Performance Audit of

Hydrocarbon Production Sharing Contracts

Ministry of Petroleum and Natural Gas

Report of the

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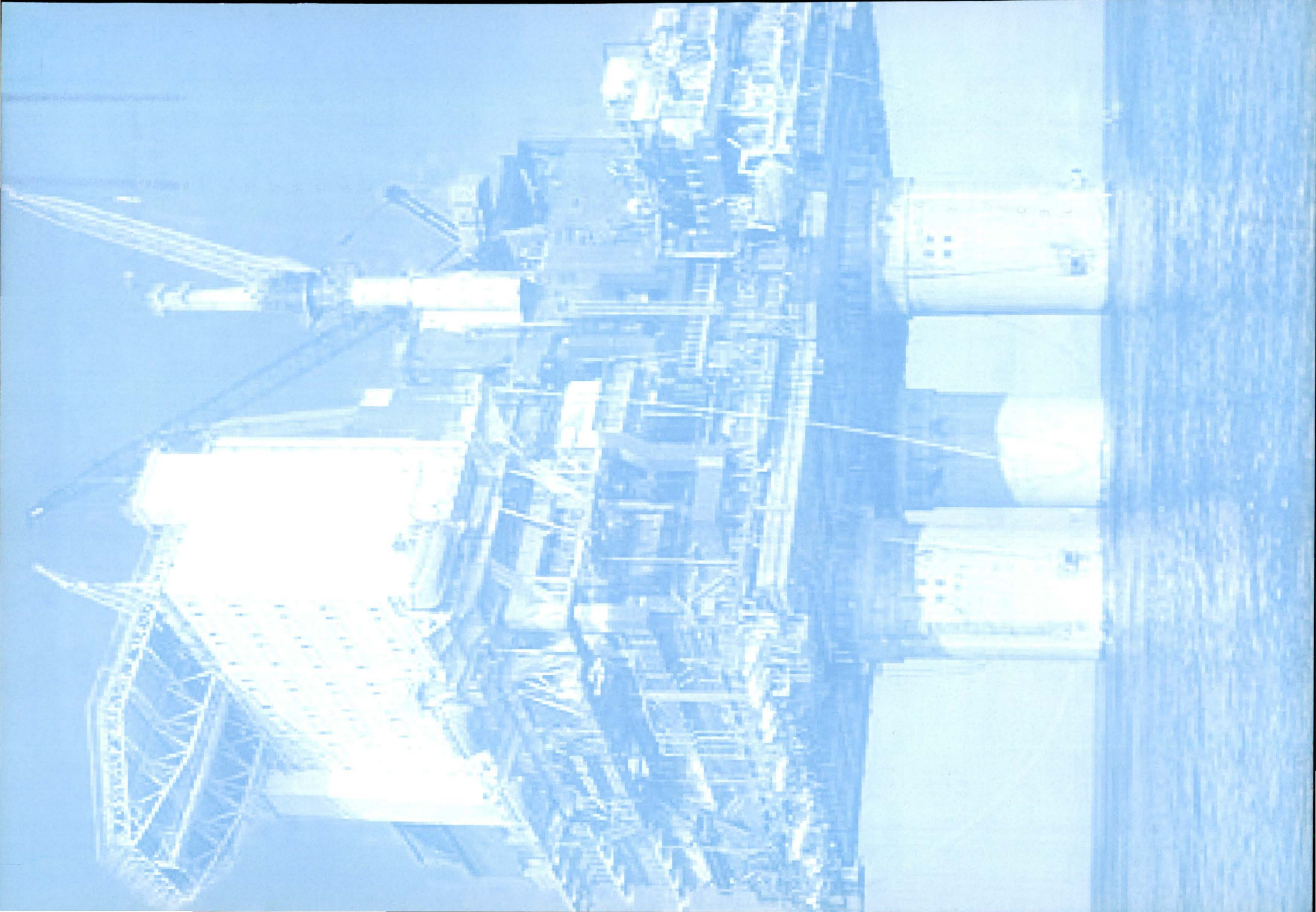


Preface

With the reforms in the economy which took place in the 1990's, Government decided to liberalise the framework governing the oil and gas Exploration and Production (E&P) sector, which has earlier been the sole preserve of the Government Sector. After award of small and medium sized discovered and producing oilfields as well as some exploratory blocks in the early 1990's, Government formulated the New Exploration Licensing Policy (NELP) in 1997 and notified this policy in 1999. This policy had the objective of not only attracting private capital to the E&P Sector but also introducing the technical expertise and efficiency of global players in this field.

In order to ensure balanced and effective partnerships with global E&P Companies, the Production Sharing Contracts (PSCs) between the Government and the private players were revised. These contracts were structured in such a fashion that the exploration risk *viz.* the cost incurred in searching for oil and natural gas, without certainty of discovery, was to be borne by the private contractors. The private contractors incur capital expenditure towards discoveries, irrespective of the fact whether oil or gas is discovered or not. It is only when hydrocarbons are discovered and assessed to be commercially viable, that the contractor has the first rights on the revenue streams accruing from sales of oil and gas till his costs are recovered. The balance revenue, termed as "Profit Petroleum", is shared between the Government and the contractors, with the contractors generally getting a higher share in the initial stages since he has to recover contract costs. The Government share of revenues becomes significant only when the production reaches substantial levels and the contractor has recovered his accumulated capital cost. Further, under NELP, Government companies and private players are treated at par.

The principle underlying the PSC model, under the NELP, as it currently stands, involves a scale for profit sharing between the Government of India and the contractor, based on a critical parameter – the Investment Multiple (IM). This is essentially an index of the accumulated net cash flow to the contractor relative to the accumulated expenditure on exploration and development activities. The objective underlying the PSC is that ideally the operator would attempt to maximize simultaneously both the government revenues and his own profit by minimizing contract costs for any level of production.

In order to ensure that the expenditure proposed to be incurred as well as actually incurred by the operator does not adversely affect the Government's revenue interests, the PSC contemplates the Management Committee (MC), chaired by a GoI representative, as responsible for approving field development plans as well as annual work programmes and budgets for development and production operations. However, operational control of E&P activities would vest with the Operating Committee, consisting of representatives of the contractors.

This audit was conducted in response to a request from the Ministry of Petroleum and Natural Gas for a special audit of PSCs in the context of large Government stake in the form of profit petroleum and concerns about the capital expenditure being incurred by some contractors in development of blocks awarded under NELP. We scrutinized records of the Ministry of Petroleum and Natural Gas and the Directorate General of Hydrocarbons (DGH) in respect of a sample of 20 PSCs covering the period from 2003-04 to 2007-08. In addition we also conducted supplementary scrutiny of records of operators of 4 blocks/ fields (KG-DWN-98/3, RJ-ON-90/1, Panna-Mukta and Mid & South Tapti), covering the two year period 2006-07 and 2007-08. Our audit was interrupted due to difficulties in obtaining access to the records of operators for supplementary scrutiny, which were later resolved with assistance and cooperation of Ministry of Petroleum and Natural Gas.

This report of the Comptroller & Auditor General of India for the year ended March 2011 containing the results of Performance Audit of Hydrocarbons Production Sharing Contracts has been prepared for submission to the President of India under Article 151 of the Constitution of India.

Executive Summary

Background

Private sector participation in hydrocarbon Exploration and Production (E&P) in India dates back to the Government of India (GoI) decision of 1991 to invite foreign and domestic private sector companies to participate in the development of oil and gas fields already discovered or partly developed by the National Oil Companies such as ONGC. This was followed by three rounds of bidding for small and medium-sized discovered or producing fields and six rounds of bidding for "pre-NELP" exploratory blocks.

The New Exploration and Licensing Policy (NELP), announced by GoI in 1997 and notified in 1999, represented a landmark in hydrocarbon E&P in India. For the first time, National Oil Companies were to compete with private sector companies for obtaining E&P licenses through a competitive bidding process, instead of getting them on nomination basis. The pre-tax Investment Multiple for sharing of "profit petroleum" between the GoI and private contractors was introduced. Royalty rates were standardised on ad valorem basis, and cess as well as signature, discovery and production bonuses done away with. Eight rounds of award of exploration blocks under NELP were completed, while submission of bids for the IXth round has concluded recently.

The basis for the contractual relationship between the GoI and the private contractors is the Production Sharing Contract (PSC). The PSC lays out the roles and responsibilities of all parties, stipulates the detailed procedures to be followed at different stages of exploration, development and production, and also indicates the fiscal regime (cost recovery, profit sharing etc.).

Request of GoI for special audit by CAG

In November 2007, the Secretary, Ministry of Petroleum and Natural Gas (MoPNG) requested the CAG to conduct a special audit of PSCs for eight blocks for which regular audit had already been carried upto 2003-04/ 2004-05. MoPNG's request was made in the context of large stakes of the Government in the form of royalty and profit petroleum, and concerns voiced in some quarters about the capital expenditure being incurred by some contractors in the development projects awarded under NELP. We agreed to the MoPNG's request for audit, indicating that we would be covering, in the first instance, five blocks – Panna-Mukta, Tapti, KG-DWN-98/3, Hazira, and PY-3 - out of the eight blocks for which special audit was requested by MoPNG. We also subsumed a Performance Audit of Hydrocarbon PSCs, covering a sample of discovered/ pre-NELP Production Sharing Contracts and NELP PSCs.

(Para 3.1)

The main objectives of the performance audit of hydrocarbon PSCs were to verify whether:

- The systems and procedures of MoPNG and Directorate General of Hydrocarbons (DGH) to monitor and ensure compliance by the operators and contractors of the blocks with the terms of the PSCs were adequate and effective; and
- The revenue interests of the Government (including royalty and GoI share of profit petroleum) were properly protected, and adequate and effective mechanisms were in position for this purpose.

Concerns have been raised in certain quarters as to our conducting "performance audit" of individual blocks, and the operations of the contractors/ operators thereof. We take this opportunity to clarify that the scope of our performance audit covered the MoPNG and the DGH and not the private operators of individual blocks. Consequently, access to the records of the operators of selected blocks was only supplementary to the scrutiny of records of MoPNG and DGH.

The purpose of access to, and scrutiny of records of the operators was to verify whether the Government's revenue in the form of profit petroleum (current and future) and royalty were correctly calculated, and its revenue interests were properly protected. Towards this larger objective, we intended to verify (based on access to operators' records for the specified accounting periods) whether:

- Capital expenditure (capex), operating expenditure (opex), and net cash income and individual items thereof were accurately and reliably reflected, and these amounts were supported by adequate documentation;
- The figures of individual items of capex/ opex were reasonable, and also commensurate with original/revised budgets, plans, feasibility reports or other similar documents; and
- There was collateral evidence which would provide assurance regarding the authenticity of goods and services procured and provided.

(Para 3.2)

Our audit scope covered a twin approach:

- Scrutiny of records at MoPNG and DGH in respect of a sample of 20 PSCs so selected as to provide a balanced coverage of (a) onshore and offshore (shallow and deepwater) blocks (b) a cross section of operators (c) fields with oil discoveries and gas discoveries (d) pre-NELP and NELP and (e) blocks at different stages of E&P – under exploration, relinquished, discovery, production etc.; this covered the period from 2003-04 to 2007-08.
- Supplementary scrutiny of records of operators of four blocks/ fields (KG-DWN-98/3, Panna-Mukta, Mid & South Tapti and RJ-ON-90/1) covering the two year period 2006-07 and 2007-08.

(Para 3.3)

Our audit was, however, interrupted due to difficulties in obtaining access to the records of operators for supplementary scrutiny, which were later resolved with the active assistance and co-operation of the Ministry of Petroleum and Natural Gas.

(Para 3.5)

Scope Limitation

Production of Records by PMT JV

Despite our repeated efforts, the Panna Mukta Tapti Joint Venture (PMT JV – joint operators BGEPIL, RIL, and ONGC) did not provide important and relevant records on the ground that scrutiny of these records did not fall within our audit scope, which was limited to accounting records in terms of the PSC provisions. The PMT JV also did not respond to the majority of our preliminary observation memoranda, on the ground that the issues raised therein were outside the scope of audit rights envisaged in the PSC.

We do not agree with the views expressed by the PMT JV. In our opinion, the records sought by our audit teams (in particular the procurement-related records) were fully covered by the PSC, and access to such records was essential for the purpose of our scrutiny. **Consequently, our scrutiny of records of the Panna-Mukta and Tapti fields was incomplete**, as also the findings arising therefrom. After the issue was raised yet again in June and July 2011, the PMT JV furnished part of the relevant records in July 2011, and assured that they would furnish the relevant records shortly. The records furnished recently by them as well as the records, in respect of which assurances have been received, will be covered subsequently, and findings arising therefrom included in subsequent audit reports.

(Para 3.7.1)

Comments on Audit Scope by Operator

The operator of KG-DWN-98/3 block challenged the scope, extent and coverage of our audit at various points of time, indicating that the CAG had conducted a "performance audit", which was not permitted under the PSCs. It was stated that nothing in the PSC permitted an audit of the operational, commercial and technical decisions of the operator. Further, an exercise, whereby the auditor would step into the shoes of the operator and attempt to evaluate whether the decisions by the operator – taken within his authorized area of operation – were in accordance with some undefined norms or the processes adhered to by bureaucratized decision making processes and that too without having the advantage of access to technical expertise or having the accountability for implementing such projects, was clearly beyond the provisions of the PSC.

We do not agree with the operator's views. In our opinion, our scrutiny was entirely consistent with the provisions of the PSC. Further, ***verification of charges and credits relating to the contractor's activities and other documents considered necessary to audit and verify the charges and credits,*** is not merely limited to an arithmetical totaling of charges and credits or tracing of charges/ expenses from the accounting statements to the contracts/ expense vouchers. Such an exercise would extend to verifying whether the costs being depicted in the PSC accounts by the contractor, which would critically affect the determination of profit petroleum and GoI's share therein, are correctly determined, and in particular, costs incurred for procurement of goods and services are determined through a competitive process, so as to minimize costs (and ultimately maximize the GoI share of profit petroleum). Such verification does NOT amount to the auditor stepping into the shoes of the operator and evaluating such decisions in accordance with "bureaucratized" decision making processes as stated by RIL. Our objective remains restricted to verifying whether GoI's revenue interests (including impact on current/ future GoI share of profit petroleum) are properly protected. **As stated earlier, we did not intend to, nor have we conducted a performance audit of the activities of the operators.**

Audit also wishes to firmly emphasise that all our enquiries and findings emerge from, and are limited to the PSC. We do not profess to go into any procedure or policy related aspects leading to the conclusion of the PSC. Taking the PSC as given, we have merely examined the contractual obligations of the signatories to the contract, viz., the Government and the private contractors. Our findings are totally guided by the "written word" of the contract.

In its response, MoPNG (July 2011) has agreed that the scope of audit conducted by the CAG is within the common audit parameters, and that financial/accounting audit also envisages review of activities and resources contributing to financial events and the controls thereon.

(Para 3.8.1)

Main Findings

KG-DWN-98/3 (Operator: RIL)

The KG-DWN-98/3 block, which is operated by RIL, was awarded in the first NELP round in the year 2000. It has India's largest gas discoveries (Dhirubai-1 and Dhirubai-3 gas fields) and also has a large oilfield discovery (MA oilfield). Our main findings and recommendations relating to the KG-DWN-98/3 block are as follows:

Non-relinquishment of area and declaration of entire contract area as discovery area

We found that the contractor was allowed to enter the second and third exploration phases without relinquishing 25 per cent each of the total contract area at the end of Phase-I and Phase-II as against Articles 4.1 & 4.2 of PSC. Subsequently, in February 2009, GoI also conveyed approval to treat the entire contract area of 7645 sq.km. as 'Discovery Area', thus enabling the operator to completely avoid relinquishment of area.

'Discovery Area' is defined in Article 1.39 of the PSC as ***"that part of the contract area about which, based on discovery[1] and results obtained from a well or wells drilled in such part, the contractor is of the opinion that petroleum exists and is likely to be produced in commercial quantities"***. The delineation of 'discovery area' is inextricably linked to results obtained from wells drilled and finding of petroleum deposits recoverable at the surface (which can be discovered only through drilling of successful wells). At the end of the Exploration Phase-I, the operator had drilled all wells - in the north-west part of the block only. The sequence of events between April 2004 and February 2009 clearly demonstrates that:

- Originally DGH did not agree (May 2004) to RIL's proposal (while preparing to proceed from Exploratory Phase-I to Phase-II) for not relinquishing any part of the contract area (at the end of Exploration Phase-I) and reiterated the PSC contractual provisions for relinquishment of 25 per cent at the end of Phase-I (even identifying "least priority" areas

[1] *'Discovery' is defined in Article 1.38 as 'the finding, during petroleum operations, of a deposit of petroleum not previously known to have existed, which can be recovered at the surface in a flow measurable by conventional petroleum industry testing methods'.*

for consideration for relinquishment). DGH, further, stated that none of the existing discoveries extended beyond 'priority area-I', and no well had been drilled in 'priority area-II', and hence it was not possible to consider the total block area as the discovery area.

- However, by April/ May 2005, DGH capitulated. While noting that there were "no two different interpretations possible as far as the definition of discovery provided in the PSC", DGH felt it would be "prudent to acquire and interpret the 3D seismic data in the remaining part of the block on a fast track basis". Subsequently, "the relinquishment area could also be worked out in a proper manner". In the meanwhile, RIL had already moved from Phase-I to Phase-II without any area relinquishment, and was notifying its intent to move from Phase-II to Phase-III, again without any relinquishment. In August 2006, DGH informed MoPNG that the Management Committee (MC) (chaired by DGH representative) had, in July 2006, permitted the contractor to enter the next phase without relinquishing any area, since data showed "continuity of discovery" in the block area (on the basis of RIL's presentation based on the results of seismic data acquired).

- Thereafter, there was extensive correspondence between MoPNG and DGH from August 2006. MoPNG raised pertinent questions as to **whether the coverage of wells was over the entire block** for DGH to reach the conclusion of discovery extension, but failed to pursue this aspect further.

- By April 2007, MoPNG felt that the proposal might be considered on getting a certification from DGH that the whole area had been covered by a reasonable number of wells/ 3D seismic to substantiate continuity of channels and the extent of discovery area. DGH gave a certificate in May 2007 to MoPNG.

- Even in May 2007, internal notes of MoPNG indicated their awareness that the whole of the block had been provided as a discovery area on the basis of 3D seismic and not on drilling of wells, which were mainly confined to the NW part of the block. However, MoPNG now proposed that on the basis of the proposed discovery area, the operator should be asked to appraise the area as per appraisal-related PSC provisions. After concerns expressed by the then Minister, PNG as to whether the decision sought to be ratified was consistent with the PSC provisions, the case was referred to a committee under the chairmanship of Additional Secretary, MoPNG. The Committee accepted the contractor's claim (February 2008) and decided (April 2008) that the timeline for appraisal of discoveries would commence from 11 July 2006 (viz. MC's acceptance of the contractor's claim). This was finally approved by the Minister in July 2008, but communicated to DGH only in February 2009.

RIL's views at different points of time (that the contractor was "of the opinion that petroleum was likely to exist", "the contract area was having hydrocarbon potential", "ultimately additional exploratory wells needed to be drilled to establish the additional hydrocarbon potential in the deeper water area of the block for which they were making efforts to hire ultra-deepwater rigs" clearly attempted to confuse potential/ prospectivity with actual discovery of hydrocarbons. Their difficulties in hiring ultra-deepwater rigs for the deep water area of the block (essentially the SW part, where no discoveries had been made) had no linkage with the contractual provisions for discovery area and relinquishment.

Thus, RIL's proposal of April 2004 to not relinquish any area and retain the whole contract area as 'discovery area' was submerged in a sea of correspondence between RIL and DGH, without relinquishment action being taken in terms of the PSC provisions, while RIL was allowed to proceed from phase to phase. By April/ May 2005, DGH had "waived" its earlier objections, and now advised/ directed the operator to complete 3D seismic data. By July 2006, DGH completed its about-turn and agreed (through the MC) to the contractor's proposal. MoPNG was aware of the flaws in the MC's decision for retention of the entire area, but, instead of reversing the same (in line with PSC provisions), it chose to accept DGH's certification for such retention.

MoPNG gave a detailed reply (July 2011) regarding acceptance of operator's opinion by DGH and MoPNG. We, however, do not agree with the reply as allowing the contractor to retain entire block area as discovery area was not in compliance with PSC provisions. The reply of MoPNG and our rebuttal thereof are given in detail in Chapter 4.

We recommend that MoPNG should review the determination of the entire contract area as 'discovery area' strictly in terms of the PSC provisions. Further, it should delineate the stipulated 25 per cent relinquishment area at the time of the conclusion of the 1st and 2nd exploratory phases, and then correctly delineate the 'discovery area' strictly based on the PSC definition, linked to well or wells drilled in that part, without considering any subsequent discoveries (which would be invalid on account of non-compliance with PSC provisions).

(Para 4.2.1)

Discovery related issue

In violation of PSC provisions, in the case of 13 out of 19 discoveries between October 2002 and July 2008, the operator had, without first furnishing the initial particulars of the discoveries in writing to the MC and Government, directly given written notifications regarding potential commerciality of the discoveries.

MoPNG replied (July 2011) that in the beginning, systems and processes were not fully established, however, over a period of time, the procedures had now been strengthened, and were being strictly followed for subsequent discoveries as per PSC requirement.

(Para 4.2.4)

D1-D3 gas discovery

The operator submitted an "Initial" Development Plan (IDP) in May 2004 (with estimated capital expenditure (capex) of US$ 2.4 billion). The IDP was followed up with an Addendum to the IDP (AIDP) in October 2006 (estimated capex of US$ 5.2 billion for Phase-I and US$ 3.6 billion for Phase-II). We found that:

- Most procurement activities were undertaken late in line with the schedules of the IDP of May 2004. By contrast, activities in respect of items in the AIDP were initiated even before the submission/approval of the AIDP. Clearly, the development activities of the operator were guided by AIDP, rather than IDP.

- As indicated by the operator, advance action was taken to tie up vendors for timely development of D1/D3 fields in anticipation of the MC approval of the AIDP. While a view could, perhaps, be taken that such pre-approval action is at the risk and cost of the contractor, in reality, this increases the probability of such approvals becoming a fait accompli.

Since approval of estimates does not constitute acceptance of the cost projections of the operator, validating the cost incurred by him can be done only after audit of the actual cost through proper norms. Part of the expenditure in respect of individual items under AIDP incurred during 2006-07 and 2007-08 has been audited. Remaining expenditure incurred from 2008-09 onwards will be covered in future audits.

(Para 4.3.1)

Procurement-related activities

We found that payments during 2006-07 and 2007-08 revealed instances of huge procurement contracts where we could not derive assurance as to the reasonableness of costs incurred, primarily due to lack of adequate competition – award on single financial bids; major revisions in scope/ quantities/ specifications; post-price bid opening; substantial variation orders - with consequential adverse implications for cost recovery and GoI's financial take.

In particular, regarding the MA oilfield, we found that well before submission, let alone approval, of the Field Development Plan (FDP) and Mining Lease (ML) application, the operator had placed orders for various critical items required for development activities/ production facilities from 2006 itself. We also found serious deficiencies in the award, on a single financial bid, of a 10 year hiring contract for US$ 1.1 billion for a Floating Production, Storage and Offloading (FPSO) vessel from Aker Floating Production (AFP).

(Para 4.4)

During our scrutiny of the operator's records, we have come across instances, where multiple vendors were pre-qualified. However, when technical bids were received, all vendors (except one) were rejected, and the contract was finally awarded on a single financial bid.

In our opinion, such disqualification of vendors on technical grounds, after a pre-qualification process and bidders' meetings for technical clarifications, limits the competitiveness which is not in accordance with the spirit of the procurement procedure given in the PSC. In many cases, it resulted in no competing financial bids, and the contract was awarded on the basis of a single financial bid. In such a situation, the letter and spirit of the MC's role at the pre-qualification stage is vitiated.

Consequently, in our opinion, in cases of procurement (under procedure 'C' – high value contracts), where pre-qualified bidders are subsequently disqualified/ declared non-responsive on various technical and other grounds and there is only one financial bid being considered, the Operator should either go back to the pre-qualification process, and ensure that more vendors/ parties are pre-qualified. Alternatively, if the operator wishes consideration of only a single financial bid, the matter has to be necessarily referred back to the MC (including GoI representatives)/ GoI for ex ante relaxation from PSC stipulated procurement procedures. Post facto approval of the MC may be provided for in emergent cases, with adequate justification.

Likewise, extension of contracts (beyond the extension periods already stipulated in the contract) is not in consonance with PSC provisions. If the operator wishes to extend such contracts, the matter has to be necessarily referred back to the MC for necessary relaxation.

(Para 4.6)

We, therefore, recommend that in the case of the KG-DWN-98/3, MoPNG carefully review in depth the award of 10 specific contracts (of which 8 were awarded to Aker Group companies) on the basis of a single financial bid. In this recommendation we are not even remotely suggesting that the operator should follow government procurement procedures, yet any commercially prudent private acquisition would also attempt to generate competition and thereby obtain the most competitive price. Such concern for a cost effective acquisition is not perceptible in the aforementioned process.

RJ-ON-90/1 block (Operator: Cairn Energy)

This onland block (mainly in Rajasthan) was awarded in 1995 under the pre-NELP exploratory rounds, and is currently operated by Cairn Energy. It now has India's largest onland oil discoveries, and also has significant gas discoveries. The high "pour point" of the crude oil has necessitated a 660 km oil pipeline with insulation and heating facilities to the Gujarat coast. Our main findings and recommendations with regard to the RJ-ON-90/1 block are as follows:

- 13 fresh discoveries were made during/ between the appraisal phase and in the development phase in areas already delineated as development areas. Consequently, in our opinion, the declaration of fresh discoveries during the appraisal/development phases within delineated discovery/development areas amounted to irregular extension of exploration activities, which is not in consonance with the terms of the PSC. This also indicates that the discovery/development areas were not strictly delineated, and included excess area.

(Para 5.2.3)

- There were instances of non-compliance with regard to the PSC provisions for notification of potential commercial interest, appraisal programme, submission of Field Development Plans etc.

(Para 5.3)

Panna-Mukta and Mid & South Tapti Fields

The Panna-Mukta and Mid & South Tapti fields are offshore shallow water fields in the offshore Bombay basin, which were initially discovered and operated by ONGC. Subsequently, these were awarded in 1994 to a consortium of private operators under a JV arrangement with ONGC.

As already pointed out, our scrutiny of records of the PMT JV and findings arising thereon are incomplete, due to non-production of records. Based on the limited records made available to us, our main findings are as follows:

- GoI incurred a substantial loss (on account of royalty) by failing to finalise the norms for post-well head costs of gas, and consequentially, gas wellhead prices. Even the norms for post well-head costs notified in August 2007 had significant deficiencies.

- MoPNG has accepted all our detailed findings relating to calculation of wellhead value of natural gas, and has agreed to take necessary action thereon.

(Para 6.2.2)

- MoPNG and its nominee for gas purchase (GAIL) failed to comply with the terms of the PSC during 2005-08 with regard to the pre-determined gas 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.

(Para 6.3.1)

- The PMT JV had not completed key work commitments in respect of the Mukta Field, which remained undeveloped (with very low volumes of oil and gas production). The committed work programme in respect of the Mid & South Tapti fields was also incomplete.

(Para 6.4.1 & 6.5.1)

Compliance and Control Issues

We also found numerous deficiencies in compliance and control vis-a-vis the PSC provisions by MoPNG/ DGH, notably with regard to:

- Irregular declaration of entire contract area of KG-OSN-2001/2 as discovery area;
- Non-compliance to PSC provisions regarding notification of discovery and submission of test reports;
- Delay in submission/ review of appraisal programme;
- Numerous deficiencies in functioning of the Management Committees for individual blocks; and
- Deficiencies in timely submission of stipulated periodical reports.

(Para 7.2. , 7.3, 7.4, 7.7 & 7.8)

Conclusions and General Recommendations

Our audit indicated that there is considerable scope for improvement in the management of hydrocarbon E&P with private sector participation.

Structure of PSC

The PSC, as it currently stands, is based on a scaled formula for profit sharing between the GoI and the private contractors. This is based on a critical parameter – Investment Multiple (IM) – which is essentially an index of the capital-intensive nature of the E&P project i.e. the amount of "capex" on exploration and development activities relative to income. The slabs for profit sharing are so designed that more the capital intensive the project (i.e. lower IM), the lower the GoI share of "profit petroleum" (which could be as low as 5 to 10 per cent). Contrarily, the higher the IM (i.e. less capital intensive vis-a-vis income), the higher the GoI share of "profit petroleum" (which could be as high as 85 per cent).

In practice, however, the private contractors have inadequate incentives to reduce capital expenditure - and substantial incentive to increase capital expenditure or "front-end" capital expenditure, so as to retain the IM in the lower slabs or to delay movement to the higher slabs.

The structure of the IM-based profit sharing formula (especially when there is a huge jump in GoI's profit share from 28 per cent to 85 per cent on an IM slab of 2.5 or more) is such that in certain scenarios, an increase in capital expenditure, upto a point, could conceivably result in an increase in the contractor's share of profit petroleum, despite a reduction in the total profit petroleum as well as GoI's share of profit petroleum. Further, "front-ending" of capital expenditure (i.e. skewed towards the initial phases) decreases the IM, and postpones the movement to higher IM slabs; this results in a reduction in GoI share on a discounted cash flow basis, since the slabs involving higher GoI share come later, rather than earlier.

Operational control of E&P operations is largely with the private operators, and the GoI's oversight role is restricted essentially to its representation (through MoPNG and/ or DGH) in the Management Committee for the block, especially in approval of Annual Work Programmes and Budgets and Field Development Plans, as well as a few approval functions delineated in the PSC.

Ashok Chawla Committee Report

We are given to understand that the report of the Ashok Chawla Committee on allocation of natural resources also draws similar conclusions regarding the IM-based profit-sharing formula. This committee had, inter alia, representatives from MoPNG and the Ministry of Finance, so it can safely be presumed that its conclusions were well considered. However, the report is not currently available in the public domain.

According to media reports, the Committee has stated that the system ***"gives incentive (to an operator) to increase his investment, or front-end his work plan in order to see that the threshold where Government's profit take rises rapidly is not reached"***. Citing the example of KG-DWN-98/3, the Committee has stated that "***the relationship between the pre-tax IM and the share of contractor profit petroleum changes dramatically once the pre-tax IM crosses 2.5, with the government's share increasing from 28 per cent to 85 per cent. It is useful to remember that this schedule is bid by the operator, and not determined by the Government."***

Further, according to the Committee, ***"a high share of some pre-tax IM will help to win the bid, depending on the financial mode of evaluation used, but it does raise concerns that such a radical change would provide very strong incentives for any operator to adopt all investment and strategies possible to ensure that the pre-tax IM stays within the 2.5 limit".***

The report clearly points out the risks associated with the IM-based formula for sharing of profit petroleum, especially with a steep jump in profit sharing from one slab to another. In our view, even the linearity introduced in the sliding scale for IM slabs from NELP-VII onwards does not fully address these risks.

The oversight/ control of GoI representatives on high value procurement decisions is also very limited in scope (largely restricted to prior intimation of the list of pre-qualified bidders). In fact, a comparison of the procurement procedure under PSCs in Bangladesh and India reveals that the clauses are similar, except that the Bangladesh PSCs require approval by the Management Committee for high value procurements (typically greater than US$ 500,000). This clause is, however, strangely missing from the Indian PSCs in almost all its versions.

Our audit review also revealed that, by and large, the MoPNG as also DGH, both through the Management Committee and otherwise, did not pay adequate attention to protecting - at every stage of E&P, be it exploration, development or production - GoI's financial interests. Adequate attention was not paid to specifically how every proposal/ decision would potentially affect GoI's share of profit petroleum. In addition to their failings, the constraints of adequately skilled resources with MoPNG/ DGH for monitoring several hundred PSCs simultaneously cannot also be ignored. By contrast, it is inconceivable that the private contractor would fail to protect his financial interests, and assess every investment/ operational proposal to see whether it would result in incremental revenues for him both in terms of cost recovery and contractor's share of profit petroleum.

Given the similar conclusions that two independent agencies have reached as regards the adverse impact of the profit sharing mechanism in protecting GoI's share (linked to the IM), designed in the late 1990s, there does seem to be enough ground to revisit the formula. The PSC as drawn up then, was with the limited expertise available with the GoI at that point of time. In view of the fact, albeit by hindsight, that we have gained the knowledge now, there is need to conclusively address this issue in respect of future PSCs.

(Para 8.1)

Recommendations for Future PSCs

The stated strength of the profit sharing mechanism is the sharing of risks between the contractor and the Government – if the profits are low or non-existent, both parties suffer.

For future PSCs, we recommend that the IM-linkage with the profit sharing formula (even with the linear sliding scale introduced from NELP-VII onwards) be removed by the GoI. Instead, the biddable profit-sharing percentage should be a single percentage. This will reduce the incentive for skewed volume and timing of capital expenditure resulting in very low GoI share of PP. Further, in order to ensure a modicum of control, very high value procurement decisions above a specified limit should be subject to approval by the MC, more specifically the approval of the GoI representatives. Such a mechanism already exists in PSCs operating in Bangladesh.

(Para 8.2)

Bid Evaluation Criteria

The Bid Evaluation Criteria (BEC) currently give weightage to technical/ financial ability and two biddable parameters - committed exploratory work and fiscal package (royalty + GoI share of profit petroleum). As regards fiscal package, the current evaluation model generally involves multiple scenarios of oil reserves and oil prices (typically high, medium and low) as well as a projected profile.

The assumptions based on which calculations of fiscal packages of different bidders are made are completely hypothetical. In the absence of high quality seismic data, let alone drilling and discovery findings, estimates of oil/ gas reserves and production profiles, as also projected capital and operating expenses and even crude oil and natural gas prices, are completely speculative. Admittedly, the evaluation model is applied consistently across all bidders. However, when the current system allows multiple bidding points (viz. different GoI shares of PP for different IM slabs), these hypothetical assumptions can not only make a significant difference as to who comes out as the winning bidder, but can also convey extremely unrealistic assumptions about what GoI's share of PP will be (e.g. when will GoI's share of PP reach the highest IM slab?).

Consequently, we recommend that the bidders should be allowed to make only a single point bid, which can be compared straightaway without resorting to hypothetical assumptions.

As regards the biddable exploratory work programme, we are generally in agreement with the bid evaluation process, except for the system of awarding points for well depth. As pointed out in Chapter 4 (relating to KG-DWN-98/3), it is unrealistic and impractical, without having accurate and reliable seismic data, to bid upfront how deep the well should be drilled, and then expect that, notwithstanding geological objectives, the well will be drilled to the committed depth even if it means a waste of money.

Consequently, in future, while considering the bid evaluation criteria, we recommend that either no weightage be allocated for well depth, or alternatively, well commitments be categorised into two groups – wells above and below a specified depth, *e.g.*, 1500 or 2000 metres, and points be awarded accordingly.

(Para 8.3)

MoPNG stated (July 2011) that they are prepared to look at alternative formulas and would consider the suggestion of the CAG and the Ashok Chawla Committee with an open mind and take a final view on merits.

Management of existing PSCs

The vast majority of blocks with high prospects for hydrocarbon discovery have already been awarded through various pre-NELP/ NELP rounds, and GoI has no option but to work within the constraints of the existing PSC structure and clauses to the fullest extent possible.

Development Plans and Annual Work Programmes and Budgets

It is inconceivable that a private operator/ contractor will make investments in absolute as well as incremental terms, in petroleum operations under the PSC without assessing whether such investments would result in increased revenues for him in terms of cost recovery and contractor's share of profit petroleum. It is necessary for MoPNG and DGH to function in a similar manner, with regard to GoI's financial interests. Consequently we recommend the following:

- Review and approval of development plans should be considered not just from a "technical perspective" viz. how best can oil and gas be extracted from the reservoirs, but also from a financial perspective – not only overall (i.e. what is the project NPV, Rate of Return etc.), but specifically from GoI's point of view (what are the projections of royalty and GoI share of profit petroleum? What are the risks to these revenues? How will increases/ decreases in capital expenditure, reserves, reservoir productivity, prices etc. affect GoI's financial take?).
- While reviewing and approving development plans, GoI representatives on the MC as well as DGH and MoPNG should ensure that detailed and appropriately validated estimates of GoI take and contractor take are included as an integral part of these plans at the approval stage. A suitable range for GoI take, say ± 15, 20 or 25 *per cent*, as considered appropriate by MoPNG could be stipulated.
- Approval by MoPNG of such development plans should be on the clear stipulation that any changes in capital and operating expenditure, expenditure commitments, production quantities and other factors, which have the impact of reducing the Investment Multiple and GoI share of profit petroleum **beyond *the stipulated range*** must be submitted for prior approval by GoI representatives on the MC, with detailed justification.
- Annual Work Programmes and Budgets should be strictly in line with the approved development plans. Any deviations or changes vis-à-vis the development plan which have the impact of reducing the IM and GoI share of profit petroleum ***beyond the stipulated range*** must be submitted for prior approval of the MC. Similarly, any significant variations from the approved Work Programme and Budgets with similar impact ***beyond the stipulated range*** must also be subject to prior approval.
- Incurring of any costs which vary from the Development Plans and Annual Work Programmes & Budgets on an overall basis, as well as in terms of significant line items with significant adverse impact on IM and GoI share of profit petroleum – ***beyond the stipulated range*** - without prior approval of GoI representatives on MC should automatically be ineligible for cost recovery.

