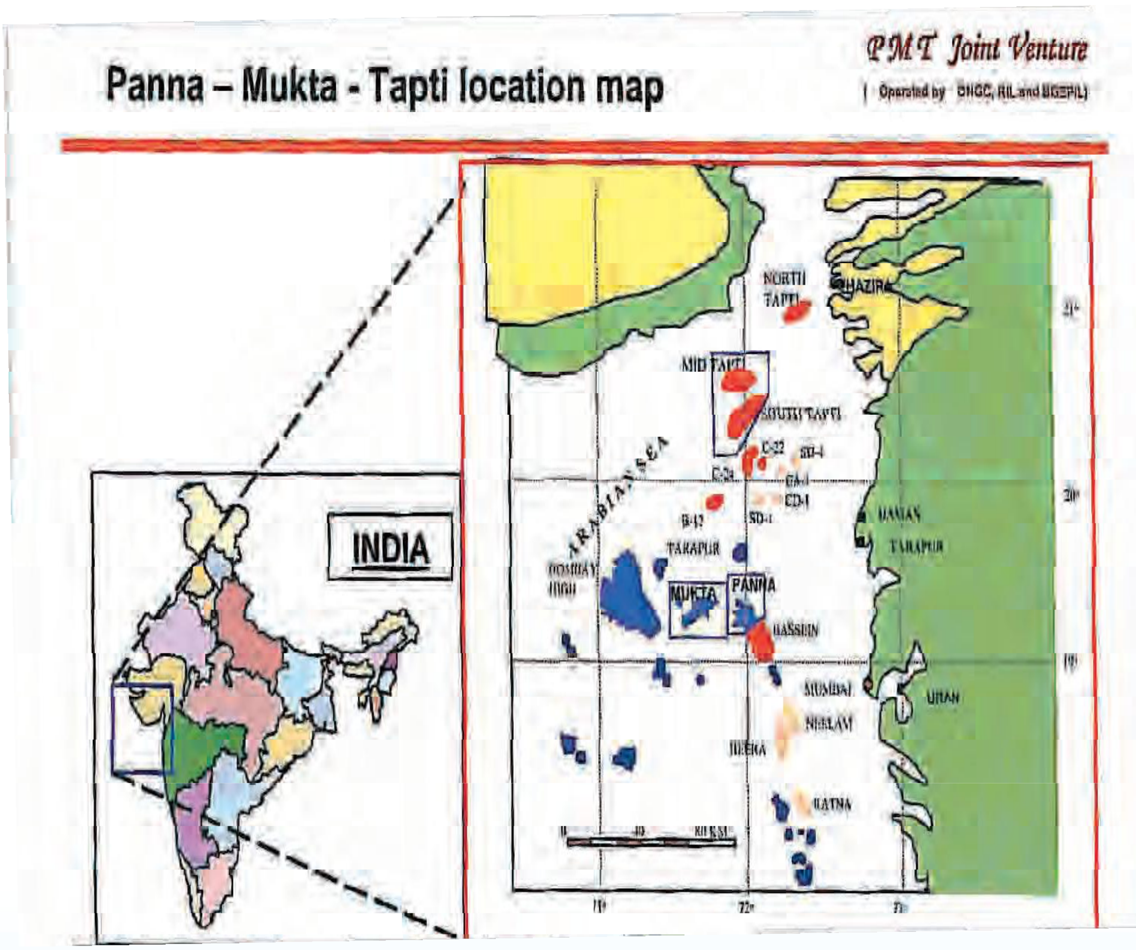
Chapter 6 - Findings in respect of Panna-Mukta and Mid & South Tapti Fields

6.1 Overview

6.1.1 Background to PSCs

The Panna-Mukta field (primarily an oil field) and the Mid & South Tapti field (a gas field), which are offshore shallow water fields located in the offshore Bombay basin, were initially discovered and operated by ONGC. In February 1994, these were awarded to a consortium of Enron Oil & Gas India Ltd (Enron)[40] and RIL for development under a production sharing arrangement. ONGC, Enron and RIL formed a joint venture (PMT JV) with participating interests of 40, 30, and 30 per cent respectively, and the PSCs for these fields for duration of 25 years were signed in December 1994. In February 2002, Enron's 30 per cent stake in the JV was acquired by British Gas Exploration and Production India Ltd. (BGEPIL)[41].



[40] Incorporated in the Cayman Islands
[41] Also incorporated in the Cayman Islands

As opposed to the PSCs under the NELP, the distinguishing features of the PSCs for PMT include the following:

- Development commitments detailed in Appendix G to the PSCs, indicating activity timelines upto 1996 (assuming a project start date of July 1993) for Panna-Mukta. In respect of Mid & South Tapti, the activity timelines (assuming a project start date of July 1993) extended upto 2010; however, except for drilling-work over operations and compressors, other activities were to be completed by 2005.
- Cost Recovery Limits (CRLs) of US$ 577.50 million for Panna-Mukta and US$ 545 million for Mid & South Tapti respectively were stipulated.
- The Investment Multiple was to be calculated on a post-tax basis, with notional Income Tax liability determined on the basis of a 50 per cent tax rate. The GoI share of profit petroleum varied with different slabs of IM as follows:

Table 6.1– Investment Multiple – GoI Share and Contractor Share for Panna-Mukta and Tapti

