transportation of facilities to Abu Dhabi for modification and back: US$ 6.10 million 3. Variation orders relating to SWP: US$ 1.7 million. 4. Modifications: US$ 3.7 million.*

Subsequent decision to abandon the SWP project was based on revised geological interpretation of SWP area. Since the submission of POD, significant work has been carried out on the newly acquired Mukta Seismic, reinterpretation of the geological model and modeling the fluid behavior model. Plans and proposals for particular works or projects are commonly revised including as an Operator's knowledge of the geology of a field develops based on new data and experience over time.

3.6.4.1.5. MoPNG in reply stated (July 2014) that

Every reservoir has uncertainty without exception and every reservoir poses possibilities of upside potential as well as downside risk. (The MC has never described SWP as uncertain reservoir).

Subsequent to the approval of SWP project, the Operator carried out a thorough study of Mukta new 3D seismic data that covered SWP area as well. The 2006 depth model for SW Panna, which was used for the development plan, was part of the Panna model which was built on well control and depth trends from impedance data. The velocity modelling for the seismic data of 2009 was done using Panna/Mukta wells and seismic velocities as depth. In this depth model PJ well markers are also incorporated which were unavailable for the 2006 model.

It is a global practice and phenomenon in E&P industry to always refine and update the G&G model prior to implementation. In this case, the Mukta new seismic was used to refine the placement of the SWP wells and also to cross check the geomodel built for SWP based on earlier data. The total analysis of Mukta new seismic, in light of every available G&G data, indicated a lowering of reservoir rock volumes in SWP area, because of lowering of structural level of reservoir top and shallowing of OWC by about 07 mts.

The only issue raised by audit is that the SWP project could have waited till the new 3D was available. SWP project was envisaged based on the 3D data already available with the Operator, based on which all other successful projects were undertaken under this PSC. The new 3D was essentially for development of Mukta field and also provided more insight about SWP using new and better technology. The audit view is only a hindsight analysis which could not be done by the Operating Board when the project was commenced. Audit's proposal for deferring the project for a later date is inappropriate.

3.6.4.1.6. The reply needs to be viewed in light of the following:

- The JV while intimating (October 2009) the downward revision in the reserves of SWP brought out that *"SWP seismic data was recorded in 1996-97 alongwith Panna field and processed in 1997. The data quality (signal/noise ratio) was very poor at the reservoir level, however, this data was used to plan and drill the SWP-1 well in 2006 and was also used to calculate the volumes for the development plan for SW Panna. The same was reprocessed in 2007 with slight improvement in the signal/noise ratio* *than the previously recorded Panna seismic data. As a consequence of new 3D data time interpretation of the seismic data has changed and the new data has a higher degree of confidence*".

- The PJ wells were drilled during April 2008 to September 2008. The contract for SWP Platform was awarded in September 2008 and the processed data was available in November 2008. The installation of SWP platform was taken up in January 2009.
- While it is true that revisions to the plans/projects are made due to changes over a period of time or gaining of better understanding of field parameters/reservoir characteristics, the fact was that there was uncertainty in the porosity of the SWP field right from the beginning. PMT was finalising the POD for SWP and at the same time was also firming up the proposal for acquisition of new 3D data. Since PMT JV was aware of the uncertainties in the SWP area it should have waited for the results of 3D data. Since the POD was approved by the MC, it is presumed that the above points were known to the MC in February 2008. The PMT JV had included the 3D acquisition work under firm category in the WPB of 2007-08 for 'achieving better definition of the in place volume to reduce the uncertainty for future phase development and placement of development wells'. In fact, as acknowledged by PMT JV, '*the key reason for acquiring the 3D data for Panna along with Mukta was upcoming development of SWP area*'.
- Article 7.3 (b) of PSC states that '*Contractor shall conduct all Petroleum operations within the contract area diligently, expeditiously, efficiently and in safe and workman like manner -------.'* Since JV was aware of the shortcomings in existing 3D data and had specifically decided to include Panna area to get better picture of SWP area, it should have waited for the results of 3D data before putting up the facilities. While the contract for PK and SWP platform was awarded in September 2008, the processed 3D data was available in November 2008.

3.6.4.2 Delay in water injection project in Panna field resulting in declining production

3.6.4.2.1. Oil production from a field undergoes three phases: primary, secondary and tertiary. Primary oil recovery is limited to hydrocarbons that naturally rise to the surface. With the passage of time and continuous production of oil reserve, the natural reservoir pressure gets depleted and secondary recovery methods like water and gas injection are employed for displacing the oil and driving it to the surface.

3.6.4.2.2. The reservoir pressure of Panna field which was 2550 psia[80] at the beginning (1986) gradually started falling. Consequently, the production from Panna field started declining. The declining rate which was 10-12 *per cent* in 2003 increased to 12-15 *per cent* in 2007-08, and to 18-20 per cent in 2010-11.