While some of these recommendations could be misconstrued as hampering operational flexibility in petroleum operations by the contractor, the importance of the overall objective of protecting GoI's revenue interests cannot be ignored

(Para 8.4.1)

Procurement Activities

The provisions relating to procurement procedures in the PSCs do not provide for adequate oversight / control by GoI representatives on procurement processes. However, given the existing provisions, we recommend the following measures for protecting GoI's financial interest:

- The objective of effective procurement is to ensure optimum, not necessarily lowest, prices through effective competition. As long as adequate number of 'responsive' financial bids, typically three or more, from reputed vendors, who are pre-qualified after following due process, are received and duly considered (*i.e.,* not withdrawn, disqualified on technical or other grounds, deviations/ non-responsiveness or otherwise not considered), generate adequate competitive tension, the probability of effective procurement at optimum costs remains high.
- However, when high value contracts are awarded on the basis of single 'responsive' financial bids, in our opinion, these are awarded without competition, effectively on nomination basis. In all such cases, prior approval of the MC should be necessary for such awards. Post facto approval, with appropriate justification, for emergent procurement decisions may also be considered. Similar provisions would also apply to all procurement decisions involving post-priced bid opening changes to scope, quantities, work, prices, conditions etc.
- Also, the practice of repeated extensions, subsequent substantial variations in scope etc. of existing contracts is also not in line with the existing PSC procurement provisions, which incidentally makes no mention of extensions. Extensions or scope variations for high value contracts, beyond the contractually stipulated extensions, should also be subject to prior MC approval, with provisions for post facto approval in emergent cases.

(Para 8.4.2)

Relinquishment of area, and delineation of discovery and development areas

The entire PSC process is designed to ensure that the private contractors fully explore the contract area within designated timelines, relinquish areas where hydrocarbon prospects appear poor in a phased manner, and retain only those areas where hydrocarbon discoveries are made, relinquishing the remaining area for re-allocation – through a competitive bidding process - to other potential bidders, whose hopes/ views in terms of hydrocarbon prospectivity differ (either on account of technical and other capabilities or in terms of their risk appetite) from the contract holders who have relinquished such area. We, therefore, recommend the following:

The stipulated timelines and processes in the PSC for relinquishment of contract area should, under no circumstances, be relaxed, and compliance with these provisions should be invariably ensured.

Further, the discovery and development areas should be rigorously delineated, keeping strictly to the discoveries made through exploratory and appraisal well drilling and proper delineation of reservoir boundaries. Attempts by contractors for delineation of excessively wide discovery/ development areas through elastic (and incorrect interpretation) of hydrocarbon discovery should be strongly rebutted.

(Para 8.4.3)

Compliance with other PSC provisions

The PSC is a contractual document, and compliance with every contractual clause is of utmost importance. It would be inappropriate to distinguish between "major" and "minor" clauses, and neglect monitoring of compliance with so-called "minor" PSC clauses.

We recommend that DGH, and where necessary, MoPNG should put into place adequate and effective measures to ensure that compliance with all provisions of the PSC are fully monitored on a timely basis and appropriately documented, and action taken against operators on a timely and consistent basis, for non-compliance with PSC provisions. For such purposes, strengthening of the resource basis of DGH in terms of adequate quantity of skilled resources may be necessary.

DGH should also consider developing a comprehensive PSC monitoring system, which will not only provide details of compliance with PSC provisions for any block/ contract at a glance, but will also enable operators to "file" returns/ documents/ information electronically through the web and/or e-mail. The cost of developing (and maintaining) such an IT system will be miniscule, compared to the total GoI Profit Petroleum revenues as well as the potential (although not exactly quantifiable) gains from more effective and timely monitoring of compliance.

(Para 8.4.4)

Role of DGH

In our view, the roles and functions of DGH encompass two sets of functions with potential conflict of interest – an upstream regulatory function, and a function of rendering technical advice to GoI. While in 1993 (when DGH was set up), there was lack of adequate clarity on the role and position of regulators in various economic sectors, the need for clear autonomy of sectoral regulators (from the Executive) is now well recognised.

Consequently, we recommend that the functions currently discharged by the DGH be clearly demarcated. The technical advisory and related functions should be discharged by a body completely subordinate in all respects to MoPNG (either a cell/ attached office/ subordinate office within the MoPNG or a separate entity under MoPNG). Functions of a regulatory nature (review of hydrocarbon reserves and reservoir management, laying down of norms for declaration of discoveries, laying down safety and related norms and conducting safety inspections/ audits etc.) should be discharged by an autonomous body, with an arm's length relationship with GoI.

(Para 7.1)

MoPNG has assured that conclusions and recommendations drawn by CAG would be considered for appropriate action.

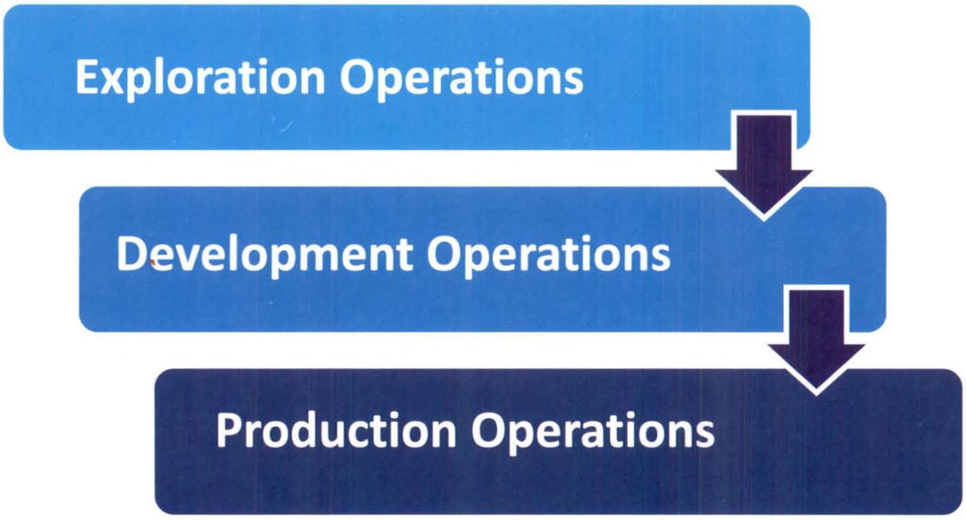
Chapter 1 - Hydrocarbon Production Sharing Contracts – An Introduction

1.1 Petroleum Exploration and Production (E&P)

1.1.1 Background

Petroleum covers hydrocarbons in liquid form (*viz.* crude oil) as well as in gaseous form (*viz.* natural gas). While hydrocarbon fields primarily contain either crude oil or natural gas, they also include associated natural gas (natural gas produced in association with crude oil), as well as condensate (liquid hydrocarbons segregated from natural gas).

Petroleum Exploration and Production (E&P) operations, also referred to as upstream operations[1], can be broadly grouped into three categories:



1.1.2 Petroleum Exploration

The first phase in the process for extraction of petroleum is exploration – the search for oil and gas deposits beneath the earth's surface. Such deposits could either be onshore or offshore. Exploration consists of several sub-phases:

[1] Downstream operations include refining of crude oil, and marketing of petroleum and gas products. Midstream operations (which are often included under downstream operations) include storage, transportation and related operations.

Figure 1.1 - Phases of Petroleum Exploration

Initial Surveys

- Areas thought to contain hydrocarbons are subjected to aerial, geological, geochemical, topographical and other surveys to detect large scale features of sub-surface geology.

Seismic Surveys

- After narrowing down the list of potential areas, detailed seismic surveys are carried out to identify formations with high probability of being petroleum reservoirs. These work on the principle of the time it takes for reflected sound waves to travel through matter (rock) of varying densities and using the process of depth conversion to create a profile of the substructure.
- Typically, the seismic survey involves **A**cquisition of seismic data, computer-based **P**rocessing of the data (including reprocessing of existing data), and its **I**nterpretation by geologists to identify formations with high probability of being reservoirs (the API process). There are different types of seismic surveys – two dimensional (2D), three dimensional (3D) standard/ high resolution, 4D/ 4C etc

Exploratory Well

- When a prospect has been identified and evaluated, and passes the oil companies selection criteria, an exploration well is drilled to conclusively determine the presence or absence of oil or gas.
- The well could turn out to be "dry". Alternatively, hydrocarbons (oil and/or gas) could be "discovered", and a discovery area is delineated.

Appraisal Wells

- Once a 'discovery' is made and is considered to be of potential commercial importance, 'appraisal' wells are drilled around the discovery in order to determine the contours of the reservoir (in terms of thickness and lateral extent) and its characteristics, and come up with a relatively accurate estimate of the recoverable oil / gas reserves.

Commercial Discovery

- If hydrocarbons are considered to be discovered in commercially viable quantities, a "commercial discovery" is declared (as per contractual provisions) and the commercial discovery area is delineated.

1.1.3 Development Operations

The next phase in the extraction of potential is the development of field, where a commercial discovery of hydrocarbons has been made. This will first involve the drawing up of a field development plan to ensure the most efficient, beneficial and timely extraction of petroleum, keeping in view engineering, economic, safety and environmental considerations.

Development will then include the following aspects, among others:

- Drilling of production wells (for producing crude oil and gas);
- Drilling of injection wells (for injecting water or gas, in order to sustain or accelerate the production of hydrocarbons);
- Installation of offshore platforms and installations, for handling offshore production of oil and gas; and
- Laying of gathering lines, and installation of separators, tankages, pumps, artificial lift facilities, which are required to produce, process, store, and transport petroleum.

1.1.4 Production Operations

Production operations involve operations after the commencement of production from a developed field. This would typically involve, among others:

- operation and maintenance of existing facilities;
- workovers;
- plugging and abandonment of wells;
- improved oil recovery; and
- site restoration (after cessation of petroleum operations) etc.

1.2 Private Sector Participation in Petroleum E&P in India

Efforts to involve foreign and domestic private sector companies in the business of Exploration and Production (E&P) of oil and gas in India began as early as 1973, followed by three rounds of bidding between 1980 and 1986, which did not yield any concrete results.

In 1991, the Government of India decided to invite foreign and domestic private sector companies to participate in the development of discovered oil and gas fields, and in some cases, fields partially developed by the National Oil Companies (NOCs) – Oil and Natural Gas Corporation Limited (ONGC) and Oil India Limited (OIL). In 1993, the Government introduced a policy of round-the-year bidding for exploratory blocks. In all, a total of nine rounds were held:

- One round for medium-sized discovered/ producing fields (1992);

- Two rounds for small-sized discovered fields (1991 and 1993); and
- Six rounds for pre-NELP exploratory blocks (1993 to 1995)[2].

1.3 New Exploration Licensing Policy (NELP)

In 1997, the Government announced the New Exploration Licensing Policy (NELP), under which NOCs would compete with Private Sector Companies for obtaining E&P licenses through a bidding process, instead of getting them on nomination basis. The main features of NELP, which was notified in 1999, are summarised below:

Feature	Brief Description
No special privileges for National Oil Companies (NOCs)	The NOCs were required to compete with the private sector for obtaining Petroleum Exploration Licenses, instead of getting them on nomination basis. There was no mandatory State participation through the NOCs, nor any "carried interest"[3] of the State.
Open availability of exploration area	There would be open availability of exploration acreages, to be demarcated on a grid system, to provide a continuous window of opportunities to all companies[4].
Sharing of profit petroleum	Government's share would be based on pre-tax sharing of profit petroleum based on investment multiple achieved. Contractors would be allowed full cost recovery.
Marketing freedom	Contractors were free to market the crude oil and gas in the domestic market.
Royalty rates	Royalty rates were fixed at 12.5 per cent of the wellhead value of crude oil in onshore areas and 10 per cent for offshore areas, while the rate was fixed at 10 per cent for natural gas. In addition, to encourage exploration in deep water and frontier areas, royalty was reduced by 50 per cent for offshore deep water areas for the first 7 years after commencement of commercial production. Further, there would be no payment of signature, discovery or production bonuses, nor would any cess be levied on crude production.

[2] In common parlance, the term "pre-NELP" is applied to the rounds for pre-NELP exploratory blocks

[3] Carried interest: An agreement whereby one party (usually the private partner) pays for a portion of the pre-production costs of the other party (usually the NOC).

[4] This has not taken place, with acreage still being auctioned in rounds rather than on an open availability basis.

Feature	Brief Description
Tax Holiday	There would be a seven year tax holiday after commencement of commercial production, and exemption from import duty for goods imported for petroleum operations.
Empowered Committee of Secretaries (ECS)	An Empowered Committee of Secretaries, consisting of Secretary, MoPNG, Finance Secretary and Law Secretary would consider bid evaluation criteria, conduct negotiations with the bidders, wherever necessary, and make recommendations to the Cabinet Committee on Economic Affairs (CCEA) on award of blocks.

1.4 Legal Framework

The Oilfields (Regulation and Development) Act, 1948 provides for regulation of oilfields and development of mineral oil – petroleum and natural gas – resources. The Petroleum and Natural Gas Rules, 1959 (PNG Rules), which are drawn up under Sections 5 and 6 of the Oilfields (Regulation and Development) Act, regulate the grant of exploration licenses and mining leases in respect of petroleum and natural gas. Under these Rules, GoI has the power to grant exploration licenses/ mining leases for offshore areas, while the State Governments are empowered to do so for onland areas.

Rule 5(2) of the PNG Rules specifically empower the GoI to include *"additional terms, covenants and conditions as may be provided in the agreement between the Central Government and the licensee or the lessee"*, after consulting the State Governments (where onland areas are involved). The Production Sharing Contracts (PSCs) between the GoI and the contractor (s) are signed under the provisions of this rule.

1.5 Organisational Structure

The Ministry of Petroleum and Natural Gas (MoPNG) is *inter alia* responsible for the exploration and production of petroleum and natural gas, including the administration of the Oilfields (Regulation and Development) Act, 1948. MoPNG is assisted by the Directorate General of Hydrocarbons (DGH), which was established in April 1993 with the objective of promoting sound management of Indian petroleum and natural gas resources having a balanced regard for the environment, safety, technological and economic aspects of petroleum activities.

1.6 Award of Production Sharing Contracts (pre-NELP/ NELP)

The position of PSCs awarded/ signed under different fiscal regimes was as follows:

- Discovered/ Producing fields rounds– 29;
- Pre-NELP Exploration Rounds – 28; and
- NELP Rounds (I to VIII) – 235

Details are given below:

Table 1.1 – Blocks awarded prior to NELP

Rounds	Year of offer	Fields/ blocks awarded	Offshore blocks awarded	Onshore blocks awarded	Blocks relinquished/ surrendered	Blocks converted to Mining Lease
Discovered/ producing fields	1991 to 1993	29	6	23	1	N/A
6 Pre-NELP Exploration Rounds	1993 to 1995	28	11	**17**	10	1

Table 1.2 – Blocks awarded under NELP

Round	Year of offer	Blocks awarded	No. of offshore blocks awarded		Onshore blocks awarded	Blocks relinquished /surrendered	Discoveries
			Deep water	Shallow water			
1st Round	1999	24	7	16	1	12	**39**
2nd Round	2000	23	8	8	7	17	**7**
3rd Round	2002	23	9	6	8	1	**15**
4th Round	2003	20	10	0	10	1	**11**
5th Round	2005	20	6	2	12		**12**
6th Round	2006	52	21	6	25		2
7th Round	2007	41	11	7	23		
8th Round[5]	2009	32	8	11	13		
Total		**235**	**80**	**56**	**99**	**31**	**86**

1.7 Bid Evaluation and Award under NELP – An Overview

1.7.1 Process

The process of award of contracts under the NELP rounds is broadly as follows:

[5] Under 9th NELP round (launched in October 2010), Government of India has offered 34 exploratory blocks (19 onland, 8 deep water and 7 shallow water). The NELP Round, for which submission of bids closed on 28 March 2011, attracted a total of 74 bids for 33 out of the 34 blocks on offer.

- Preparation of data package[6] and basin information docket[7];
- Road shows for publicizing the NELP round;
- Publishing of bid document (which includes the Notice Inviting Offer (NIO), the bid format, the Model Production Sharing Contract (MPSC), the petroleum tax guide, the Site Restoration Fund scheme, and price list for information docket, data package etc.);
- Purchase of bid document and data package/ basin information docket by contractors;
- Submission of bids, evaluation thereof, and award of blocks; and
- Signing of Production Sharing Contracts (PSCs).

1.7.2 Bid Evaluation Criteria (BEC)

Evaluation of bids is carried out, on weightages based on technical and financial capability, proposed exploratory work programme, and the fiscal package offered.

Area	Biddable inputs
Technical Capability	• Production, reserves of oil and gas, and acreage holding of the companies/consortium. • Experience of operatorship in oil & gas E&P of the companies/ consortium.
Financial Capability	• Net worth • Debt equity ratio • Average profit before tax for last three years
Exploratory Work Programme	Separately for each exploration phase: • API of new seismic data (specifying line kms of 2D seismic surveys and/or sq. kms. of 3D seismic surveys); • Re-processing of existing seismic data; • technical assessment by the bidders; and • exploratory drilling - number of exploration wells (with minimum stated objective depths)
Fiscal Package	• Percentage of annual production to be allocated for cost recovery

[6] Data package contains seismic data, navigation data, relevant maps and well log data for the individual block.

[7] Basin information docket is for the basin as a whole, and less detailed than the data package. It contains information on regional and local geology, status of exploration activities, hydrocarbon potential and a brief write-up on the blocks.

Area	Biddable inputs
	• Contractor's share of Profit Petroleum at various levels of pre-tax multiples of investment reached. • (Royalty receivable is also considered for calculation of Government NPV)

The exact criteria and weightages (in percentage terms) varied between different rounds of NELP, as summarised below:

Table 1.3 – Weightages of Bid Evaluation Criteria for different NELP rounds

Criterion	I, II & III	IV and V		VI				VII					VIII		
		On-land, Shallow	Deep water	Onland, Shallow		Deep water		Onland, Shallow			Deep water		On land	Other Onland, Shallow	Deep water
				Type A	Type B	Type A	Type B	A	B	S	A	B	S		
Technical Ability	6	6	9	15	15	20	20	-	-	-	30	30	-	-	25
Financial Ability	4	4	6								-	-			-
Work Programme	60	60	55	25	35	20	30	40	50	40	15	25	50	50	25
Fiscal Package	30	30	30	60	50	60	50	60	50	60	55	45	50	50	50
Total	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

The qualifying criteria included non-zero score under technical capability[8]; confirmation to Minimum Work Programme Commitment; and Certificate from a Chartered Accountant that net worth was equal to or more than the MWP for Exploration Phase I.

As regards the fiscal package, nine scenarios were envisaged with low, medium and high reserve sizes and oil/ gas prices. The ratio of Government NPV (Net Present Value) to Project NPV was calculated, using a discount rate of 10 per cent, in each of the nine scenarios, and a weighted average was calculated to arrive at the final value offered by the bidder. The bidder offering the highest Government NPV was given the maximum points, with other bidders receiving proportionate points.

[8] which included acreage holding, operatorship experience, average annual accretion of proved + probable (2P) reserves, and average annual production

As can be seen, substantial weightage is given to exploration work as part of the bidding criteria, so as to incentivise an aggressive exploration programme with better prospects for discovery of new national oil and gas resources.

The exploration programme, which includes both seismic surveys as well as drilling of exploration wells, is to be carried out in a phased manner within clearly defined timeframes and similarly phased relinquishment of portions of the contract area. At the end of the exploration period, the entire area (except for areas where oil and gas has been discovered, or is being developed) is to be returned to the Government, which can then re-offer it through a bidding process to other parties. Evidently, the idea is to prevent hoarding/ accumulation of exploration acreage.

Aspect	PSC Provisions
	consulting firm. ❖ Any audit exception should be notified to the Contractor in writing within 120 days, to which the Contractor shall respond within 120 days. ❖ Agreed adjustments resulting from an audit shall be made to the Government take within 30 days. For amounts claimed but not accepted by the contractor, the amount shall be deposited in an escrow account[21], pending decision of the sole expert/ arbitral tribunal.

The Production Sharing Contracts provide elaborate and detailed mechanisms/ procedures for protecting the interests of the GoI. Such procedures/ mechanisms would not be necessary if the Government's share was in the nature of royalty, linked only to the quantity and/or value of gas and oil produced. In such a situation, Government's concerns would be limited to obtaining assurance as to the quantity of oil and gas produced and proper valuation thereof. However, a profit-sharing mechanism inevitably requires detailed controls and procedures to ensure that the Government's financial interests are properly protected.

[21] The provision relating to depositing the money in an escrow account came into effect from NELP-IV onwards.

Aspect	PSC Provisions
	Participating Interest (70 per cent or more) with Government representatives' positive vote. The MC has two sets of functions – review/ advisory and approval. **Review/ Advisory functions:** ❖ Annual Work Programmes and Budgets for Exploration Operations ❖ Proposals for surrender/ relinquishment ❖ Proposals for appraisal programme ❖ Declaration of discovery/ commercial discovery ❖ Actual depth objective for each exploration well **Approval functions:** ❖ Annual Work Programmes and Budgets for Development and Production Operations ❖ Proposed Development Plans; Determination of Development Area ❖ Yearly Programme Quantity ❖ Extension of Exploration Phase ❖ Abandonment of Exploration Drilling on account of geological conditions encountered
GoI's Role	• Extension of Exploration Period for Appraisal Programme by 30 months[20] • Approval of Development Plans, after rejection by the MC • Approval of assignment or transfer of participating interest by a contractor
Accounts and Audit	• Annual audit of accounts shall be carried out by an independent CA firm. The appointment of the auditor and the scope of audit need prior approval of MC. • Further, the GoI shall have the right to audit the accounting records of the contractor, within 2 years from the end of the financial year: ❖ This audit may be undertaken either through its own representatives or through a qualified firm of CAs or a reputed

[20] 3 years in the case of NANG discovery

Aspect	PSC Provisions
Petroleum Industry Practices (GIPIP)	*prudent, diligent, skilled and experienced operators in Petroleum Exploration, Development and Production Operations and which, at a particular time in question, in the exercise of reasonable judgement and in light of facts then known at the time a decision was made, would be expected to accomplish the desired results and goals established in respect of which the practices, methods, standards, procedures and safety regulations, as the case may be, were followed; provided, however, that "Good International Petroleum Industry Practices" is not intended to be limited to the optimum practices or methods to the exclusion of all others, but rather to be a spectrum of reasonable and prudent practices, methods, standards, procedures and safety regulations. In the event that a question is raised by a party as to what constitutes GIPIP in a particular circumstance, it shall be agreed to by the Management Committee and failing which the same shall be decided by the Government with input from DGH or inputs from amongst a list of organisations or persons, as decided by the Government based on recommendations of DGH and its decision shall be binding provided, however, that in case a party has earlier approved or agreed to a plan, activity, practice, procedure etc. under this Contract, then it shall not raise a question about GIPIP on that matter".*
	However, GIPIP is not a document, set of documents or standards, and has not been codified by any internationally recognised organization/ body in the petroleum industries. Enquiries made by us with MoPNG/ DGH did not indicate the existence of any such codified set of GIPIP standards. ***The definition of GIPIP in the NELP PSC itself indicates that what constitutes Good International Petroleum Industry Practices in a particular circumstance is subject to agreement by the MC, failing which decision by GoI with inputs/ recommendations from DGH. Clearly, GIPIP is not a clear, unambiguous, and self-evident "gold standard", but "reasonable judgement" exercised by operators.***
Management Committee	The Management Committee (MC) for each PSC shall have two representatives from the GoI and one each from the companies constituting the contractor[19]; the GoI representative shall be the Chairman. If decisions are not unanimous, decisions need majority

[19] If the contractor constitutes only one company, it shall have two members on the MC

Aspect	PSC Provisions
	Development Area. • Within 30 months[17] of a discovery of crude oil, the Contractor should notify the Management Committee whether it should be treated as a Commercial Discovery or not. • Within 200 days[18] of declaration of a commercial discovery, the contractor should submit a comprehensive development plan, which should characterize the reservoir, indicate estimates of reserve in place, possible production magnitude and sustained production rate, outline the production facilities to be installed, and wells to be drilled, and estimate the development and production costs. • On submission of the development plan, the contractor should also submit an application for a Petroleum Mining Lease for the proposed Development Area. The lease shall be for 20 years with an extension of 5 years (10 years in the case of natural gas)
Natural Gas (Special Provisions)	• For Associated Natural Gas (ANG) in excess of requirements, if the contractor does not choose to exploit it, the Government can take it free of charge • In respect of Non Associated Natural Gas (NANG), on the Contractor's submission of a proposal for Commercial Discovery, the MC shall consider the contractor's proposal: ❖ With reference to commercial utilization or commercial development of NANG in the domestic market; and ❖ In the context of Government's policy on gas utilization, and the chain of activities required to bring NANG to potential consumers • Valuation of Natural Gas would be on the basis of competitive arm's length sales in the region for similar sales under similar conditions. The formula or basis on which prices shall be determined shall be approved by the Government, which will take into account the prevailing policy, if any, on pricing of Natural Gas, including any linkages with traded liquid fuels.
Good International	The PSC defines GIPIP inter alia as *"those practices, methods, standards, and procedures generally accepted and followed internationally by*

[17] 3 years in case of a NANG find.

[18] 1 year for a NANG find.

Production Sharing Contracts (MPSCs) being drawn up for each NELP round). The main features of the NELP PSCs are summarized below:

Table 2.2 – Main Features of NELP PSCs

Aspect	PSC Provisions
Exploration Period and Phases	• The Exploration Period consists of three Exploration Phases for a total of maximum 7 years; in the case of deepwater areas and frontier areas, the time frame is extended to 8 years (the first phase may be up to 4 years). • In each of the exploration phases, the contractor has to commit in his bid the Mandatory/ Minimum Work Programme (MWP) that he will undertake during that phase in terms of initial surveys (gravity and geochemical surveys etc.), seismic programme, and exploration wells (including depth objective). • If the MWP is not completed, the contractor will have to carry out additional, substitute or alternate work programme (to match the bid commitment) or pay the equivalent cost to Government. If the MWP is not completed, the contractor cannot proceed to the next phase. • After the 1st Exploration phase, the contractor can retain upto 75 per cent of the contract area (including development and discovery areas), while after the 2nd Exploration phase, he can retain up to 50 per cent[15] of the contract area, and after the 3rd Exploration phase, he can retain only the Discovery and Development Areas.
Discovery and Development	• Once a discovery of hydrocarbons is made, the Contractor should inform the Government and Management Committee, run tests to determine whether the discovery is of potential commercial interest (meriting appraisal) and inform the Management Committee within 60 days. • If the discovery is of potential commercial interest, the contractor should submit, within 120 days[16], a proposed Appraisal Programme (with a Work Programme and Budget) to determine whether the Discovery is a Commercial Discovery, and also delineate the

[15] If the development and discovery areas exceed the stipulated 75/ 50 per cent, the contractor can retain areas to that extent.

[16] One year in the case of a Non-Associated Natural Gas (NANG) find.

	Discovered fields	Pre-NELP exploratory blocks	NELP blocks
	production		market.
Carried interest of NOCs (without payment by NOC)	Nil	30 per cent exercisable on commercial discovery	Nil
Participating interest by NOCs	40 per cent in case of medium sized field and Nil in case of small sized fields.	Up to 40 per cent	NOCs to compete for acreage on "level-playing field"; no Participating Interest reserved for NOCs

2.5 Production Sharing Contracts (PSCs)

The Production Sharing Contracts (PSCs) between the Government of India and the contractor(s) for specific fields/ blocks provide the contractual basis for petroleum operations, cost recovery, profit sharing and other aspects. In most PSCs, there are many contracting parties with varying shares of Participating Interest (PI); one party (usually the party with the majority PI) is designated as the **"operator"**. The constituents of the contractor have to enter into an "Operating Agreement"[13] for conduct of petroleum operations. This agreement should provide for, among other things:

- The appointment, resignation, removal and responsibilities of the operator;
- The establishment of an "Operating Committee" (OC)[14] comprising of an agreed number of representatives of the Companies chaired by a representative of the operator;
- Functions of the Operating Committee (taking into account the PSC provisions), procedures for decision making, frequency and place of meetings; and
- Contribution to costs, default, sole risk, disposal of petroleum, and assignments between the parties to the Operating Agreement.

The content of these PSCs vary substantially between those for discovered fields, pre-NELP exploratory blocks and NELP blocks, and even within different NELP rounds (with Model

[13] Termed as "Joint Operating Agreement" in the Panna-Mukta and Tapti PSCs

[14] Termed as "Operator Board" (OB) in the Panna-Mukta and Tapti PSCs.

	Discovered fields	Pre-NELP exploratory blocks	NELP blocks
	to their Participating Interest	their participating interest)	
Rates of Royalty	Rs.481/MT for crude oil; @ 10 per cent of wellhead value of gas		10 per cent of wellhead value of gas; For crude oil – 12.5 per cent for onland areas, and 10 per cent for offshore areas; For deepwater areas, royalty is 50 per cent of applicable rates for first seven years of commercial production
Rates of Cess	Rs. 900/ MT for crude oil		No cess leviable
Tax structure	Rate of corporate income tax leviable as per the provisions of the Income Tax Act for Indian companies.		There is an income tax holiday in respect of deepwater block for the first 7 years[12]; however, Minimum Alternative Tax (MAT) is applicable. 100 per cent deduction allowable for all expenditure in respect of exploration and drilling operations. Also, unsuccessful exploration costs in respect of other contracts can also be deducted 100 per cent.
Custom duty	All equipment imported for petroleum operations exempt from customs duty on the basis of Essentiality Certificate (EC) issued by DGH		
Marketing of oil/gas	First right of GoI on purchase of 100 per cent oil and gas		Freedom to market the crude oil/gas discovered in domestic

[12] Ministry of Finance subsequently clarified that the seven year holiday is only for oil production (and not gas production)

	have any provision for levy of cess.
Petroleum Exploration License (PEL)	For undertaking exploration activities, the Contractor has to obtain a Petroleum Exploration License (PEL) under the provisions of the Petroleum and Natural Gas Rules, 1959: • From the Central Government in respect of offshore blocks; and • From the concerned State Government in respect of onland blocks (with the previous approval of the Central Government). The PEL fee, which is levied during the exploration period, consists of a security deposit of Rs. 4,00,000, an initial fee of Rs. 1,00,000, and a yearly advance license fee increasing from Rs. 200 to Rs. 4000 per sq. km per year within 5 years.
Mining Lease (ML)[11]	For extraction of petroleum, the contractor has to obtain a Mining Lease under the PNG Rules from the Central / State Government. The Mining Lease fee consists of a security deposit of Rs. 8,00,000, an initial fee of Rs. 2,00,000, and dead Rent or royalty (whichever is higher).

2.4 Comparison of fiscal regimes

A comparison of the fiscal regimes under discovered fields (e.g. Panna-Mukta and Tapti); pre-NELP exploratory blocks (e.g. RJ-ON-90/1); and NELP (e.g. KG-D6) on key issues is summarised below:

Table 2.1 – Comparison of Fiscal Regimes for discovered fields, pre-NELP exploratory blocks, and NELP blocks

	Discovered fields	**Pre-NELP exploratory blocks**	**NELP blocks**
Basis of sharing of profit petroleum	Post-tax Investment Multiple (IM) or Post Tax Rate of Return (PTRR)		Biddable pre-tax Investment Multiple (IM)
Recovery of cost petroleum	100 per cent cost recovery		Biddable Cost Recovery Factor (CRF) of upto 100 per cent
Liability for payment of royalty/ cess	All constituents of PSCs according	100 per cent liability on NOCs (irrespective of	All constituent of PSCs according to their Participating Interest

[11] Also referred to as PML (Petroleum Mining Lease)

	The amount of costs recoverable from annual revenues is termed as **Cost Petroleum**
Profit Petroleum	After deducting the recoverable costs (Cost Petroleum) from the revenues, the resulting **Profit Petroleum** is then divided between the Government and the Contractor. The sharing of profit petroleum, which is linked to the pre-tax Investment Multiple (IM) of the previous year, is a biddable parameter, and is evaluated as part of the fiscal package.
Investment Multiple	The pre-tax Investment Multiple (IM) is the ratio of cumulative Net Cash Income[9] to the cumulative exploration and development costs. The lower the IM, the more capital-intensive the project. As part of their bid, the contractors are required to specify the GoI share at different IM slabs e.g. less than 1.5, 1.5 to less than 2.0 etc. Generally, the contractors bid for a lower GoI share for the lower IM slabs, and the highest GoI share for IM of 3.5 and above (i.e. where net cash income is highest compared to the capital expenditure). Also, since capital expenditure in the initial years will generally be high and will decrease over time, the IM is expected to increase over time from year to year.

It may be noted that instead of the pre-tax IM (under NELP), the earlier fiscal regimes in respect of discovered fields or pre-NELP exploratory fields involved post-tax IM or Post Tax Rate of Return (PTRR).

2.3 Other receipts

Royalty/ Dead Rent	Royalty is payable by the contractor/ licensee[10] either at a fixed rate (in respect of oil produced from discovered fields/ pre-NELP exploratory blocks) or as a percentage of the "wellhead" value of oil/ gas produced. For offshore blocks, royalty accrues to GoI, while for onshore blocks, royalty accrues to the State Governments. Where no royalty is leviable (usually when there is no oil/ gas production), dead rent is payable on the area covered by the mining lease
Cess	Under the Oil Industry (Development) Act, 1974, cess is leviable on indigenous crude oil. The cess on crude oil produced from fields under PSCs prior to NELP is limited to Rs. 900/ tonne. PSCs under NELP do not

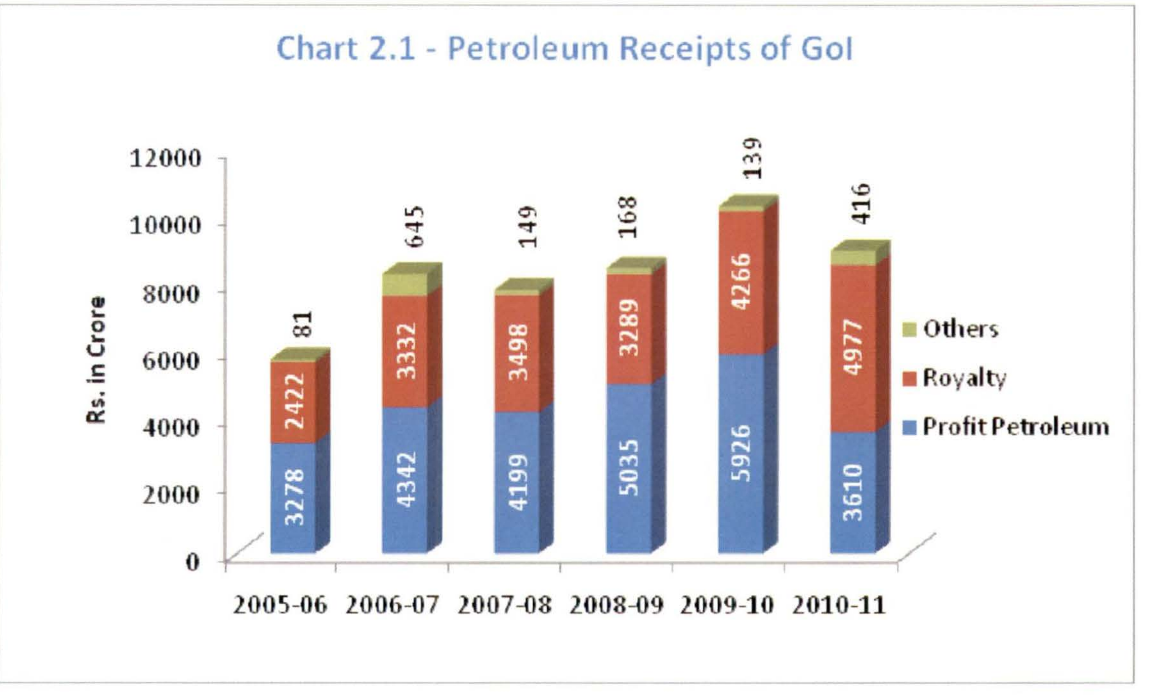
[9] Net Cash Income = Cost Petroleum + Contractor's Share of Profit Petroleum (based on last year's IM) + Incidental Income – Production Costs – Royalty

[10] The entity which holds the Mining Lease under the PNG Rules, 1959

Chapter 2 - Fiscal and Contracting Regime for Hydrocarbon Production Sharing Contracts

2.1 Non-Tax Receipts of GoI

Details of Non-Tax Receipts under the Major Head 0802- Petroleum during the last six years are shown below:



Source: Finance Accounts for data from 2005-06 to 2009-10, and PAO, MoPNG for 2010-11 data.

2.2 Cost Petroleum and Profit Petroleum under PSCs

The key feature of the PSC is that the contractors bid on the percentage of the reward that the GoI receives from the hydrocarbon block. The contractor undertakes the initial exploration risks. If no hydrocarbons are discovered, or the quantities are small, the revenues generated may not be sufficient to recover the costs incurred; this risk is borne by the contractor.

The three key issues under the NELP fiscal regime are Cost Recovery, Profit Petroleum, and Investment Multiple; these are described below:

Cost Recovery	The contractor bids the Cost Recovery Factor – i.e. the percentage of revenues which he is entitled to take in a year to recover his exploration, development and production costs. This percentage can be up to 100 per cent. The higher the cost recovery factor that the contractor bids, the earlier the costs can be recovered; however, in such a situation, his fiscal package will be relatively unattractive as part of the bid evaluation.

Chapter 3 - Audit Approach

3.1 Request for Audit by MoPNG

In November 2007, the Secretary, MoPNG requested the CAG of India to conduct a special audit of PSCs for eight blocks (viz. Ravva, Panna-Mukta, Tapti, KG-DWN-98/3, RJ-ON-90/1, Hazira, KG-OSN-2001/3, and PY-3) for which regular audit had already been carried upto 2003-04/ 2004-05. MoPNG's request was made in the context of large stakes of the Government in the form of royalty and profit petroleum, and concerns voiced in some quarters about the capital expenditure being incurred by some contractors in the development projects awarded under NELP.