Investment Multiple (Post-Tax)	Panna-Mukta		Mid and South Tapti	
	GoI share (per cent)	Contractor share (per cent)	GoI share (per cent)	Contractor share (per cent)
Less than 2.0	5	95	20	80
Between 2 and 2.5	15	85	40	60
Between 2.5 and 3	25	75	45	55
Between 3 and 3.5	40	60		
3.5 or greater	50	50	50	50

6.1.2 Development of Panna-Mukta and Tapti fields

The Panna and Mukta fields (comprising of a contract area of 1207 sq. km), which commenced production in December 1994, was developed by the PMT JV in two phases:

- Initial Plan of Development (IPOD) executed during 1995-99, wherein the PMT JV installed three wellhead platforms[42], along with drilling of development wells and associated processing and transportation facilities; and
- Expanded Plan of Development (EPOD) executed between November 2004 and March 2007, wherein the PMT JV installed two wellhead platforms[43] in the Panna Field and pipelines.

[42] Wellhead platforms PC, PF and PG

[43] Wellhead platforms PH and PJ

The Mid & South Tapti field, which commenced production in 1997-98, was also developed by the PMT JV in two phases:

- Initial Plan of Development (IPOD) executed during 1995-97, wherein the PMT JV installed three wellhead platforms[44] in the South Tapti field and associated processing and transportation facilities; and
- New Revised Plan of Development (NRPOD), executed between March 2005 and August 2007, wherein the PMT JV installed one well-head platform[45] in the Mid Tapti field and additional processing and transportation facilities.

Additionally, the PMT JV also installed one wellhead platform[46] in the South Tapti field in August 2006 to maintain the plateau production.

6.1.3 Financial and Operational Performance

A comparison of the operational performance (in terms of cumulative production of crude oil/ condensate and natural gas) vis-à-vis the envisaged production profile as per the PSCs is given below:

Table 6.2- Operational Performance of Panna-Mukta and Tapti fields

Field	Crude Oil/ Condensate (million MT)		Gas (million cubic metres)	
	Envisaged Production Profile (as per PSC) till 2019	Actual (till March 2011)	Envisaged Production Profile (as per PSC) till 2019	Actual (till March 2011)
Panna-Mukta	19.87	19.13	10170	16850
Mid and South Tapti	13.314#	14.69#	31389	32709

 # MMBBL for condensate produced from Tapti

A summary of the sharing of profit petroleum between GoI, ONGC and the private parties from 2000-01 to 2008-09 in respect of the Panna-Mukta and Mid & South Tapti fields is given below:

---

44 Wellhead platforms STA, STB and STC

45 Wellhead platform MTA

46 Wellhead platform STD

Table 6.3– Profit Petroleum for Panna-Mukta Field

Year	Investment Multiple	Profit Petroleum (PP) in US$ million			
		PP of private contractors	PP of ONGC	PP of GoI	PP of ONGC + GoI
2000-01	1.03	68	46	6	52
2001-02	1.23	125	84	11	95
2002-03	1.48 (1.65)	160 (204)	106 (136)	14 (18)	120 (154)
2003-04	1.73 (1.93)	171 (182)	114 (121)	15 (16)	129 (137)
2004-05	1.88 (2.13)	217 (235)	144 (156)	19 (21)	163 (177)
2005-06	1.92 (2.11)	297 (277)	198 (185)	26 (81)	224 (266)
2006-07	2.05 (2.18)	428 (395)	285 (263)	38 (116)	323 (379)
2007-08	2.14	529	352	155	507
2008-09	2.06	400	266	118	384

Table 6.4– Profit Petroleum for Mid & South Tapti Field

Year	Investment Multiple	Profit Petroleum (PP) US$ million			
		PP of private contractors	PP of ONGC	PP of GoI	PP of GoI + ONGC
2000-01	1.21	79	53	33	86
2001-02	1.38	77	51	32	83
2002-03	1.58	84	56	35	91
2003-04	1.73	77	51	32	83
2004-05	1.66 (1.77)	72	48	30	78
2005-06	1.67 (1.76)	84	56	35	91
2006-07	1.24 (1.46)	5	3	2	5
2007-08	1.32	192	128	80	208
2008-09	1.63	402	268	168	436

Note: Figures of IM and PP indicated by MoPNG (after considering the impact of audit exceptions) are given in brackets; the IM and PP figures outside the brackets are the calculations furnished by the PMT JV.

The IM in respect of the Panna-Mukta field crossed 2.0 only in 2004-05 (as per MoPNG's calculations) and moved to the second slab (GoI share moving up from 5 to 15 per cent), while the IM in respect of the Mid & South Tapti field still remains in the lowest slab (below 2.0 with GoI share of 20 per cent). With more than 13 years of operation of the PSC

till March 2008, the IM still remains in the first and second slabs. In our opinion, the prospect of IM rising to 3.5 (resulting in GoI share of 50 per cent) over the remaining contract period is remote; this, further, calls into question the appropriateness of the IM slab-based sharing of profit petroleum.

6.2 Royalty

6.2.1 Contractual Provisions

Royalty is payable on the "wellhead" value of crude oil and natural gas produced:

- Under the NELP PSCs - @10 per cent of wellhead value of gas and for crude oil – 12.5 per cent for onland areas, and 10 per cent for offshore areas. Further, for deepwater areas, royalty is 50 per cent of applicable rates for the first seven years of commercial production;
- Under the PSCs for discovered fields/ pre-NELP exploration blocks - @ Rs.481/ MT for crude oil and @ 10 per cent of the wellhead value of gas.