[80] *pounds per square inch absolute.*

3.6.4.2.3. Both DGH as well as the JV in 2003 itself was aware of the declining production. Though the JV carried out a feasibility study for water injection[81] in Panna at that time, the low prevailing oil prices (US$ 18-20/bbl) rendered the project uneconomical. The crude oil price subsequently increased from an average of US$ 27.69 per barrel (2003) to US$ 50.00 per barrel (2005) and to US$ 64.2 per barrel (2007). The JV, however, did not review the feasibility for water injection. By 2007, the reservoir pressure had further declined to about 2000 psia. On the direction (February 2007) of DGH, the JV conducted studies in 2007-08 and 2008-09 and found water injection to be technically feasible. The returns were, however, expected to accrue only after 4-5 years from start date. Since the PSC term was to expire in 2019, the JV desired for extension of the PSC term. In 2008-09 DGH had also agreed for request of PSC term by the JV and in the MC meeting held on 20 January 2009, DGH asked the JV to submit an outline of water injection proposal together with request for PSC extension. The JV, in February 2009, informed DGH that it had prepared a detailed report on feasibility of water injection but submitted the feasibility report to DGH only in September 2011. It also made a request for extension of PSC term.

3.6.4.2.4. DGH is yet to approve the feasibility report. DGH, however, wrote (March 2012) to JV stating that '*pressure maintenance should have been started as soon as it was evident that the reservoir pressure was falling below saturation point*' and that the Operators '*should have proposed WI in early 2000 if they were serious about good operational standards and reservoir management*'. As on date there is no further progress in the WI scheme pending approval of pre feasibility study and decision on the PSC extension by DGH.

3.6.4.2.5. Audit observed that PMTJV and DGH recognized that delays would result in irreversible loss of oil recovery. Each year of delay was expected to result in loss of reserves of 4-5 mmbbl. As per the JV's letter of April 2012 to DGH 'any delay was expected to have an exponential and detrimental impact on its overall technical and economic viability due to pressure drop and watering out of the existing wells'.

3.6.4.2.6. The protracted delay in submission and correspondence was, however, not followed by any action. With each year of delay the voidage would increase resulting in need for more facilities and higher cost impacting project viability. Though DGH was aware of the need for implementing the WI at the earliest as a technical requirement for enhancing the recovery of production, they failed to expedite the same mainly due to indecision on the extension of PSC term. Meanwhile, the reservoir health deteriorated.

3.6.4.2.7. PMT JV in its reply to Audit (February 2014) and to MoPNG (July 2014) stated that

[81] *Water injection involves drilling injection wells and introducing water into the reservoir to encourage oil production. While the injected water helps to increase depleted pressure within the reservoir, it also helps to move the oil in place.*

(i) *"PMT JV had sought an alternative method to optimize production level at Panna namely through drilling of development wells and active reservoir management. As stated in an Operating Committee resolution dated 7 April 2003 'infill drilling in Panna along with a gradual relaxation of field gas rate is a robust reservoir management and field development strategy for a coning dominated reservoir like Panna B zone, both from a technical and economic view point.*

(ii) *PMT JV did not reconsider the decision to opt for infill drilling rather than water injection when oil prices began to rise as the infill drilling and EPOD work proved to be a robust reservoir management and field development strategy.*

(iii) *The technical risks of water injection when compared to its relatively low economic value both for the PMT JV and the GoI, have deterred the PMT JV from performing this work. PMT JV had identified water injection as a marginal project as the potential incremental increase in production does not appear to justify the high upfront capital costs of US$ 2.2 billion required for water injection...' '... and that the project was not economically viable within the current PSC period and was only marginally economically viable even if an extension were granted.*

(iv) *Early breakthrough of injected water reducing the anticipated hydrocarbon recovery has already been seen in a tracer study. Implementation of water injection scheme in earlier years carried the risk of causing an uneven movement of hydrocarbons in and lower ultimate recovery from Panna reservoir, where a thin oil column enclosed between large gas cap and an aquifer is very sensitive to water to any such water injection scheme.*

(v) *The PMT JV has diligently properly and efficiently developed the oil and gas fields underlying the Panna-Mukta and Tapti PSC contract areas in accordance with the PSC terms and best international practices and standards".*

3.6.4.2.8. MoPNG in reply stated (July 2014) *that declining of production has always been explicitly known whereas all geological phenomena may not have technical solutions, as cost factor will also be a matter of significance.*

3.6.4.2.9. DGH raised (January, March and April 2012) the following issues: *a) the proposal included water injection scheme for B-zone and did not include water injection for A-zone; b) many technical queries to JV remain unanswered. In a MCM held on Jan. 04 2013, the JV informed that they would be reevaluating the water injection project feasibility in view of recent geological surprises (quick recovery of tracer within two days from wells 2-3 kms apart after water dumping) in Panna field.*