In March 2008, we agreed to the MoPNG's request for audit, indicating that we would be covering, in the first instance, five blocks - Panna Mukta, Tapti, KG-DWN-98/3, Hazira, and PY-3 - out of the eight blocks for which special audit was requested by MoPNG (with the audit of the remaining three blocks to be taken up subsequently in a phased manner). We also subsumed a Performance Audit of Hydrocarbon PSCs, covering a sample of discovered/ pre-NELP PSCs and NELP PSCs[22] (for which an entry conference had been held in November 2007 with the then Secretary, MoPNG) into MoPNG's audit request.

3.2 Audit Objectives

The main objectives of the Performance Audit of Hydrocarbon PSCs were to verify whether:

- The systems and procedures of MoPNG and DGH to monitor and ensure compliance by the operators and contractors of the blocks with the terms of the PSCs were adequate and effective; and
- The revenue interests of the Government (including royalty and GoI share of profit petroleum) were properly protected, and adequate and effective mechanisms were in position for this purpose.

Concerns have been raised in certain quarters as to our conducting "Performance Audit" of individual blocks, and the operations/ activities of the contractors/ operators thereof. We take this opportunity to clarify that the scope of our performance audit covered the Ministry of Petroleum and Natural Gas (MoPNG) and the Directorate General of Hydrocarbons (DGH) and not the private operators of individual blocks.

Consequently, access to the records of the operators of selected blocks was only supplementary to the scrutiny of records of MoPNG and DGH.

The purpose of access to, and scrutiny of records of the operators was to verify whether the Government's revenue in the form of profit petroleum (current and future[23]) and royalty

[22] Originally, a sample of 22 PSCs was selected; subsequently, this was modified slightly.

[23] Since recovery of costs could affect GoI's future share of profit petroleum.

was correctly calculated, and its revenue interests were properly protected. Towards this larger objective, we intended to verify (based on access to operators' records for the specified accounting periods) whether:

- Capital expenditure (capex)[24], operating expenditure (opex), and net cash income and individual items thereof were accurately and reliably reflected, and these amounts were supported by adequate documentation;
- The figures of individual items of capex/ opex were reasonable, and also commensurate with original/revised budgets, plans, feasibility reports or other similar documents; and
- There was collateral evidence which would provide assurance regarding the authenticity of goods and services procured and provided.

3.3 Audit Scope

The audit scope covered a twin approach:

- Scrutiny of records at MoPNG and DGH in respect of a sample of **20 PSCs** so selected as to provide a balanced coverage of (a) onshore and offshore (shallow and deepwater) blocks (b) a cross section of operators (c) fields with oil discoveries and gas discoveries (d) pre-NELP and NELP and (e) blocks at different stages of E&P – under exploration, relinquished, discovery, production etc.; this covered the period from 2003-04 to 2007-08.
- Supplementary scrutiny of records of the operators of **four blocks/ fields** (KG-DWN-98/3, Panna-Mukta, Mid & South Tapti and RJ-ON-90/1) covering the two year period 2006-07 and 2007-08.

The blocks selected for the audit review are listed below; details (in brief) are indicated in **Annexure-3.1**.

Table 3.1 – Blocks Selected for the Audit Review

Sl. No	Contracting Parties	Operator	Basin	Block/ Field	Pre-NELP/ NELP	Shallow/ Deep water/ Onland	Status
1	BGEPIL, ONGC & RIL	BGEPIL	Mumbai Offshore	Panna/ Mukta	Medium sized	Shallow water	Producing
2	BGEPIL & ONGC	BGEPIL	Mumbai Offshore	Mid & South Tapti	Medium sized	Shallow water	Producing

[24] i.e. Investment expenditure considered under the terms of the PSC for computation of Investment Multiple

Sl. No	Contracting Parties	Operator	Basin	Block/ Field	Pre-NELP/ NELP	Shallow/ Deep water/ Onland	Status
3	CEIL, CEHL & ONGC	CEIL	Barmer Rajasthan	RJ-ON-90/1	Pre-NELP	Onland	Producing
4	RIL & NIKO	RIL	Krishna Godavari	KG-DWN-98/3	NELP-I	Deepwater	Development/Producing
5	GSPC & GAIL	GSPC	Cambay	CB-ONN-2000/1	NELP-II	Onland	Producing
6	ONGC	ONGC	Cauvery Offshore	CY-OSN-2000/1	NELP-II	Shallow water	Relinquished
7	ONGC	ONGC	Pranhita-Godavari	PG-ONN-2001/1	NELP-III	Onland	Exploration
8	RIL & HEPI	RIL	Krishna Godavari	KG-OSN-2001/2	NELP-III	Shallow water	Exploration
9	OIL & ONGC	OIL	Rajasthan	RJ-ONN-2002/1	NELP-IV	Onland	Exploration
10	RIL & HEPI	RIL	North Eastern Coast	NEC-DWN-2002/1	NELP-IV	Deepwater	Exploration
11	RIL	RIL	Kerala Konkan	KK-DWN-2003/1	NELP-V	Deepwater	Exploration
12	Petrogas, GAIL, HPCL, GSPC & IOC	Petrogas	Mumbai Off.	MB-OSN-2004/2	NELP-VI	Shallow water	Exploration
13	RIL	RIL	Mahanadi -NEC Offshore	MN-DWN-2004/3	NELP-VI	Deepwater	Exploration
14	CEIL, Tata Petrodyne & ONGC	CEIL	Cambay offshore	CB-OS-2 Lakshmi	Pre-NELP	Offshore	Producing

Sl. No	Contracting Parties	Operator	Basin	Block/ Field	Pre-NELP/ NELP	Shallow/ Deep water/ Onland	Status
15	CEIL, Tata Petrodyne & ONGC	CEIL	Cambay offshore	CB-OS-2 Gauri[25]	Pre-NELP	Offshore	Producing
16	RIL, TIOL & OOHL	RIL	Cambay	CB-ON/1	Pre-NELP	Onland	Exploration
17		Essar Oil	Mumbai Offshore	Ratna R-Series	Small sized	Offshore	PSC not signed
18	NIKO & GSPCL	NIKO	Cambay	Hazira	Small sized	Onland	Producing
19	ONGC & GAIL	ONGC	Kerala Konkan	KK-DWN-2000/2	NELP-II	Deepwater	Relinquished
20	ONGC & IOC	ONGC	Mumbai offshore	MB-DWN-2000/1	NELP-II	Deepwater	Relinquished
21	RIL	RIL	Mumbai Offshore	MB-OSN-97/3	NELP-I	Shallow water	Relinquished

3.4 Sources of Audit Criteria

The main sources of audit criteria were the following:

- Oil Fields (Regulation and Development) Act, 1948;
- Petroleum and Natural Gas Rules, 1959;
- New Exploration Licensing Policy (NELP) and subsidiary instructions of MoPNG;
- Bid documents viz, Bid Evaluation Criteria (BEC), Notice Inviting Offers (NIOs) and Model Production Sharing Contracts (MPSCs) for different NELP rounds; and
- Signed Production Sharing Contracts (PSCs) of selected blocks.

3.5 Difficulties in access to operators' records

Our audit effort was interrupted, due to difficulties in obtaining access to the records of the operators. The problem arose initially in July 2008 in respect of the records of the Panna-

[25] CB-OS-2 Lakshmi and CB-OS-2 Gauri involve a single PSC, but two separate fields, resulting in a total of 20 PSCs but 21 fields within our audit sample

Mukta and Tapti fields (PMT Joint Venture) but could not be resolved for an extended period of time, despite correspondence with MoPNG (and issue of instructions by MoPNG to the operators) as well as interactions with MoPNG and the operators.

Audit Provisions in the Production Sharing Contract (PSC) – A Summary

Articles 25.4 and 25.5 of the PSC provide that:

- The annual audit of accounts shall be carried out on behalf of the contractor by a qualified, independent firm of recognized chartered accountants registered in India and selected by the contractor with the approval of the MC, and a copy of the audited accounts shall be submitted to the GoI within 30 days of receipt;
- The GoI shall have the right to audit the accounting records of the contractor in respect of petroleum operations as provided in the Accounting Procedure, and for the purpose of this audit, the contractor shall make available to the auditor all such books, records, accounts and other documents and information as may be reasonably required by the auditor.

Further, Section 1.9 – Audit and Inspection Rights of the Government – of the Accounting Procedure to the PSC provides, *inter alia*, that:

- The GoI shall have the right to inspect and audit *"all records and documents supporting costs, expenditures, expenses, receipts and income, such as contractor's accounts, books, records, invoices, cash vouchers, debit notes, price lists or similar documentation with respect to petroleum operations conducted in each financial year within two years (or such longer period as may be required in exceptional circumstances)"* from the end of the relevant financial year;
- The GoI may undertake the conduct of audit either through its own representatives or through a qualified firm of recognized chartered accountants registered in India or a reputed consulting firm;
- In conducting the audit, the GoI or its auditors shall be entitled to examine and verify *"all charges and credits relating to the contractor's activities under the contract and all books of account, accounting entries, material records and inventories, vouchers, payrolls, invoices and any other documents, correspondence and records considered necessary to audit and verify the charges and credits"*.
- The procedure for issuing, responding to, and resolving audit exceptions has also been laid down.

The matter was finally taken up by the CAG in August 2009 with the then Minister, Petroleum and Natural Gas (PNG) for expediting access to the operators' records, in response to which, the then Minister, PNG provided assurances for such access. We are grateful for this.

Consequently, in September 2009, in view of the extreme difficulty in access to records of operators for earlier years (upto 2006-07), we suggested a revised audit approach, whereby we requested access to the operators of four blocks (Panna-Mukta, Mid & South Tapti, KG-DWN-98/3 and RJ-ON-90/1) covering a two year period from 2006-07 to 2007-08 (with access to records of previous years linked to transactions of current years). We also clarified the scope and extent of our scrutiny of operators' records, and indicated the initial list of records required from the operators.

After further correspondence and interaction with MoPNG, and issue of further directions by MoPNG to the operators on 27 November 2009, the initial records requested by us were finally provided by the operators and "kick-off"/ preliminary meetings held with the operators. Subsequently, field scrutiny of the records of the operators of the four blocks commenced between January and May 2010.

3.6 Audit Methodology

Field scrutiny of records by the audit teams included issue of audit requisitions and Preliminary Observation Memoranda (POMs)/ Audit Memoranda (AMs) to MoPNG/ DGH as well as the operators. Discussions were held at various points of audit with MoPNG/ DGH as well as with the operators during scrutiny of their records. Interactive sessions were held in June 2011 with the MoPNG and representatives of two operators to discuss certain key audit issues, on which clarifications were sought.

Thereafter, the draft Audit Report was issued to MoPNG in June 2011, requesting its response/ comments. Subsequent to the issue of the draft Audit Report, an Exit Conference was held in July 2011 with MoPNG/ DGH and the operators of the four blocks (Panna-Mukta, Tapti, KG-DWN-98/3 and RJ-ON-90/1) to discuss the major draft audit findings; at this Exit Conference, representatives of operators of two blocks (KG-DWN-98/3 and RJ-ON-90/1) also made detailed presentations, explaining their position on various issues. The Exit Conference also included a separate session with MoPNG/ DGH to discuss the draft audit findings relating to the role/ activities of MoPNG/ DGH.

MoPNG provided a detailed response to the draft audit report, and also forwarded copies of the responses of some of the operators with their comments thereon.

The responses/ comments furnished by MoPNG, as well as responses furnished by the operators during the Exit Conference, have been duly considered and incorporated, to the extent deemed appropriate, in this Audit Report.

We acknowledge the co-operation and assistance extended by the Ministry of Petroleum and Natural Gas, DGH, and the operators of two blocks (RIL and Cairn Energy in respect of KG-DWN-98/3 and RJ-ON-90/1) during the course of our audit of MoPNG/ DGH and scrutiny of operators' records.

3.7 Audit Scope Limitation

3.7.1 Production of Records by PMT Joint Venture

In order to fulfill our audit objectives and scope, during scrutiny of the records of the Panna-Mukta and Tapti blocks, operated by the Panna-Mukta Tapti Joint Venture (PMT JV), we sought access to records relating to pre and post contract award/ purchase order documents (e.g. bidding documents, purchase orders, change orders, procurement files and contracts) relating to two key development projects of these blocks viz. EPOD (Expanded Plan of Development) for Panna-Mukta and NRPOD (New Revised Plan of Development) for Mid & South Tapti, and other supplementary documents from British Gas Exploration and Production India Ltd. (BGEPIL), a joint operator for the PMT JV being the identified partner for furnishing records and documents for our field scrutiny.

However, BGEPIL did not produce many of the relevant records on the ground that Government audit was under Section 1.9 of Appendix C to the PSC, and was therefore limited to the accounting records of the JV. ***We do not agree with the views expressed by the PMT JV. In our opinion, the records sought by our audit teams (in particular the procurement-related records) were fully covered by Section 1.9 of Accounting Procedure to the PSC, and access to such records was essential for the purpose of our scrutiny.***

In addition to the non-furnishing of critical records, the PMT JV also did not respond to the majority of our POMs, on the ground that the issues raised therein were outside the scope of audit rights set out in the PSC.

Consequently, our scrutiny of the records of Panna-Mukta and Tapti blocks for 2006-07 and 2007-08 and findings arising thereon, as reflected in this audit report are incomplete, due to reasons beyond our control. We were also unable to vouchsafe the reliability of expenditure stated to have been incurred by the PMT JV during 2006-07 and 2007-08.

Based on the audit scope limitation indicated in the draft report issued to the MoPNG, DGH again directed PMT JV (22 June 2011) to provide the requested records. During the exit conference (12 July 2011), the PMT JV offered to provide records under Article 26.8 of the PSC (relating to inspection of records by the GoI) and not under Article 25 (which cover the auditing rights of GoI), if GoI made a request to this effect under Article 26.8. However, the representatives of MoPNG and CAG did not agree to the PMT JV's offer and insisted on the production of requested documents/ records under Article 25 of the PSC.

Subsequently, on 14 July 2011, the PMT JV indicated that they would provide the requested documents that were readily available at the earliest, in any event within the next seven days to our audit teams. They also indicated their readiness to submit other documents and records, as may be requested by our audit teams. However, they clarified that the submission of information would be without prejudice to their position on the scope of audit i.e. with respect to a financial audit contemplated under the provisions of the PSC in respect of 2006-07 and 2007-08.

On 20 July 2011, the PMT JV furnished part of the relevant records/documents requested by our audit teams. Subsequently (22 July 2011) the PMT JV furnished 10 service contracts (except price bids) in respect of NRPOD/EPOD project and assured that they would be furnishing the remaining records/documents shortly.

We take note of the assurance provided by PMT JV, as well as the documents provided on 20/22 July 2011 by the PMT JV. However, the records cannot obviously be scrutinised in time for the relevant findings to be included in this audit report.

The records furnished recently by the PMT JV as well as those records, in respect of which assurances have been received, will be covered in scrutiny of the records of the operator (PMT JV) for future years, and audit findings arising thereof included in subsequent audit reports.

3.7.2 Production of records by other operators

In respect of KG-DWN-98/3, RIL provided all records requested by audit teams, except for:

- Forward linkages to future years of transactions/ payments undertaken in 2006-07 and 2007-08 (period covered for scrutiny of operators' records);
- Complete accounting data on the SAP IT system (including both the expenditure i.e. debit side, and the credit side of transactions/ line items); this is described subsequently in Chapter 4.

No problems were encountered in respect of records requested from the operator of RJ-ON-90/1 block (Cairn Energy). In fact, the operator also provided extracts of records relating to periods outside our scope in order to clarify/ explain issues raised by us during the course of record scrutiny.

3.8 Comments on Audit Scope by Operator(s)

3.8.1 KG-DWN-98/3 block

The operator of KG-DWN-98/3 block (RIL) challenged the scope, extent and coverage of our audit at various points of time – during the course of field scrutiny of records, in a presentation at the Exit Conference, and also in written responses furnished by MoPNG. According to the operator,

- The audit scope was limited by Article 25.5 of the PSC, read with Section 1.9 of the Accounting Procedure. The right to audit under Section 1.9 of the Accounting Procedure was limited to verification of charges and credits (authenticity of expenditure) and inspection of books and records.
- The accounting audit by Government-appointed auditors was to be conducted within two years from the end of a financial year. The audit rights for 2006-07 had already been exercised by GoI. MoPNG confirmed (November 2009) that audit was under section 1.9 of the accounting procedure.

- Despite MoPNG's communication, CAG had conducted a "performance audit", which was not permitted under the PSCs, as:
  - ❖ All operational and technical matters were under purview of the Management Committee (MC), and were governed, regulated and measured by GIPIP (Good International Petroleum Industry Practices); and
  - ❖ Accounts auditors were not familiar with GIPIP;
  - ❖ Audit was limited to verification of charges and credits. GIPIP, and not audit, was the measure of performance in a PSC.
- Nothing in the PSC permitted an audit of the operational, commercial and technical decisions of the operator.
- With regard to one audit objective (verifying reasonableness of figures of individual items of capex/ opex), the exercise of revisiting either the decisions of the MC or the wisdom of the decisions of the operator in areas where commercial or technical decisions or details were left to the judgement of the operator was incompatible with the terms of the PSC.
- An exercise, whereby the auditor would step into the shoes of the operator and attempt to evaluate whether the decisions by the operator – taken within his authorized area of operation – were in accord with some undefined norms or the processes adhered to by bureaucratized decision making processes and that too without having the advantage of access to technical expertise or having the accountability for implementing such projects, was clearly beyond the provisions of the PSC.
- The gold standard prescribed in the PSC was Good International Petroleum Industry Practice (GIPIP), and a reference to GIPIP was conspicuous by its absence in the audit report.

We do not agree with the operator's views regarding our audit scope, extent and coverage.

- ***One of our key audit objectives was to verify whether the revenue interests of the Government (including royalty and GoI share of profit petroleum) were properly protected, and for this purpose, verify whether the figures of individual items of capex/ opex were reasonable (and also commensurate with original/revised budgets, plans, feasibility reports or other similar documents); and also whether there was collateral evidence which would provide assurance regarding the authenticity of goods and services procured and provided. In our opinion, this is entirely consistent with Article 25 of the PSC, and Section 1.9 of the Accounting Procedure to the PSC.***
- ***"Verification of charges and credits relating to the contractor's activities and other documents considered necessary to audit and verify the charges and credits" is not merely limited to an arithmetical totaling of charges and credits and tracing of***

charges/ expenses from the accounting statements to the contracts/ expense vouchers. Such an exercise would extend to verifying whether the costs being depicted in the PSC accounts by the contractor, which would critically affect the determination of profit petroleum and GoI's share therein, are correctly determined, and in particular, costs incurred for procurement of goods and services are determined through a competitive process, so as to minimize costs (and ultimately maximize the GoI share of profit petroleum). Such verification does NOT amount to the auditor stepping into the shoes of the operator and evaluating such decisions in accordance with "bureaucratized decision making processes".

- *Our objective remains restricted to verifying whether GoI's revenue interests (including impact on current/ future GoI share of profit petroleum) are properly protected. As stated earlier, we have not conducted a performance audit of the activities of the operators.*
- *Audit also wishes to firmly emphasise that all our enquiries and findings emerge from and are limited to the PSC. We do not profess to go into any procedure or policy related aspects leading to the conclusion of the PSC. Taking the PSC as given, we have merely examined the contractual obligations of the signatories to the contract, viz., the Govt and the private contractors. Our findings are totally guided by the "written word" of the contract.*
- *As regards the "gold standard" of GIPIP, we have already pointed out that there is no such codified document or set of standards brought out by any international body or organization in the petroleum industry. Rather than being a clear, unambiguous, and self-evident "gold standard", GIPIP merely represents "reasonable judgement" exercised by operators. While not questioning the exercising of professional judgement by the operators, we have been mandated by the GoI to scrutinize expenses, and the underlying procurement and related decisions, which impact GoI's take in terms of profit petroleum.*
- *The challenge of the Operator with regard to the expertise of the institution of the CAG in conducting audit of oil and gas Exploration & Production (E&P) is unwarranted. This institution has been conducting audit of India's largest E&P Company, ONGC Ltd. as well as Oil India Ltd. for several decades. The collective audit expertise of our institution is adequate to meet the challenges of scrutiny of hydrocarbon PSCs.*

In its response, MoPNG (July 2011) has agreed that the scope of audit conducted by the CAG is within the common audit parameters, and indicated that financial/accounting audit also envisages review of activities and resources contributing to financial events and the controls thereon.

3.9 Structure of Audit Report

The findings in the Performance Audit Report are divided into the following parts:

- Chapters 4 to 6 relate to audit findings relating to four blocks - KG-DWN-98/3, RJ-ON-90/1, and Panna-Mukta/ Tapti.

The findings in Chapters 4, 5, and 6 relating to the KG-DWN-98/3, RJ-ON-90/1 and Panna-Mukta-Tapti blocks/ fields include both findings based on audit of the records of MoPNG/ DGH and those audit findings arising out of the scrutiny of the records of the operators of these blocks/ fields.

- Chapter 7 relates to general audit findings (in respect of the other blocks/ fields) relating to compliance with the terms of the Production Sharing Contracts, and the adequacy and effectiveness of monitoring and control by MoPNG and DGH thereto;
- Chapter 8 relates to conclusions and general recommendations.

Chapter 4 - Findings relating to KG-DWN-98/3 block

4.1 Overview

The KG-DWN-98/3 deepwater block (also referred to as the KG-D6 block), with a contract area of 7645 sq. km., was awarded in the first NELP round in 2000 to a consortium of Reliance Industries Limited (RIL), the operator, and Niko Resources Limited (NIKO) with 90:10 participating interests. The PSC was signed in April 2000. The block is classified as a "deepwater block", with water depth ranging from 400 m in the NW to 2700 m in the SE. A total of 19 discoveries (Dhirubhai-1, 2, 3, 4, 5, 6, 7, 8, 16, 18, 19, 22, 23, 26, 29, 30, 31, 34 and 42) have been made in the block between 2002 and 2008, out of which 18 are gas discoveries, and one is an oil discovery.

After substantial gas discoveries at Dhirubhai-1 and Dhirubhai-3 (D1-D3), a Declaration of Commercial Discovery (DoC) was notified (D1 in April 2003 and D3 in March 2004) and the D1-D3 development area, covering an area of 339.41 sq. km. (4.5 per cent of the total block area) was delineated. An Initial Development Plan (IDP) for delivery of a production rate of 40 mmscmd (million metric standard cubic metres per day) of gas from these two discoveries, with probable gas reserves of 5.3 tcf (trillion cubic feet), was submitted in May 2004; this envisaged total capital expenditure of US$ 2.39 billion with 34 producing wells (the main components of expenditure being development wells- US$ 944 million, and production facilities-US$ 1.35 billion). Operating expenditure of US$ 62 million per annum was envisaged. The IDP was approved by the MC on 5 November 2004.

However, in October 2006, RIL submitted an Addendum to the IDP (AIDP) for delivery of a production rate of 80 mmscmd of gas, with increased probable gas reserves of 11.3 tcf; this envisaged capex of US$ 5.2 billion for the initial development phase upto 2008-09 with 22 producing wells (the main components being development wells - US$ 1.16 billion and production facilities - US$ 3.74 billion). Later in November 2006, RIL, after technical meetings/ correspondence with DGH, submitted a revised proposal as Phase – I US$ 5.2 billion and Phase – II US$ 3.6 billion totalling US$ 8.8 billion with 50 producing wells. The AIDP was approved by the MC on 12 December 2006.

In addition, a DoC was notified for the D-26 (MA Oil field) with a development area of 49.71 sq km. A separate development plan for the MA Oil Discovery, with capex of US$ 2.23 billion, was submitted in August 2007, and approved in April 2008. Oil production from the MA oil field started in September 2008, while gas production from the D1-D3 field started in April 2009.

Details of individual discoveries in KG-DWN-98/3 are indicated in **Annexure 4.1**.

One of the main features of this deepwater project is the laying of 450 kilometers of pipelines and umbilicals. We appreciate the efforts of the operator in executing this world class mega greenfield deepwater oil and gas infrastructure in India within record time.

4.2 Exploration and Appraisal Activities

4.2.1 Non-relinquishment of area and declaration of entire contract area as discovery area

Articles 4.1 and 4.2 of the PSC stipulate phased relinquishment of areas, allowing the contractor to retain a maximum of 75 percent and 50 per cent of the contract area (including the discovery and development areas)[26] after Exploration Phase-I and Exploration Phase-II, before entering the next exploration phase. At the end of the exploration period, the contractor is permitted to retain only the discovery and development areas.

Acceptance by DGH and MoPNG of entire contract area of KG-DWN-98/3 as discovery area not in terms of the PSC

We found that contrary to the PSC provisions, the contractor was allowed to enter the second and third exploration phases without relinquishing 25 per cent each of the total contract area at the end of Phase-I and Phase-II. Subsequently, in February 2009, GoI also conveyed approval to treat the entire contract area of 7645 sq.km. as 'discovery area', thus enabling the operator to completely avoid relinquishment of area.

The chronology of events relating to the approval of the entire contract area of KG-DWN-98/3 as "discovery area" is given below:

Table 4.1 - Chronology of events relating to Non-relinquishment and declaration of entire contract area as discovery area

Date	Event	Further Comments of Audit
21-Apr-04	DGH informed RIL that as per Article 3.5 of the PSC, the operator had to give a notice to GoI at least thirty days prior to the expiry of relevant phase either to proceed to the next exploration phase or to relinquish the entire contract area (except for any discovery area and any development area) and to conduct development and production operations in relation to any Commercial Discovery. Accordingly, DGH requested RIL to call an MC meeting before 06 May 2004 to discuss this issue.	
29-Apr-04	RIL informed DGH that: • Ten exploratory wells had been drilled in the block, based on which eight discoveries had been notified. Commerciality in respect of D-1,	2D and 3D seismic surveys are to be conducted by the operator as per the committed MWP to identify prospects for exploratory drilling. API of

[26] If the discovery and development areas exceed 75 percent/ 50 percent of the contract area, the contractor can retain the entire development and discovery areas.

Date	Event	Further Comments of Audit
	D-2 and D-3 had been approved by DGH and Development Plan for D-1 & D-3 was under finalization and would be submitted for MC approval. • After examining the potential and nature of the complexities, the operator believed that huge potential existed in the block, which deserved an extensive exploration, and as per Article 3.5 of PSC, notified its intent to proceed to the 2nd Exploration Phase on the expiry of the 1st Exploration Phase on 6 June 2004. • RIL also submitted that it was not in a position to identify any area in the block for relinquishment as required under Article 4 of the PSC due to the following reasons: ➢ The entire block area had been covered by 2D during 2001 and based on this, prospective leads had been identified which spread over the entire block area. Some of the leads had also been covered by 3D followed by exploratory drilling. All the wells drilled till then were hydrocarbon bearing. ➢ Based on the 2D and 3D coverage so far in this block, RIL was able to map several independent channels spreading over the block. The channels displayed different architecture and continuity, both laterally and vertically. ➢ RIL had recently completed the acquisition of additional 3165 sq.km of 3D seismic data in the block. The data had been sent to Australia for processing. The complete data set covering 4987 sq km would be processed, which would require about five to six months time. Further, RIL had also collected huge information from the 10 wells drilled in the block till then, by way of various logs, core data, DST (Drill Stem Testing) data, inversion studies etc. This vast data	2D and 3D data is to be completed in exploratory phases only. Once discovery is made, only appraisal for delineation of the reservoir and consequential demarcation of development area is to be done. However, without drilling of wells, the conditions attached to discovery/ discovery areas, as per the PSC provisions, are not fulfilled. All the discoveries (arising out of exploratory wells) had taken place in the North West (NW) part of the contract area (in general, less deep than the South East (SE) part, where no discoveries had taken place). The operator's opinion that petroleum existed in the entire contract area, without wells drilled in all parts of the contract area, was thus baseless, and DGH should have forced the contractor to relinquish the stipulated 25 per cent of the contract area, before entering the 2nd exploration phase on 7 June 2004.

Date	Event	Further Comments of Audit
	needed to be analysed and utilized for an in-depth assessment of their understanding of the seismic attributes and prospective areas. ➢ RIL also proposed to reprocess the entire 2D acquired in the block based on the results of drilling so far to refine the interpretation and mapping of the channel system. ➢ On the basis of additional/reprocessed seismic data, additional exploratory/appraisal drilling would be undertaken to cover the entire block area. • Based on the above, the operator was of the opinion that petroleum existed and was likely to be produced in commercial quantities after an exhaustive exploratory/appraisal programme from the entire contract area, which it considered to be the "Discovery Area". The operator would continue with the efforts to assess the potential of this discovery area during the second Exploration Phase.	
7-May-04	DGH informed RIL that: • The reasons put forth by RIL did not make a case for its inability to identify at least 25 per cent of the area for relinquishment. • Based on 2D seismic interpretation, two priority areas were identified –Priority -1 and Priority –II. The prospective areas based on 2D seismic interpretation were also within Priority –I and Priority –II areas. At that time, RIL's main focus area from point of further exploration and development was localized within Priority –I area. Therefore, the areas of least priority, along with some other low priority areas, could be identified for relinquishment. • Besides, the extension for 12 months was	DGH did not accept the reasons given by RIL showing its inability to identify 25 per cent of the contract area for relinquishment. DGH suggested the areas of low prospectivity which could be relinquished.

Date	Event	Further Comments of Audit
	granted (September 2003) effective June 2003 to enable the Operator to identify the area(s) for relinquishment, based on a comprehensive technical evaluation at the end of the 1st First Exploration Phase. • Therefore, DGH could not agree to the operator's request for not relinquishing any area prior to entering Phase-II of exploration as it was against the spirit of the PSC. Consequently, the operator was advised to relinquish the area(s) as per the PSC provisions prior to entering Phase-II of exploration.	
22-May-04	RIL wrote to DGH stating that: • It was true that based on 2D seismic data interpretation, the operator did identify two priority areas. That prioritization was also influenced by water depth, distance from shore and development considerations in case of discovery, apart from prospectivity angle. Accordingly, most of the efforts were concentrated on the exploratory initiatives, particularly in priority 1 where most of the wells were drilled. **Considering the limited period available under Phase-I, the operator had to prioritize the areas for exploration, and it did not mean that the other areas were not prospective.** • Within the short period of 4 years, the operator had acquired 4987 sq. km. of 3 D data and also collected huge information from the 10 wells drilled in the block. They had also planned to acquire further 3 D data in the balance area. The reprocessing of the entire 2D and 3D data and also the detailed analysis of the various logs, core data, inversion studies etc. would help in enhancing the understanding of the operator on the seismic attributes and prospective areas	The spirit of NELP is to maximise exploration efforts and minimise hoarding of exploration acreage. It is the contractor's job to prioritise areas for exploratory initiatives (in particular, drilling) within the PSC-specified timelines for exploration, and relinquish areas (as per his assessment of relative prospectivity/ prioritisation) in line with the PSC provisions. Prospectivity of an area indicates a higher **probability** of finding petroleum deposits, but is **NOT** equivalent to discovery, which implies actual finding of petroleum. RIL's belief was contrary to the PSC provisions. The relinquishment of area in line with PSC provisions

Date	Event	Further Comments of Audit
	indentified on the basis of 2 D. They had also acquired seismic data in the adjoining blocks awarded to them, and this would help them in building a regional geological model and mapping the prospectivity on the regional basis. • It was "perhaps" on that premise that the PSC allowed the contractor to retain all of the "Discovery Areas" at the end of the relevant exploration phase and, by definition, the "Discovery Area" was based on the contractor's opinion which was considered as the entire block area. • RIL believed that relinquishment of any area at that stage without completing the assessment of the hydrocarbon potential amounted to premature termination of exploratory initiatives, and would be detrimental to the spirit of PSC. • RIL once again appealed to DGH to reconsider its view and asked to give them an opportunity to complete their assessment of the hydrocarbon potential of that prospective block, considering the entire contract area to be the "Discovery Area".	was not a "premature" termination of exploratory initiatives.
11-June-04	DGH informed RIL that the operator had notified eight discoveries in the block located in Priority-I area. No well had been drilled in the Priority-II area to consider it as a discovery area. Therefore, the whole area could not be considered as a discovery area, and DGH had no data from RIL to support the fact that the whole area was a discovery area. Entire 2D and 3D seismic data was not available with them, and DGH was unable to understand the map enclosed (by RIL) showing the prospective areas based on 2D seismic data. As per PSC, RIL was to surrender at least 25 per cent of the block area before entering Phase-II of exploration.	DGH was right to mention its assessment on discovery area. However, DGH should have prevented RIL from proceeding to the 2nd Exploration Phase, without the relinquishment of 25 per cent area.
19-July-04	DGH, while bringing to RIL's notice that the issue was discussed at DGH on 25.06.2004 along with	At this point of time, RIL had already violated the

Date	Event	Further Comments of Audit
	RIL's representatives, clarified that **none of the existing discoveries extended beyond Priority area-I and no well had been drilled in Priority area-II. Therefore, it was not possible to consider the total block area as the discovery area.** Therefore, DGH requested RIL to relinquish 25 per cent of the block area at the earliest.	PSC provisions by entering phase-II without relinquishing 25 per cent of the block area.
24-July-04	• RIL informed DGH that they had done intrinsic exploration activities in the block. The extensive seismic data processing/ reprocessing and interpretation in the block helped in understanding of complex deepwater geological setting in the block besides acquiring a broad knowledge of KG offshore basin. The exploratory drilling carried out in channel, mid and distal levee complexes had resulted in the presence of a number of hydrocarbon gas bearing sandstone reservoirs of Plio-Miocene ages. The operator, based on the seismic and well database, had critically examined a conceptualized geological model along with sand development patterns and associated reservoir complexities. • Integration of outcome of interpretation of existing 2D and focused 3D seismic along with complete set of drilled well information including wire line/ LWD-MWD information and mud logging data indicated that sizeable quantities of hydrocarbon gas volumes did exist within the channel sand reservoirs as well as reservoirs, in the inter-channel areas. • RIL said that considering the overall evidence obtained through the exploration activities carried out by him, the following could be summarized: • A series of sub-marine channel complexes had been mapped, based on the evidence obtained from the existing and newly acquired 2D and 3D	The contractor's opinion that petroleum was "likely" to exist in the entire contract area and 'could be produced after an exhaustive exploratory/ appraisal programme' is not in consonance with the PSC definition of 'discovery area', which is centred on 'existence' of petroleum, based on wells drilled in that part.

Date	Event	Further Comments of Audit
	seismic data. • Deposits of gas, not previously known to have existed in the exploration block, had been found with commercial flow characteristics at the surface. • Gas occurrence with multiple Gas Water Contacts (GWCs) within some of the mapped channel systems enhanced the possibility of finding additional and new volumes of gas in distal fan lobes mapped in the southern and eastern areas to the existing 3D area. • Gas reservoirs (both in thin beds and thick sands) were found within channel sands as well as inter-channel areas. • Therefore, based upon the discoveries made so far and the results obtained from the drilled wells in the contract area, the contractor was of the opinion that the petroleum was 'likely' to exist and could be produced in commercial quantities after an exhaustive exploratory/appraisal programme from the entire contract area which it considered to be the "Discovery Area". The operator would continue with the efforts to assess the potential of this Discovery Area during the Second Exploration Phase.	
12-Aug-04	DGH reiterated that the entire contract area could not be considered as the Discovery Area and in accordance with Article 4.1 of the PSC, RIL had to relinquish 25 per cent of the block area. DGH further mentioned that to help RIL in that regard, they had identified a few areas of the block for relinquishment as an alternative which RIL could conveniently agree to relinquish and fulfil its PSC obligations. The alternatives had been taken from their (RIL's) map. DGH, accordingly, mentioned that it would be convenient for them to relinquish 25 per cent of the area out of those alternatives. However,	DGH's identification of areas for possible relinquishment was correct. However, this should have been done before RIL proceeded to the 2nd Exploration Phase, or else, RIL should have been prevented from moving into the 2nd Exploration Phase without such relinquishment.

Date	Event	Further Comments of Audit
	RIL was entitled to relinquish any other part of the block and put up an alternate proposal for consideration.	
19-Oct-04	DGH sent a reminder to RIL, requesting that the areas for relinquishment may be identified and a proposal be put up for consideration of MC to fulfil the PSC obligation.	
15-Apr-05	While inviting reference to Articles 4.1 & 1.39 of PSC and technical views exchanged between DGH and RIL's geoscientist, RIL mentioned that in the meetings it was amply explained by the contractor regarding the basis for the contractor's opinion on the existence of petroleum system in the entire contract area, through various seismic maps both on the work stations and paper prints. RIL also stated that the recent discoveries made by the Contractor in D6-H1 and D6-G1A further reinforced the Contractor's opinion conveyed earlier regarding the existence of petroleum system in the entire Contract Area. Further, the contractor had recently carried out reprocessing of existing 2D seismic data acquired by the Contractor earlier in 2001 to improve upon the imaging of deeper events including the basement. This study had also brought to light presence of similar bright seismic amplitude attributes in the entire Contract Area. As per PSC Provisions, the Contractor's view was fully in accordance with the relevant provisions of PSC. The Operator also enclosed updated stratmap slices, 'plio-pliestocene sweetness' amplitude map, depositional model and deepwater play types which, according to them, demonstrated extension of discovery area over the entire contract area. It was the opinion of the Contractor that the Discovery Area extended over the entire original Contract Area, and hence the Contractor shall be entitled to retain the entire Discovery Area i.e. entire Contract Area. This opinion of the contractor was communicated to DGH/GoI in Phase-I itself. As such, the Contractor was not required to relinquish any part of the original Contract Area. In view of the above, RIL reiterated that the determination of the Contractor on the extent of	DGH had allowed RIL to continue exploration work in the 2nd phase for nearly 9 months, while discussing and debating the delineation of 'discovery area'. The fact of non-availability of rigs capable of drilling to high water depths (as in the SE part of the contract area, unlike the NW part where all the discoveries had taken place) merely confirms RIL's hoarding of exploration acreage, without relinquishment. Non-availability of drilling rigs is no reason for declaring the entire contract area as 'discovery area', or for non-relinquishment.