Wellhead price i.e., the price at wellhead is calculated in backward fashion from the sale price (i.e. price at delivery point), by deducting post wellhead expenses up to the delivery point. Any increase in those expenses decreases the wellhead price and, consequentially, the royalty and vice-versa.

6.2.2 Delay in finalization of norms to determine wellhead price of gas for purposes of royalty

MoPNG decided the norms for determination of wellhead price of crude oil in March 2003, which retrospectively covered the time period from April 1998 onwards and also stipulated adjustment(s) for royalty according to those norms. In the absence of a definition of 'value at wellhead', each party to the PSCs worked out 'wellhead value' by reckoning different cost elements *viz.* processing and transportation charges, operating cost for processing and transportation, amortization of process and transportation investment, interest on capital employed, royalty on gas etc.

The norms for determination of post wellhead costs (a key element in the determination of wellhead value) were notified by MoPNG only in August 2007, even though natural gas was being produced by PSCs as early as 1997-98. As per this notification, per unit of post wellhead cost was to be determined based on the actual post wellhead expenditure reported in the previous year's audited accounts. Further, oil industry development cess, depreciation expense, income tax, surcharge thereon, education cess and profit petroleum were not to be allowed as post wellhead costs.

This undue delay in deciding the components of post wellhead cost to calculate the wellhead value allowed different PSC operators to follow different practices for calculation of post wellhead costs, impacting the government take in the form of royalty.

Unlike in the case of the March 2003 notification in respect of norms for wellhead price of crude oil, the norms of August 2007 for post wellhead costs were not made effective from the date of commencement of production (although the gas production from Panna-Mukta and Mid & South Tapti fields commenced in June 1997 and July 1998 respectively).

In our opinion, GoI should have treated the royalty payment from these fields as provisional, pending the finalization of norms for post-wellhead costs. Even if this not had been treated as provisional from the start of gas production in 1997/ 1998 (although the modalities of calculation were reflected in the royalty statements submitted to MoPNG/ DGH and this issue could have been flagged right away), GoI should have treated the royalty payment as provisional at least from January 2002, when DGH highlighted the problem for MoPNG's consideration.

Due to MoPNG's failure to take prompt action on the issue of royalty, GoI incurred a substantial loss on account of royalty:

- The amortization of capital expenditure amounting US$ 42.96 million was considered as an item of post wellhead cost during the period from April 2006 to July 2007, with a resultant loss of royalty of US$ 4.30 million to the Government, though this was not admissible as an item of post wellhead cost as per the subsequent GoI notification of August 2007.
- The loss for the period from April 1997 to March 2006 could not be quantified in the absence of details.

In response, MoPNG stated (July 2011) that the royalty notification should not fall under the Performance Audit of PSCs, since it was issued under the Oil Field (Regulations and Development) Act 1948 and tabled in Parliament. We do not agree; the calculation of royalty is critical to GoI's take under the PSCs.

Further, MoPNG, while explaining the chronology of royalty notification, stated that wellhead value/ price is a common terminology, not requiring any norm for determination. To enable simplicity and to avoid the complex computation of amortization, some items were disallowed as post well cost deduction, and an exercise was in hand to further simplify the system.

The disputes arising out of post-wellhead expenses and appointment by MoPNG of a committee to suggest the methodology belie MoPNG's claim that wellhead value was a common terminology, not requiring any norm for determination. Further, there were disputes raised by the operators even after the issue of the August 2007 notification.

We await the results of MoPNG's efforts to simplify/ clarify the system for calculation of post-wellhead expenses and remove ambiguities therein.

Our detailed findings on deficiencies in calculation of well-head value of natural gas are summarized below. ***MoPNG has accepted all our findings in this regard and has agreed to take necessary action.***

Table 6.5– Deficiencies noticed in calculation of well-head value of natural gas

Cost Item	Audit Finding	Further Action
Processing cost prior to transportation	• MoPNG clarified (April 2008) that only the cost on post wellhead transportation up to the delivery point only was allowable as operating expenditure on post wellhead infrastructure, and that the processing cost incurred prior to transportation was not admissible as post wellhead cost. However, the PMT JV had incorrectly considered the processing cost prior to transportation as a post-wellhead cost. We could not quantify the resulting short payment of royalty, due to the absence of a breakup between the pre-transportation processing cost and the transportation cost[47].	• MoPNG stated (July 2011) that royalty differential in respect of Panna-Mukta and Tapti fields had been computed for raising demand notice. Meanwhile, the contractors of these two PSCs (excluding ONGC) had invoked arbitration on the issue and applied for interim relief of stay on any recovery. The modalities of handling this issue were being worked out.
Amortization of CAPEX not based on upgraded reserves	• The PMT JV applied the amortization rate considering the PSC reserves (given in Appendix G-7) instead of upgraded reserves.	• The Ministry agreed (July 2011) with our view, and stated that the quantification of the audit

[47] By contrast, in respect of the Ravva PSC, the processing cost had correctly been excluded from post well-head expenditure for determination and payment of royalty.