The PMT JV is yet to submit the modified water injection pre-feasibility reports for both Panna-B and A zones incorporating the present geological observation and find out a techno-economically viable project. The technical issue before the JV is to find out a techno-economically viable project to enhance the recovery. Arresting the rate of fall in reservoir *pressure will be one of the favourable technical outcomes expected from a water injection project.*

3.6.4.2.10. The replies need to be viewed in light of the following:

- The reservoir pressure continued to fall and production decline increased from 10-12 *per cent* in 2003 to 12-15 *per cent* in 2007-08 and to 18-20 *per cent* in 2010-11. As per the JV the decline in production due to pressure depletion in 2011 alone was estimated at about 2 mmbbls of oil. Also 40 *per cent* of wells in Panna were closed due to increase in water cut.

- DGH from time to time (January 2009, March 2010, November 2010 and August 2011) had directed PMT JV to implement the WI in Panna field at the earliest to resolve the reservoir health and to control the decline in pressure. DGH in March 2010 had stated specifically that 'until WI started no infill wells were likely to be considered'. DGH however, continued approval of infill wells in 2011-12.

- In the various technical committee meetings/workshops conducted during March 2010 and October 2011) while the JV acknowledged that '*studies over the past few years had provided a better understanding of the field which now allowed WI project to be implemented effectively and that WI scheme was appropriate for implementation and reasonable*', DGH observed '*Technical studies of WI had reached substantial maturity for it to be implemented now. Model refinement and project optimization would continue but in parallel with WI project implementation'*. DGH strongly advised to schedule all activities targeting start of WI from early 2014.

- Besides, the technical scheme, incremental reserves and facilities cost for the B zone water injection project were also reviewed and endorsed by independent Auditors viz. Worley Parsons and Reservoir Knowledge in October-November 2010.

- The Pre-Feasibility report submitted in September 2011 had also brought out that '*the project risks with regard to Reservoir uncertainties around reservoir heterogeneity, residual oil saturation, movement of oil into gas cap, injectivity, water injection compatibility with reservoir, etc. would always exist as part of nature and would be addressed on a regular basis as part of ongoing reservoir characteristics*.' Most of the risks were stated to be contained and factored in the current analysis as part of model calibration process.

- The PMT JV while submitting the Pre Feasibility study report brought out that expeditious implementation of Water injection scheme as envisaged could yield 6% incremental gain (71.6 million stock barrels oil and 94.9 bcf gas upto economic life of 2038).

- DGH took six months (October 2011 to March 2012) to review the report and communicated its comments to the JV in piecemeal even though it had actively participated in the technical committee meetings/workshops and had also directed the JV on the studies to be conducted.

- Considering that the water injection study is yet to be approved and a decision on PSC term is yet to be taken and with delay having adverse impact on the recovery factor, it is unlikely that the WI scheme would be implemented in near future.

3.6.4.2.11. The loss in production during 2008-09 to 2011-12 was to the extent of 77282848 bbls of oil valuing US$ 661.86 million.

3.6.5 Non-Compliance to PSC provisions

3.6.5.1 Delay in submission and approval of Work Programme & Budget

3.6.5.1.1. As per Article 4.2 of the Panna-Mukta and Mid & South Tapti PSCs, Contractor is required to submit annual WP&B for each FY ninety (90) days before commencement of each following FY. Contractor is required to submit the WP&B to the MC through OC for approval. Such annual WP&B is required to be approved by the MC. Further, Article 4.3 of the PSC states that the Contractor may propose amendments to the details of an approved WP&B in the light of the then existing circumstances and shall submit to the MC, through the OC, modifications or revisions to the WP&Bs. Thus, approval of MC is prerequisite for conducting any petroleum operation in the contract area.

3.6.5.1.2. The timeline for submission of WP&B is laid down to ensure that MC's review/approval to WP&B is completed properly before start of the next FY so that the work can be implemented and expenditure incurred as per the approved WP&B. It also helps JV to plan the petroleum activities and to mobilize the requisite resources well in advance.

3.6.5.1.3. Review of records for the FYs 2008-09 to 2011-12 relating to submission and approval of WP&B and signing of MCR, revealed that there were delays ranging from 13 to 89 days (except during 2008-09) in submission of WP&B to MC for approval.