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	the Discovery Area in the block KG-DWN-98/3 was based on sound technical rationale, and was fully in line with the provisions of the PSC. RIL, as a prudent Operator had already planned acquisition of additional 2D/3D seismic data in the Contract Area and drilled more exploratory wells in the Discovery Area. Drilling could not be done in some of these areas due to high water depths beyond the capacity of the drillship mobilized and required a higher generation rig.	
22-Apr-05 / 2-May-05	DGH mentioned that it might be agreed that several play types were continuing from 3D covered to 2D covered area, but this did not imply that discovery was also continuing over the entire contract area. Further, the continuance of a play type in a particular area did not necessarily imply continuance of the discovery also in the same area, without undertaking certain obvious exploratory steps. **Moreover, there were no two different interpretations possible as far as the definition of the discovery provided in the concerned PSC.** However, DGH said that they did agree that the prospectivity of the remaining part of the block was also high, based on available 2D seismic data. DGH further mentioned that as most of the play types in the contract area were stratigraphic in nature, their geometry and continuity in the remaining part of the contract area could be properly established only through acquisition and interpretation of 3D seismic data. Therefore, DGH said that it would be prudent to acquire and interpret the 3D seismic data in the remaining part of the block on a fast track basis, so that the geometry and continuity of play types as well as relationship between the high amplitude anomalies observed through available 2D seismic could be established with the discoveries already made in the contract area. Subsequently, the relinquishment area could also be worked out in a proper manner. Further, clarifications/ interpretations furnished by RIL on various PSC Articles related to the above matter i.e. Article 4.1 and Article 1.39 needed to be reviewed by RIL, as	**This evidences the beginning of the about turn in the DGH's opinion, where, instead of drilling wells in all parts of the contract area (with resulting discoveries), the emphasis was merely on acquisition and interpretation of 3D seismic data in the remaining part of the block, with the "relinquishment to be worked out in a proper manner" subsequently.**

Date	Event	Further Comments of Audit
	the same did not seem to be correctly interpreted and therefore were not agreeable to DGH. Consequently, DGH asked RIL about their future plans with realistic time frames for acquisition of 3D data in the remaining part of the block, so that the geometry and continuity of play types could be properly established in the whole block.	
13-May-05	While agreeing to acquire and interpret the 3D seismic data in remaining part of the block on a fast track basis, RIL described the other work done and proposed to be done by them. Further, they reiterated that based on sound technical rationale, the contractor was not required to relinquish any part of the original contract area. However, RIL said that they were planning additional exploration/ appraisal programme to support their views on the extent of discovery area.	
24-May-05	RIL gave notice to DGH for entering the 3rd Exploration Phase for KG-D6 Block giving details of the work carried out in the 1st and 2nd EP. In view of the extensive exploratory work programme taken up in the block and their ongoing / planned exploratory efforts to strengthen their view that the entire contract area was having hydrocarbon potential, the Operator (RIL) notified, in pursuance of Art. 3.5 of the PSC, its intention to proceed to the 3rd Exploration Phase without relinquishment of any part of the contract area as the reasons notified during entering 2nd Exploration Phase still prevailed.	RIL managed to be on course to proceed to the 3rd phase, without relinquishing any area.
24-May-05	• DGH informed RIL (w.r.t their letter dated 13th May 2005) that: • By acquiring 700 sq. km. of seismic data as indicated in their (RIL's) letter, the total 3D coverage would be round 70 per cent of the block area and the remaining 30 per cent area would be without any 3D coverage for any meaningful interpretation to demonstrate the extension of the geobodies / channel levee complex. • DGH again (in furtherance to their letter dated	The shift in DGH's opinion to just have 3D coverage of the whole block in order for the contractor to retain the whole area is apparently complete. DGH was no more insisting for relinquishing of any part of the block area. It was a significant change in stance.

Date	Event	Further Comments of Audit
	2nd May 2005) requested RIL to provide a realistic time frame for acquisition of 3D seismic data for the remaining area to establish the geometry and continuity of play types in the whole block. • Their (RIL's) request for retaining the whole block area would be examined, only after complete 3D coverage over the block area was achieved.	
4-June-05	RIL forwarded the Operating Committee resolution dated 10 May 2005 for entering the 3rd Exploration Phase and retaining the entire contract area (other than the Development Area) as the "Discovery Area" without any relinquishment.	
16-June-05	RIL intimated DGH (w.r.t. the issue that retention of entire block area would be considered after 3D coverage of the entire block area) that 70 per cent of the block area had already been covered by 3D survey, and the balance had been covered by the original 2D. They were taking steps to cover the remaining area. Further, they intimated that while the 3D coverage was expected to further confirm their opinion regarding continuity of the channel system throughout the block area, ultimately additional exploratory wells needed to be drilled to establish the additional hydrocarbon potential in the deeper water area of the block for which they (RIL) were making efforts to hire ultra-deepwater rigs. It would revert with realistic programme for 3D seismic acquisition for the remaining KG-D6 area, after identifying a suitable seismic vessel.	DGH no longer mentions any requirement other than 3D seismic coverage
17-June-05	DGH intimated RIL (in ref. to RIL's notice dated 24 May 2005 for entering 3rd EP) quoting reference of Art. 4.2 of PSC that the issue of relinquishment of 25 per cent of the block area at the end of Phase – I had still not been resolved and again requested RIL to convey a realistic time frame for acquisition of the 3D seismic over the whole block area.	
15-July-05	RIL intimated DGH that they had firmed up the 3D acquisition programme in RIL's blocks in the east	

Date	Event	Further Comments of Audit
	coast, including KG-D6. The tendering process had been initiated and the proposed acquisition programme was likely to commence during the field season 2005-06 (after monsoon break).	
11-July-06	MC, in its meeting, decided that in the light of results of 3D seismic data acquired in the entire block as presented by the contractor, they agreed with the opinion of the contractor that the prospective geological plays had continuity in the entire block, and hence no block area needed to be relinquished pursuant to Article 4 of PSC.	
1-Aug-06	While giving the background for allowing the operator to retain the whole contract area as discovery area, DGH informed MoPNG that on the basis of a technical presentation given by RIL to MC at its meeting on 11 July 2006, he established the presence of channel-levee complex associated with fan system in the southern limit of the block. MC permitted RIL to enter the next phase without relinquishing any area, since data showed continuity of discovery in the block area. In its letter, DGH mentioned that RIL completed MWP of Phase-I and entered Phase-II on 7.6.04. As per the PSC, they were supposed to relinquish 25 per cent of the block area 1912 sq. km. out of the total block area of 7645 sq. km. RIL informed DGH on 29.04.04 about entering the second phase from 7.06.04 without relinquishing 25 per cent area. DGH did not agree to RIL's request and asked RIL to relinquish the stipulated area. However, RIL stated that it had acquired 4987 sq. km. of 3D seismic data and on that basis, the geological model prepared by them depicted that the whole of the block area had continuity of channel system. DGH examined all the documents and viewed the data on work stations, and on 24.05.05 directed RIL to cover the whole block area with 2D/3D seismic survey for establishing the extension of plays of reservoir sand i.e. channel and levee complex throughout the block. At the directive of DGH, RIL carried out the seismic survey of 3474 sq. km. of the block, thereby covering almost the whole of the block area. In the	DGH displayed even more flexibility, and even with a "remaining small portion of the block" not being covered by 3D seismic survey, MC (with one DGH representative) permitted retention of the whole block area.

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	16th MC meeting held on 11.07.06, RIL made a technical presentation and established presence of channel-levee complex associated with fan system in the southern limit of the block. MC directed RIL to cover the remaining small portion of the block also with 3D seismic survey and permitted RIL to enter phase-III without relinquishing any area, since data showed continuity of discovery in the block area. DGH would like to inform MoPNG that RIL had been permitted to retain the whole of the block area as it had entered phase-III.	
1-Nov-06	**On coming to know that MC had allowed the operator to enter Phase-II by retaining the entire area as a discovery area in contravention of the PSC provisions, MoPNG asked DGH to clarify the position in this regard.** In its letter, MoPNG indicated that DGH did not agree to the contention of RIL to retain area at the end of phase-I. However, after carrying out 3D seismic coverage, DGH allowed the contractor to retain entire area (at this time the contractor entering into phase-III). At the end of phase-I, the contractor had not carried out 3D in the entire area and that process continued almost till the end of exploration phase-II. DGH, only after entering phase-III and based on the data available then, had allowed retention of the entire area deeming it as discovery area. The entire 3D data was not available at the end of phase-I, where a decision was required on relinquishment of area. MoPNG further stated that the discovery area was prescribed around well or wells, and nowhere it had been mentioned to decide discovery area. After discovery area, a number of consequences follow, such as appraisal of discovery area in a time bound manner as provided in the PSC. MoPNG mentioned that it was therefore clear that the PSC provision had not been complied in allowing retention of entire area.	At this stage, MoPNG rightly highlighted the definition of 'discovery area' being around well or wells, and that the PSC provisions had not been complied with, in allowing retention of the contract area.
23-Nov-06	While clarifying its position, DGH informed that at the end of Phase-I, in the block area of 7645 sq. km., the contractor had carried out 1000 LKM of reprocessing, 1434 LKM of 2D API, and 4987 sq. km.	DGH's statement regarding the entire contract area being "likely" to contain

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	of 3D API, and also drilled 10 exploratory wells. Contractor had made 7 discoveries in Phase-I and on the basis of reinterpretation of the reprocessed data, interpretation of the newly acquired 2 D & 3 D seismic data and data generated from the exploratory wells drilled, it emerged that the entire contract area was likely to contain hydrocarbons and there was a continuation of channel, levee and over bank deposits, and fan bodies existed in the entire block area. DGH further mentioned that to conclude and finally confirm that there was a continuity of the prospects, DGH had directed the contractor to cover the whole block area with 3D API. Contractor agreed with the suggestion, and he was allowed to proceed to next phase without relinquishment. It was thought prudent that a decision on the relinquishment would be taken, after the whole block area was covered with API of 3D seismic survey. At the end of Phase-II, the contractor had carried out 1000 LKM of reprocessing, 1434 LKM of 2D API, and 5991 sq. km. of 3D API and also drilled 15 exploratory wells. Total discoveries were 9. From the additional 3D data generated and from the data generated from 5 wells drilled in phase-II, the level of confidence in continuation of prospect with channel and levee increased to a great extent. Contractor was, therefore, allowed to enter phase-III without relinquishment and with advice to cover the remaining area with API of 3D. Further, DGH said that in the blocks where hydrocarbon discovery had been made and there were indications of continuation of prospects in the whole block, and the contractor was prepared to carry out additional work and cover the whole of the block with API 3D, the contractors had been allowed to proceed to next phase without relinquishment. Based on technical merits and technical justifications and keeping in view interest of exploration, DGH stated that the contractor was allowed to proceed to phase-II and phase-III without relinquishment.	hydrocarbons, or increase to a great extent in "level of confidence in continuation of the prospect" is again not in compliance with the PSC provisions regarding discovery area.
8-Mar-	On the basis of DGH's reply, MoPNG raised some	MoPNG again flagged the

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07	further questions to DGH regarding: • how much area of the block was covered by 3D (in terms of area and percentage 3D coverage of the block area) at the end of Phase-I and II; • their comments on PSC provisions relating to the definition of discovery area and the discovery related provisions; • confirmation whether the coverage of wells was over the entire block for DGH to reach the conclusion of discovery extension; • whether MC was competent to give waiver from the relinquishment norms in the light of the PSC provisions. Further, MoPNG stated that in future, all matters pertaining to relinquishment not in accordance with the PSC provisions, technical advice of DGH along-with the recommendations should be submitted to the Government for a decision in the matter.	extent of coverage of wells over the entire block to reach the conclusion of discovery extension. **Importantly, MoPNG also indicated that in future, all matters pertaining to relinquishment not in accordance with PSC provisions should be submitted to GoI for a decision, perhaps indicating that this was one such case.**
4-Apr-07	As per the reply, DGH informed MoPNG that on the basis of drilled wells, 2D and 3D surveys carried out, the operator claimed that there was continuity of meandering channels throughout the block and the contention of the operator had been confirmed by DGH, based on drilling of the wells and seismic data acquired. Further, the instant case was well covered within the definition of discovery area as given in Article 1.39. The contractor had opined that the hydrocarbon bearing channels were continuing throughout the block and had the potentiality to produce gas in commercial quantities. Channels responsible for flow of hydrocarbons from discovery wells in the area were at different stratigraphic/ depth levels and belonged to different pools. The distribution of such channels extended to almost entire area indicating favourable prospectivity perception in the area. That feature had been confirmed by the technical team of DGH in the work station at RIL office. Article 10 of PSC was also followed in that case, as all discoveries made later were followed by	DGH again referred to "favourable prospectivity perception", not in accordance with PSC provisions. While we note the combination of well and seismic data to prove continuity, the fact remains that all discoveries were confined to the NW part of the block.

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	commercial potentiality, appraisal and commerciality. Further, DGH mentioned that it was not necessary to drill wells in the entire block to establish continuity of discovery. A well is a calibration tool, and the seismic survey is an extensional tool. The combination of both paves the way to prove the continuity of the discovery area. In the block, continuity had been established conclusively by carrying out total 9475 sq. km. of API – 3D and drilling 28 wells in the block. As regards whether MC was competent to give waiver from the relinquishment norms in the light of the PSC provisions, DGH stated that MC did not violate the PSC provisions and did not grant any waiver for relinquishment.	
11-Apr-07	A meeting was held in MoPNG to discuss this issue. It was decided that the proposal might be considered on getting a certification from DGH that the whole area had been covered by a reasonable number of wells/ 3D seismic to substantiate continuity of channels and the extent of discovery area.	MoPNG evidently attempted to avoid taking a clear decision on this issue in line with PSC provisions.
15-May-07	DGH gave a certificate to MoPNG stating that on the basis of the existing report, special 3 D seismic processing (High Frequency Image, AVO, Jainson inversion), basin and facies modeling, it was concluded that the hydrocarbon bearing channels and levees associated with the discoveries were present and extended throughout the block area and hence, in accordance with Article 4.2 and 1.39 of the PSC, the whole of the block area was a discovery area.	
29-May-07	While giving the background regarding approval given by DGH to the operator for entering into next phase without relinquishment, Under Secretary, MoPNG submitted the case for seeking approval of the Hon'ble Minister through IFD of the MoPNG. As regards the definition of discovery area, it was noted that Art. 1.39 defined discovery area to mean "that part of the contract area about which, based upon discovery and result obtained from a well or wells drilled in such part, the contractor is of the	**While reproducing Article 1.39 (definition of discovery area), US, MoPNG noted that the terming of the whole of the block as discovery area by DGH was on the basis of 3D seismic, and not on drilling of wells.** However, the focus now

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	opinion that petroleum exists and is likely to be produced in commercial quantities". On the basis of special 3D seismic processing, DGH had arrived at the conclusion that hydrocarbon bearing channels and levees associated with the discoveries were present and extend throughout the block area. The whole of the block had been provided as a discovery area by DGH on the basis of 3D seismic and not on drilling of wells, which were mainly confined to the North-West part of the block. The development area for which ML had been taken by RIL, covered about 339 sq. km. of the northwest part of the Block. Further, it was noted that with respect to the discovery areas, there were provisions in Art. 10 of the PSC prescribing time lines for undertaking appraisal programme with a work programme and budget to carry out adequate and effective appraisal with the objective of determining the boundaries of the areas to be delineated as the discovery area. DGH had proposed the entire contract area as the discovery area in the 3rd phase, which was effective from 7th June 2005. It was presumed that DGH would have taken consequential action in terms of the provisions of the PSC, which prescribed time lines for undertaking appraisal programme. This had to be ensured by DGH so that the potential commercial nature of the discoveries was established in terms of the timelines provided in the PSC. Under-Secretary concluded that DGH, a technical body of the Ministry, had certified that the entire contract area was a discovery area in terms of Article 4.2 and 1.39 of the PSC, and therefore, the operator could be allowed to proceed to phase-III w.e.f. 7.6.05 without relinquishment on the technical advice of DGH, subject to the operator agreeing to carrying out the appraisal programme, including drilling of wells covering the entire contract area in accordance with the timelines provided in the PSC for discoveries.	shifted to timelines for appraisal, evidently taking the declaration of the entire area as 'discovery area' as a given.
29-May-07	Joint Secretary (E), MoPNG noted that the Ministry may ratify the decisions taken by DGH with a direction that as the entire block had been certified to be 'discovery area', DGH may ask the operator to	

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	appraise the same, as per the appraisal related provisions. The PSC envisaged relinquishments at the end of phase-I and phase-II barring discovery areas. But if they were discoveries, they should be appraised, leading to Declaration of Commerciality and submission of development plan which had perhaps not been done. Normally, such a large block is not approved as the development area. Therefore, relinquished areas can be recycled in future rounds. JS noted that they may approve the proposal with the above directions for compliance with PSC provisions.	
1-June-07	JS&FA conveyed IFD's no objection to the course of action suggested by JS (E), MoPNG, subject to approval by the competent authority.	
4-June-07	Secretary, MoPNG observed on file that DGH had allowed retention of the entire area at the end of Phase-I, without reference to Government which was not proper. Now, it was a case of ratification. Secretary submitted the case for Minister's approval, subject to DGH's certification that the whole area had been covered by reasonable number of wells/ 3D seismic processing to substantiate continuity of channels and the extent of the discovery areas, subject to approval by the competent authority.	Secretary, MoPNG's mention of ratification implied that this was not in line with the PSC provisions and needed "ratification".
14-June-07	PS to Minister (P&NG) noted that Minister had desired that the fact of availability or not of the ''Declaration of Commerciality'' should be clearly brought on record. He also noted that the Minister had further desired that the concern of JS (E) may be examined by IFD and Secretary, to ensure that the decision sought to be ratified was consistent with the PSC and that a "conditional" ex-post-facto ratification of the manner should perhaps be avoided.	
29-June-07	MoPNG wrote to DGH that DGH had proposed declaration of entire block area as a discovery area. MoPNG mentioned that in case of discoveries, those should be appraised leading to declaration of commerciality and submission of development plan.	

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	Further while mentioning that there were timelines given in PSC on various activities that set in after discovery was announced, it was not clear to them whether those provisions had been complied with. DGH was further requested to intimate about the availability or not of the declaration of commerciality about discovery area/ areas in the block in terms of PSC provisions. MoPNG asked DGH whether the contractor was appraising the entire block in the light of the fact that the entire block was being accepted as discovery area.	
24-July-07	In reply, DGH intimated that the entire block had been declared as discovery area as per Article 1.39. Contractor had made 16 discoveries in the block. After issuance of notice of discoveries, the contractor had to declare its potential commercial within 60 days. Appraisal plan was submitted within 120 days and appraisal could take upto 36 months. On the basis of appraisal, contractor decided whether to declare it to be commercial or not, and thereafter the development plan was to be submitted. In a block like KG-DWN-98/3 having multiple discoveries at different time levels, all these activities ran simultaneously and are at different stages. However, the timeline prescribed in the PSC had been followed. Further, DGH intimated MoPNG that out of 16 discoveries, 11 had been declared commercial and out of which development plans had been submitted for two. Development plan could be submitted for the remaining nine within 12 months, and there was still time to do so.	
5-Feb-08	The case was referred to a Committee under the chairmanship of Additional Secretary, MoPNG to deliberate and take a view on the issue of regularization of DGH's decision relating to the operator's entry into phase II and III, without relinquishment of 25 per cent and 50 per cent of the contract area. The Committee, in its meeting in February 2008, accepted the operator's claim of whole of the block area as discovery area based on the technical recommendation made by DGH. The Committee agreed that no area needed to be	

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	relinquished by the operator at the end of exploration phases I and II.	
21-Apr-08	After accepting the contractor's claim regarding the entire block area as discovery area in February 2008, the Committee in its meeting on 21 April 2008, agreed that the three year timeline for appraisal of the discoveries may be reckoned from 11th July 2006 i.e. the date when MC accepted the claim of the contractor to enter into subsequent exploration phases without relinquishment. The committee accordingly decided that since the entire block area was accepted as the discovery area, the block area, therefore, must be appraised within the timeframe of three years, commencing from 11 July 2006 (and ending on 10 July 2009).	
9-June-08	In view of the recommendations of the Committee, the following were submitted for seeking approval of Minister: • the entire contract area of the Block KG-DWN-98/3 may be accepted as the discovery area. • The operator may be allowed retention of entire contract area of the block KG-DWN-98/3 as discovery area in the 2nd and 3rd exploration phase. • The timeline for appraisal of the Discoveries may be reckoned from 11th July 2006, i.e. the date when MC accepted claim of the Contractor to enter into subsequent exploration phases without relinquishment. • Since the entire Block area was accepted as the Discovery Area, the Block Area, therefore, must be appraised within time frame of three (3) years, commencing from the above date. • Other terms and conditions of the PSC would remain unchanged.	
31-July-08	After accepting the above mentioned assurances and with the conditions above, the approval was accorded by the Minister.	

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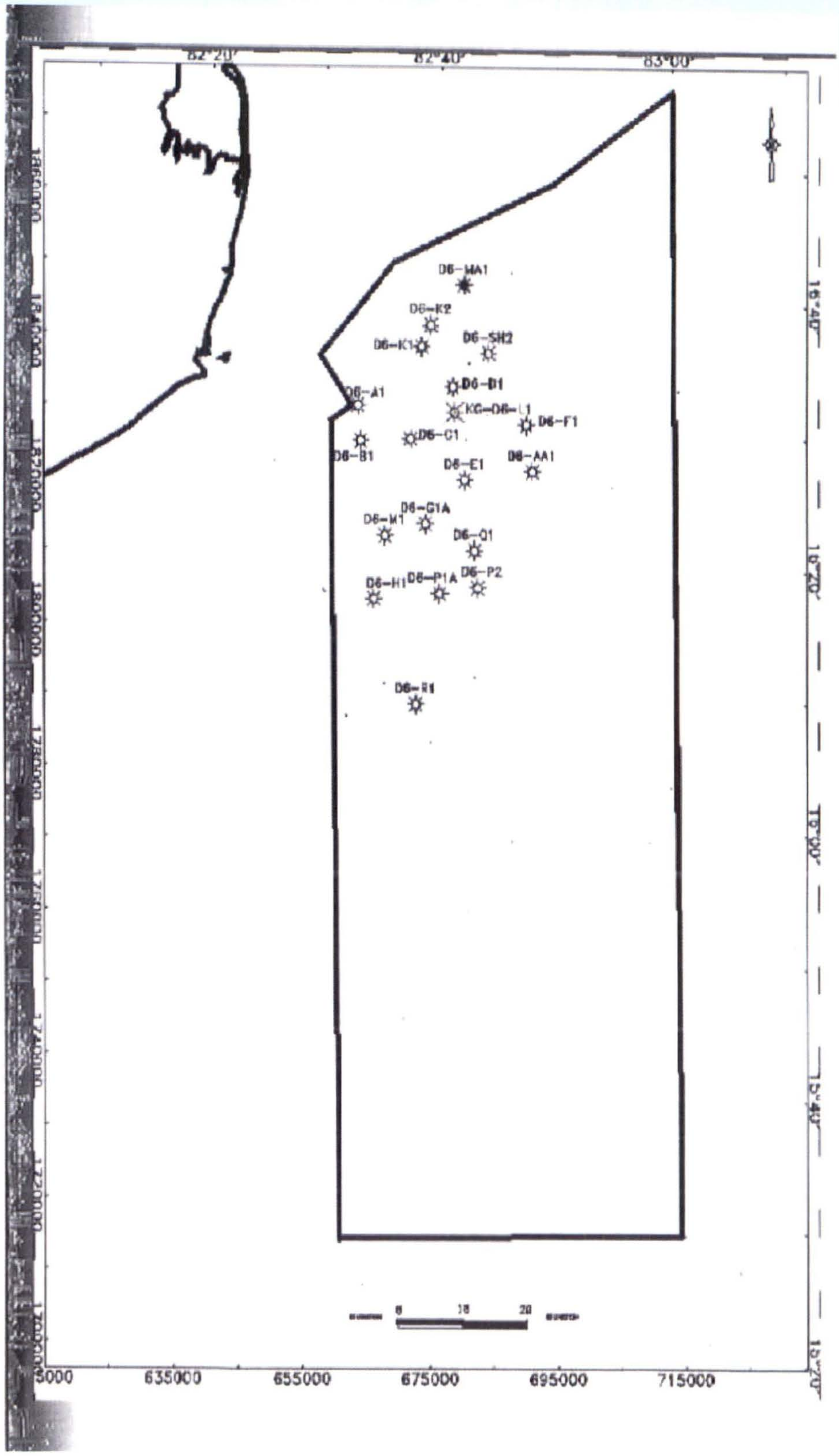
24-Feb-09	MoPNG conveyed GoI's approval to DGH.	

'Discovery Area' is defined in Article 1.39 of the PSC as ***"that part of the contract area about which, based on discovery[27] and results obtained from a well or wells drilled in such part, the contractor is of the opinion that petroleum exists and is likely to be produced in commercial quantities"***. The delineation of 'discovery area' is inextricably linked to results obtained from wells drilled and finding of petroleum deposits recoverable at the surface (which can be discovered only through drilling of successful wells). At the end of the exploration phase-I, the operator had drilled all wells - in the north-west part of the block only. ***The map below depicting the location of discoveries in the block as of January 2010, clearly confirms our position that allowing the declaration of the entire contract area as discovery area was not in terms of the PSC as was more or less done as a fait accompli after repeated examination at different levels.***

[27] 'Discovery' is defined in Article 1.38 as *'the finding, during petroleum operations, of a deposit of petroleum not previously known to have existed, which can be recovered at the surface in a flow measurable by conventional petroleum industry testing methods'.*



Map showing location of discoveries through wells in KG-DWN-98/3 Block (January 2010)

The above sequence of events between April 2004 and February 2009 clearly demonstrates the following:

- ***Originally (May 2004 onwards), DGH did not agree to RIL's proposal (while preparing to proceed from Exploratory Phase-I to Phase-II) for not relinquishing any part of the contract area (at the end of Exploration Phase-I) and reiterated the PSC contractual provisions for relinquishment of 25 per cent at the end of Phase-I (even identifying "least priority" areas for consideration for relinquishment). DGH, further, clarified that none of the existing discoveries extended beyond 'priority area-I', and no well had been drilled in 'priority area-II', and hence it was not possible to consider the total block area as the discovery area.***

- ***However, by April/ May 2005, DGH undertook an about-turn. While noting that there were "no two different interpretations possible as far as the definition of discovery provided in the PSC", DGH felt it would be "prudent to acquire and interpret the 3D seismic data in the remaining part of the block on a fast track basis". Subsequently, "the relinquishment area could also be worked out in a proper manner". In the meanwhile, RIL had already moved from Phase-I to Phase-II without any area relinquishment, and was notifying its intent to move from Phase-II to Phase-III, again without any relinquishment. In August 2006, DGH informed MoPNG that the MC (chaired by DGH representative) had, in July 2006, permitted the contractor to enter the next phase without relinquishing any area, since data showed "continuity of discovery" in the block area (on the basis of RIL's presentation based on the results of seismic data acquired).***

- ***Thereafter, there was extensive correspondence between MoPNG and DGH from August 2006. MoPNG raised pertinent questions as to whether the coverage of wells was over the entire block for DGH to reach the conclusion of discovery extension, but failed to pursue this aspect further.***

- ***By April 2007, MoPNG felt that the proposal might be considered on getting a certification from DGH that the whole area had been covered by a reasonable number of wells/ 3D seismic to substantiate continuity of channels and the extent of discovery area. DGH gave a certificate in May 2007 to MoPNG.***

- ***Even in May 2007, internal notings of MoPNG indicated their awareness that the whole of the block had been provided as a discovery area on the basis of 3D seismic and not on drilling of wells, which were mainly confined to the NW part of the block. However, MoPNG now proposed that on the basis of the proposed discovery area, the operator should be asked to appraise the area as per appraisal-related PSC provisions. After concerns expressed by the then Minister, PNG as to whether the decision sought to be ratified was consistent with the PSC provisions, the case was referred to a committee under the chairmanship of Additional Secretary, MoPNG. The Committee*** *accepted the contractor's claim (February 2008) and decided (April 2008) that the timeline for appraisal of discoveries would commence from 11 July 2006 (viz. MC's acceptance of the contractor's claim). This was finally approved by the Minister in July 2008, but communicated to DGH only in February 2009.*

- *RIL's views at different points of time (that the contractor was "of the opinion that petroleum was likely to exist", "the contract area was having hydrocarbon potential", "ultimately additional exploratory wells needed to be drilled to establish the additional hydrocarbon potential in the deeper water area of the block for which they were making efforts to hire ultra-deepwater rigs" clearly attempted to confuse potential/ prospectivity with actual discovery of hydrocarbons. Their difficulties in hiring ultra-deepwater rigs for the deepwater area of the block (essentially the SW part, where no discoveries had been made) had no linkage with the contractual provisions for discovery area and relinquishment.*

Thus, RIL's proposal of April 2004 to not relinquish any area and retain the whole contract area as 'discovery area' was submerged in a sea of correspondence between RIL and DGH, without relinquishment action being taken in terms of the PSC provisions, while RIL was allowed to proceed from phase to phase. By April/ May 2005, DGH had "waived" its earlier objections, and now advised/ directed the operator to complete 3D seismic data. By July 2006, DGH completed its about-turn and agreed (through the MC) to the contractor's proposal. MoPNG was aware of the flaws in the MC's decision for retention of the entire area, but, instead of reversing the same (in line with PSC provisions), it chose to accept DGH's certification for such retention.

Even the interpretation of declaration of discovery area from July 2006 was not followed through properly by MoPNG and DGH. Implementation of this interpretation (which is incorrect, in our opinion) required cessation of exploration activities, commencement of appraisal from July 2006 and completion thereof by July 2009. After this point of time, the contractor's only course of action was to prepare development plans on the basis of appraisal, identify development areas for development, and relinquish the balance area forthwith within the PSC-stipulated timelines. This was also not done. DGH and MoPNG chose to go along with differing interpretations of the operator concurrently – to continue with exploration activities, side by side with declaration of the entire contract area as discovery area.

MoPNG gave a detailed reply (July 2011) on this aspect, indicating that ***"the issue under examination is highly technical and the Ministry is relying upon the DGH, the only technical arm of the Ministry of Petroleum and Natural Gas, whose report is as follows"***:-

- 'Discovery Area' is defined in Article 1.39 of the PSC as 'that part of the contract area about which, based on discovery and results obtained from a well or wells drilled in such part, the contractor is of the opinion that petroleum exists and is likely to be produced in commercial quantities'.

- The contractor had made 8 gas discoveries till the end of Phase-I period (6 June 2004), including two large size gas discoveries D1 & D3.
- On 11 June 2004, DGH intimated the contractor for relinquishment of 25 per cent of the block area before entering Phase-II.
- RIL, through number of correspondences, mentioned that the operator was of the opinion that petroleum exists and is likely to be produced in commercial quantities after an exhaustive exploratory and appraisal programme from the contract area. The contractor also mentioned that it would be in the overall national interest as any prematurely relinquished area may be mistaken as non prospective and, consequently, further exploratory/ appraisal efforts which the contractor plan to undertake in such area may be either get deferred or may never be under taken.
- The relinquishment of 25 per cent of the block area at the end of Phase-I was examined from the PSC point of view. However, based on the technical data provided and coverage of entire block area by 2D seismic survey, all the ten wells drilled in phase-I being gas bearing, **it is not unusual to draw the inference to retain the total area as discovery area at the end of Phase-I period**.
- Exploration in the KG basin was initiated way back in early sixties, but was mostly confined to on-land and shallow water areas till the beginning of the year 2000. Geo-scientific data in the deepwater areas was almost negligible at that time. The beginning of advanced seismic tools and techniques and evaluation methods, followed by generation of drilled well data, led to validation of depositional models subsequently. The area under reference forms part of larger KG deepwater basin. The tertiary sedimentation in the area is quite enormous and ranges in thickness from 2 to 8 kms. The sediments in the tertiary system are deposited mainly in the deepwater setting forming deepwater fan delta systems and channel levee complexes.
- Hydrocarbon reservoirs of KG-DWN-98/3 block are of stratigraphic nature, which resulted in deposition of discrete geo-bodies with wide geographical distribution. The exploration efforts for such complex deposition types require proper understanding of hydrocarbons reservoirs with regular refinement through new data set including seismic, well, core and other petrophysical and reservoir data.
- In the KG-DWN-98/3 block, the entire block area was covered by 2D seismic data with good coverage of 3D seismic data in Phase-1. All the ten wells drilled in phase-1 were gas bearing. Available geoscientific data indicated that the channel levee and fan complexes found in the northern part of the area appeared continuing in the southern part of the block, and seismic signature on 2D and 3D seismic data were similar to those

seen in the northern part of block wherein all the ten (10) drilled wells in phase-I encountered gas.

- KG D6 discoveries do not constitute a classical discrete reservoir system. Instead they occur as levees and channels with hydrocarbon geo bodies connected and spread all over the entire contract area.
- Subsequently, DGH, while taking the note of the technicality of basin geological set up and the Contractor's proposal that geological plays extended to the entire Contract Area, advised the Operator vide letter dated 24 May 2005 to acquire additional 3D seismic data covering the entire Contract Area for additional evidence and assurance. The contractor subsequently carried out additional 3D seismic survey covering 1004 sq. km.in Phase-II (total area 5991 sq.km.)
- The extensive seismic data processing/ reprocessing and interpretation in the block helped in understanding of complex deepwater geological setting in the block, besides acquiring broad knowledge of the Krishna-Godavari offshore basin. The exploratory drilling carried out in channel, mid and distal levee complexes has resulted in the presence of a number of hydrocarbons gas bearing sandstone reservoirs of Plio-Miocene ages. The Operator, based on the seismic and well database, has critically examined a conceptualized geological model along with the sand development patterns and the associated reservoir complexities. The operator has also deployed state of the art software and hardware available in the industry, particularly for mapping of Geo-bodies delineation, configuration of sub-marine channel system using spectral decomposition techniques, stratigraphic sequence slicing using volume interpretation. Advanced techniques like Sharp-ELAN and anisotropy have been successfully implemented by the operator for resolving the thin bedded reservoirs from the conventional thick beds.
- Integration of outcome of interpretation of existing 2D (speculative, reprocessed and newly acquired & processed) and focused 3D seismic along with complete set of drilled well information including wire line/LWD-MWD information and mud logging data indicated that sizeable quantities of hydrocarbons gas volumes do exist within the channel sand reservoir (main channel; proximal, mid and distal levee complexes, over bank/crevasse splay deposits) as well as reservoirs in the inter channel areas.
- Based on the outcome of the robust work flow adopted by the Operator, it was envisaged that the entire Contract Area of Block D6 is characteristically criss-crossed by a number of submarine channels, out of which only three have been drilled by the operator. Complexity of the channel geometry has also been demonstrated by the presence of multiple Gas-Water Contacts (GWCs) encountered in the drilled wells. Wells drilled in the channel systems to the deeper parts of the basin had encountered GWC at deeper levels.
- Considering the overall evidence obtained through the exploration activities carried out by the Operator so far, the following can be summarized:

- ❖ A series of sub marine channel complexes have been mapped based on the evidence obtained from the existing and newly acquired 2D and 3D seismic data;
  - ❖ Deposits of gas, not previously known to have existed in the exploration block, have been found with commercial flow characteristics at the surface;
  - ❖ Gas occurrence with multiple GWCs within some of the mapped channel systems **enhances the possibility of finding additional and new volumes of gas** in distal fan lobes mapped in the southern and eastern areas to the existing 3D area;

- Gas reservoir (both in thin beds and thick sands) are found within channel sands as well as inter-channel areas and after technical review of the additional 3D data acquired, the MC in its meeting held on 11 July 2006 agreed with the opinion of the Contractor that the prospective geological plays had continuity in the entire block, and hence no block area needed to be relinquished. Therefore, the opinion of the Contractor, which it had prior to the expiry of exploration phase-I that entire area was discovery area, was reconfirmed in the MC.
- MoPNG, in February 2009, conveyed that the entire contract area of the block KG-DWN-98/3 has been accepted as the discovery area.
- Further, based on the technical merits, the entire block area was considered as discovery area in some other blocks as well viz. RJ-ON-06 (Operator: FOCUS), and KG-DWN-98/2 (Operator: ONGC).
- It may be noted that the contractor has already made 19 discoveries in the block, out of which only 8 discoveries were made in the Pliocene and Pleistocene Formation during Phase-I. Similarly, 4 more discoveries were made in the Phase-II period and 7 discoveries in Phase-III. The above mentioned discoveries, based on the available seismic, drilled and petro physical data of the wells, have wide spatial distribution in the block area. Presently, fifty seven (57) wells in total had been drilled in KG-DWN-98/3 block, comprising of exploratory, appraisal and development wells.