Cost Item	Audit Finding	Further Action
	This resulted in higher amortization of capex, lower wellhead value and lower payment of royalty.	exception for the period prior to August 2007 would enable direct action on the part of the GoI. In the absence of such quantification, the JV would be advised to rectify the mistake and pay differential royalty, subject to arbitration proceedings.
Inclusion of cost of wellhead flow lines as post well-head expenses	• Opex was allocated between post wellhead and pre-wellhead operating cost in the ratio of the post wellhead capex to the pre-wellhead capex. Although the capex of wellhead platforms was excluded, the capex of wellhead flow lines laid for carrying of gas from wellhead to the wellhead platforms was considered by the PMT JV for computation of post wellhead capex, which resulted in under valuation of wellhead value and consequently short payment of royalty.	
Incorrect inclusion of facilities under execution as of March 2007	• OPEX was bifurcated between wellhead cost and post wellhead cost, based on the ratio of value of wellhead facilities and value of post wellhead facilities of the previous year's audited figures. In our view, only the facilities which were commissioned and used for the purpose of production and transportation of natural gas should have been considered for calculating this ratio. The JV had, however, reckoned the facilities under execution at the end of March 2007 also for calculating the above ratio, which was not correct. This resulted in incorrect allocation of OPEX and under	• The Ministry agreed (July 2011) with our view, and stated that for the period subsequent to August 2007, the cost of facilities would not constitute part of post wellhead cost. For the years 2006-07 and 2007-08 till the date of 2007 notification, quantification by audit would enable direct action on the part of the Government. In the absence of such quantification, the JV would be advised to rectify the mistake and pay differential royalty, subject to

Cost Item	Audit Finding	Further Action
	payment of royalty to the Government by Rs 0.56 crore (US$ 0.124 million) for the period from August 2007 to March 2008.	arbitration proceeding. However, in our opinion, the rectification should extend back to the date of commencement of gas production (June 1997/ February 1998), since the same methodology has been adopted by the PMT JV right through.
Maintenance costs of SCADA facilities included as post well-head activity	• The JV considered the maintenance costs of the SCADA[48] facility installed on wellhead platforms as post wellhead activity instead of wellhead activity in determination of wellhead value. This resulted in lower valuation of wellhead value and resultantly lesser payment of royalty to the Government.	

6.3 Crude Oil and Gas Sales

6.3.1 Pricing of gas sales from PMT

The PSCs of Panna-Mukta and Mid & South Tapti stipulate a pricing formula for gas sales with initial floor and ceiling prices of US$ 2.11/mmbtu (million metric British Thermal Unit) and US$ 3.11/mmbtu with an option to the contractor to revise the ceiling price after 7 years from the date of first delivery viz. January 1998 for Panna-Mukta and June 1997 for Mid & South Tapti:

- The gas price reached the initial ceiling price of US$ 3.11/ mmbtu in April 2000.
- The period of 7 years from the date of commencement of commercial gas production ended in June 2004 and February 2005 in respect of the Tapti and Panna-Mukta contract areas respectively. Consequently, the PMT JV exercised its option to revise the ceiling prices to US$ 5.57/ mmbtu for Tapti and US$ 5.73/ mmbtu for Panna-Mukta;
- The gas prices reached these revised ceiling prices in a phased manner between June 2004 and April 2005.

However, GAIL, which was nominated by MoPNG to purchase the entire gas production, refused to honour the revised gas prices[49], and continued to pay the gas price at the earlier ceiling of US$ 3.11/ mmbtu till March 2005. The chronology of subsequent events is summarised below:

[48] Supervisory Control and Data Acquisition

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

- In November 2004, MoPNG directed the PMT JV to supply 6 mmscmd[50] (out of the total gas production of 10.8 mmscmd) to GAIL at US$ 3.86/ mmbtu for one year, and allowed the PMT JV to market the gas directly at a price higher than US$ 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 US$ 3.96/mmbtu for a three year period upto March 2008.
- In view of the criticality of the supply of PMT gas to the priority sector, MoPNG reassessed its decision in March 2006. Based on MoPNG's directives, the PMT JV agreed to provide all gas in excess of the quantity of 4.8 mmscmd (already committed to private customers) to GAIL at a "market-driven" price of US$ 4.75/mmbtu for 2 years till March 2008. As regards additional gas from the Phase-II development of PMT, GoI decided that a separate meeting would take place at an appropriate time. However, no such meeting took place.
- With the development of Phase-II, the production increased to 16.69 mmscmd in 2007. However, the JV restricted its gas supply at 5.3 mmscmd, with the additional gas produced being shared by JV partners according to their participating interest and sold at different prices[51].
- In November 2007, MoPNG reviewed the position of sale of PMT gas to private customers. While expressing its displeasure to DGH on not following its directions, MoPNG directed the PMT JV to cancel all contracts for direct marketing beyond 4.8 mmscmd. It also directed the PMT JV to make available the additional gas to GAIL at PSC prices and terms, as well as the 4.8 mmscmd of gas hitherto contracted to private customers after the expiry of the contracts in March 2008. Consequently, from April 2008, all gas was being sold to GAIL at PSC prices.

In response, MoPNG stated (July2011) that the higher price demanded by the JV would have affected ONGC's APM gas price and that if the GoI had chosen to sell the gas at PSC prices, this would have meant either subsidising higher price to be paid by the fertilizer and power sector, or would have been passed onto customers resulting in higher generation cost and higher urea cost.

The key issue here is that MoPNG and its nominee (GAIL) failed to comply with the terms of the PSC during 2005-08 with regard to the pre-determined pricing formula. Not honouring the PSC formula severely affects the sanctity of the contract (which is to be maintained by all parties), which is highly undesirable from the long-term perspective of all contracting parties.