3.6.5.1.4. While agreeing to the delay in submission of WP&B for 2009-10 to 2011-12 PMT JV in its reply to Audit (February 2014) and to MoPNG (July 2014) stated that *it would continue its efforts to ensure timely submission and approval of WPB. The difficulties in scheduling of MC meetings have been observed also under other PSCs in India leading MoPNG to issue a circular on holding of MC meetings. Thus, issue of timely approval and holding of MC meetings is something the industry faces difficulties with in general and not specific to the PMTJV.*

3.6.5.1.5. The MoPNG in reply (July 2014) stated that *the CAG observation that the annual work program budget should be submitted by PMT JV in time and that the MC should approve before commencement of the year is noted for compliance.*

3.6.5.1.6. MoPNG may ensure adherence to the PSC provisions for timely submission of WP&B and holding MC meetings. (See Audit Recommendation No. 1)

3.6.6 Audit findings relating to MoPNG/DGH

3.6.6.1 Non-signing of COSA

3.6.6.1.1. As per Article 18.1 of Panna-Mukta PSC, each constituent of the Contractor shall be required to offer to the GoI or its nominee all of the Contractor's entitlement to Crude Oil from each Field in order to assist in satisfying the national demand. GoI appointed IOCL as its nominee to purchase entire crude oil produced from the Panna-Mukta field. Further, Article 19.4.4 of the PSC, envisaged formulation of COSA between Panna-Mukta JV and IOCL (GoI nominee) under terms and conditions, normally contained in international COSAs of a similar nature. However, COSA has not been signed (November 2013) due to non-resolution of issues on (i) delivery point, (ii) storage charges, (iii) dead freight, (iv) voyage loss, (v) voyage costs, (vi) terminal charges, (vii) measurement conversion table, (viii) dollar rupee exchange rate, (ix) lay time in monsoon and (x) delayed payments and interest thereon.

3.6.6.1.2. The non-signing of COSA for Panna-Mukta PSC has been commented by the C&AG in its previous audit reports of 1996, 2005 and 2011 and on each occasion MoPNG stated that *agreements were likely to be finalized soon/suggestions of CAG on COSA would be examined*. However, COSA has not been signed between JV and IOCL till date (November 2013). Thus, due to non-resolution of delivery point and related issues the COSA has not been signed even after a lapse of 19 years of signing of the PSC. The non-signing of COSA led to non- resolution of storage expenses -INR 724.18 crore and voyage expenses-INR 63.56 crore and are shown as recoverable by PMT JV from GoI/GoI's nominee i.e. IOCL as on 31.3.2012. Further during 1995 to 2007 IOCL deducted dead freight of INR 29.83 crore and voyage losses of US$ 37.03 million which were also under dispute.

3.6.6.1.3. PMT JV in its reply to MoPNG (July 2014) stated that *JV has been adhering to the provisions of the Panna-Mukta PSC by selling the crude oil produced from Panna-Mukta to IOCL and that it has also be engaging with the IOCL with the aim of reaching a mutual understanding to enable the signing of COSA.*

3.6.6.1.4. While MoPNG in its earlier reply stated (February 2014) that*, COSA was not signed between the contractor and IOCL due to continued differences between Contractor and IOCL despite the best efforts made by MoPNG,* in July 2014 it stated that *in the event of any disagreement between Contractor and the oil marketing companies, the Contractor should have resolved the disputes though appropriate dispute resolution mechanism.*

3.6.6.1.5. Since only five years are left for the expiry of the PSC and considering huge impact on IM and GoI PP that may result in case of any change in price, MoPNG may intervene as assured in reply to previous PAs for an early resolution of the disputes and facilitate signing of COSA.

Audit Recommendation 15: GoI may ensure the signing of COSA between IOCL and PMT JV by expeditiously resolving the contentious issues.

3.7 Conclusion

The follow up Performance Audit on Production Sharing Contract of PMT JV for the period 2008-12 indicated instances where there was scope for better monitoring to ensure adherence to the terms of the PSC.

Audit noticed that PMT JV was charging production inventory to accounts at the time of purchase instead of charging it only when such material was removed from inventory and used in petroleum operations which was in contravention to the PSC provision. Common expenditure was equally allocated between Panna-Mukta and Tapti contract areas instead of on a reasonable basis *viz*. actual expenditure identifiable to a particular contract area or in the ratio of expenditure on the primary activity, thereby impacting the GoI PP.

Instances of deficiencies in award of contracts were noticed. PMT JV did not consider all the facilities used for petroleum operations (pre-wellhead and post-wellhead activities) for computing the well head value thereby impacting the royalty payable to the GoI. Upgraded reserves (1997 to August 2007) were not considered for amortization of capex and remitting additional royalty payable to GoI. PMT JV had commenced South West Panna Project without waiting for new seismic data leading to subsequent abandonment of the project which entailed infructuous expenditure. Delay in implementing the water injection project in Panna resulted in decline in production. COSA has not been formalized with IOCL since 1994 due to non resolution of disputes on delivery point, storage charges, dead freight, voyage costs/losses etc. PMT JV is yet to determine transportation losses of condensate as agreed with ONGC in the settlement agreement in December 2005.