These discoveries further enabled contractor to submit three development plans (D1 & D3 gas, MA Oil, 9 satellite gas discoveries/ 4 satellite gas discoveries), one declaration of commerciality (DOC) covering 4 gas discoveries (D 29,30,31 and 34) in addition to one appraisal plan for one discovery (D-42). These discoveries proved the Contractor's claim for entire block area as discovery area.

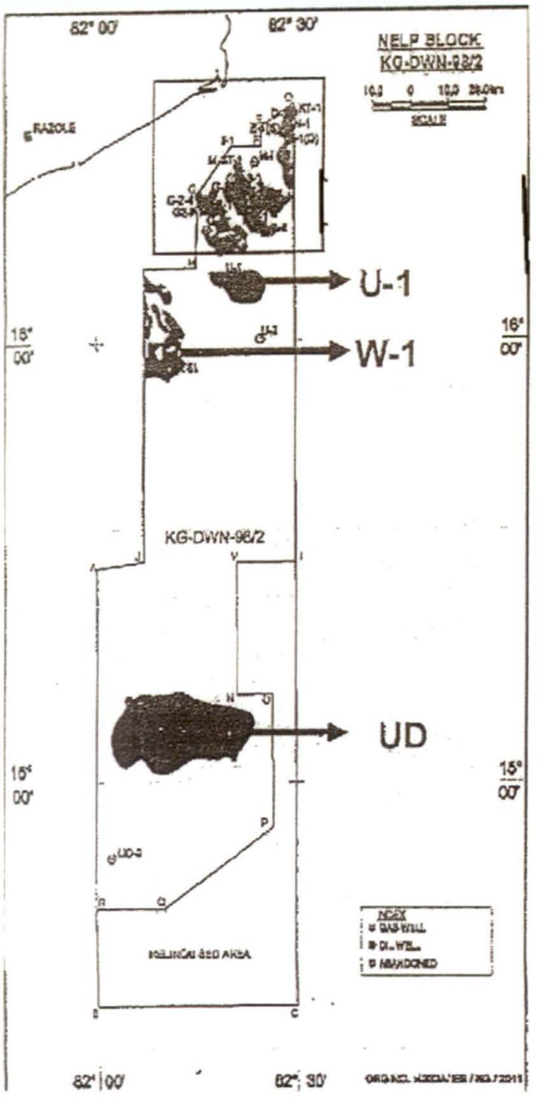
The reply of MoPNG is not tenable, and merely restates the opinions of the contractor, DGH and MoPNG summarized in the chronology indicated at Table 4.1.

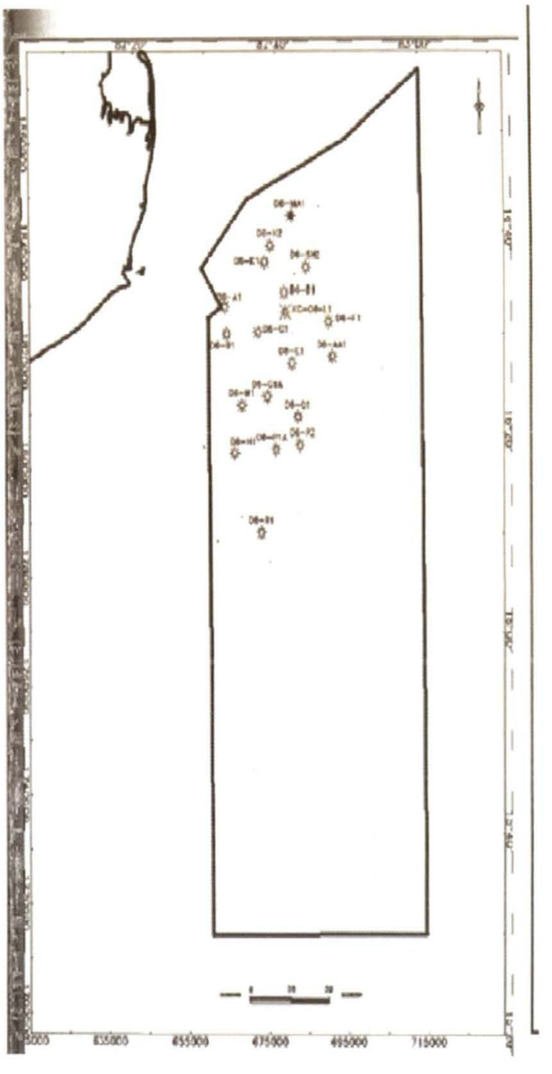
The clear definition of discovery area based on discovery (viz. finding of petroleum) and "results obtained from a well or wells drilled in such part" was sought to be incorrectly confused with prospectivity/ probability and likelihood of petroleum. Finding of petroleum (viz. based on wells drilled in "that part" taken together with seismic data) cannot be equated with searching for petroleum, based on prospectivity. The contractor's discoveries were all in the North West part of the contract area. In fact, the contractor also expressed its difficulties in, and efforts made to hire ultra-deepwater rigs for exploratory drilling in the "deeper part" of the contract area (viz. the SE area, as opposed to the NW area) and thus, clearly acknowledged the need for exploratory drilling in other "parts", but, at the same time, held on to its opinion of the entire contract being a 'discovery area'.

While DGH initially (May 2004) objected to the contractor's view that it was not in a position to identify any area for relinquishment, and advised RIL to relinquish 25 *per cent* area, it allowed the contractor to proceed from Exploration Phase I to Phase II without such relinquishment (while continuing to debate and discuss the question of relinquishment). By April/ May 2005, DGH undertook an about-turn, indicating that "it would be prudent to acquire and interpret the 3D seismic data in the remaining part of the block on a fast track basis"; and subsequently, "the relinquishment area could also be worked out in a proper manner". Meanwhile, RIL gave notice for moving from the 2nd to the 3rd phase without any relinquishment. By July 2006, after a presentation made by RIL, DGH informed MoPNG that the MC had permitted to enter the next phase without any relinquishment, even when a "small portion of the area" remained to be covered by 3D seismic.

MoPNG raised pertinent questions as to whether the coverage of well was over the entire block for DGH to reach the conclusion of discovery extension, but failed to pursue this aspect further. Instead, they chose to focus on getting a certification from DGH that the contractor's claim was correct, and thereafter on timelines for appraisal of discoveries premised on the MC's approval of the entire contract area as discovery area on 11 July 2006. After concerns expressed by the Minister, PNG as to consistency with PSC provisions, the case was referred to a Committee under the Additional Secretary, MoPNG and then finally approved by the Minister in July 2008, but communicated to DGH only in February 2009.

In its reply, MoPNG has drawn reference to the retention of discovery area in other blocks, including KG-DWN-98/2 (Operator: ONGC). The maps of discoveries of KG-DWN-98/3 (the focus of this chapter) and KG-DWN-98/2 shown below indicates that the situation in the two blocks is not comparable.





Comparison of maps of ONGC operated KG-DWN-98/2 (left) and RIL operated KG-DWN-98/3 block (right) clearly indicates that exploratory wells were drilled in the entire contract area of the ONGC operated block, whereas these were limited to the north western part of RIL operated block. Moreover, ONGC had also relinquished a part of the contract area.

Recommendation

MoPNG should review determination of the entire contract area of KG-DWN-98/3 as 'discovery area' strictly in terms of the PSC provisions. Further, it should delineate the stipulated 25 per cent relinquishment area at the time of the conclusion of the 1st and 2nd exploratory phases, and then correctly delineate the 'discovery area' strictly based on the PSC definition, linked to well or wells drilled in that part, without considering any subsequent discoveries (which are invalid on account of non-compliance with PSC provisions).

4.2.2 Unjustified extension of exploration phases

Article 3 of the PSC permits only limited extensions to the time period allocated for exploration phases:

- If, at the end of an exploration phase, the Minimum Work Programme (MWP) for that phase is not completed, the time for completion of MWP shall be extended, with the MC's consent, by a maximum of six months for "technical or other good reasons" shown by the contractor; this period of extension shall be subtracted from the succeeding exploration phase;
- If, at the end of an exploration phase, execution of any work programme in addition to the MWP is in progress, the exploration phase shall be extended by a maximum of six months, provided that the MWP has been completed **or** the MC gives its consent to the said extension.
- In April 2006, GoI introduced a New Extension Policy, according to which:
- The first 6 months extension could be granted by the MC or the GoI in terms of the provisions of respective PSCs.
- Additional extensions of upto 12 months could be given for different type of proposals (but excluding any proposed demonstrable excusable delays on account of the Government approvals/permits/clearances, etc.) on fulfilment of certain conditions such as furnishing of a bank guarantee and/or cash payment of liquidated damages.

In June 2007, MoPNG, on DGH's recommendation, granted an extension of 13 months and 9 days for Exploration Phase-III from 7 June 2007 to 15 July 2008. The operator's stated reasons for delay in completion of exploration were:

- Delay of 109 days in grant of Petroleum Exploration License (PEL) during Phase-I; and
- Delays of 173 days and 122 days in Ministry of Defence (MoD) clearance for sending 2D seismic data and 3D seismic data abroad in December 2000 (Phase-I) and January 2006 (Phase-III) respectively.

However, we found the first two reasons for delay of 109 and 173 days to be unjustified because:

- The benefit of delay in grant of PEL had already been availed of by the operator, while seeking extension under Phase-I.
- While examining the request for extension in Phase-I, DGH considered that MoD granted permission within a normal period of 2 months after completion of data acquisition job by the operator, and did not find this a valid ground for extension.
- Both the above reasons did not have any consequential effects, as the work programme for which Phase-I extension was given had been completed before Phase-III.

In response, MoPNG stated (July 2011) that the objective of the New Extension Policy of April 2006 was to stimulate exploration of oil and gas in the country. The entire process of exploration was highly cost intensive. The letter and spirit of the policy for grant of extension under excusable delays could be given during the exploration period, not restricting to any particular phase. Extension granted for excusable delay entitled the contractor to more time than PSC stipulated normal time, whereas the extension granted on other grounds would get set off in subsequent phases without prolonging the PSC time. Therefore, the distinction needs to be made between time extension for excusable delays and time extension for other reasons. Further, delays in granting permissions/approvals entitled the contractor for more time. It is difficult to demonstrate presence/absence of consequential effects and the PSC, as well as the extension policy, do not stipulate demonstration of consequential effects.

MoPNG's response does not address the specific issues pointed out by Audit. Giving extension on the same reason twice (phase-I and phase-III) indicates undue favour extended to the operator.

4.2.3 Non-drilling of exploration wells to 4,000/ 5,000 meters depth in KG-DWN-98/3

The work programme committed under the PSC for KG-DWN-98/3 included drilling of one exploration well of 4,000 metre depth in Exploration Phase-I, two wells of 4,000 metre depth each and one well of 5,000 metre depth in Phase-II, and two wells of 4,000 metre depth each and two wells of 5,000 metre depth each in Phase-III (all deepwater). The significance of the extra-ordinarily high well depth in deepwater exploration, in terms of both cost and operational complexity, cannot be understated. However, we found that 3 wells of 4,000 metre each in the first two phases and 2 wells of 5,000 metre depth each were not drilled by the contractor in the last two exploration phases.

In response to an audit enquiry, the Operator stated (April 2010) that:-

- The exact depth of plays identified for drilling was not known correctly at the time of bid; this got firmed up after building detailed geological model, and therefore, underwent changes.
- The contractor was required to drill to the depths as per geological objective reviewed by the MC, which was in the best interest of exploration operations, and was not required to drill to depths without looking into the merits of exploration operations.
- In 2007, GoI had come out with a policy on substitution of additional metreage against MWP. While formulating the policy, GoI considered metreage on aggregate basis without sticking to the depths committed in the PSC or number of wells. The policy clearly stated that as long as the marks/points computed (as per BEC for NELP) based on the actual work carried out was more than the marks/points scored for the committed MWP under the bid/PSC, the drilling metreage is deemed to have been completed based

on the revised depth parameters. In the block, the actual number of exploratory wells drilled in each exploration phase as well as corresponding aggregate drilling metreage is much higher than the MWP commitments.

From a literal perspective, the PSC mandates drilling to the committed well depths, notwithstanding the geological objectives and the merits of such exploration operations. However, in our opinion, the problem lies with the defective system of awarding points at the bid evaluation stage based on well depth. This acts as a perverse incentive to some potential bidders to commit to high well depths on a purely hypothetical basis with extremely basic / limited geological data, knowing fully well that the actual depth objective can be determined only subsequently after API of seismic data and other relevant data. We, however, agree that it is impractical to insist on drilling of 4,000 / 5,000 metre wells at this stage, which would only result in infructuous cost to both the contractors and GoI. In future, if exploratory well drilling is to be retained as a bid evaluation criteria, we recommend that either no weightage be allocated for well depth, or alternatively, well commitments be categorised into two groups – wells above and below a specified depth (e.g. 1500 or 2000 metres) and points awarded accordingly.

We also do not agree with the operator's response regarding subsequent policy revisions, of GoI as any revisions in subsequent NELP rounds or GoI's policies have no relation whatsoever with the provisions of the PSC already signed for KG-DWN-98/3 block.

In response, MoPNG stated (July 2011) that the CAG's comment was well taken. The CAG's suggestions on the issue of well depth being considered for bid evaluation would be examined by GoI and addressed in future bidding rounds in consultation with other ministries.

4.2.4 Non-compliance to PSC provisions regarding notification of discovery and submission of test reports

Articles 10.1 & 10.2 of the PSC provide that when a discovery is made within the contract area, the contractor should:

- Forthwith inform the Management Committee and Government of the discovery and furnish particulars in writing within 30 days of the discovery;
- "Promptly" run tests to determine whether the discovery is of potential commercial interest;
- Within 60 days of completion of the tests, submit a report to the Management Committee with a notification of whether, in the contractor's opinion, the discovery is of potential commercial interest and merits appraisal;
- Notify the Government at least 48 hours in advance of any drill stem/ production test (with Government having the right to have a representative present during the test).

We, however, found that in the case of 13 out of 19 discoveries between October 2002 and July 2008 **(Annexure 4.2)**, the operator had, without first furnishing the initial particulars of the discoveries in writing to the MC and Government, directly given written notifications regarding potential commerciality of the discoveries. Clearly, this is in violation of the PSC provisions, which stipulate clear time frames for various activities in a serially linked fashion.

In response, MoPNG clarified that (July 2011) the first 13 discoveries were the initial discoveries in NELP-I round in deepwater area which were made within a very short period of time from the award of the contract. At that point of time, systems and processes were not fully established. Over a period of time, the same had been refined and improved. The procedural variation during the initial NELP period does not pose any material impact. ***However, the procedure had now been strengthened, and were being strictly followed for subsequent discoveries as per PSC requirement.***

4.2.5 Lack of Appraisal Programme

Articles 21.5.2 and 10.3 of the PSC stipulate that if the contractor notifies the MC that the discovery is of potential commercial interest, he should submit, within one year in case of Non Associated Natural Gas (NANG) and 120 days in case of an oil discovery, a proposed Appraisal Programme (with a Work Programme and Budget) to the MC with the objectives of:

- Determining whether the discovery is a commercial discovery; and
- Determine "with reasonable precision" the boundaries of the Development Area.
- Further, "appraisal programme" is defined as a programme for the purpose of appraising the discovery and delineating the petroleum reservoirs to which the discovery relates in terms of thickness and lateral extent and determining the characteristics thereof and the quantity of recoverable petroleum thereof. A maximum timeframe of 3 years in case of NANG and 30 months in case of oil is provided from the date of notifying the MC that the discovery is of potential commercial interest to the submission of proposal of commercial discovery, which essentially includes the appraisal programme. The MC should, within 45 days (90 days for gas) of submission of the proposal, review it and request any other additional information so as to complete the review of the proposal. The contractor should submit the additional information within 30 days from the date of the request. The review of the MC should be made and conveyed to the contractor with in the later of (i) 90 days (150 days for gas) from the date of receipt of the proposal, or (ii) 45 days (60 days for gas) of receipt of such other information.

Audit, however, noticed that there was no appraisal programme in respect of 14 out of 19 discoveries, notably the D1-D3 gas discoveries and D-26 oil discovery. The operator moved directly from discovery to commercial discovery without an appraisal programme. **Besides being clearly in violation of the PSC provisions, lack of an appraisal programme, duly reviewed by the MC in line with PSC provisions, for an "adequate and effective appraisal"**

of the discovery may result in a high degree of uncertainty regarding the reliability of the declaration of commercial discovery and the consequential development plan, as well as the associated estimates of reservoir reserves, production rates, development and production costs, etc.

Non-submission of Appraisal Programme for D-5 & D-18 Gas discoveries

We also noted that submission of appraisal programme relating to Dhirubhai-5 and Dhirubhai-18 Gas discoveries was pending since July 2004 and April 2006 respectively. Although PSC Article 21.5.4 prescribes that if no proposal is submitted to MC by the Contractor within three years from the discovery, the Contractor should relinquish its rights to develop such discovery and the area relating to such discovery should be excluded from the Contract Area, no action in this regard had been taken by DGH/MoPNG.

In response (July 2011), MoPNG stated that as pointed out by CAG, the area of D5 and D18 discoveries would be considered for relinquishment by MC as per PSC provisions as and when the discovery area for 9/4 satellite gas discoveries was delineated for development.

The reply is not satisfactory as the two discoveries are not covered under the 9 satellite discoveries. Therefore, not taking action for exclusion of the relevant area since July 2004 and April 2006 is in violation of the PSC provisions.

In reply (July 2011), MoPNG stated that:

- Based on the conventional testing carried out in the discovery wells, the contractor generated substantial test data which was supported by extensive coring, advance set of logging for formation evaluation, close grid 3D seismic API data in addition to Q-marine survey data (Q-marine is highly advanced seismic technology, and delivers added value through unmatched resolution and repeatability within reservoir required timeframes) The 3D seismic data/Q-marine has enabled the contractor to demarcate the extent of the reservoir.
- Besides detailed geo-scientific studies (2D/3D seismic, logging, testing etc), the contractor appraised D1-D3 and D-26 oil discoveries by drilling three appraisal wells viz. KGD6-A2, KGD6-B2 and KGD6-MA2 respectively. The G&G data generated from the above studies enabled the contractor to submit the 'DOC' of these discoveries. The above G&G data was sufficient to delineate the extent of petroleum reservoirs, satisfying the objective of carrying out appraisal programme.
- These discoveries were further evaluated by the engagement of internationally renowned independent energy consultants by the contractor, besides in-house examination by DGH.

MoPNG's reply is to be viewed in light of the following:

- PSC provisions prescribe formal procedures and timelines for submission, review and adoption of the appraisal programme and budget. The appraisal programme is also required to be conducted in the **proposed appraisal area** within the timelines as per the adopted appraisal programme to determine the commerciality of discovery/discoveries and **finally** delineating the development area. However, as per the information collected from MoPNG/DGH, **no formal appraisal programme and budget** was submitted by the contractor in respect of the first 14 discoveries (including D1-D3 and D-26 discoveries) as per the PSC provisions. In fact, the MA-2 appraisal well was drilled after submission of DoC proposal for MA field, which is in violation of PSC provisions as commerciality of a reserve cannot be determined without appraisal/delineation; this also casts doubts on the robustness and completeness of data supporting the DoC proposal.

- On one hand, the contractor had not found it necessary to submit any formal appraisal programme for the first 14 discoveries, and on the other hand, he submitted two separate formal appraisal programmes in the extended period of phase-III in respect of the last five discoveries (one combined appraisal programme for D-29, D-30, D-31 and D-34 discoveries and the other for D-42 discovery) covering vast appraisal areas.

4.2.6 Delays in submission, review and approval of Appraisal Programme, / Declaration of Commerciality and Development Plan

PSC prescribes different timelines for submission, review and approval of Appraisal Programme, Declaration of Commerciality, and Development Plan. However, we noticed many cases of such delays **(Annexure - 4.3).**

4.3 Development activities for D1-D3

4.3.1 Delayed action after IDP approval for D1-D3 Gas Discovery

After declaration of commerciality for the D1-D3 gas discoveries, the operator submitted (May 2004) an Initial Development Plan (IDP) with an estimated capital expenditure of US$ 2.39 billion. The IDP envisaged gas production of 40 mmscmd (34 producing wells), with design provision to augment the capacity to 80 mmscmd by installing additional equipment. As per the schedule, the project was to be completed by July 2006, with first gas production by August 2006. The IDP was approved by the MC on 5 November 2004.

However, the development activities were not scheduled in-line with project completion schedule, and by the scheduled date of project commissioning and commercial production, the operator submitted (20 October 2006) an Addendum to the IDP (Phase-I) with capex of US$ 5.2 billion for phase-I to be completed upto 2008-09. The plan envisaged delivery of a plateau production rate of 80 MMSCMD with first gas production by mid-2008. The capex for phase-II (after 2008-09) was submitted as US$ 3.6 billion, adding up to a total of US$ 8.8 billion (50 wells), with facilities upgradeable to production of 120 mmscmd. The AIDP was approved by MC on 12 December 2006.

In this connection, we observed the following:

- Article 21.5.6 of PSC stipulates the submission of a comprehensive development plan within one year of DoC. Instead, the operator submitted an "Initial Development Plan" in May 2004, which was amended through an Addendum to the IDP in less than

2½ years. While the PSC permits modifications/ revisions to the FDP for "good cause" with the MC's approval, the scale of the revision of the IDP through the addendum in such a short time span (even considering the stated justification of doubling of probable gas reserves) casts doubts on the robustness of the data and assumptions underlying the development plan(s). Recent reports, as appearing in the media, indicate the production coming down to 43 mmscmd that is close to the level of 40 mmscmd envisaged in the IDP. This raises doubts as to whether the upgradation to 80 mmscmd with substantial increase in development cost was justified in view of the non-submission of any appraisal programme for the review of the MC.

- Article 21.5.10 of the PSC provides that after approval of the development plan, the gas discovery should be promptly developed by the Contractor in accordance with the approved plan. However, after approval (November 2004), progress in field development work was not as per the schedule of the IDP. The operator did not initiate immediate action for procurement of major equipment/materials/services for field development. Instead, development related major tendering activities were initiated in 2006, with target gas production by mid-2008 and by October 2006, most of the activities were at tender stage or initial mobilisation or initial start stage (**Annexure 4.4**).
- There was a 117 percent increase (i.e. US$ 2.81 billion) in estimated capex from US$ 2.39 billion at IDP stage to US$ 5.2 billion at AIDP (Phase-I). Despite shifting of the time frame from "first gas" production to mid-2008 and most of the orders being placed by the Operator in line with requirements as per AIDP (even before its approval), gas production commenced in April 2009.
- Information on estimated versus actual spend, scheduled versus actual completions, etc. for development related contracts was not provided by the Operator, though asked for. In response to an audit enquiry, the Operator stated that the expenditures for development operations associated with contracts under the AIDP that were incurred after March 2008 were not within the current audit scope. As per the expenditure statement collected from DGH, actual spend till June 2009 was US$ 5.07 billion, despite contracts close-out for many items being still in progress, thus indicating that the cost would further increase. We observed upward revisions in quantity and rates in AIDP vis-à-vis IDP, as well as variations and cost escalations in actual spend vis-à-vis cost. Details of cost variations in terms of quantity, rates as well as other factors in respect of different cost elements of the project development are highlighted in **Annexure 4.5**.

Further, we found that the operator had awarded contracts/placed orders for different major items required for development activities/production facilities relating to D1-D3 field as per the AIDP even before its submission/approval, (rather than the IDP), as mentioned below:

- The operator awarded the Engineering, Procurement, Installation and Commissioning (EPIC) contract for onshore-offshore facilities for Euro 764.085 million only in September

2006, although the list of vendors was initially approved by the OC way back in February 2003.

- Though there was no provision for Control-cum-Riser Platform (CRP) in the Initial Development Plan of May 2004, the operator awarded the contract for CRP for US$ 329.55 million in September 2006 as per the proposed revised Development Plan.

In response to audit enquiries regarding the justification for submission of the AIDP and delayed action after approval of IDP, the operator indicated that:

- The initial plan was based on the geological reservoir model generated in early 2004 integrating limited data & understanding. The model had a high degree of volumetric uncertainty mainly due to limited core data, limited understanding of depositional processes, poor calibration between rock property and seismic etc.
- Post IDP approval, work done included extensive studies based on additional data generated e.g. re-processing & interpretation of data, permeability modelling and assessment of in-place reserves.
- Geological and reservoir understanding keeps on improving as additional well data, reservoir data and production data becomes available; however, investment decisions are still taken on the basis of the then understanding.
- Progress of development activities could not be scheduled strictly in line with project schedule as, during Q4 2004 to Q4 2005, studies brought out that the reserve base was much higher and made the operator to re-think on original plans, in view of huge demand. **Both JV partners decided to propose an option to develop known reserves in cost effective manner and make available higher volume of gas.** ***Advance action was taken to tie up vendors for timely development of D1/D3 fields in anticipation of the MC approval of the AIDP.***
- IDP clearly indicated that the project schedule was subject to timely approval as well as receipt of all other statutory clearances relevant to the project. The approval of the plan and other statutory approvals were, however, delayed. Permission to install gas pipelines[28] was accorded only in March 2006.
- The good weather window of 2005-06 was missed due to delayed IDP approval and production was not achievable in October 2006, but earliest in August 2007.
- Due to higher reserve base, it was decided to start working on the revised plan to raise production level from D1-D3 discoveries to almost double the original plans. The operator's internal resources were focused on preparation of AIDP which required extensive re-work on additional data, original concept & FEED studies, plot plans for higher production and increased handling capacities.

[28] The laying of gas pipelines is reportedly being undertaken by Reliance Gas Transportation Infrastructure Ltd. This does not form part of the PSC and its activities, and is hence outside the scope of this audit.

In response, MoPNG stated (July 2011) that:

- Both the development plans included all the data/information and hence were comprehensive as per the PSC provision.
- Subsequent to approval of IDP in 2004, the contractor carried out the work program to assess the overall hydrocarbon potential of the block/ development area. The recoverable reserve figure more than doubled from the earlier estimate made under the original development plan.
- FDP is based on the present day knowledge of the reservoir. As the development of the field progress, more and more data is gathered about the field in terms of actual reservoir performance, geological knowledge and production behaviour. Hence, the development of any oil/gas field is a dynamic process and approved development plan undergoes changes and is likely to be modified /revised accordingly for optimal exploitation of oil/gas. Further, in India there are instances where the development plan has been revised /modified from time to time. This is an industry accepted practice and quite common in E&P industry.
- DGH also verified and validated the capital expenditure for development of D1 & D3 field through internationally reputed energy consulting firm Mustang International and subsequently by Dr. P Gopalakrishnan, a reputed independent consultant.
- Further, as per Article 21.5.12 of the PSC, the Operator had a time line available upto 2012, whereas he commenced development operations about five years ahead of the maximum permissible PSC time limit.
- There was neither delay in implementation of FDP nor any violation of PSC on account of the following:
  - The operator could modify the development plan under PSC provisions.
  - The revision was in line with established industry practices and PSC stipulations.
  - The operator completed additional work program between original plan and revised plan
- The actual expenditure on D1 & D3 capex upto March 2011 as per books of accounts is US$ 5.59 billion out of which US$ 2.59 billion was incurred till March 2008, the period of CAG's audit. The evidence of expenditure and vouchers are the subject of audit and any unsubstantiated expenditure is liable for disallowance. The expenditure incurred upto March 2011 is being audited by an independent firm of auditors appointed by MC.
- CAG comments are well taken and would be kept in view for policy making and any specific improvement/ amendment/ suggestions in respect of cost/ expenditure related to AIDP, to the extent feasible, if proposed by CAG, will be considered for appropriate action.

The above explanations are to be viewed in the light of the following:

- After submission of the IDP in May 2004, the operator expected its approval within one month of submission, as against the six months prescribed in the PSC. It was necessary for the operator to plan and project reasonable timelines considering the good weather window.
- Since purchase orders for major project execution activities were not processed, immediately from November 2004, processing time taken for other approvals from different authorities did not, in reality, contribute significantly to project delays.
- While the cost of oil and gas related equipment and services increased dramatically due to various factors (including the spiralling crude oil prices contributing to dramatic demand-supply imbalances in the oil and gas industry), the operator's delay in initiating procurement activities in 2004 and 2005 contributed, at least partly, to the increased cost of development.

Further:

- The Mining Lease application was submitted on 4 January 2005 i.e. seven months after the submission of the IDP (26 May 2004).
- Most procurement activities were undertaken late in line with the schedules of the IDP of May 2004. By contrast, activities in respect of items in the AIDP were initiated even before the submission/approval of the AIDP. Clearly, the development activities of the operator were guided by the AIDP, rather than the IDP.
- As indicated by the operator, advance action was taken to tie up vendors for timely development of D1/D3 fields in anticipation of the MC approval of the AIDP. While a view could, perhaps, be taken that such pre-approval action is at the risk and cost of the contractor, in reality, this increases the probability of such approvals becoming a *fait accompli.*

Approval of estimates does not constitute acceptance of the operator's projections of cost as being payable. The acceptance of the cost incurred by the operator can be certified only after audit of his expenses through proper norms. Part of the expenditure in respect of individual items under AIDP incurred during 2006-07 and 2007-08 has been audited. Remaining expenditure incurred from 2008-09 onwards will be covered in future audits.

4.4 Development/ Procurement activities (MA Field)

The development of MA field is a case of hasty decisions taken by the operator to award various contracts to four companies of one group in order to start development activities irregularly without waiting for approval of the DoC and Field Development Plan (FDP). The Operator awarded contracts at non-competitive rates without ensuring price reasonability and following procurement procedure and other provisions of PSC in letter and spirit.

4.4.1 Chronology of events

The chronology of major procurement and development/ PSC events relating to the MA oil field is given below:

Table 4.2 – Chronology of major events relating to MA oil field

Procurement-related activities	Date	PSC-related events
	15-Dec-05	Drilling of 1st Exploratory Well in MA Oil Field.
EOI for charter hiring of Mobile Production Facility (MPF) for various blocks operated by RIL. No EOI received.	5-Jan-06	
	12-Jan-06	Testing of 1st Exploratory Well as oil bearing.
Issue of contract to INTEC for concept selection, Front End Engineering Design (FEED) and validation of Floating Production, Storage and Offloading (FPSO) facility engineering for early production.	12-Jan-06	
Aker Floating Production (AFP) incorporated (i.e. after invitation of EOI in January 2006 and before Vendor Qualification Criteria (VQC) analysis conducted by Contractor in September 2006).	14-Mar-06	
	24-Jun-06	Notification of oil discovery D-26 to MC (after the expiry of the PSC stipulated timeline – 60 days after testing).
AFP listed on Oslo Stock Exchange.	26-Jun-06	
Vendor Qualification Criteria (VQC) for charter hiring of MPF sent to OC for approval[29].	6-Jul-06	
VQC approved by OC.	7-Jul-06	
VQC analysis (prepared on the	4-Sep-06	

[29] This could have been done before inviting EOI, as a fair, transparent and reliable practice.

Procurement-related activities	Date	PSC-related events
basis of details of prospective firms from the internet[30]) sent to OC for approval.		
RFP for charter hiring of FPSO (issued to 15 firms with bid due date as 11-Oct-06 (revised in stages to 25-Oct-06); in between, after discussions with bidders, addenda to RFP issued	21-Sep-06	
	20-Oct-06	Declaration of Commerciality of Discovery (DoC) submitted to DGH for approval, without appraisal of discovery.
Unpriced techno-commercial bids of eight bidders were opened.	27-Oct-06	
Discussions held with two vendors (AFP and SBM), including meeting in Oslo in Nov 2006) Bids were subsequently revised, based on technical qualifications to resolve deviations/ exceptions.	14-Nov-06	Spudding of 2nd Well for appraisal (after submission of DoC), completed on 5-Dec-06.
AFP declared as single acceptable bidder, and bids of seven other bidders rejected on technical grounds.	2 to 6 Dec-06	
LOI issued to AFP for FPSO (amended on 05.01.2007).	11-Dec-06	
	2-Feb-07	Review of DoC of MA oil field by MC.
Issue of Project Management Consultancy contract to Bechtel.	24-Mar-07	
Contract for supply of Subsea Hardware awarded to Aker Kvaerner Subsea (US$ 356.10 million).	27-Apr-07	
Contract awarded to Aker Contracting FP (subsidiary of AFP) with certain modification to LOI issued to AFP for charter hiring of	4-May-07	

[30] Supporting documents to VQC analysis not found on record by audit.

Procurement-related activities	Date	PSC-related events
FPSO - US$ 1075 million.		
FPSO sailed away from Jurong Shipyard.	28-Jul-07	
	18-Aug-07	Submission of Initial Development Plan for MA field to MC.
	31-Aug-07	Application for obtaining Mining Lease submitted.
Contract awarded to ABO (Aker Borgestad Operations) for operation and maintenance of FPSO (with certain modifications to the LOI issued to AFP) - US$ 276 million.	7-Oct-07	
Installation of Christmas Trees (XMTs) for MA Field commenced.	24-Feb-08	
	17-Apr-08	Approval of Field Development Plan by MC.
	12-May-08	Mining Lease granted by GoI effective 17-Apr-08.
FPSO sailed away from Singapore Deepwater anchorage.	6-Aug-08	
FPSO reached MA field location after customs clearance.	16-Aug-08	

4.4.2 Irregular action before approvals as required in PSC

As can be seen above, the timing of various procurement related activities, well before PSC-related approvals, was highly irregular:

- The EOI for hiring of the Mobile Production Facility (MPF) was issued on 5 January 2006 even before the testing of the first exploratory well as oil-bearing on 12 January 2006.
- RFP for charter-hiring of the Floating Production Storage and Offloading (FPSO) vessel was issued on 21 September 2006 even before submission of DoC to DGH on 20 October 2006, while the LoI to the successful bidder (AFP) was issued on 11 December 2006, well before the review of the DoC by the MC on 2 February 2007.
- The Initial Development Plan for the MA field was submitted only on 18 August 2007, with the application for the Mining Lease being submitted on 31 August 2007. The Field Development Plan was approved by the MC only on 17 April 2008, while the Mining

Lease (ML) was granted by MoPNG on 12 May 2008, but effective from 17 April 2008 (the date of approval of the FDP)[31]. By this time, the installation of Christmas Trees for the oil field had already commenced from 24 February 2008, which was in violation of the OF (RD) Act and the PNG Rules in the absence of a valid Mining Lease.

- Essentiality Certificates (ECs) were irregularly issued by DGH during 2007-08 for US$ 729.38 million for import of goods before approval of FDP and grant of ML for petroleum operations.
- The Concept Selection Technical Report by INTEC Engineering, which was provided as FEED for FDP, was received on 21 June 2007 after award of all works to Aker group companies. The INTEC report, in effect, merely endorsed what already had been designed and awarded to Aker Group companies.
- The reply of RIL, endorsed by MoPNG, that INTEC Engineering in fact provided technical inputs to RIL on the concept and technical documents, is unacceptable, as RIL did not provide any documentary evidence in support. Moreover, RIL itself said that INTEC was asked to prepare Concept Selection Report when asked by the MC in February 2007 while approving DoC. This clearly indicates that the INTEC report on FEED was obtained only to comply with the MC's directive and to justify the contracts already awarded.

4.4.3 Deficiencies in pre-qualification process

For pre-qualification of vendors for issue of Request for Proposal (RFP) for charter hiring of Floating Production Storage and Offloading facility (FPSO), a VQC analysis was prepared on the basis of details of prospective firms downloaded from the internet and sent to OC on 4 September 2006 for approval. The supporting documents to this VQC analysis were not found on record, as they were not maintained by the operator.

Aker Floating Production ASA (AFP)/ Aker Group (the finally successful bidder) was selected for issuing Request for Proposal (RFP), despite lack of any experience of operating and maintaining an FPSO. Also, there was no specific criterion for assessment of financial capability.

Further, AFP should have been disqualified at the RFP stage, as it had not fulfilled many significant RFP requirements, *e.g.*:

- Non submission of Technical and Commercial checklists;
- Non submission of preceding three financial years' audited financial statements; instead, AFP enclosed the Aker group's annual report for the last two years;

Aker Floating Production (AFP) was incorporated only on 14 March 2006, i.e. between the EOI invitation in January 2006 and VQC analysis in September 2006.

[31] MoPNG refused to accede to the request for grant of mining lease retrospectively to August 2007, and granted the lease effective from the date of FDP approval only.

- Some vital information regarding technical competence of the bidder was not submitted by AFP. This included quality plan, inspection and test plan, and HSE details. Despite these, AFP was declared technically qualified.

The operator's response (furnished through MoPNG in July 2011) on these aspects is not tenable, as explained below:

- The operator's contention that the checklists were enclosed with the RFP mainly to ensure that the bidders were able to ensure the completeness of their bids, is unacceptable as the bidder, AFP, had not fulfilled many significant requirements as indicated in the checklists. The operator obtained the checklist on 4 November 2006, i.e. after the bid opening date.

- The operator's reply that AFP had submitted the audited financial statements for two years, which provided three years' financial results as required in the RFP, is incorrect and therefore unacceptable. **The bidder, AFP, had enclosed financial statements of the Aker group as a whole for two years (2004 and 2005), while AFP itself was formed only in 2006. Further, against the column of parent company guarantee, AFP had indicated that the parent company guarantee would not give RIL remedies against the parent guarantor beyond the remedies which were available against the contractor under the contract. Subsequently, AFP became the parent company and contracts were awarded to its subsidiary companies.**

4.4.4 Irregular selection of AFP

Except for the bids of two vendors (AFP and SBM), all the other six bids received by 25 October 2006 were technically rejected on 2.12.2006. We found that:

- Technical qualification was done (6.12.2006), not of the bids originally received by 25 October 2006, but of the revised bids of AFP and SBM, submitted after discussions held with them (including a meeting in Oslo in November 2006). In addition to being contrary to Clause 5.6 of Instruction to Bidders in the RFP, which clearly forbids any revision in bids after the bid due date, allowing changes to bids by selected (and not all) bidders is against the spirit of obtaining reasonable prices through competitive tendering.