---

[50] During April and May 2005, GAIL uplifted only 1.5 to 2 mmscmd, against the agreed quantity of 6 mmscmd. The PMT JV had to shut in Tapti wells, as it had not entered into contracts with other buyers for the quantities committed to GAIL.

[51] RIL's sales to its group companies at US$ 5.58/mmbtu, and ONGC's sales to Rajasthan Rajya Vidyut Utpadan Nigam Ltd and Torrent Power Generation Ltd. at US$ 4.60/ mmbtu and US$ 4.75/mmbtu.

6.3.2 Condensate loss during transportation

Transportation and processing of PMT gas is being undertaken by ONGC through its South Bassein-Hazira Trunk gas pipelines and its Hazira facilities, and is governed by a settlement agreement of December 2005 between ONGC and the PMT JV. Also, ONGC agreed to purchase all the condensate produced from the Mid & South Tapti field at the "delivery point", as per the following process:

- The volume of condensate purchased/ sold is measured at the Tapti offshore platform, reduced by the Tapti condensate transportation losses.
- 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 the PMT JV. Pending determination of such losses, it was agreed to treat the provisional Tapti condensate losses as "zero". As of March 2010, no condensate expert had been appointed.

The PSC for Mid and South Tapti is silent on the treatment of condensate.

In our view, the above arrangement is seriously flawed:

- Internally, ONGC had been considering 6 per cent as transportation and processing losses from condensate. Treating "provisional" losses as "zero" from 2005 onwards implies that any such losses are to ONGC's detriment.
- The settlement agreement is defective, as rates for usage of affiliated facilities (including oil and gas transportation systems) shall be subject to separate agreement with the Government, as per section 3.1.4(c) of the PSC Accounting Procedure.

In response, MoPNG stated (July 2011) that the JV had already shortlisted international agencies for assessment of transportation losses. As the expertise to frame the scope of work was not available in-house, and this was required to be undertaken for the first time by ONGC, there had been some unavoidable delay in appointing the expert. As a way forward, the JV and the Institute of Oil and Gas Petroleum Technology (IOGPT) 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. Hence, pending assessment and establishment of losses by an expert, it may not be correct to agree that treatment of provisional losses was to ONGC's detriment. While we do not agree with MoPNG's views, we will await further progress in this regard.

As regards the agreement of GoI on the charges of affiliates, MoPNG indicated that the methodology for working out the processing tariff viz. 'incremental cost of facilities' was indicated in Article 13.1.3(g) (read with Appendix I). We do not agree; in our opinion, as per Section 3.1.4(c) of the PSC accounting procedure, such rates should be subject to separate agreement with the Government.

6.3.3 Non-signing of Crude Oil Sales Agreement

Article 19 of the Panna-Mukta PSC envisaged formulation of a crude oil sales agreement (COSA) between the PMT JV and the IOC (the designated nominee of GoI for purchase of crude oil) under the terms and conditions normally contained in international crude oil sales agreement of a similar nature. However, despite lapse of more than 16 years after the signing of the PSC, the COSA was yet to be executed between the parties mainly on account of non resolution of disputes on delivery point, voyage expenses during monsoon period and delivery of 'free crude' free from water by the PMT JV.

Ministry stated that the suggestions of CAG on COSA would be examined. This issue had been highlighted in the earlier CAG's Audit Reports of 1996 and 2005[52]. We urge that a quick decision be taken, since nearly 2/3rd of the term of the PSC is already over.

6.4 Findings in respect of Panna-Mukta

6.4.1 Non-completion of Development Work Commitments

The PSC for Panna-Mukta specified a Cost Recovery Limit (CRL) of US$ 577.5 million, and also indicated details of committed work programme separately for the Panna and Mukta fields to be completed by 1996. However, the JV had not completed key work commitments in respect of the Mukta field, as summarized below:

- Fabrication and installation of the MB jacket;
- Fabrication (or refurbishment) and installation of the MB deck package;
- Drilling of 6 directional wells from MB;
- Laying MB-MA wellfluid line; and
- Laying PPA-MA-MB gaslift line

Consequently, the Mukta field (which has 3P reserves of more than 1000 mmboe) remains largely undeveloped. Till May 2007, the PMT JV could produce only 14 mmboe. Consequently, there was deferment of production of oil and gas production[53] of 12 mmboe and 32,484 mmscf of gas, with consequential deferment of revenue, adverse impact on IM and GoI PP, and deferment of royalty/ cess to GoI.

In response, MoPNG stated (July 2011) that the Mukta pay zones were seismically difficult to map and the performance may not be compared with the Panna field. While we agree that the Mukta field is more complex, the work commitment made in the PSC should have been completed within the PSC-stipulated time period (1996). ***Even after lapse of more***

[52] Report No. 5 of 1996 (Commercial) and Report No. 6 of 2005 (Commercial)

[53] Based on the design flow rates adopted by BGEPIL for the Minimum Facilities Study Report (September 2006) for Mukta-B.

than a decade, the JV had not completed many of the development activities committed under Appendix G of the PSC.

In respect of the Panna field, the PMT JV substituted two infill wells drilled in 2005 from the PD platform instead of the two wells from PD platform indicated in the development work commitments as per the PSC; this substitution was approved by DGH in October 2007. However, the MC, while approving (May 2003) the proposal for drilling of infill wells, had affirmed that the drilling of Panna infill wells was outside the IPOD and Appendix G of the PSC.

In response, the Ministry stated that in development parlance, infill and development wells were the same. We do not agree, since the MC's affirmation in this regard was to the contrary.

6.4.2 Cost Recovery

Against the Cost Recovery Limit (CRL) of US$ 577.5 million,

- The cost recovered on the committed works was US$ 420 million, as of September 2007. The PMT JV had estimated that for completing the balance committed work, an expenditure of US$ 208 million to US$ 233 million (average US$ 220 million) would be additionally required[54].
- After deducting the estimated cost of US$ 220 million, DGH determined an excess cost recovery of US$ 62.5 million, along with short remittance of GoI PP of US$ 6.219 million for the period 2002-03 to 2004-05. MoPNG issued directives (December 2008) to reverse the excess cost recovery and remit additional PP to the GoI.

In response, MoPNG stated (July 2011) that the reversal of cost in excess of CRL was effected through the National Oil Companies (viz. IOC/ GAIL). We take note of Ministry's reply.

6.4.3 Instances of excess expenditure

Other instances of excess expenditure, deficiencies in procurement affecting competitiveness of costs etc. with implication for GoI's financial take are summarized below:

Item	Brief details
Expenditure on acquisition of seismic data	The acquisition of seismic data by the PMT JV covering approx. 250 sq.km of the Panna field at an additional cost of US$ 9.36 million (calculated on pro rata basis) was irregular, as the MC approval of July 2007 for data acquisition was only for the Mukta field.
Execution of EPOD	There were enormous delays in finalization of the tender for EPIC[55] of the EPOD Project. Against the Operator Board's recommendation of

[54] Since the PSC did not mention the itemized details of cost for the items listed in the PSC, we are unable to quantify the original estimated cost of the unfinished committed work.

[55] EPIC: Engineering, Procurement, Installation and Commissioning

Item	Brief details
Project	November 2003 that the contract had to be awarded by March 2004 so as to achieve installation of the well platforms by pre-monsoon 2005, the tender was awarded only in November 2004. Let alone pre-monsoon 2005 completion, even pre-monsoon 2006 completion could not be achieved. Ultimately, production from the PJ and PH wells commenced only in February 2007. Due to inordinate delays in award and execution, the total expenditure on the project increased from the originally approved amount of US$ 169.07 million to US$ 329.88 million. Further, in return from a commitment from the vendor to complete the remaining scope of work by 24 February 2007, the PMT JV agreed not to impose LD (amounting to US$ 13.27 million).
Invitation to bid not published in Indian newspapers	In respect of major contracts valuing more than US$ 100 million (e.g. EPOD and Project Hydra-PK and SWP) executed during 2006-08, the PMT JV invited only limited tenders from short-listed prospective bidders and did not publish the invitation to bid in Indian newspapers (as required under Article 6.8 of the JOA).

In response, MoPNG stated (July 2011) that the reply of the Operator had been called for and was awaited. We await further progress in this regard.

6.5 Findings in respect of Mid & South Tapti field

6.5.1 Non-completion of Committed Work Programme and delays

The development commitments under the PSC inter alia included, but were not limited to:

- 10 wellhead platforms[56]; and
- 35 development wells (with an additional 30 infill wells – not representing a committed work obligation, but included in the Cost Recovery Limit – if the drainage area of the 35 primary development wells was inadequate).

As against the above:

- The JV installed only 5 wellhead platforms and drilled only 30 development wells. The committed work in respect of the balance 5 wellhead platforms and 5 development wells was yet to be executed.
- Even the NRPOD project, for which a draft was initiated in June 1999 (with the first gas expected from 2003) ran into considerable delays. No development work was undertaken between March 2001 and November 2003 due to disagreement among JV partners over approval of early costs, lack of consensus over Original Gas In Place (OGIP) etc. Early activities for NRPOD were conducted during 2004, the NRPOD project

[56] 6 in South Tapti and 4 in Mid-Tapti

approved by the MC in March 2005, contracts awarded during 2005-06, and the first gas started flowing only in August 2007.

In response, MoPNG stated (July 2011) that as and when the need arose, the JV may drill the wells and the Cost Petroleum would be regulated in accordance with the PSCs.

The fact remains that there were no firm plans for the installation of the remaining 5 wellhead platforms committed in the PSC.

6.5.2 Cost Recovery in excess of Cost Recovery Limit (CRL)

The PSC stipulated a Cost Recovery Limit (CRL) of US$ 545 million (excluding costs on site restoration, exploration/ appraisal drilling, development of satellite fields etc. but including the cost of the additional 30 infill wells). However, against this CRL:

- The PMT JV incurred expenditure of US$ 729.09 million (till December 2007), despite not completing the full Committed Work Programme, and also recovered these costs.
- After considering estimated costs of US$ 140.26 million on account of the committed work yet to be executed, there was an excess cost recovery of US$ 324.35 million over the CRL.
- In addition, the PMT JV incorrectly adjusted savings of US$ 20.93 million (on account of the cost of the export pipeline not executed due to a reduction in scope[57]) from the excess over the CRL in respect of other items.

The CRLs stipulated in the PSC were based on international market conditions relating to availability and costs of materials and services in the international petroleum industry at constant 1993 US$. The PSC stipulated that in the event that the CRLs were exceeded on account of delays due to delays in obtaining necessary approvals, material change to the international market conditions of availability and costs, variation to the Development Plan approved by the MC etc., the MC should consider what, if any, increase in CRLs should be made to fairly reflect the circumstances. However, the MC shall not be obligated to consider what, if any increase where, and to the extent that, such delay had been caused by the companies' failure to act in a diligent manner.