- The operator did not fix a bid opening date in advance, nor were representatives of bidding firms invited for the bid opening, so as to ensure transparency and fairness.

- We did not find the priced bids of technically unqualified bidders sealed or intact, so as to have assurance that these were not opened.

- Interestingly, the priced bid of AFP bid was not signed by the bidder (as required); the possibility of modification of priced bid cannot be ruled out.

- **The price quotes for optional items by AFP were left blank for *'open book' cooperation with RIL.***

RIL's response, furnished by MoPNG, indicated (July 2011) that, out of the eight bids, seven bids (including SBM - subsequently) were rejected on the following grounds:

- Permanently moored system offered against requirement for disconnectable system (Nortech & SBM);
- Various deliverables required as per RFP were not submitted (Fred Olsen);
- DP vessel offered instead of a moored system (FPSOcean);
- Silent on safe abandonment of risers in bad weather, FFP not offered, hull life not determined (Compass Energy EPS);
- Specific details not provided, geo-technical & geo-physical studies not included (EMAS); and
- Bidder expressed inability to comply with operator's requirement with regards to scope of work, responsibilities, schedule & commercial mechanism (Sea Production).

This wholesale disqualification leads us to question the entire pre-qualification process. The contention of the operator (forwarded through MoPNG) regarding selection of AFP over others is not tenable for the following reasons:

- The information on availability of relevant resources, know-how and expertise within Aker Group was the subject of public announcements and part of process for Aker's qualification for listing on the Oslo Stock Exchange, and that the operator had reviewed the financial background and technical experience for award of contracts is not acceptable, as the acceptance of qualifications for listing on Stock Exchange is not related to the fulfillment of qualification and experience criteria specified in the RFQ.
- ABO, a subsidiary of AFP, was also established in July 2006 for operating the FPSO for AFP; the contract with RIL was their first operation and maintenance contract. All other bidders, including those experienced in that field, were rejected during technical evaluation.
- Operator's reply that AFP had suggested 'open book' cooperation for optional items on the basis that certain salient details could only be finalized during detailed engineering, is not tenable, as the approved procurement procedure does not provide for it. In any case, the operator should have finalized the engineering details, before issuing the RFP.

Audit is constrained to make these observations as in terms of the PSC, the full cost is recoverable by the operator. Hence, it is incumbent on the operator to ensure that a fully transparent, and cost-effective process is adopted which gives assurance to the Government that costs have indeed been minimized.

4.4.5 Lack of Competition

- MC approved FDP with 'first oil' on or before June 2009 with an oil and gas production profile for 11 years and recommended grant of Petroleum Mining Lease for 20 years. Though there was sufficient time available with the operator for the field development and producing 'first oil', with regard to the FPSO procurement, the operator insisted on the first oil date on or before 15 February 2008, which led to insufficient competition and consequently expected higher costs. Also, one bidder expressed their inability to commence oil production by the said 'first oil' date. Therefore, apparently higher cost was paid on the logic of completing it on fast track basis. We found that though first oil production initially started on 17 September 2008, but subsequently, problems developed at the FPSO and on 9 December 2008, the production stopped. The shutdown in December 2008, forced some design changes on the FPSO and after three months, production was resumed in March 2009.
- We do not agree with the reply of RIL, endorsed by MoPNG, that the 'first oil' date was designed to address the national energy needs including the requirement to reduce import of crude oil. The MC, having representatives of both GoI and the Contractor, while approving the FDP had fixed the date of production as 'on or before June 2009'. RIL's contention that fixing early production date did not affect the competitiveness of prices is also unacceptable because the technical bids analysis made by RIL clearly indicates that Fred Olsen could not bid as it was not able to meet the first oil date. The successful bidder, AFP, did not reduce the rates for FPSO and subsea hardware, since special arrangements were made and slots booked for production of these facilities so as to meet the production deadline. Further, the date of early production could not be met as it was unrealistic, the production could start only in September 2008.

4.4.6 High Price of FPSO

AFP submitted various sets of rates for different items asked for in the RFP, like charter hire rate and buy price of FPSO, and supply and installation of subsea hardware. RIL changed the scope of work a number of times before and after bid opening.

AFP, the only single acceptable bidder to the Operator, quoted charter hire day rates under various categories e.g. '10 year term', '7 years firm + 3 years optional', '5 years firm + 5 years optional', along with buy option at any time and the 'buy price'. The 'buy price' for FPSO at the beginning was quoted as US$ 601.89 million, as per the scope of work exhibited in the RFP. In the initial offer, AFP quoted a lump sum amount for Phase-I with option for RIL to consider Phase-II on 'Open Book' basis. Phase-II price break-up was submitted by AFP on 8 December 2006. However, the revised proposal submitted by SBM was, however, not considered. The rates quoted by AFP vis-a-vis estimate made in the DoC are given below:

Table4.3 - Different Estimates submitted/considered by RIL for FPSO 'Buy price' and 'Bare Boat' Charter Hire Rate'

Stage(Date)	Buy Price#	Day Rate Range(10 year term)*	Day Rate Range (7 year firm+3 year optional)	Day Rate Range(5 year firm + 5 year optional)
	US$ in million	US$	US$	US$
DoC (20.10.06)	300			
AFP bid dated 23.10.06	601.89@	486,042 - 526,257	579,706 - 216,969	710,647 - 216,969
AFP bid dated 30.11.06	970.7	495,763 - 536,782		724,860 - 219,458
AFP quote dated 11.12.06	951.7	479,475 - 521,765	572,339 - 215,117	702,162 - 215,117
LoI	943.6	479,475 - 521,765	572,339 - 215,117	702,162 - 215,117
AFP revised quote 5.6.07	745	294,581	355,815	436,761
Agreement	713.8	294,580	355,813 - 91,736	436,758 - 91,736
IDP	785			
FDP (18.8.07)	733			

 # Before completion of mobilization. @ For Phase-I only.

**All day rates show the range from 1 April 2009 as 1st or 2nd year to 10th year.*

We found that:

- As per the DoC, the capital cost of FPSO submitted to the MC was US$ 300 million;
- Initial 'buy price *before mobilisation'* quoted by AFP was US$ 601.89 million which was later revised to US$ 943.6, 951.7, 970 and 745 million at different stages of negotiation and due to change in scope of work.
- Similarly, the day rates under various charter hire options were also revised. Buy price mentioned in LOI issued was US$ 943.6 million. Later in the agreement signed with AFP, the buy price agreed was US$ 713.8 million and day rate for 10 years term was US$ 294,580. The Operator later finalised the option of charter hiring for 10 year term for US$ 1.075 billion.
- Immediately after the placement of LOI, the operator carried out a further review and observed that it would be more beneficial to export the produced gas for sale instead of injecting in to the reservoir. Also, enhancement of gas injection capacity as envisaged in Phase-II would not be required. On review, the facilities envisaged earlier were modified

and additional facilities envisaged in phase-II were either deleted or advanced to phase-I. After incorporating technical specifications, contract (No. OGF/3627982) was signed (May 2007) with Aker Contracting FP AS, Norway (ACFP). Also, contract (No. 86759) for O&M of FPSO for ten years was signed (October 2007) with Aker Borgestad Operations, Norway (ABO) for US$ 276 million. In January 2008, RIL exercised the option to call a 10-year bare boat 'contract' for FPSO for US$ 1.075 billion.

The newsletters of Jurong Shipyard indicate that AFP had bought two tankers for conversion into FPSO for US$ 55 million and awarded conversion contract to Jurong Shipyard, Singapore for S$ 133 million (US$ 88 million). The FPSO hired by RIL was converted from tanker 'Polar Alaska' to 'Aker Smart-I' with a processing capacity of 60000 BLPD and a storage capacity of 1.3 million barrels. Jurong Shipyard had secured a contract for S$ 200 million (US$ 132 million) for conversion of Very Large Crude Carrier (VLCC) tanker to a FPSO with processing capacity of 150,000 BOPD and storage capacity of 1.6 million barrels of oil for MODEC. Similarly, it also secured a contract for S$ 99 million (US$ 66 million) for conversion of a tanker to FDPSO with drilling and storage capacity of 300,000 barrels. This indicates that the 'bare boat' charter hire rate of US$ 107.5 million per annum finalized with AFP appears to be high and unjustifiable.

We do not agree with the reply of the operator, furnished by MoPNG (July 2011), for the following reasons:

- The operator's claim that the estimate submitted in the DoC was only preliminary and for evaluation purpose is not acceptable because the Operator, being in the E&P business, should have[32] sound knowledge of the business and prevailing market prices. Moreover, RIL had issued RFP for charter hiring of FPSO and subsea hardware supply and installation one month before submission of the DoC proposal to the MC, and should have been in possession of robust data regarding estimated costs.
- Operator's reply that FPSO cost in DoC was net of 40 per cent salvage value appears to be an after-thought, since there is no mention of 40 per cent salvage value in the DoC proposal.

The Work Programme and Budget for 2007-08 was delayed and submitted on actual basis after incurring the expenditure of US$ 808 million. No details were provided thereof. MC, however, gave post-facto approval.

We do not agree with the operator's argument, endorsed by the Government, that expenditure incurred on "pre-development activities" was at the risk of the Operator. Carrying out pre-development activities before approval of FDP was irregular.

- Operator did not produce to Audit, the Project Completion Report, Quality Surveys and Systems Audit conducted by it, reviews of Health Safety and Environment (HSE)

[32] as per GIPIP

requirements, monthly progress reports, etc by stating that these were technical details and did not have a bearing on payments.

- List of key personnel as required under Clause 8.6 of the Contract were not produced to Audit. Operator also did not provide to audit the FPSO mobilization completion report, production programme, oil production data, actual offloading rate, 'first certificate of preliminary acceptance', performance run time, downtime/ shutdown details, statement of Classification Society certifying the FPSO as 'Ready for Hydrocarbon Confirmation', list of approved RIL's representatives as defined in Clause 11.2 of the Contract, Verification report by the verification society, etc. by stating that these records pertained to the period beyond audit scope, although, in our opinion, they were necessary to conclude our audit findings.

4.5 Procurement activities (D1-D3 discoveries)

4.5.1 Cost Plus Contracts for Terminal and Jetty against single bid

The operator invited (January 2006) EOI for construction of Onshore Terminal (OT) and Jetty on Lump Sum Turnkey (LSTK) basis. The operator received responses for onshore terminal from three bidders viz. (i) Larsen and Toubro Ltd., (ii) Punj Lloyd Ltd. and (iii) Bechtel and for Jetty also from three bidders viz. (i) Afcons, (ii) Punj Lloyd and (iii) Bechtel. The operator invited (May 2006) RFQs on cost plus basis to speed-up the work, as detailed engineering and FEED update commenced in April 2006. It was observed that two bidders viz. Punj Lloyd Ltd. and Bechtel expressed their inability to submit their proposals due to their other commitments, which resulted in only single bidders in both cases i.e. L&T for construction of Onshore Terminal facilities and Afcons for construction of Jetty. Accordingly, the operator awarded contract (June 2006) based on single bids to L&T for OT (No.OG8/82505) and to Afcons for Jetty (No. OG8/82645) at estimated costs of INR 263 crore and INR 24 crore respectively.

It was also noticed that the operator allowed:

- L&T a compensation of 25 per cent in addition to the actual cost along with compensation over the value of free issued materials at 12.5 per cent and 25 per cent of two categories of materials.
- Afcons a compensation of 22 per cent in addition to the actual cost along with 12.5 per cent on the cost of free issue materials of all category.

After award of contract, during execution, RIL observed slow progress of construction of OT by L&T and accordingly off-loaded a part of work to Afcons (contract No.OG8/86589) at cost plus 22 per cent and 12.5 per cent of cost of free materials at estimated cost of INR 80 crore. In our view:

- The initial pre-qualification exercise sheet indicates that two pre-qualified bidders (Bechtel SA France and Punj Lloyd Ltd.) did not have any previous experience in construction of oil and gas related projects and jetty respectively. Both vendors responded to EOIs and were included in the vendor's lists, but later responded to RFQs stating their inability to quote, leading to single bids for both the works. As there was only one bidder for each of those works left, agreed rates were non-competitive and not depicting market rates. This further confirms deficiency in competitiveness of the prices. Further, they were much higher than the prevailing rates of 10-12 per cent.

- Comparison of rates for partially off-loaded work of OT to Afcons in June 2007 revealed that percentage compensation for cost incurred by the contractor and cost of partial RIL issued free material was higher by 3 per cent and 12.5 per cent respectively for the work awarded to L&T.
- As per the time schedule submitted by L&T at the time of bid, OT was to be handed over by December 2007; however, based on post bid discussions, time schedule stipulated in the contract was March 2008. Payments for the work done made till 31 March 2008 to L&T and Afcons was INR 238.86 crore and INR 27.14 crore respectively. In response to an audit query to provide latest status of work completion, and final hand-over of OT complex and payments, the operator informed (May 2010) that the completion of the work was achieved beyond March 2008 and was therefore, beyond the scope of this audit. The operator furnished the completion certificate in July 2010, indicating that the facilities were fully completed on 31 October 2009, though gas production commenced on 1 April 2009.

The Operator stated in March 2010-in response to an audit enquiry and in July 2011-reply furnished through MoPNG:

- The procurement procedure established under the PSC does not preclude inviting bids on cost plus basis. Rates of vendors cannot be termed as non-competitive, as those were quoted in a competitive environment, in which three reputed companies were in race to bid and bidders were unaware that they were the only bidder submitting the offer.
- Punj Lloyd and Bechtel had adequate experience in marine works carried out by them.
- Completion of the OT and timely readiness of the jetty were critical for the project. Lump sum bids would be possible only if sufficient engineering was completed. If engineering for Jetty and OT were to be completed, and RFQ floated thereafter on LSTK basis, contracts would have been awarded by end 2006 and late 2007 respectively.
- The compensation paid to L&T and Afcons for OT should not be compared, as two separate contracts were awarded with different scopes of activity, at different point of time and after thorough negotiations. Further, the overall result that mark-up for goods acquired the contracts was in the range of only 11 per cent to 13 per cent.

We do not agree for the following reasons:

- The inadequate experience of Punj Lloyd and Bechtel was recorded by the operator in the initial pre-qualification exercise sheet. Thus, the list of the vendors turned out to be largely meaningless.
- Although the construction of OT was a critical aspect, no action was initiated by the Operator immediately after approval of IDP in November 2004. Further, if construction of the jetty was a critical aspect, then it should have been included in the IDP in May 2004 (which it was not). In the opinion of audit, subsequent actions of May-June 2006 to award cost plus contracts on the grounds of criticality for the project are not justified, as these contracts were awarded even before approval of AIDP.
- A switch from LSTK to cost-plus mid-way through the contract process, combined with single bid award on cost plus 25 per cent basis, can in no way be termed as competitive, as it deprived other potential bidders from bidding on cost plus basis.

Further, the operator, in its reply furnished through MoPNG (July 2011), also enclosed information relating to material consumed/installed by the contractors. However, item-wise break-up of material consumed, net compensation paid, deductions on non-allowable items, wastage and along with project closure reports, and bills/vouchers for verifying the actual compensation range of 11 per cent to 13 per cent (as stated by the operator) would be reviewed by audit subsequently.

Such issues should have pro-actively been considered by the operator with the MC, even if it was not required under the letter of the PSC, merely to give comfort to the Government of its transparent and contractually acceptable procedure.

4.5.2 Cost escalation due to post-award abnormal man-hours increase for Detailed Engineering of Onshore Terminal

The operator issued (December 2005) RFQ for the work "Detailed Engineering of Onshore Terminal" to seven vendors, for completion in three stages viz. Preparation of Design Basis, FEED Update (for 80 mmscmd capacity) and Detailed Engineering. After evaluation, the contract was awarded (April 2006) to Aker Kvaerner Australia Pty. Ltd. (AKAP) at an estimated value of US$ 13.78 million and INR 13.73 crore. During execution, four amendments, proposed by AKAP for various reasons, were issued escalating the cost to US$ 23.94 million and INR 36 crore till March 2008. Thus, despite providing necessary inputs at the RFQ stage, there was 124 per cent escalation in man-hours over the original envisaged and cost overrun of 90 per cent i.e. US$ 15.11million (@US$1= INR 45) over contract cost and time overrun of 8 months till March 2008, which is expected to increase further till completion. Incidentally, we found no evidence of urgency, with the contract process taking nearly 5 months from December 2005 (issue of RFP) to April 2006 (award of contract).

In response to an audit enquiry, the Operator stated (April 2010) that the initial man-hours estimated by bidders were based on facilities envisaged in initial FEED for 40 mmscmd and the increase in man-hours was primarily due to increase in scope based on updating of FEED leading to better understanding of work involved. The Operator further stated (July 2011), as per the response furnished through MoPNG, that as the development of the D1-D3 fields was being done as fast-track basis, certain activities were being done in parallel rather than a strictly sequential basis.

Evidently, the scope of work for "Detailed Engineering" (stage 3), as defined in the RFQ issued in December 2005/ January 2006 was deficient and incomplete. We still hold the view that had the scope of work for "Detailed Engineering" been clearly defined before award of the contract, it would have resulted in better competition and rates.

4.5.3 Rates Revision for EPIC of offshore facilities

The operator issued RFP (March 2006) inviting seven pre-qualified bidders (based on EOI) to bid for the whole of the Engineering, Procurement, Installation and Commissioning (EPIC) package for onshore-offshore facilities as part of the D1-D3 field development. Two bidders declined to submit their offers. The remaining five bidders expressed concerns during pre-bid meetings held in March and April 2006 regarding undertaking the full scope of work of the project. After pre-bid meetings and clarifications, an addendum to the RFP was issued (April 2006) to all the vendors allowing them to bid for one or more of any three sections of the EPIC package viz. (a) installation in shallow water and river section downstream of Control-cum-Riser Platform (CRP) including onshore part, (b) fabrication and installation of CRP in the field, and (c) installation in deepwater section upstream of CRP including pipelines, manifolds, umbilicals, etc.

Of the remaining five bidders, two bidders viz. Technip and Saipem bid as a consortium, and three bidders viz. Allseas, Acergy and JRM bid individually. The operator observed (July 2006) that none of the four bidders quoted for the full scope of EPIC work. Out of the four bidders, Allseas and Acergy were technically accepted for sub-sea scope of work for installation of Pipelines, Umbilicals, Sub-sea structures, etc. of the EPIC package. Technip-Saipem consortium submitted the bid for CRP related work and EPIC of offshore facilities, excluding some scope, and JRM submitted the bid only for CRP.

Bids for CRP were evaluated separately. On evaluation, the Technip-Saipam consortium was rejected due to quoting longer project schedule and also for not submitting a priced bid because it was unable to meet the project schedule. The **single technically acceptable bidder** for CRP, JRM, quoted US$ 317.50 million. But three days after opening of priced bid, JRM submitted a revised bid (31 August 2006) with net value increase by US$ 12.05 million to US$ 329.55 million and OC approved (1 September 2006) the award of contract (No. OG8/3611331 and OG8/3391768).

On opening of the priced bid (1 September 2006) for EPIC offshore facilities , Allseas was lowest with Euro 476.50 million (equivalent to US$ 619.45 million) against Acergy's bid for US$ 1399.47 million, as its bid was for a much lower portion of the scope of work set out in RFP than the Acergy's bid. **After the priced bid comparison**, RIL persuaded Allseas to take on a wider scope of work than it had indicated in its bid so that its scope of work corresponded to the scope of work in the RFP. Accordingly, Allseas submitted a revised priced bid (18 September 2006), for Euro 764.085 million (equivalent to US$ 993.311 million). Acergy also submitted (8 September 2006) a revised quote for US$ 1444.425 million. Following OC approval, the contract was awarded to Allseas (19 September 2006) for Euro 764.085 million. On comparison, we observed upward rate revision for different elements amounting to Euro 166.5 million (excluding Euro 121.09 million for elements for which price was not quoted in the initial bid).

Giving reasons for price increases, the Operator stated (April 2010 - in reply to our audit enquiry - and July 2011, as furnished through MoPNG) as under:-

- Allseas made price adjustment due to (a) an increase in the portion of the work to be undertaken; (b) conversion of a number of items quoted on a provisional sum basis into lump sum amounts, as requested by RIL; (c) mobilisation of additional vessels leading to increased mobilisation and demobilisation costs; (d) inclusion of certain Indian taxes (except service tax and royalty) in its bid price rather than simply Swiss taxes as in its initial bid; (e) increase in design engineering and project management costs due to Allseas agreeing to undertake design engineering, project management etc for additional work not quoted earlier and taking more risks; (f) Allseas agreeing to take up dewatering and nitrogen purging not quoted earlier; and (g) withdrawal of certain technical and commercial deviations, etc.
- JRM revised prices due to (a) increases in the indicative prices of various items earlier quoted on cost plus basis; (b) shifting of location for transportation of piles and jacket appurtenances from Indonesia to Dubai leading to suitable adjustments in the indicative transportation duration; (c) increase in hourly rate for design and detailed engineering at bidder's office, earlier quoted as cost plus; (d) increase in steel rates and estimated steel quantity for CRP; (e) inclusion of cost of tools, construction equipment, consumables in hourly rates, (f) revised estimation for jacket installation; (g) JRM agreeing to provide a performance bank guarantee for US$ 15 million rather than US$ 10 million as per initial bid; and (h) JRM agreeing to an overall liability cap at 20 per cent of contract price rather than 10 per cent as per initial bid etc;
- There was no lack of transparency and fairness. In requesting Allseas to increase its scope of work (thereby resulting in Allseas revising its price), RIL sought to increase its chances of obtaining the most competitive price possible from the available qualified bidders.

We do not agree because the scope of work was described in the RFP. Also, there were pre-bid meetings with the bidders and an addendum was also issued to clarify scope issues. Therefore, upward revision in price after opening of priced bids does vitiate the tendering process and affect its transparency.

4.5.4 Rates revision for MEG Plant ordered against single bid

The Operator issued (May 2006) RFQ for design and supply of Mono Ethylene Glycol Regeneration & Reclamation (MEG) Plant at the onshore terminal, to produce 80 mmscmd of gas in two stages, viz. stage I–study to select optimum technology and stage II–design and supply. After evaluation of four bids, the Operator decided to award stage-I work to CCR Technologies and AKPS (Aker Kvaerner Process Systems), but as the non-disclosure agreement could not be finalised by RIL with CCR, order was placed on AKPS. Based on stage-I report and stage-II estimate provided by AKPS, work was awarded, without any comparison of optimum technology due to single bid, for US$ 22.16 million and INR 4.57 crore. In this connection, we observed that:

- Despite rates estimation after study by AKPS, man-hours frozen for engineering increased by 85 per cent from 31,800 hours to 58,700 hours leading to time and cost overrun of 1½ years and US$ 5.01 million respectively.
- Levy of LD was linked to certain stages of work and not contract completion in all respects, due to which no LD was levied despite inordinate delay in completion.
- While agreeing to extend the time line as well as frozen man-hours, the Operator could not ensure extension of the validity of the lower man-hour rates viz. US$ 186 extended for post December 2007 period, leading to additional cost recovery for man-hours spend subsequently at higher rates of US$ 200 per hour; financial impact on cost recovery would be in post March 2008 period.

In response, the operator stated (March 2010 / July 2011) that:

- Stage-I scope was limited to evaluation of MEG reclamation technologies and estimates for engineering services were not based on detailed engineering, but as per a similar project executed previously by the vendor for another client. No contractor, based upon concept study and the prevailing market condition, would have been likely to have agreed to accept a cap on its man-hours or to imposition of liquidated damages in the event that its original time estimates were exceeded.
- It was not possible for the contractor to provide precise estimates upfront based upon a study for concept selection. In fact, the scope of the work was changed after the contract was awarded, in order for the requirements of the project to be met.
- As the project was on a fast-track basis, it was not practical to carry out all engineering and studies needed to better define the scope of work before awarding the contract in circumstances where the relevant activities were being undertaken in a parallel manner.
- Applicability of LD was linked only to the critical stages of the contract and defining more milestones was not feasible.

We do not agree for the following reasons:

- Despite the fact that the Operator had invited bids from four vendors, three had to be rejected for various reasons, ultimately leaving AKPS as the only firm which had to conduct the concept study and submit the proposals for engineering and supply of key equipments thereafter.
- It was a scenario where both the contracts i.e. (i) study for selection of optimum technology and (ii) design & supply for the MEG Plant were being carried out by the same firm, i.e., AKPS (together with its associates).
- The contention of the Operator that no contractor in the prevailing market condition would have agreed to put a cap on its man-hours or complete the work in the reduced rates etc., is unfounded and is only an post audit assumption as no records were available showing that the Operator had ever negotiated with the contractor on these issues.
- Huge post award revisions in man-hours with consequential increase in cost and time is not acceptable.
- The contention of the Operator that the project was being carried out in a fast track basis also does not hold ground, as there was already a time overrun of more than 1 ½ years as of March 2008.

4.5.5 Other findings relating to procurement activities

Audit findings in respect of other procurement activities in respect of the block are summarised below:

Table 4.4 – Other findings on procurement activities

Pre-paid insurance	Insurance policies for D1-D3 gas field and MA field for the periods 1 September 2006 to 15 July 2008 and 1 August 2007 to 30 June 2008 were obtained at premia of US$ 51.99 million and US$ 9.22 million (payable in instalments). However, during 2007-08, the operator paid premium of US$ 48.88 million and US$ 8.49 million respectively, and booked the amount in cost recovery. This included excess booking of US$ 6.97 million of pre-paid insurance for 2007-08, which is admissible for cost recovery only in 2008-09. In his response (furnished through MoPNG), the operator stated (July 2011) that, as per Article 25.2 of the PSC, accounting is "based on generally accepted and recognised accounting principles and modern petroleum industry practices". Being a policy taken for the project's setup, all payments towards policy were capitalised and recorded as part of the capital WIP in the year of payment. We do not agree. Insurance amount only up to March for the financial year 2007-08 was to be booked in financial statements for the year

	2007-08, and excess amount paid was to be booked as prepaid insurance during the period 2007-08.
Excess allocation of insurance charges	The operator obtained insurance policy for exploratory and drilling for all its exploration blocks, including KG-D6. The total premium paid was to be allocated to the respective blocks based on well depth and water depth of wells drilled during the period, after reduction of special discounts and admissible low claim rebates. During the period April 2006 to March 2008, the operator allocated US$ 6.43 million to KG-DWN-98/3, instead of actual premium (US$ 5.35 million net after adjustments), leading to excess booking of US$ 1.08 million to cost recovery. The operator, in his response (furnished through MoPNG), stated (July 2011) that the nature of the relevant adjustments could not be calculated until the end of the relevant financial period. This is because RIL's eligibility for such adjustments could be ascertained only after the expiry of the policy, including the completion of all activities in the well in progress at the time of policy expiry. Accordingly, and in accordance with the applicable accounting practice, the unadjusted cost of the policies was properly booked in 2007-08, subject to an appropriate adjustment subsequently being made to take account of the applicable discount and rebates once the same are determined. The reversal for the relevant adjustments were all accounted for in SAP entries on 19/30 March 2010. In our opinion, such adjustments (if ascertained after the expiry of the policy) could have been carried out in 2008-09 and not 2009-10. Hence, the excess amount booked was not entitled for cost recovery up to 31 March 2008.
Asset usage charges	Asset usage charges for 2006-07 and 2007-08 were allocated/ charged over a 12/24 months period, instead of allocating over the useful life of the asset; in the company's accounts, fixed assets were being depreciated using the written down value method as per rates prescribed in the Companies Act. This leads to higher cost recovery, and adversely affects GoI's financial interests. The charges allocated upto March 2008 for KG-DWN-98/3 were US$ 3.69 million. In his response (furnished through MoPNG), the operator stated (July 2011) that the assets were allocated to the blocks at a faster rate than the depreciation rates provided in the Income Tax Act and Companies Act to reflect the risk associated with the continuation of the exploration

	phase for each block. The useful life of IT assets is very short and rate of obsolescence on account of technology changes is high. Further, the methodology for charging asset usage charges for furniture & fixture, plant & machinery as per Companies Act was implemented from financial year 2008-09. We do not agree. The operator cannot arbitrarily fix the useful life of asset in order to cover its exploration risk. Assets Usage Charges must be determined, keeping in view the useful life of the block/ field.
Excess cost booking for helicopter	Against the actual cost of two helicopters for supply operations of US$ 18.781 million, an amount of US$ 19.14 million was booked in the 2007-08 accounts, leading to excess recoverable cost of US$ 0.36 million. The operator informed (July 2010) that necessary rectification would be passed in 2010-11. Further, although the helicopters were customs cleared at Delhi airport on 16 December 2007, and certificates of registration issued by DGCA on 9 January 2008, O&M charges of INR 1.29 crore for the period upto December 2007 were irregularly booked, leading to excess cost recoverable. In response (furnished through MoPNG), the operator informed that the contractor was advised to procure the infrastructure and mobilise the required manpower on 15 November 2007 and also provided services like pre-dispatch inspection, approvals and permissions from various authorities, monitoring of reassembly of helicopter etc. till commencement of operations as Rajahmundry. However, we observed that the services provided by the contractor are neither in the scope of contract nor approved by OC. Further, this information was not provided earlier, and cannot be verified at this stage. This will be reviewed subsequently.
Expenditure on Social Obligations, Sponsorship, Gifts Cost	Expenditure of US$ 57,116 was incurred during 2006-07 and 2007-08 on social obligations/ programme, sponsorship and gifts. If MoPNG feels that the expenditure of this nature is eligible for cost recovery, clear norms/ limits should be specified for such cost recovery (to be applied transparently across all blocks/ operators).
Freight forwarding and transportation services	Post contract award, the operator agreed for higher rates of INR 1,000/ ton (against INR 700/ton "wrongly quoted" by the vendor, Transoceanic Fagioli, UK) for transportation to Kakinada Port, resulting in additional payment of INR 2.23 million upto March 2008, with more impact post-

March 2008. In our opinion, this is not admissible for cost recovery.

4.6 Violation of PSC-stipulated Procurement Procedure

The main provisions of the PSC related to procurement of goods and services are summarised below:

- Article 8.3(f) stipulates inter alia that:
  - ❖ The contractor shall, having due regard to GIPIP, establish and submit for MC's approval appropriate criteria and procedures including tender procedures for the acquisition of goods and services as provided in Article 23.2 (relating to "Local Goods and Services") **and** for the purchase, lease or rental of machinery, equipment, assets and facilities required for petroleum operations, based on economic considerations and generally accepted practices in the international petroleum industry with the objective of ensuring cost and operational efficiency in the conduct of petroleum operations.
  - ❖ **Notwithstanding provision provided herein**, the procedure for acquisition of goods and services shall be as per Appendix –F, which may be modified or changed with the approval of the MC, when circumstances so justify.
- Article 23.2 (under Article 23 – Local Goods and Services) directs the contractor to establish appropriate procedures, including tender procedures for the acquisition of goods and services which shall ensure that suppliers and subcontractors in India are given adequate opportunity for the supply of goods and services.
- "Appendix F – Procedure for Acquisition of Goods and Services" indicates that the objective of these procedures are to ensure that goods and services are acquired at the optimum cost (taking into consideration all relevant factors including price, quality, delivery times and the reliability of potential suppliers) and delivered in a timely manner (taking into consideration the consequences of delays in acquisition on the project as a whole), and implementation of provisions of Article 23 (Local Goods and Services).
- Three separate procedures (A, B and C) have been laid down in Appendix 'F' for acquisition of goods and services depending on value. Procedure 'C' (US$ 500,000 or more) indicates *inter alia* the following:
  - ❖ Publishing invitations for parties to pre-qualify for the proposed contract, and include those parties who qualify, as per the pre-qualification criteria approved by the OC, in the list of entities from whom the operator proposed to invite tenders;
  - ❖ Provide the MC members with a list of pre-qualified entities qualified for the proposed contract, as well as entities identified as approved vendors by the OC for the applicable contract category, and any other entities from whom the operator proposes to invite tender; and also add any entities requested by a party (i.e. the GoI or any of the companies constituting the contractor);

- If requested by any party (i.e. the GoI/ companies), the operator should evaluate the listed entities to assure that they are qualified as per the approved pre-qualification criteria to perform under the contract;
- Thereafter, dispatch tendering documents, consider and analyse bids, prepare a competitive bid analysis, and obtain OC's approval[33] to the recommended bid.

As per the PSC, the role of the MC (including the GoI representatives) is thus restricted to the pre-qualification of vendors for the contract, and does not, in general, extend to the approval of contract award.

During our scrutiny of the operator's records, we have come across several instances (e.g. award of the FPSO contract for the MA oil field), where multiple vendors were pre-qualified. However, when technical bids were received, all vendors (except one) were rejected, and the contract was finally awarded on a single financial bid.

In our opinion, such disqualification of vendors on technical grounds, after a pre-qualification process and bidders' meetings for technical clarifications, limits the competitiveness which is not in accordance with the spirit of the procurement procedure given in the PSC. In many cases, it resulted in no competing financial bids, and the contract was awarded on the basis of a single financial bid. In such a situation, the letter and spirit of the MC's role at the pre-qualification stage is vitiated.

Consequently, in our opinion, in cases of procurement (under procedure 'C' – high value contracts), where pre-qualified bidders are subsequently disqualified/ declared non-responsive on various technical and other grounds and there is only one financial bid being considered, the Operator should either go back to the pre-qualification process, and ensure that more vendors/ parties are pre-qualified. Alternatively, if the operator wishes consideration of only a single financial bid, the matter has to be necessarily referred back to the MC (including GoI representatives)/ GoI for ex ante relaxation from PSC stipulated procurement procedures. Post facto approval of the MC may be provided for in emergent cases, with adequate justification.

Likewise, extension of contracts (beyond the extension periods already stipulated in the contract) is not in consonance with Appendix 'F'. If the operator wishes to extend such contracts, the matter has to be necessarily referred back to the MC for necessary relaxation.

We, therefore, recommend that in the case of the KG-DWN-98/3, MoPNG carefully review in depth the award of 10 specific contracts (of which 8 were awarded to Aker Group companies) on the basis of a single financial bid. In this recommendation, we are not even remotely suggesting that the operator should follow government procurement procedures, yet any commercially prudent private acquisition would also attempt to

[33] However, failing OC approval, any company may refer the issue to the MC for decision.

generate competition and thereby obtain the most competitive price. Such concern for a cost effective acquisition is not perceptible in the aforementioned process.

Incidentally, we have been provided a copy of the MC Resolution in respect of KG-DWN-98/3 (apparently taken up at the 8th MC meeting on 29 November 2003 at DGH office) and approved by circulation. The MC resolution states that ***"pursuant to Article 23.2 of the PSC"***, the operator had submitted the procurement procedure for acquisition of materials and services for its blocks under NELP rounds, I, II and III, and that the procurement procedure was examined by DGH and discussed in a separate meeting with RIL and DGH representatives on 22 September 2003, and subsequently deliberated and approved by MC with the agreed modifications.

The above referred procurement procedure (RIL Document No. ROG-GPP-004) stipulates a set of detailed procurement procedures. Some interesting features of this document include the following:

- RIL shall award work on single/ nomination basis in several circumstances – urgent requirement; items/ services of proprietary nature; items/ services of special nature.
- Instead of the pre-qualification process for each ***"proposed contract"*** falling under procedure 'C' – (estimated value of US$ 500,000 or more), as stipulated in PSC Appendix 'F', an EOI (Expression of Interest) stage has been introduced. The EOI process would be done only once in 2 years and would cover all blocks in which RIL is the operator; the MC members were to be involved only at the EOI stage, and not for pre-qualification for each proposed contract.
- The document provides for technical evaluation of "un-priced bids" (a separate stage after the EOI stage), and opening of only technically accepted bids; bids of technically unacceptable bids would not normally be opened.
- Any recommendation not based on the lowest total evaluated price is to be substantiated with reasoning.
- Extension of contract/ work order period is permissible where the extension is attributable to RIL or increase in the scope of work, or exercising the option available in the contract.

The provisions of the above "procurement procedure" (RIL Document No. ROG-GPP-004) are clearly contrary to the stipulations of Appendix 'F' to the PSC. However, the provisions of the PSC – Article 8.3(f) – are very clear ".... Notwithstanding provision provided herein, the procedure for acquisition of goods and services... shall be as per Appendix –F". Appendix-F has not been modified by the MC. Hence, the provisions of the RIL document, which has been approved by the MC under Article 23.2 (which relate to procedures for ensuring adequate opportunity to suppliers and sub-contractors in India) are invalid.

We, therefore, recommend that in the case of the KG-DWN-98/3, MoPNG carefully validate the award of the following contracts on the basis of a single financial bid so as to draw assurance that government interests have been protected.