However, we found that:

- The PMT JV approached DGH in June 2008 for enhancement of the CRL by US$ 324.35 million, which had not been approved. However, notwithstanding the lack of approval of the enhancement in CRL, the JV had already irregularly undertaken cost recovery of the excess expenditure over the CRL.

[57] The CRL included an amount of US$ 66.5 million for laying of an export pipeline from the Tapti process platform to the onshore terminal at Hazira. Instead, the JV laid a pipeline from the Tapti process platform to ONGC's existing gas pipeline from Bassein to Hazira at a cost of US$ 45.82 million, resulting in a difference of US$ 20.93 million.

- Incidentally, when the NRPOD project (at a cost of US$ 519 million) was approved in March 2005 by the MC, it was decided that the CRL would be reviewed by a team of representatives from the PMT JV and DGH within the next three months; however, no such review was conducted.
- The PMT JV had executed certain activities[58] under the IPOD and NRPOD projects outside the committed work programme; however, approval for change in the committed work programme had not been obtained from MoPNG.

In response, MoPNG stated (July 2011) that:

- The proposal of the operator for enhancement of CRL, so as to treat the total expenditure as contract cost, placed before the MC was not agreed upon.
- A revised proposal for reversal of US$ 365 million towards the excess cost recovered in respect of development cost and revision of notional income tax and Investment Multiple calculation had been considered by the Ministry, and was being placed before MC.
- Meanwhile, the operator had invoked arbitration on this issue, which would have a bearing on the final resolution.

With regard to the work done outside the scope of Appendix G, MoPNG directed (May 2011) DGH to obtain the audited report from the PMT JV for the expenditure of US$ 346 million incurred on activities outside Appendix G, and permit accordingly towards cost petroleum.

We await further progress in this regard.

6.5.3 Instances of excess expenditure and cost recovery

The PMT JV entered into two contracts for mobile offshore rigs, as summarized below:

Rig	Award	Operating Day Rate (ODR)	Primary period	Actual deployment	Extension
Ensco-50	Dec. 2003	55,500	310 days	Feb.2004	Option to exercise 3 successive extensions of 6, 3 and 3 months on mutually agreed terms and conditions.
Ensco-53	Dec. 2004	61,800	270 days	Feb. 2005	Right to extend for 3 months at same rates and terms and conditions

[58] These included Tapti temporary compression, TCPP platform (excluding compressor) etc. amounting to US$ 345.06 million, which were outside the committed work programme.

Both these contracts were extended at higher rates from time to time for various periods ranging from 3 months to 2 years in the light of the scheduled drilling programme, upward rig market scenario and shortage of rig availability.

It may be noted that 33 wells were planned to be drilled during 2005-09 as per the development projects (EPOD, NRPOD, and STD). Also, as per the Work Programmes and Budgets for 2006-07 and 2008-09, the JV was to drill 27 wells (14 firm and 13 contingent) and 20 wells (15 firm and 5 contingent) respectively. From a very conservative perspective – considering only the firm wells – at least one rig should have been hired for the entire period. If the contract for the cheaper rig (Ensco-50) had been extended for 2 years (while extending the contract in October 2005) at the ODR of 97,500 instead of for nine months, additional expenditure of US$ 31.85 million could have been avoided.

Other instances of excess expenditure, deficiencies in procurement affecting competitiveness of costs etc. with implication for GoI's financial take are summarized below:

Expenditure item	Brief details
Acquisition of seismic data; wells planned drilling without API (fully)	The PMT JV acquired and processed new 3D seismic data in the mid-Tapti area (completed in 2007-08) at a cost of US$ 32.56 million; this was to reduce the risk of placement of wells not only for the lower channels sands, but also for the 1st phase wells from MTA wellhead platform (which had, by then, been installed). However, even before the API of the new 3D data, 5 out of the 8 wells planned from the MTA wellhead platform were drilled by December 2007. This negated, at least partly, the purpose of API of 3D data.
Construction of STD wellhead platform with 12 slots	The development commitments in the PSC involved installation of 10 wellhead platforms with only 8 drilling slots. However, based on a quantitative risk assessment (June 2002), the PMT JV decided to install a new wellhead platform STD with 12 slots by 2003 monsoon (to maintain deliverability of gas in excess of 200 mmscfd). The platform was finally completed in August 2006 at a cost of US$ 33.06 million. In our opinion, the increase in drilling slots from the estimated 8 to 12, with avoidable additional expenditure of US$ 7 million (on account of increased tonnage), was inappropriate: • Even in the NRPOD, the JV brought out (January 2005) economics indicating completion of STD with only 5 wells (4 firm + 1 contingent). • Only 4 wells were drilled in 2006-07, of which only 2 were flowing as of March 2010 (with production rates of 40 mmscfd against the

Expenditure item	Brief details
	projected 120 mmscfd).
Invitation to bid not published in Indian newspapers	In respect of 9 contracts ranging from US$ 3.15 million to US$ 86.75 million, the PMT JV invited only limited tenders from pre-qualified vendors and did not publish the invitation to bid in Indian newspapers (as required under Article 6.8 of the JOA).

In response, MoPNG stated (July 2011) that the issues had been flagged to the operators for their response, and the views of the operators were awaited. We await further progress in this regard.