S.No.	PO No.	PO Date	Order Placed on	Original PO Value (US$)	Item Description
1.	86759	06.10.2007	Aker Borgestad Operations AS	276,443,000	Operation & Maintenance of FPSO RIL Equipment and Operation of Subsea Equipment in connection with production of Oil & Gas
2.	3627982	04.05.2007	Aker Floating Production/ Aker Contracting FP ASA	1,094,002,520	Chartering of FPSO facility in connection with extraction and production of Oil & Gas
3.	3639935	20.09.2007	Aker Installation FP AS, Norway	281,118,779	Installation of Subsea Facilities
4.	3370813	03.07.2006	Aker Kvaerner Subsea AS Norway	431,284,407	Supply of subsea hardware
5.	310783	27.09.2006	Aker Kvaerner Process System	1,000,000	License Agreement for MEG R&R Plant
6.	3610783	20.10.2006	Aker Kvaerner Power Gas / Aker Power Gas Pvt. Ltd.	100,000	Services relating to MEG R&R Plant
7.	3610598	15.09.2006	Aker Kvaerner Process System	5,914,800	Engineering of MEG Regeneration and Reclamation plant
8.	3392654	30.09.2006	Aker Kvaerner Process System	16,154,400	Supply of key equipment for MEG Regeneration & Reclamation package
9.	3391768	27.09.2006	J. Ray McDermott Middle East Inc.	206,990,342	Supply, loadout & seafastening of CRP
10.	3611331	26.09.2006	J. Ray McDermott, Eastern Hemisphere	122,558,268	Transportation, installation, testing and pre-commissioning

Legend

(pink)	Contracts relating to MA oilfield.
(green)	Contracts relating to MEG Regeneration & Reclamation package.
(blue)	Contracts relating to Installation of CRP

4.7 Deficiencies in Appointment of Auditors

RIL, the Operator, invited (12 July 2007) quotations from three Chartered Accountants firms viz. Pricewaterhouse Coopers, S.R. Batliboi & Co. and Haribhakti & Co. for appointment of auditors for RIL operated blocks with due date 28 July 2007. Pricewaterhouse sent the quotation on 27 July 2007, but on the last date, based on verbal requests of two firms, the due date was extended by two weeks. Later, OC/MC approved (August/November 2007) appointment of Haribhakti & Co. as auditors for 2007-08 for INR 2 million for all the 35 blocks (INR 1.5 million allocated to KG-D6).

Audit observed deficiencies in the approval process viz. (a) evaluation criteria for audit firms not fixed before bids invitation & evaluation, (b) time extension was allowed for two bidders after receipt of bid from third firm, and (c) signature/initials of operator's representative on the bids indicating date of receipt & opening of bids were not found.

In response to an audit enquiry, the Operator stated (May 2010) that (a) comparative bid analysis provides the selection criteria i.e. experience in PSC/JOA and experience in Oil/Gas Accounting, (b) time extension was granted as rate competitiveness would be lost if process was closed on receipt of one quotation, and (c) quotes were to be sent to the RIL's Audit Chief in Head Office and then to be passed on to E&P; thus, there might be variation in dates of receipt at E&P when compared with actual receipt and hence dates were not mentioned on the quotes.

The operator's reply is to be viewed in the light of the following:

- As major development activities for D6 field were carried out in the year 2006-07 and 2007-08, evaluation criteria viz. number of years of experience for E&P companies' audit and minimum level of E&P Company with examples like ONGC, OIL, etc. were required to be fixed before inviting quotations and bids evaluation.
- Recording dates of receipt and opening of priced bids is an important aspect of fairness and transparency in bid evaluation.

Time extension was granted on the last date by which the quotations were required to be submitted and after receipt of bid from one firm of auditors. Also on review of the documents produced to the audit for verification, it was not known, whether the quotations were in the sealed cover or not, and also when the quotations of each one of the firm were actually opened.

MoPNG stated (July 2011) that under the provisions of PSC, the value of bidding involved did not require MC decision. MC approved the appointment of auditor under Article 25.4 of PSC as proposed by the Operator and not the evaluation process.

In future, we recommend that the GoI representatives on the MC may consider requesting a certificate from the auditors regarding their not rendering any audit or other services to the contractors during the last 2/ 3 years. This will promote greater independence and effectiveness on the part of the auditors.

4.8 Incomplete access to SAP System

As per Section 1.9.3 of Appendix C (Accounting Procedure) to PSC, in conducting the audit, the Government or its auditors shall be entitled to examine and verify, at reasonable times, all charges and credits relating to the contractor's activities under the contract and all books of account, accounting entries, material records and inventories, vouchers, payrolls, invoices and any other documents, correspondence and records considered necessary by the Government to audit and verify the charges and credits.

In terms of section 1.4.1 of the Accounting Procedure to PSC, within ninety (90) days of the Effective Date of the Contract, the Contractor had to submit and discuss with the Government a proposed outline of Chart of Accounts (CoA). The sequence of related events in respect of KG-DWN-98/3 is summarised below:

- RIL forwarded the CoA to the DGH on 19 January 2001.
- Subsequently, certain modifications were carried out to the CoA and communicated to DGH on 26 March 2002. This communication stated that the new CoA would be effective from the new budget year starting 1 April 2002.
- DGH on 2 April 2002 requested for specific modifications to the earlier CoA which could enable them to examine the revised CoA.
- RIL stated on 11 April 2002 that a one-to-one matching of the modification was not possible and that the changes to the CoA were necessitated because RIL was in process of implementing SAP software to address the complex reporting requirements under the PSC.
- Finally on 25 July 2003, RIL stated that all the accounts were being maintained in SAP ERP System from September 2002 and that the CoA was revised to suit the SAP parameters. RIL also sought approval for the revision.
- The approval was finally communicated by DGH on 24 September 2003.

RIL, the Operator, maintains one common SAP (Version 4.6) over all its group companies and accounts of KG-DWN-98/3 and other exploration blocks are maintained in the JV module.

As part of verification of figures of expenditure up to the year 2007-08, a request was made to provide complete access to the SAP. Despite repeated requests, however, complete access was not provided.

- Instead, the operator informed that the E&P Division being a part of RIL group, it was not possible to restrict access to only KG-DWN-98/3 and not other modules of SAP, other than FI (the Financial Accounting module of SAP). Therefore, it was not possible to provide access to KG-DWN-98/3 block alone. The operator, further, stated that requisite access to SAP could not be provided as SAP contained information regarding assets held by RIL other than KG-DWN-98/3 block, which it would not be appropriate to share with the audit team.

- Consequent upon the Operator's refusal to provide complete access to SAP, the Operator agreed in a meeting to restore a back-up of the database and extract the data pertaining to KG-DWN-98/3 block, but later on stated that RIL had a database of more than 4TBs in size and KG-DWN-98/3 block data may be very small. However, it was difficult to predict the timeline when such backup system would be ready. The operator, further, stated that it was difficult to manage and arrange resources required for such exercise, hence, restoring the database was not feasible.

- In view of incomplete access to SAP, we agreed to the operator's request that line-item wise breakup of the Cost Recovery Statements would be provided in Microsoft Excel format. On verification of line items, we observed that total of the detailed breakup did not match with the total of Trial Balance provided by the Operator. We also observed that the data provided was incomplete. In reply to our query, ***the Operator stated that the line items provided only included the debit side of the transactions and credit side was not provided.*** Thus there was incomplete access to SAP, and incomplete data provided for our analysis.

- On comparison of Purchase Orders (POs) details provided in the Excel Sheets format with the list of 337 orders (valuing over US$ 1 Million) provided separately by the Operator on request, we observed that 222 Purchase orders in the list did not form part of the data provided in the Excel Sheets format. In reply to an audit enquiry, the Operator stated that those Purchase Orders related to procurement of material or common expenditure like shore based activity, common orders allocated on utilization basis, common transportation costs, hiring of choppers, common HSE cost etc. and hence would not appear in the expenses ledger (for which the debit side line items was provided to audit). Thus, on cross-referencing the two set of data base/information provided by the Operator, the POs details did not match.

As per Article 3.1.8 of the Accounting Procedure, material and equipment held in inventory shall only be charged to the accounts when such material is removed from inventory and Cost shall be charged based on the 'First-in-First-out method'. As per Notes forming part of the Trial Balance as on 31 March 2007, Drilling Inventory and consumables are valued at cost based on Weighted Average or net realisable value, whichever is lower. We, however, observed the following:

- There was a change in the Trial Balance as on 31 March 2008, stating that Inventory and consumables were valued at cost based on Weighted Average. The impact of change was not quantified and reported in the Trial Balance for the year 2007-08. On analysing the data provided in the Excel Format, we further observed that there were 215782 Line Items with Material Code valuing US$ 409.76 million during the years 2006-07 and 2007-08. However, due to limited data/details as well as very restricted SAP access, we were not able to quantify the impact of adopting Weighted Average method of valuation as against FIFO method, on the cost booked in the accounts forming part of cumulative cost approved for recovery as on 31 March 2008.
- The Operator, in reply to our enquiry, referred (March 2010) to Accounting Standard No. 2 and stated that the majority of companies, including RIL, follow Weighted Average Method of stock valuation and maintaining two different valuation methods, i.e. one for PSC accounting purpose and the other for Company's accounting purpose is not worth pursuing considering the insignificant difference involved in the two methods over time. We do not agree, in view of the fact that accounting provisions are guided by the PSC for KG-DWN-98/3 block and not by any other standards.
- The operator did not implement the 'Audit Information System' of SAP. Also providing facility to create queries on SAP was not possible.

Thus, the data provided by the Operator as line-item wise breakup of Cost Recovery Statements contained only the expenditure side of the transactions. The failure of operator to provide complete access to SAP as well as provide complete KG-DWN-98/3 block Data after segregation from the system also indicates deficiencies in the implementation design of the SAP, in so far as suitability for maintaining PSC related accounting records is concerned.

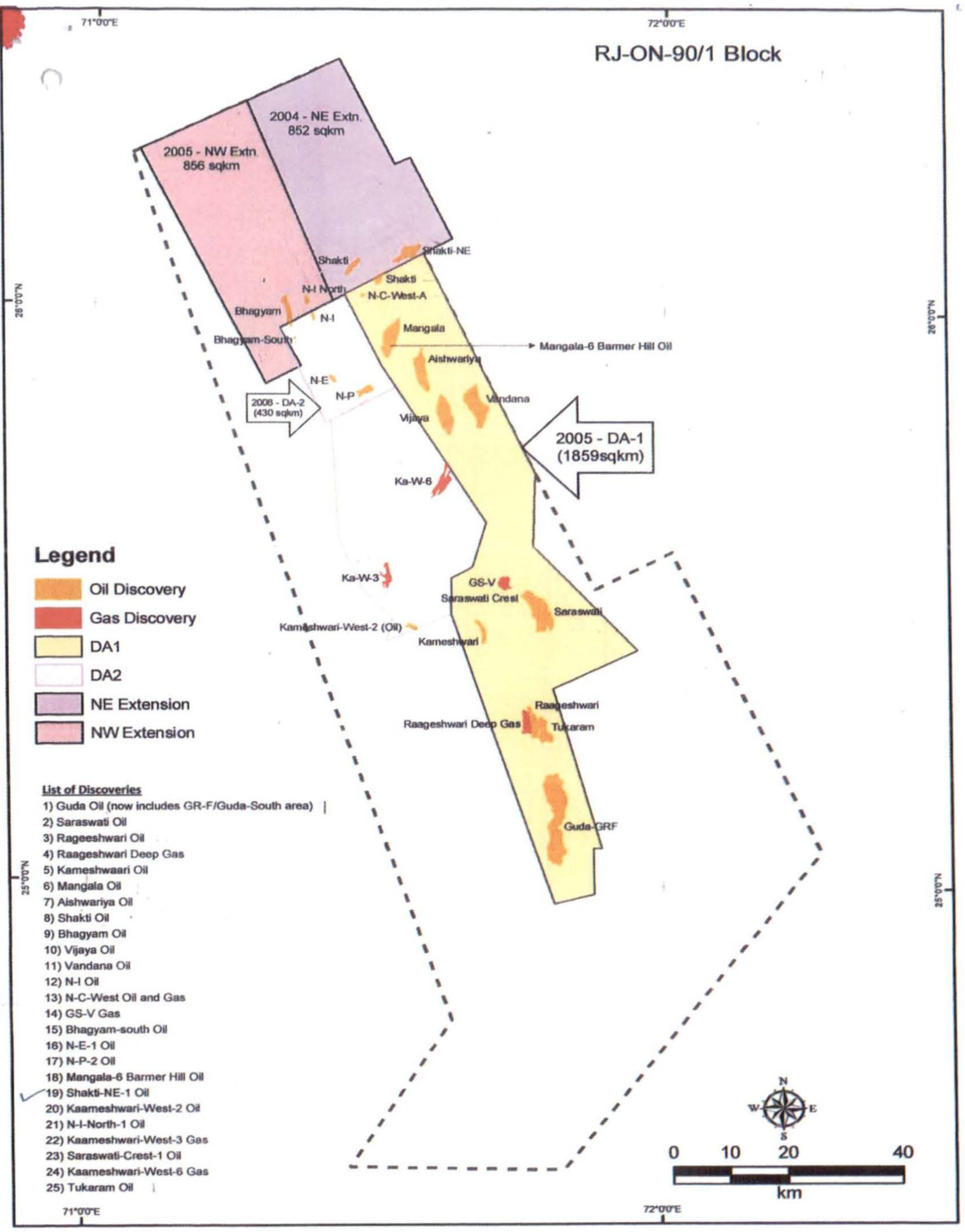
In its response, MoPNG stated (July 2011) that the SAP system had provisions to give selective 'read' authorisation to auditors through appropriate command from master user. SAP also had standard reports available for downloading in excel or any other desired format. Audit may take appropriate technical assistance from SAP service providers to get direct online access to SAP database or to download the output data in desired format. Reply of MoPNG may be seen in the light of the fact that the issue is not on account of the technical skills required to access the SAP database, but the extremely restricted access given to SAP modules, other than the FI module.

MoPNG also stated that the operator would also be given necessary instructions through the MC for making changes in system configuration, including configuration of 'Audit Information System' as desired by Audit, to facilitate detailed examination.

Chapter 5 - Findings relating to RJ-ON-90/1 block

5.1 Overview

This onland block (mainly in Rajasthan, with a small portion in Gujarat) is one of the pre-NELP exploration blocks awarded in Round IV of the pre-NELP exploration rounds in May 1995 to Shell India Production and Development (BV) (SIPD). The PSC was signed between GoI, SIPD and ONGC on 15 May 1995. Subsequently, SIPD's participating interest was transferred in three phases between September 1998 and June 2003 to Cairn Energy India Limited and Cairn Energy Hydrocarbons Limited (collectively termed as "Cairn Energy").



Under the terms of the pre-NELP exploration block PSCs, ONGC was the licensee and was responsible for obtaining the Petroleum Exploration License (PEL) and Mining Lease (ML), and also payment of royalty and PEL/ ML fees. ONGC also had the right, as the designated nominee of GoI, to take a Participating Interest (PI) upto a maximum of 30 per cent in each Development Area (DA) within 90 days of Declaration of Commercial Discovery (DoC). Till date, three DAs have been delineated as given below:

Table 5.1 – Development Areas in RJ-ON-90/1 block

Development Area (DA)	Date of creation (grant of ML)	Area	Participating Interest	
			Cairn Energy	ONGC
DA-1	20 June 2005	1859.00 sq km	70 per cent	30 per cent
DA-2	15 November 2006	430.17 sq km	70 per cent	30 per cent
DA-3	6 November 2007	822.00 sq km	#	#

 # ONGC acquired 30 per cent PI in two development areas, while its decision to acquire 30 per cent in DA-3 was under reference to MoPNG.

There have been 25 hydrocarbon discoveries (21 oil and 4 gas) in the block between July 1999 and November 2008. The status of these discoveries is summarised below:

Table 5.2 - Status of discoveries in RJ-ON-90/1 block

S.No	Name of the Discovery	Date of discovery	Type	Remarks
1	Guda	23-Jul-99	Oil	14 discoveries indicated at serial nos 1 to 14 were falling in DA-1, Mining Lease (ML) for which was granted on 20 June 2005. However, the FDP for DA-1 covered only 5 discoveries (Mangala including Raageshwari Deep Gas, Aishwariya, Raageshwari and Saraswati). For the other nine discoveries, no separate FDP(s) were yet submitted by the operator.
	G-R-F-1 (now part of Guda)		Oil	
2	Saraswati	29-Oct-01	Oil	
3	Raageshwari Oil	25-Dec-02	Oil	
4	Raag Deep gas	25-Dec-02	Gas	
5	Kameshwari	21-Sep-03	Oil	
6	Mangala	20-Jan-04	Oil	
7	Aishwariya	5-Mar-04	Oil	
8	Vijaya	28-Aug-04	Oil	
9	Vandana	7-Aug-04	Oil	
10	GSV	4-Jul-05	Gas	
11	N-C-West	4-Jul-05	Oil	
12	Mangala Barmer Hill	20-Jan-04	Oil	
13	Saraswati-Crest-1	5-May-07	Oil	
14	Raageshwari-East-1z/Tukaram	24-Nov-08	Oil	

S.No	Name of the Discovery	Date of discovery	Type	Remarks
15	Bhagyam	7-Aug-04	Oil	8 discoveries indicated at serial nos 15 to 22 were falling in DA-2, ML for which was granted on 15 November 2006. FDP for Bhagyam discovery was submitted and approved. FDP for Shakti had not been submitted till date. In respect of the remaining 6 discoveries, no separate FDPs were yet submitted by the operator.
16	Shakti	18-Apr-04	Oil	
17	N-I	18-May-05	Oil	
18	Bhagyam South	3-Dec-05	Oil	
19	N-E	9-Jan-06	Oil	
20	N-P	6-Apr-06	Oil	
21	Shakti-NE-1	21-Oct-06	Oil	
22	N-I-North	21-Nov-05	Oil	
23	K-W-2	21-Nov-06	Oil	3 discoveries indicated at serial nos 23 to 25 were falling in DA-3, ML for which was granted on 6 November 2007. FDP in respect of these three discoveries was submitted by the operator in July 2009. MoPNG stated (July 2011) that FDP evaluation of these discoveries had been completed and submitted for MoPNG's decision.
24	K-W-3	13-Dec-06	Gas	
25	K-W-6	20-Jul-07	Gas	

RJ-ON-90/1 is one of the largest onland oil discoveries in India, with 450 million barrels as the current estimate of recoverable resource potential. Oil production from the block started on 29 August 2009. A notable feature of development in this block is the 580 kilometer oil pipeline from Barmer to Salaya (completed) and 80 kilometer Salaya to Bhogat (in progress), with insulation and heating features to maintain the temperature at 65 degrees C, in view of the high "pour point" of the crude oil (48 degrees C).

5.2 Exploration and Appraisal Activities

5.2.1 Delayed relinquishment of area

The PSC stipulated an exploration period of seven years, also permitting an extension of upto three years. This extended exploration period expired on 14 May 2005. At this stage, the operator was required to relinquish the entire area, except for discovery and development areas.

However, out of the original contract area of 11,108 sq.km., a total area of 6678.10 sq.km. (including extended area of 1708.20 sq. km.) was retained, comprising of:

- 1859 sq. km. of development area in DA-1 field;
- appraisal area of 2884 sq. km. (Northern Appraisal Area); and
- an additional 1935.10 sq. km. of area in the southern part , which was not designated as a discovery or development area. This area was irregularly retained till 7 November 2007 (due to non-submission of maps by the operator in time), when it was finally relinquished.

Further, out of the appraisal area of 2884 sq. km. in the Northern Appraisal Area:

- an area of 430.17 sq. km. was converted into Mining Lease (DA-2 development area)[34] on 15 November 2006.
- Out of the remaining area of 2453.83 sq. km., the contractor sought retention of the entire area for six months (from 15 November 2006), but was allowed by MoPNG to retain an area of 879.50 sq. km. under PEL from 8 May 2007 till 7 November 2007.
- 822.00 sq. km. of the area of 879.50 sq. km. was converted into Mining Lease (DA-3 development area) on 6 November 2007; however, the balance area of 57.5 sq. km. was deemed relinquished.

In response, MoPNG stated (July 2011) that :

- The delays in relinquishment were procedural and did not have any commercial implications.
- No activity during delays in relinquishment had been reviewed by the MC, which would have an adverse material impact on the contract.
- Further, DGH had conveyed on 14 November 2006 to the operator/ licensee that except for the area of 430.17 sq. km., the remaining block area (2453.83 sq. Km.) in the Northern Appraisal Area stood relinquished from 15 November 2006.

We do not agree. Despite the DGH's communication of 14 November 2006, an area of 1574.33 sq. km. continued to be retained by the contractor till 7 November 2007, when the area was deemed to be relinquished.

5.2.2 Extension of Appraisal Period by six months

- MoPNG extended the stipulated exploration period of 7 years by 36 months in June 2002 and, in June 2005, approved another extension of 18 months (15 May 2005 to 14

[34] Interestingly, although the initial term of the PSC is only for 25 years (from May 1995 to May 2020 (subject to extension by mutual agreement pursuant to PSC provisions), the Mining Lease granted by the Government of Rajasthan for DA-2 (430.17 sq.km) is for 20 years from November 2006 to November 2026 (which is beyond the initial term of the PSC). The PSC term is, however, subject to extension by mutual agreement as per PSC provisions.

November 2006) to complete appraisal of the Bhagyam and Shakti discoveries in the Northern Appraisal Area (NAA).

- In December 2006, the operator requested a further extension of six months for completing appraisal work in the NAA[35] to cover up the work which was *inter alia* hampered for more than three months in view of severe floods in Rajasthan. DGH did not recommend further extension, since the appraisal work (for which the earlier 18 month extension was sought and agreed to) was already over. However, in May 2007, MoPNG granted a further extension of 6 months effective from 8 May 2007[36]. Interestingly, the period of 6 months between 15 November 2006 and 8 May 2007 was not formally covered by extension.

In response, MoPNG stated (July 2011) that the Government granted (8 May 2007) six months extension on the basis of Cairn's track record with regard to survey, exploration and discovery, besides the fact that Cairn was quite confident of making more discoveries in the Northern Appraisal Area. However, the fact remains that this extension was beyond the PSC provisions.

5.2.3 Irregular extension of exploration activities through fresh discoveries during appraisal and development phases

Article 1 of the PSC for RJ-ON-90/1 block defines Exploration operations, Exploration well, Discovery, Discovery Area, Appraisal well and Development area as follows:

Table 5.3 - Definition of key terms in RJ-ON-90/1 PSC

Term	Definition
Exploration operations	Operations conducted in the contract area in ***searching for petroleum*** and in the course of a programme to appraise any discovery and shall include but not limited to ...... all work necessarily connected therewith that is conducted in connection with petroleum exploration.
Exploration well	A well drilled for the purpose of ***searching for undiscovered petroleum accumulations*** on any geological entity .....
Discovery	The ***finding of a deposit of petroleum not previously known to have existed***, which can be recovered at the surface in a flow measurable by conventional petroleum industry testing methods.
Discovery Area	An area within the contract area **in which there has been a discovery** and over which the contractor is of the opinion that the deposit of

[35] The request was for an area of 2453.83 sq.km (after excluding an area of 430.17 sq.km under Mining Lease from the original area under NAA of 2884 sq. km).

[36] Covering an area of 879.50 sq.km.

Term	Definition
	petroleum discovered could extend, based upon the results of exploration operations.
Appraisal well	A well drilled as part of a work programme carried out following a discovery of petroleum in the contract area ***for the purpose of delineating the petroleum reservoirs to which the discovery relates*** in terms of thickness and lateral extent and determining the characteristics thereof and the quantity of recoverable petroleum therein.
Development Area	An area within the contract area containing one or more commercial discoveries whether or not within a single geological structure (to include the maximum area of potential petroleum deposits in the contract area in a simple geometric shape) which the contractor intends to develop in accordance with a Development Plan which has been approved in accordance with Article 9 or 21.4.

In our opinion, exploration and development are distinct and successive operations. Exploration is clearly the ***"search for petroleum"***, discovery is the ***"finding of petroleum"*** and development is the ***"development of one or more commercial discoveries"***. Further, although the appraisal period falls within the exploration period, appraisal is ***for delineating the petroleum reservoir to which the (existing) discovery relates*** and is, thus, distinct from exploration, which is the ***search for petroleum***.

However, we found that the operator carried out exploration activities and made new discoveries within the discovery/ development areas, as summarised below:

Table 5.4- Discoveries made after exploration period

S.No.	Name of the Discovery	Date of Discovery	Development Area (DA)	Remarks
1	N-I	18.05.2005	DA-2	The exploration period ended on 14 May 2005. Eight discoveries indicated at serial nos 1 to 8 were made after the exploration period ended, i.e. during the first appraisal period from 15 May 2005 to 14 November 2006.
2	GSV	04.07.2005	DA-1	
3	N-C-West	04.07.2005	DA-1	
4	N-I-North	21.11.2005	DA-2	
5	Bhagyam South	03.12.2005	DA-2	
6	N-E	09.01.2006	DA-2	
7	N-P	06.04.2006	DA-2	
8	Shakti-NE-1	21.10.2006	DA-2	

S.No.	Name of the Discovery	Date of Discovery	Development Area (DA)	Remarks
9	K-W-2	21.11.2006	DA-3	Three discoveries indicated at serial nos 9 to 11 were made during 15 November 2006 to 7 May 2007, i.e. the period between the first appraisal period (15 May 2005 to 14 November 2006) and the second appraisal period (8 May 2007 to 7 November 2007).
10	K-W-3	13.12.2006	DA-3	
11	Saraswati-Crest-1	05.05.2007	DA-2	
12	K-W-6	20.07.2007	DA-3	This discovery was made during the second appraisal period from 8 May 2007 to 7 November 2007.
13	Raageshwari-East-1z/ Tukaram	24.11.2008	DA-2	This discovery was made during the development phase.

Consequently, in our opinion, the declaration of fresh discoveries during the appraisal/development phases within delineated discovery/development areas amounted to irregular extension of exploration activities, which is not in consonance with the terms of the PSC. This also indicates that the discovery/development areas were not strictly delineated, and included excess area.

In response, MoPNG stated (July 2011) that there could be exceptional cases when during delineation of the pool boundary of an existing discovery through appraisal, a new pool (discovery) could be discovered which was not in hydrodynamic continuity with the existing pool.

We do not agree with the views of MoPNG. While there could be, as pointed out by MoPNG, exceptional cases of a discovery being found during delineation of an existing "pool/boundaries" through appraisal, the fact that eight discoveries were made during the first appraisal period, three discoveries made between two appraisal periods, and one each during the second appraisal period and development phase, clearly indicates that these were not "exceptional cases". This confirms the lack of strict delineation of development/discovery areas and irregular continuation of exploration activities.

During the exit conference (July 2011), the operator indicated the following aspects:

- The Development Areas hold further exploration potential; the current estimate of the resource potential was 450 mmbbls recoverable;

- Continuing exploration in the block was consistent with PSC and the Oil Fields (Regulation and Development) Act, 1948 as well as global practices and precedents in India, also citing global examples of continuing exploration in development areas[37]
- Continuing exploration was required to realize the full potential of the block to produce over 300000 bopd.

With regard to the operator's views (submitted at the exit conference) regarding continuing exploration in development areas, Section 3 (d) of the Oil Fields (Regulation & Development) Act, 1948, defines mining lease as *"a lease granted for the purpose of searching for, winning, working, getting, making merchantable, carrying away or disposing of mineral oils or for purposes connected therewith, and includes an exploring or a prospecting license".*

However, the PSC itself is covered by the Petroleum and Natural Gas Rules, 1959, which provide for an agreement between the Government and the licensee with respect to additional terms and conditions in regard to the licence or lease[38]. We believe that the provisions of the Oil Fields (Regulation and Development) Act, 1948 and the PNG Rules, 1959 cannot be read in isolation, and must be construed within the letter and spirit of the PSC which provides for the conduct of different petroleum operations (exploration → appraisal → development → production) in an orderly sequence.

While we take note of the operator's view that continuing exploration would realize the full potential of the block, we believe that such extension of exploration activities goes beyond the provisions of the PSC. Approval by the GoI of such extensions should be on clear financial quid pro quo - beyond the existing PSC provisions - for the benefit of GoI or its parties.

5.3 Discovery, Commercial Discovery and Development

5.3.1 Discovery and Potential Commerciality Report

The PSC provides that when a discovery is made within the contract area, the Contractor should:

- Forthwith inform the Licensee (ONGC) and Government of the discovery and furnish particulars in writing within 30 days of the discovery;
- "Promptly" run tests to determine whether the discovery is of potential commercial interest; and

[37] Indonesia (Offshore SE Sumatra), Nigeria (Block OML-61), Yemen (Block 18 (Marib Al Jawf) and Block 14 (Masila Dev)), Malaysia (PM-08 (EXXON) and Block K), Syria (Deir ez Zor/ Zenoubia West), and India (RJ-ON-90/1, Ravva, South Bassein (Mumbai Offshore), and Lakwa (Assam)).

[38] Rule 5 of PNG Rules, 1959

- Within 60 days of completion of the tests, submit a report to the Management Committee with a notification of whether, in the contractor's opinion, the discovery is of potential commercial interest and merits appraisal;

We found the following deficiencies in compliance with the PSC provisions:

- Out of 25 discoveries, intimation in respect of 10 discoveries was not given within the stipulated 30 days of discovery, with delays ranging between 11 and 791 days.
- Reports of potential commerciality were not submitted within the stipulated period of 60 days after completion of tests in respect of 13 out of 25 discoveries, with delays ranging between 2 to 329 days.

Further, we found that out of 25 discoveries:

- All 25 discoveries had been tested to determine potential commercial interest; however, no appraisal wells were struck in 7 discoveries. Despite lack of appraisal wells, advice of commerciality was submitted to the MC in all 7 cases (evidently based directly on test of potential commercial interests without an appraisal programme). However, DoC (Declaration of Commercial Discovery) was not declared in six of these cases. In response, the operator stated that since these discoveries fell within the existing Development Areas (DA-1 and DA-2), no separate DoC was required.
- In 22 cases, advice of DoC was given to the MC, but only 10 DoCs were formally declared. Delays in DoC approval ranged from 67 to 323 days.
- In 10 cases, advice of DoC was given to the MC, even before drilling of the last appraisal well, and in 4 of these 10 cases, the DoC was actually approved before the drilling of the last appraisal well. Consequently, the DoC approval is likely to have been based on incomplete information.
- Field Development Plans in respect of only nine discoveries were submitted (five[39] in DA-1, one in DA-2, and three in DA-3), of which six were approved; FDPs for three discoveries in DA-3 are yet to be approved by MC. Of the remaining 16 FDP for one discovery is awaiting the Operating Committee's approval, while the remaining 15 discoveries have been clubbed with FDPs for DA-1 (nine) and DA-2 (six). These 15 discoveries (which were discovered between July 1999 and November 2008) were still awaiting development. Details are given in **Annexure 5.1**.

In response, MoPNG stated (July 2011) that:

- As regards delay in intimation of 10 discoveries, these discoveries had not been reviewed by MC; hence the question of intimation did not arise.
- As regards the 15 discoveries (clubbed with DA-1 and DA-2) awaiting development, the timelines would not apply to these discoveries, as these were already in the

[39] Mangala, Aishwariya, Raageshwari, Saraswati, and Raageshwari Deep Gas

development area for which the ML had been granted, and efforts to develop MC reviewed discoveries were being made.

While we note that all discoveries cannot be developed individually (as they may not be commercially viable on a stand-alone basis), we do not agree with MoPNG's views regarding non-applicability of timelines for discoveries in the appraisal / development phases in the development area for the reasons indicated in para no 5.2.3 above.

5.3.2 Declaration of Commercial Discovery

Article 9.5 of the PSC provides that the MC shall, without any undue delay, and in any event within forty five days of the date of the notice under article 9.4, consider the proposal of the contractor and request any other additional information it may reasonably require so as to reach a decision on whether or not to declare the Discovery as Commercial Discovery. Such decision shall be made within the later of (a) ninety days of the notice under article 9.4 or (b) forty five days of receipt of such other information as may be required under article 9.5.

However, we found that there were delays in approval of DoC by the Management Committee, as given below:

Table 5.5 - Delay in Declaration of Commercial Discovery

S.No.	Name of the Discovery	Date of Discovery	Date of submission of DoC for review by MC	Date of DoC	Delay in DoC (days)
1	Saraswati	29.10.2001	11.05.2004	15.10.2004	67
2	Raageshwari	25.12.2002	11.05.2004	15.10.2004	67
3	Mangala	20.01.2004	11.05.2004	15.10.2004	67
4	Aishwariya	05.03.2004	11.05.2004	15.10.2004	67
5	Raag Deep gas	25.12.2002	11.05.2004	15.10.2004	67
6	Bhagyam	07.08.2004	08.02.2006	14.11.2006	189
7	Shakti	18.04.2004	08.02.2006	14.11.2006	189
8	K-W-2	21.11.2006	06.11.2007	24.12.2008	323
9	K-W-3	13.12.2006	06.11.2007	24.12.2008	323
10	K-W-6	20.07.2007	06.11.2007	24.12.2008	323

In response, MoPNG stated (July 2011) that in many cases, the delay was due to non-receipt of complete information; therefore, approval of DoC was done after the later of 90 days/ 45days from the receipt of required information.

We do not agree. The additional information in respect of discoveries was sought after expiry of the stipulated 90 days time limit. No details were provided in respect of two discoveries. Further, delays pointed out in the para are after considering the maximum prescribed timeline of 90 days.

5.3.3 Field Development Plans

5.3.3.1 Delays in submission and approval

Field Development Plans in terms of three development areas (DA-1, DA-2, and DA-3) were submitted and approved (DA-1 and DA-2) by the Management Committee. We found that there were delays in submission and approval of FDPs:

Table 5.6 - Delays in submission and approvals of FDPs

FDP	Delay in submission of FDP	Delay in approval of FDP by MC
Mangala, Aishwariya, Rageshwari and Saraswati (MARS) in the DA-1 area	241 days	58 days
Bhagyam (DA-2 area)	No delay	69 days
Shakti Field (part of DA-2 area)	OC approved FDP not submitted	---
Kaameshwari (DA-3)	July 2009	Not yet approved

In response, MoPNG stated (July 2011) that in many cases delay was due to non-receipt of complete information; therefore, approval of FDP was done after later of 90 days/45 days from receipt of required information. Regarding approval of Kaameshwari (DA-3) FDP, it stated that evaluation had been completed for decision by MoPNG.

5.3.3.2 Revised FDP for Mangala (including Raageshwari Deep Gas)

The original FDP of Mangala (including Raageshwari Deep Gas) was approved by the MC in May 2006 at a cost of US$ 1241.61 million. A revised FDP was submitted to the MC on 20 March 2009, due to change in delivery point from Barmer to Salaya and later to Bhogat, which necessitated laying of pipeline. On 30 June 2009, the MC approved the revised FDP at a cost of US$ 2367.31 million, plus US$ 941.05 million as the cost of the pipeline, plus US$ 35.61 million as cost of Mangala EOR; i.e. a total cost of US$ 3343.97 million.

The increase in revised FDP cost was attributed to (i) flood during 2006 in Rajasthan; (ii) delayed approval for pipeline and terminals; (iii) increase of Upstream Capital Cost index by 98 percent during 2005 to 2007; (iv) increase in Rig Day Rates and other tangibles as per current contracts; (v) delay in project schedule; (vi) change from gas to steam for power generation; and (vii) increase in excavation, foundations, construction costs due to plant relocation, increase in prices of steel and cement, additional road works, construction camps, increase in equipment and bulks.

Our comparison of individual cost elements for the original and revised FDPs (as approved) revealed that the main increases in cost were on account of surface facilities (US$ 513.40 to US$1038.03 million), well construction (US$ 433.08 to US$ 698.80 million) and project management (US$ 67.25 to US$167.52 million); details are indicated in **Annexure 5.2**. This is in addition to the cost of the pipeline (US$ 941.05 million).

In response, MoPNG stated (July 2011) that during the period 2005 to 2007, the price level for E&P services increased substantially and additional scope of work was included to the Mangala surface facilities in the revised FDP. Further, there were changes in the production facilities, in view of increased production rates from 100000 bopd to 125000 bopd.

Most of the expenditure under the revised FDP has been/ would be incurred from 2008-09 and thereafter; this would be covered in future audits.

5.4 Procurement Issues

The operator awarded contracts for procurement of goods and services to indigenous and foreign vendors. During the course of audit, 41 contracts in respect of which payment valuing more than one million US$ was made during the years 2006-07 and 2007-08 were reviewed. It was observed that:

- in three cases, payment of US$ 89.45 million was made against contracts awarded on nomination or on single financial bid basis;
- in one case, payment of US$ 1.94 million was made against the contract awarded without assessing reasonability of rates; and
- in two cases, payment of US$ 20.63 million was made against contracts extended beyond contractual provisions, without availing economies of scale.

Details are given in **Annexure 5.3.**

In response, MoPNG stated (July 2011) that any amount assessed by audit in the final report that should not be considered would be considered for appropriate action for deletion from contract cost. In this connection, we recommend that MoPNG validate the award of contracts falling under the categories listed above, so as to draw assurance that Government's interest was protected.

5.5 Cost Recovery

Production of oil from the RJ-ON-90/1 block commenced only in August 2009. Hence, cost recovery had not commenced in 2006-07 and 2007-08 (the two years for which records of the operator were scrutinised). As of March 2008, cumulative recoverable cost amounted to US$ 1088.32 million, of which additions of US$ 215.91 million and US$ 401.56 million took place during 2006 (calendar year) and 2007-08 (15 months). Our review was, thus, confined to examination of cost-recoverable items incurred during 2006-08.

In our opinion, the following items of cost are not eligible for cost recovery:

Table 5.7-Items not eligible for cost recovery

Item	Amount US$	Details
Exploration costs incurred in development area DA-1	119.78 million	Expenditure of US$ 105.18 million on appraisal wells and US$ 14.60 million towards seismic surveys and activities in DA-1 (which were not approved by MC) are not eligible for cost recovery.
Additional work beyond MWP not approved by MC	77.95 million	Additional work costing US$ 46.41 million on 16 drilled wells and US$ 31.54 million on seismic activities undertaken beyond MWP had not been approved by MC (August 2010).
Seismic survey on area already relinquished	1.59 million	Expenditure of US$ 1.59 million up to 14 May 2005 was incurred on seismic survey on area which had already been relinquished; this cost had not been approved by the MC.
Expenditure on discovery well during appraisal period	2.22 million	Expenditure of US$ 2.22 million was incurred on a discovery well KW-I (6) drilled, without MC approval, in July 2007 during the extended appraisal period. Despite DGH's objection, MC regularised it, so that it could be developed along with two other discoveries (KW-2 and KW-3). In our opinion, the MC's regularisation is not in line with the PSC provisions.