6.6 Common issues of excess expenditure and cost recovery relating Panna-Mukta and Mid & South Tapti fields

Expenditure items	Brief details
Non-competitive hiring of 3rd party drilling services	The PMT JV was operating 17 contracts for third party drilling services during 2006-08; these contracts had been awarded during 2003-05 and were rolled over on mutually agreed higher rates till August/ September 2009, when the JV finalized fresh tenders on the direction of the Operator Board (OB). We observed that: • By extending the contracts periodically over such a long period, market trends were not explored, and competitive rates not obtained; • Even after the OB directed the JV in November 2008 to invite tenders for ascertaining competitive rates, the JV initiated the tendering process in March 2009 and finalized the tenders only in August/ September 2009. • Pending tender finalization, the JV extended contracts on 2 occasions for 3 and 2 months upto September 2009. In respect of four services, the rates obtained were lower by 2 to 20 per cent than the prevailing rates, and the existing contractors emerged L-1 bidders in 3 services.
Incorrect booking of production inventory	• Production inventory was being charged off by the JV on procurement, instead of actual consumption, which is in violation of Section 3.1.8(a) of the Accounting Procedure to the PSC. This assumes greater importance, since the production inventory had increased to US$ 7.61 million and US$ 10.83 million as of 2008 for

Expenditure items	Brief details
	Panna-Mukta and Tapti fields respectively.
Non-reconciliation/ disposal of inventory	• As of March 2008, there was a difference between the drilling inventory in the SAP system (US$ 258.40 mn) and the trial balance (US$ 254.91 mn). Although the PMT JV stated (October 2010) that this had been rectified in SAP, it was yet to work out the impact on cost recovery (on account of resultant changes in inventory carrying cost) and adjust the amount in the respective years. • Delay in disposal of sparable inventory (identified at US$ 3.87 million[59] by the PMT JV during 2006-08) resulted in avoidable levy of inventory carrying cost and 1 per cent overhead, with consequential impact on GoI take.
Incorrect booking of insurance expenses	• The premium paid for offshore package policy by RIL for Oct-Dec. 2006 indicated an additional insurance premium of US$ 101,900 for Panna-Mukta and a refund of US$ 2650 for Tapti for 2004-05; this was stated to be adjustment for changes in meterage of wells drilled. However, no such adjustments for 2005-08 were effected by RIL, and no such adjustments were effected by the other JV partners for 2006-07 and 2007-08. • The premium for insurance policy for standard fire and special perils policy paid by BGEPIL included both JV and non-JV activities, while the insurance policy for marine cargo and public liability act and employee related insurance policies did not specifically mention that they were exclusively for PSC operations. However, the entire premium for insurance coverages was considered for cost recovery.
Booking of payments made to support staff	• Time spent by support staff for non-JV activities during April to July 2007 (test checked) was not allocated to non-JV activities. Out of 14,960 hours during these months, we estimated the time on non-JV activities (based on time spent by their supervisors/ executives) to be 5064 hours; this, in our opinion, would be a reasonable basis for allocation.
Booking of salaries of expatriates	• The JV allocated 100 per cent of expatriate costs to the PSCs, even though some time was also devoted for non PSC activities.

[59] Of which US$ 3.54 million purchased prior to April 2005 was lying unutilized.

The Ministry stated (July 2011) that the issues had been flagged to the operators for their response and the views of Operators are awaited. We await further progress in this regard.

6.7 Notional Income Tax

The IM in the Panna-Mukta and Tapti PSCs is post-tax. For this purpose, the PSC stipulates adoption of Income Tax rate of 50 per cent "applicable to petroleum operations". Since then, the corporate income tax rates have come down dramatically (33.99 per cent for domestic companies). However, the calculation of Investment Multiple continues to adopt a notional Income Tax rate of 50 per cent.

Article 15.7 - Taxes, Royalties, Rentals etc. stipulates that *"if any change in or to any Indian law, rule or regulation by any authority resulted in a material change to the economic benefits accruing to any of the Parties to the contract after the effective date, the parties shall consult promptly to make necessary revisions and adjustments to the contract in order to maintain such expected benefits to each of the parties."*

In view of the change in the corporate taxation rates under the Income Tax Act, which clearly benefit the JV partners in terms of calculation of post-tax IM, GoI should have instituted consultations under this provision.

In response, MoPNG stated (July 2011) that Government had not invoked Article 15.7 on fiscal stability as specific benefits were consciously extended to attract investment. MoPNG, further, added that as the contractor had invoked arbitration against the Government and claimed benefits under Article 15.7, it was proposed to take up the issue with JV for consultation.

We strongly urge that the issue of downward revision in corporate income tax rates, and corresponding benefit to the contractors, should be highlighted and included in the ongoing arbitration proceedings invoked by the contractors.

6.8 Non-determination of abandonment cost

Article 12.8 of both the Panna-Mukta and Tapti PSCs stipulates that when the contractor determines that the estimated remaining recoverable reserves (net of operating costs) are equal to 2½ times the estimated abandonment cost, GoI shall take control of the field (and the abandonment obligation) within 60 days. Failing this, the contractor can recover the abandonment cost from the remaining production and abandon the field.

However, the PMT JV had not determined (October 2010) the abandonment cost for the Panna-Mukta and Tapti fields, despite DGH's direction of May 2008 to do so. Without such determination, the procedure for abandonment stipulated in the PSC cannot be applied.

In response, MoPNG assured (July 2011) that it would pursue the matter. We await further progress in this regard.