We also found excess expenditure of US$ 27.63 million on pre-development and development activities over the approved budget for 2007-08 of US$ 160.56 million, which had not been ratified by the MC.

In response, MoPNG stated (July 2011) that:

- expenditure in respect of work program not approved by MC and adversely commented upon by audit would be disallowed; and
- the audit view on disallowing exploration expenditure incurred after exploration phase was in line with the stand of DGH on the issue.

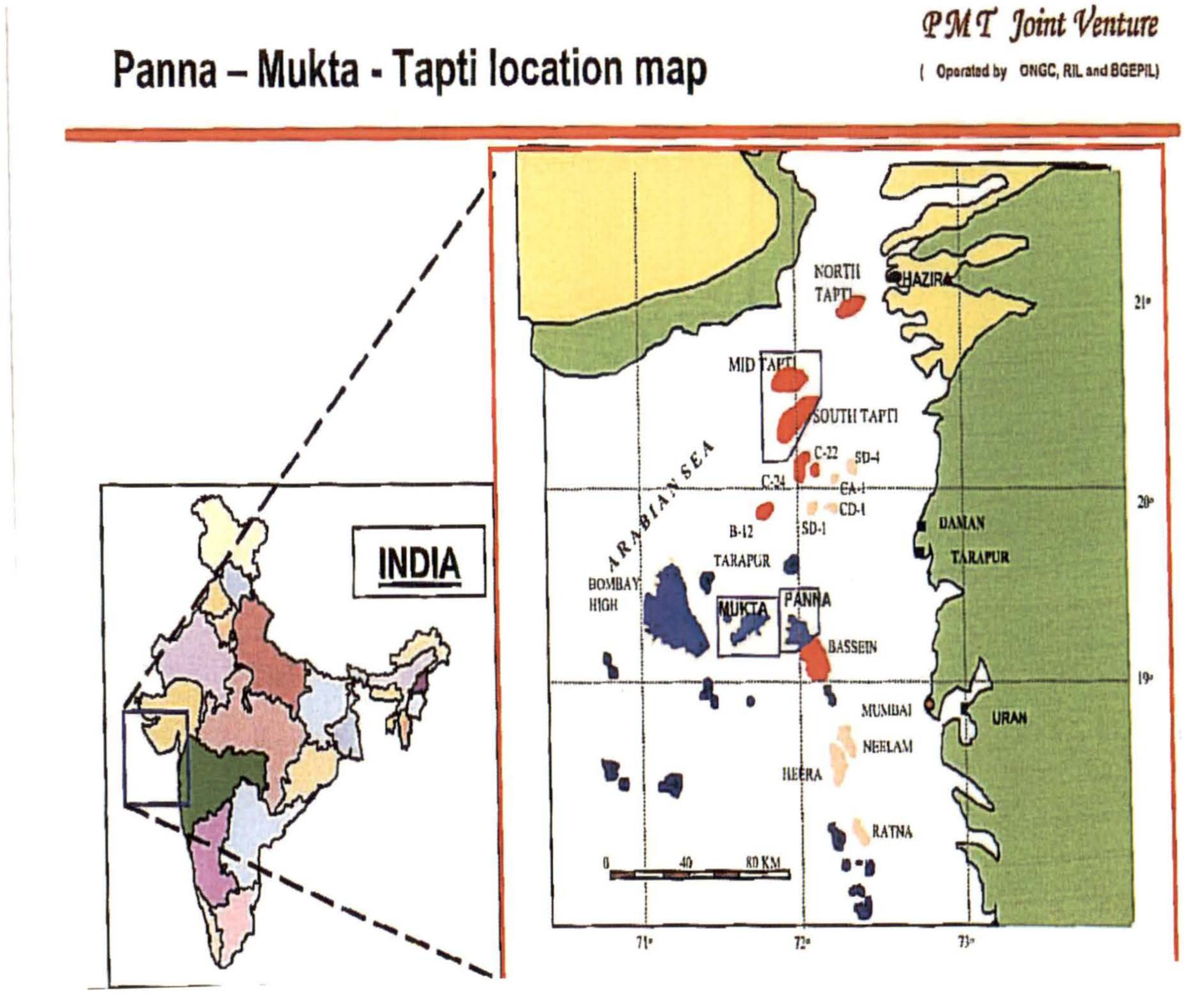
We take note of the ministry's assurance on this issue.

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.

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[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.

Chapter 7 - Compliance and Control Issues

Significant compliance and control issues relating to KG-DWN-98/3, RJ-ON-90/1, Panna-Mukta and Tapti PSCs have been discussed in chapters 4 to 6 of this report. This chapter deals with compliance and control issues relating to other PSCs, as well as less significant issues relating to these four PSCs.

7.1 Role of DGH

In April 1993, the GoI decided to set up the Directorate General of Hydrocarbons (DGH) under the administrative control of MoPNG with the objective of promoting the sound management of Indian petroleum and natural gas resources, having a balanced regard for the environment, safety, technological and economic aspects of the petroleum industry. ***The GoI resolution of April 1993 constituting the DGH refers to the need of the MoPNG to have an appropriate agency to (a) regulate and oversee upstream activities in the petroleum and natural gas sector; and (b) also advice GoI in these areas.***

Besides the Director General, the staff of DGH is drawn on deputation/ tenure basis, mainly from upstream and other oil PSUs (ONGC, OIL, IOC and BPCL).

The functions of the DGH, as stipulated in the April 1993 resolution fall into two broad categories:

To advise the GoI on:	• Exploration and optimal exploitation of hydrocarbons within the country, and on the strategy of exploration/ exploitation of reserves abroad by NOCs • Offering of acreage for exploration, and relinquishment of acreage by the companies; • Laying down of safety norms, framing regulations on safety in oilfield operations, prescribe pollution control measures, and assist in inspection and periodic safety audits.
To review:	• Exploration plans and development plans for commercial discoveries of hydrocarbons of companies, and advise GoI on their adequacy; • Review and audit concurrently the management of petroleum reservoirs on operating companies, and advise on mid-course correction required to ensure sound reservoir management; • Re-assess hydrocarbon reserves discovered and

	estimated by operating companies (in discussion with them).

In September 2006, MoPNG issued a fresh notification, indicating that the DGH shall exercise the following powers and functions:

- Monitoring upstream petroleum operations in India;
- Review and monitor the exploration programme and development plans for commercial discoveries of hydrocarbon reserves proposed by licensee/ lessee, with a view to optimising hydrocarbon recovery from a reservoir;
- Review management of petroleum reservoirs by licensee/ lessee and advise them;
- Ask for and maintain data, reports, information and samples (i.e. a data repository) from petroleum E&P;
- Review reserves discovered by licensee/ lessee;
- Lay down norms for declaration of discoveries; and
- Exercise powers of GoI under Rules 24, 25, 26 27 and 30[60] of PNG Rules

In our view, the roles and functions of DGH encompass two sets of functions with potential conflict of interest – an upstream regulatory function, and a function of rendering technical advice to GoI. While in 1993 (when DGH was set up), there was lack of adequate clarity on the role and position of regulators in various economic sectors, the need for clear autonomy of sectoral regulators (from the Executive) is now well recognised.

Consequently, we recommend that the functions currently discharged by the DGH be clearly demarcated. The technical advisory and related functions should be discharged by a body completely subordinate in all respects to MoPNG (either a cell/ attached office/ subordinate office within the MoPNG or a separate entity under MoPNG). Functions of a regulatory nature (review of hydrocarbon reserves and reservoir management, laying down of norms for declaration of discoveries, laying down safety and related norms and conducting safety inspections/ audits etc.) should be discharged by an autonomous body, with an arm's length relationship with GoI.

[60] These relate to preservation of cores and samples, directions to prevent waste, spacing of wells, restriction of production, and suspension of production.

7.2 Exploration/ Appraisal Issues

7.2.1 Irregular declaration of entire contract area of KG-OSN-2001/2 (Operator: RIL) as discovery area

In February 2007, the Operator exercised his option (under the PSC provisions) of not entering Exploration Phase-II at the end of Phase-I (March 2007), after availing two extensions of 6 and 5 ½ months. Instead, he irregularly declared the entire contract area of 210 sq. km. as 'discovery area' (although there were only two discoveries in the contract area) and decided to continue appraisal activities in the whole contract area. Subsequently, in September 2007, the MC approved a resolution to allow 15 months time up to 15 June 2008 for completion of the appraisal programme and to retain the whole area.

We noted that:

- The block was divided into two geographical parts (Part 'A' and Part 'B'). Out of the four wells drilled in the block, two wells (one in Part 'A' and the sole well drilled in Part 'B') were dry wells. Thus, treatment of the whole area as a 'discovery area' was irregular.
- Even though the contractor did not give a firm proposal for drilling of appraisal wells, he was still allowed to retain the whole of the contract area, purportedly for appraisal of two discoveries.
- Since the appraisal programme could not be completed by 15 June 2008, the contractor requested (July 2008) for further extension of four months up to 15 October 2008. Instead of taking action for relinquishment of area, DGH recommended (July 2008) to MoPNG for grant of further extension. MoPNG refused to grant extension and, in December 2009, asked for relinquishment with effect from 15 June 2008.
- The contractor avoided executing the MWP of drilling of four wells of depth 3500 metres/ basement each, which was a contractual obligation under Exploration Phase-II, by the simple expedient of opting out of Phase-II. Simultaneously, he managed to retain the entire contract area and avoid any relinquishment, by designating the entire block as 'discovery area'.

In reply, MoPNG stated (July 2011) that:

- The proposal for appraisal programme for the discoveries D-24 and 25 (in part "A") was submitted on 12-07-2006[61], and also included declaring the whole area as discovery area.

[61] Incidentally, this is just one day after the meeting of the MC of KG-DWN-98/3 on 11 July 2006, which agreed to the declaration of the entire contract area as discovery area.

- During submission of this proposal, Contractor had drilled two wells (D-24 & 25) and drilling of 3rd well was in progress in Part-A of the block. Since all the three wells were drilled in part-A, the area for retaining both part-A & B could not be decided. Accordingly, in the MC meeting held on 1 November 2006, it was decided that the contractor may drill one well in Part-B and on the basis of the results of the well in Part-B, the decision to appraise both Parts-A & B could be taken. Subsequently, the Contractor on 02-05-2007 indicated that drilling of one well (KGIII6-B1) in Part-B on 28-12-2006 indicated the presence of hydrocarbons during drilling.

- ***The validity of the geological model in conjunction with petroleum system modelling can only be proved by drilling of wells.*** Sometimes, drilling setbacks necessitate revisiting the geological model which becomes a continuous process till the production stage of a field. Even a dry well/or well with minor hydrocarbon indication does not necessarily write off an area. In the current case, the contractor had claimed that the dry well in part B of the area (where HC indication was encountered during drilling) was due to non-entrapment and non-sealing nature of the fault, which did not mean that the area was devoid of hydrocarbon; even possibility of missing the hydrocarbon zone by a whisker always existed in rollover set up.

In the case of KG-DWN-98/3, DGH was essentially of the view that drilling of wells (and successful discoveries) in all parts of the contract area was not necessary for declaration of the entire contract area as 'discovery area'. In this case, the argument for declaring the entire contract area as 'discovery area' was that while the validity of the geological model can only be proved by drilling of wells, a dry well does not necessarily mean that the area is devoid of hydrocarbons. These responses are evidently contradictory.

- The contractor had acquired 3D seismic in the whole area in excess of the committed MWP, which indicated that there was geological continuity in the two parts of the block.

- The area of Part 'B' of the block was about 78 sq. km. Relinquishment of an area of that size might not be useful for offering in bidding rounds, particularly in offshore area. On the contrary, carrying out of appraisal activities might give a chance to establish the continuation of similar hydrocarbon pool.

- MC had allowed retention of the entire/most of the contract area as discovery area (for appraising discoveries) in the case of ONGC operated block KG-DWN-98/2 and Focus Energy operated RJ-ON/6.

However, the observations made by CAG would be taken for guidance for future cases.

- As there was no provision for extension in submission of DoC, the case was recommended to MoPNG, validating the technical justifications submitted by the Contractor. Eventually, since the contractor in the block had not opted to enter the second exploration phase and DoC in respect of D-24 and 25 discoveries was not submitted within the stipulated timeline and there was no provision for extension of Appraisal Phase under the PSC, the contractor was asked on 30 December 2009 to relinquish the block with effect from 15 June 2008.

7.3 Non-compliance to PSC provisions regarding notification of discovery and submission of test reports

We found non-compliance to provisions regarding notification of discoveries in respect of KG-OSN-2001/2 block, as detailed below:

- Without first furnishing the initial particulars of the two discoveries viz. Dhirubhai-24 and Dhirubhai-25 in writing to the MC and Government, the Operator had directly given written notifications regarding potential commerciality of the discoveries.
- In the case of Dhirubhai-24 discovery, tests were completed on 4 February 2005, but the Contractor submitted the report and its opinion regarding potential commerciality to the MC on 15 December 2005 i.e. after a delay of more than eight months.

While agreeing to the audit observation regarding non-furnishing of notification of the two discoveries D-24 and D-25, MoPNG in its response (July 2011) stated that although the contractor did not provide the notification, DGH representative was present during the testing of the wells.

As regards the delay in submission of the test report, MoPNG stated that the delay occurred due to analysis of detailed testing results after observation of positive indication of hydrocarbon in well D-24, and, subsequently, results were confirmed by drilling of one more well (D-25). But the post-discovery timelines w.r.t. D-25 discovery was not compromised. MoPNG further mentioned that this practice had since been streamlined, and proper discovery notifications as per PSC provisions were being monitored.

7.4 Delay in submission/ review of appraisal programme

We noticed deficiencies relating to appraisal programme in respect of KG-OSN-2001/2 block

Block	Deficiencies
KG-OSN-2001/2 (Operator: RIL)	• Appraisal Programme and Work Programme and Budget (WP&B) were submitted after a delay of 3 and 16 months respectively.

Block	Deficiencies
	• Appraisal Programme and WP&B were reviewed after delays of 13 and 8 months respectively. In its reply (July 2011), MoPNG stated that there was a stipulated time period in PSC for submission of declaration of commerciality after carrying out appraisal programme. Since the time period for submission of commerciality was fixed, contractors had to carry out appraisal programme and then submit DoC as per PSC period. Hence, delayed submission of appraisal work programme and budget may not affect the timeline prescribed in PSC for submission of DoC. However, the observation made by audit in this regard was noted and would be followed for future cases. While we take note of MoPNG's reply that they had noted the audit observation, in fact the PSC provisions were not adhered to.

7.5 Submission of Development Plan

Article 9 of Hazira PSC stipulates that within 90 days of the effective date (signing of PSC i.e. September 1994), contractor was required to submit a Comprehensive Development Plan. However, the contractor submitted the Field Development Plan after a delay of seven years.

In reply (July 2011), MoPNG stated that at the time of award, the field had GIIP of 1.9 BCF and only one gas well (Hazira – I) onland as per Information Docket. Generally, the extent of the field could not be ascertained on the basis of one well data. Field delineation was required to prepare the development plan.

The reply appears to be an afterthought, since such views were not found / recorded in the Minutes of Meeting of MC / records produced to audit at DGH.

7.6 Operating Agreement

The PSC provisions stipulate that within 15 days of the effective date (i.e. the date of signing of the PSC or the date of grant of the PEL, whichever is later)[62], the companies constituting the contractor should execute an Operating Agreement; a copy of this agreement is to be furnished to the Government. We found that:

[62] or such longer period as agreed to by Government.

- In the case of the MB-OSN-97/3 block (operator: RIL), we could not find documented evidence of a copy of the agreement being provided by the operator to the Government;
- Operating Agreements were executed after delays in CB-ONN-2000/1 block (4 months), KK-DWN-2000/2 (3 ½ months) and MB-OSN-2004/2 (2 months).

In reply, MoPNG stated (July 2011) that the Operating Agreements were made among the consortium partners. In our opinion, since the provision is stipulated in the PSC to which GoI is also a party, DGH is required to monitor adherence to all the provisions of PSC.

7.7 Management Committee

The NELP PSCs provide for nomination of two GoI representatives on the MC. Till 2007, DGH was nominating two of its officers as GoI representatives on the MC. However, in March 2007, MoPNG clarified to DGH that:

- The main objective of delegation of powers was to utilise the technical expertise of DGH for better management of petroleum reservoirs and to function as a repository of relevant technical data;
- Approving payment for contractors such as unfinished committed work programme under the PSC and accepting such payments on behalf of GoI fell within the purview of GoI.

Accordingly, MoPNG appointed its officers as one of the two GoI representatives on the MC, with the other representative from DGH.

While forwarding (July 2011), the response of the operator of KG-DWN-98/3 to the draft audit findings, MoPNG has clarified the following:

- **The interpretation of the operator that decisions taken by members representing GoI on the MC is construed to be the approval of GoI is not correct. The PSC clearly identifies the difference between the approval of members representing GoI on the PSC, and the approval of GoI of the sovereign State. The PSC further clarifies that the MC shall not take any decision without prior approval of GoI, where such approval is required.**
- **The operator's statement that all procurement transactions are approved as per procedures defined by the operator and approved by the MC, is thus incorrect and should not be taken cognizance of.**
- **The approval of procurement procedure and the Development Plan, which is within the purview of MC approving functions cannot be construed to be approved by the GoI.**

We are fully in agreement with the MoPNG's stand that the approval of MC (including GoI representatives thereon) and approval by GoI are entirely different and distinct activities under the PSC provisions, and cannot be confused. This is, in a sense, similar to the participation of GoI nominee/ representatives directors on the PSU Board of Directors; approval of decisions/ actions by the PSU Board (including GoI nominees/ representatives) cannot be construed as approval by GoI.

Notwithstanding the above position, the importance of GoI representatives on the MC cannot be understated. Most actions, which would have a material impact on GoI's financial take, are taken at the level of MC (and not the GoI). Hence, the role of GoI representatives on the MC in protecting GoI's financial interests (besides ensuring sound technical management and guidance – appropriate reservoir management etc.) is critical.

However, we found numerous deficiencies in compliance with the PSC provisions relating to the Management Committee relating to frequency of meetings, circulation of notice and agenda to the members, and finalisation of minutes of meeting:

- Out of 20 PSCs scrutinised by us, we found that MC meetings were not conducted as per the prescribed frequency in respect of 7 PSCs (KK-DWN-2003/1, RJ-ONN-2002/1, RJ-ON/90/1, CB-OS/2 and CB-ONN-2000/1, Mid & South Tapti and Panna-Mukta). Further, due to incomplete records/ incorrect numbering of the MC meetings/resolutions and non-availability/ non-production of complete minutes/resolutions, frequency of the meetings could not be verified in respect of 5 PSCs (Hazira, KG-DWN-98/3, MB-OSN-97/3, NEC-DWN-2002/1 and MN-DWN-2004/3).
- Adherence to the prescribed procedure regarding issue of notices, circulation of provisional agenda and finalization of minutes of meeting in a time bound manner could not be ascertained due to incomplete records in respect of 8 PSCs (Hazira, CB-OS/2, KG-DWN-98/3, KG-OSN-2001/2, MB-OSN-97/3, NEC-DWN-2002/1, MN-DWN-2004/3 and RJ-ON-90/1).

In response to an audit enquiry as to why only 12 MC meetings were held in respect of RJ-ON-90/1 block between May 1995 and June 2009, DGH stated (February 2010) that it was handling about 250 PSCs and about 350 MLs with manpower strength. Hence, it was not always possible to strictly adhere to the time schedules of MC meetings.

Further, MoPNG, in its reply, stated (July 2011) that MC had been granted specific roles under PSC provisions and adequate meetings were held so as to ensure the role of MC. Depending on the circumstances, issues and operational requirement, MC meetings were held. Further, profit sharing mechanism was well defined in the provisions of PSC and the quantum of profit flows from the books of accounts.

Auditors were also deployed by Government to get assurance on the integrity of books of account.

A profit-sharing mechanism (as envisaged in these PSCs, as opposed to a simple royalty formula) necessitates constant oversight and monitoring, with the role of the government representatives on the Management Committee becoming critical. Once this mechanism has been accepted by MoPNG and operationalised in contractual form, it is incumbent on MoPNG and DGH to ensure that these controls work effectively and in a timely manner.

7.8 Periodical Reporting

As per the PSC, the contractors were required to submit, within the prescribed time limit, annual and quarterly reports to DGH covering various aspects such as:

- annual local procurement statements outlining their achievements in utilizing Indian resources;
- quarterly statements of costs, expenditures and receipts;
- quarterly cost recovery statement; and
- end of year statement etc.

Test check of records, however, revealed deficiencies in this regard in respect of 13 PSCs KK-DWN-2003/1, MB-OSN-97/3, KG-DWN-98/3, KG-OSN-2001/2, MN-DWN-2004/3, NEC-DWN-2002/1, CB-OS/2, Hazira field, CB-ONN-2000/1, CB-ON/1, KK-DWN-2000/2, MB-OSN-2004/2 and RJ-ONN-2002/1. Details are given in **Annexure 7.1**.

In reply, MoPNG stated (July 2011) that the operators had been submitting reports on utilization of Indian Resources, Quarterly Profit Petroleum Statement, End of Year Statement, Monthly Report etc. However, the reply is not specific to the deficiencies pointed out by audit.

7.9 Financial Issues

7.9.1 Submission of bank guarantee, financial and performance guarantee and legal opinion

As per PSC provisions, the contractors were required to submit (a) a bank guarantee (b) performance guarantee of the parent company[63] (c) and a legal opinion that the guarantees were legally valid, enforceable and binding. If these were not submitted in time, the PSC may be cancelled by the Government with written notice of 90 days. Further, the bank guarantees were to be renewed at least 30 days before the expiry

[63] or where there is no performance guarantee, from the company itself

of the guarantee period. However, we found deficiencies/ delays in the submission of these guarantees, as summarised below:

Block	Deficiencies
MB-OSN-97/3	• There was a delay of 5 months in submission of performance guarantee and legal opinion by RIL • Niko Resources did not furnish the performance guarantee and legal opinion. It submitted the Bank Guarantee (with 5 months' validity only upto 15 May 2002) after a delay of 18 months; also, from the available documentation, we could not verify whether the guarantee was renewed till 18 July 2003 i.e. the date of assignment of Niko Resources' participating interest to RIL.
KG-OSN-2001/2	• The contractors - HEPI and RIL - submitted the guarantees after a delay of 82 and 17 days respectively. Further, the bank guarantee submitted by HEPI, which had expired on 31 March 2004, was not got renewed after the expiry date. In reply (December 2008), DGH stated that HEPI submitted a proposal to the Government for assignment of 10 per cent of its Participating Interest (PI) to M/s RIL on 14 June 2004. This proposal was processed at DGH and was under consideration of MoPNG; approval of assignment of PI was communicated by Government on 15 March 2005. Since the PI was proposed to be transferred to RIL, HEPI did not renew the guarantee. The reply is not acceptable, as this was not in compliance with the PSC provisions, and in any case, the renewed bank guarantee could be released after transfer of PI.
NEC-2002/1	• The contractors - RIL and HEPI - submitted the performance guarantee after delays of 5 and 2 months respectively. Further, HEPI submitted the bank guarantee after a delay of 3 months; also, the bank guarantee was renewed, after its expiry, only up to 14 July2006 instead of 22 July 2008.
KG-DWN-98/3	• From the available records, we could not verify whether the requisite guarantees were submitted by Niko Resources.

Block	Deficiencies
MN-DWN-2004/3	• There was a delay in submission of performance guarantee and legal opinion of 2 months by RIL.
CB-ONN-2000/1	• There were delays in submission of performance guarantee and legal opinion of 2 and 4 months by GSPC and JTI respectively.
Panna-Mukta and Mid and South Tapti	• RIL did not submit the bank guarantee and performance guarantee.

In reply (July 2011),

- MoPNG stated (July 2011) that a strong system for monitoring the requisite guarantee was currently in place.
- Without responding to the deficiencies pointed out by audit, MoPNG mentioned that MB-OSN-97/3 and KG-OSN-2001/2 blocks had been relinquished. No justification was also given in respect of NEC-2002/1, MN-DWN-2004/3 and CB-ONN-2000/1.
- As regards KG-DWN-DWN-98/3, MoPNG sent only a copy of Financial and Performance Guarantee, copy of legal opinion and bank guarantee were not furnished.
- As regards Panna-Mukta and Mid and South Tapti, MoPNG stated that since RIL did not have a parent company, they were not required to submit the financial and performance guarantee. The reply is not tenable, as Article 29.1 of the PSC clearly stipulated that each of the companies was required to submit a financial and performance guarantee

7.9.2 Non-submission of Insurance coverage

The PSC provisions stipulated that the contractors are required to obtain and maintain insurance coverage for and in relation to petroleum operations[64] during the term of PSC and should furnish to GoI certificates evidencing that such coverage was in effect. Further, such insurance policies should include GoI as additional insured and should waive subrogation against the GoI.

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[64] For such amounts and against such risks as are customarily or prudently insured in the international petroleum industry in accordance with Good International Petroleum Industry Practices

Due to non-production of records relating to insurance coverage, we could not verify whether requisite insurance coverage in respect of 7 PSCs (CB-ONN-2000/1, CB-OS/2, Hazira, KG-OSN-2001/2, KK-DWN-2003/1, MB-OSN-97/3 and MN-DWN-2004/3) was obtained and maintained by the contractors.

In reply, MoPNG stated (July 2011) that Article 24 of NELP PSC extensively deals with the insurance required to be obtained by contractors and all insurance policies include GoI as additional insured and waive subrogation against GoI. While informing that audit exceptions on insurance flagged by GoI appointed auditors were pursued and resolved, MoPNG further requested audit to advise them for any other issues to be covered in the Insurance clause. MoPNG's reply is not specific to the points raised by audit regarding non- production of records relating to insurance coverage.

Further, in the case of Panna-Mukta and Mid & South Tapti PSCs, each contractor was securing separate insurance to cover its participating interest for offshore installation with different types of risks to a different extent, resulting in non-uniformity in coverage and premium. In response (September 2010), MoPNG stated that insurance cover was essentially a business decision of the contractor, who had invested his capital upfront and aimed at protecting his investment, and was also based on the contractor's risk perception and degree of risk aversion. If the insurance policy submitted fulfilled the requirement of PSC, the policy would be acceptable to the Government. The reply is not acceptable, as MoPNG in February 2007 had instructed DGH to formulate a standardised policy for insurance coverage for consideration by Government. However, DGH had not formulated any such policy.

7.10 Royalty

- In respect of CB-OS/2 block, we found that due to delay in notification of norms for natural gas, the contractor deflated royalty payments by charging high post wellhead costs during the year 2006-07. Comparative analysis of royalty remittance statements revealed that during 2006-07, the post well head expenses ranged from 22 to 41 per cent and during 2007-08, the same ranged between just 8 and 18 per cent.
- Comparative analysis of monthly production statement and royalty remittance statement in respect of CB-OS-2 block for the month of March 2008 revealed that against the payable royalty of Rs. 7.63 crore, the licensee had paid Rs. 6.86 crore to the Government due to wrong adoption of production figure of oil for the month of March 2008. This resulted in short payment of Rs. 0.77 crore.

In response (July 2011):

- As regards the issue of deflated royalty payments, MoPNG accepted (July 2011) audit's view, indicating that DGH, through close monitoring of statutory levies, had raised these issues, which had been reported by audit.
- Regarding short payment of Rs. 0.77 crore, MoPNG intimated that ONGC, the licensee, was yet to comply with the demand for Rs.47 million and US$ 3.8 million as short payment of royalty, and had also been advised to provide details required to calculate the short paid royalty for the years 2004-05 and 2005-06.
- MoPNG's reply does not address the specific issue of short payment of royalty due to wrong adoption of production figures of oil for the month of March 2008.

7.11 Measurement of Petroleum

PSC provisions prescribe detailed procedures to ensure accurate measurement of quantity and determination of quality of petroleum, so as to facilitate accurate Government revenue from petroleum operations, viz.

- Before commencement of production, the GoI and the contractor should mutually agree on (a) methods to be employed for measurement of volume of petroleum production, (b) point(s) at which petroleum should be measured, (c) frequency of inspections and testing of measurement appliances and relevant procedures thereto, (d) consequences of determination of error(s) in measurement.
- The contractor should give MC/ GoI timely notice of its intention to conduct measuring operations or any agreed alteration for such operations, and GoI has the right to be present and supervise, directly or through authorised operations, such operations.

However, due to non-production of complete records in this regard, we could not verify whether MoPNG/ DGH ensured strict compliance with the PSC provisions in respect of Hazira field and CB-OS-2 block.

7.12 Accounting and Auditing

7.12.1 Delayed/ non-submission of chart of accounts

As per PSC, within 90 days of the effective date, the contractor should submit and discuss proposed outline of charts of accounts and GoI should respond within 90 days. Further, Contractor and GoI should agree on chart of accounts within 180 days from the effective date. Audit, however, observed the following deficiencies in this regard:

- There was a delay in submission of Chart of Accounts in respect of CB-OS/2 (6 years), RJ-ONN-2002/1 (4 years), MB-OSN-97/3 (4½ months) and KG-DWN-98/3 (4½ months).

- Due to incomplete record provided by DGH, the fact regarding Government's response and the agreement between Contractor and Government could not be verified in respect of KG-DWN-98/3, MB-OSN-97/3 and MN-DWN-2004/3 blocks.
- Adherence of timelines in respect of any of the above three stipulations could not be verified in respect of CB-ON/1, MB-OSN-2004/2, KK-DWN-2000/2, KK-DWN-2003/1, NEC-DWN-2002/1, CB-ONN-2000/1 blocks and Hazira field, as relevant records were not made available to Audit.

In reply, MoPNG stated (July 2011) that accounts were being regularly submitted by the contractors of these initial NELP blocks in the format that is adequate to monitor the accounts. However, compliance with PSC provisions on this requirement had been streamlined in later NELP rounds.

7.12.2 Delay in submission/adoption/approval of audited accounts

As per PSC provisions, annual audited accounts were to be submitted to the MC within 60 days of the end of the year. Further, the MC was to approve the auditor's report within 30 days of submission. Audit scrutiny, however, revealed the following:

- There were delays ranging between 20 to 49 days in submission and between 1 to 9 ½ months in approval of the audited accounts in respect of 4 blocks (KG-OSN-2001/2, KK-DWN-2003/1, NEC-DWN-2002/1 and MN-DWN-2004/3). Although, no time line was provided in the PSC of KG-DWN-98/3 block regarding adoption/approval of the audited accounts by the MC after their submission, Audit noted significant delays (ranging between 8 and 20 ½ months) in approval of the accounts for the years 2000-01 to 2006-07. Details in this regard are given in **Annexure-7.2 and Annexure-7.3.**
- The process of approval and adoption of annual audited accounts had not been completed in respect of RJ-ON-90/1 (2006 and 2007) and CB-ONN-2000/1 (for 2001-02 to 2006-07). Further, the accounts of KG-OSN-2001/2 for 2007-08 were pending for adoption (November 2008) after 5 months of their submission (June 2008).
- In case of Panna-Mukta and Mid & South Tapti contract areas, the accounts had not been adopted by the MC since inception i.e. 1994-95 due to non resolution of pending Audit Exceptions.
- Timely approval and adoption of audited accounts could not be verified in respect of NEC-DWN-2002/1 (for 2005-06 and 2007-08) and KK-DWN-2000/2 (for 2002-03 and 2003-04), as supporting documents/MC Resolutions relating to adoption and approval of audited accounts for those years were not found on record.

In reply (July 2011), MoPNG stated that:

- Accounts of exploratory blocks were being adopted regularly in general. However, in some cases, due to disagreement on expenditure, work programme or related issues, the adoption got delayed. Nevertheless, the impact was immaterial, due to the fact that no cost petroleum was involved during exploration phase. We do not agree, as non-adherence to the prescribed timelines is against the spirit of PSCs.
- As regards Panna-Mukta and Tapti, there had been a wide variation in the figures indicated by the contractor and Government, and the Contractor invoked arbitration.

7.12.3 Non-compliance with GoI notified audit exceptions

As per PSCs, GoI should notify audit exceptions based on audits conducted by its representatives or CA/ consulting firms within 120 days following completion of the audit, and the contractor should answer the notice of exception within 120 days. Where the contractor failed to answer within the stipulated time, exceptions should prevail. We, however, observed that:

- In respect of CB-OS/2, DGH had not ensured compliance of audit exceptions for the years 1998-99 to 2003-04 relating to issues of policy for charging inventory to cost, parent company overheads, sale of gas etc.
- Accounts of the Panna-Mukta and Tapti JV since inception had not been approved by the Government, pending settlement of audit objections raised by the Auditors appointed by the Government.

In response, MoPNG stated (July 2011) that:

- As regards CB-OS-2, while agreeing with audit's view, the issue was being addressed in line with PSC provisions for possible reversal. CAG's advice on the issue would strengthen GoI claim.
- In respect of Panna-Mukta and Tapti, an amount of US$ 80 million was recovered under Panna Mukta PSC in respect of short paid profit petroleum for the period 2002-06. MoPNG also proposed to recover US$ 78 million for the year 2006-07 from Panna Mukta PSC after confirmation from CAG Audit. An amount of US$ 0.70 million was also proposed to be recovered from Mid and South Tapti PSC, subject to arbitration.

7.13 Work Programme and Budget (WP&B)

The PSC provisions stipulate that the annual Work Programme and Budget (WP&B) for Exploration/ Development and Production Operations were to be submitted by the Contractor to the Management at least 90 days before the start of the financial year – for review in the case of exploration operations, and for approval in the case of development and production operations. We, however, found that:

- The delays in submission of WP&B ranging from 1 to 10 months in 12 PSCs (KG-DWN-98/3, KG-OSN-2001/2, MB-OSN-97/3, NEC-DWN-2002/1, CB-ONN-2000/1, CB-ON/1, Hazira, CB-OS-2, KK-DWN-2000/2, RJ-ON-90/1, Panna-Mukta and RJ-ONN-2002/1).
- In respect of 3 blocks (KG-OSN-2001/2, KG-DWN-98/3 and CB-ONN-2000/1), Exploration & Development WP&B were reviewed/ approved after the end of the concerned financial year. In fact, in the case of CB-ONN-2000/1, the exploration budget for 2005-06 was reviewed only in March 2006 and the budget for 2006-07 was not reviewed even as of July 2008.

Block-wise and year-wise details in this regard are given in **Annexure-7.4 and Annexure 7.5** respectively.

In response to audit enquiries regarding delays in respect of the RJ-ON-90/1 block, DGH responded (October 2010) that the process of review and approval got delayed on some occasions, because of delayed submission of Operating Committee (OC)[65] approved WP&B and clarifications thereafter. Further, operations may not be stopped for want of MC's final approval; hence, in anticipation of approval, the operator continued with the work programme based on the OC recommendations.

Further, MoPNG stated (July 2011) that:

- PSC did not envisage day-to-day monitoring or oversight on the part of government representatives.
- There were instances where the operator found difficulty in placing budgets before MC as per time schedule due to factors like dispute in the operating committee stage. In RJ-ON-90/1, there had been continuous lack of agreement between ONGC, the licensee and companies, which arise out of the dispute on royalty liability. There were no quick-fix solutions for these issues.
- The operator was not permitted to drill a well before the well location was approved by DGH. The onus of obtaining MC approval lay with the operator, and work programme and associated cost not agreed were not allowed as contract cost for the purpose of profit computation. Therefore, there was adequate control over E&P operation in a license/lease area.

In our opinion, timely submission and approval of the Annual Work Programme & Budget is essential. DGH's approval for well location, before drilling, is not a substitute for regular budgetary control.

[65] Consisting of representatives of the contractors only (and not the Government)

Chapter 8 - Conclusions and General Recommendations

Private sector participation in hydrocarbon exploration and production in India is now robustly established, with major crude oil and natural gas discoveries in different basins putting India firmly on the global E&P map. The Production Sharing Contract (PSC) – the basis of the contract between the GoI and the (private) contractors – has undergone several mutations from those in respect of discovered fields to "pre-NELP" exploration blocks to the blocks under different rounds of the New Exploration Licensing Policy (NELP). However, our audit indicated that there is considerable scope for improvement in the management of hydrocarbon E&P with private sector participation in the light of experience gained by governmental agencies over the years.

8.1 Structure of PSC

The PSC, as it currently stands, is based on a scaled formula for profit sharing between the GoI and the private contractors. This is based on a critical parameter – Investment Multiple (IM) – which is essentially an index of the capital-intensive nature of the E&P project i.e. the amount of "capex" on exploration and development activities relative to income. The slabs for profit sharing are so designed that more the capital intensive the project (i.e. lower IM), the lower the GoI share of "profit petroleum" (which could be as low as 5 to 10 per cent). Contrarily, the higher the IM (i.e less capital intensive vis-a-vis income), the higher the GoI share of "profit petroleum" (which could be as high as 85 per cent).

In practice, however, the private contractors seem to have inadequate incentives to reduce capital expenditure and substantial incentive to increase capital expenditure or "front-end" capital expenditure, so as to retain the IM in the lower slabs or to delay movement to the higher slabs.

The structure of the IM-based profit sharing formula (especially when there is a huge jump in GoI's profit share from 28 per cent to 85 per cent on an IM slab of 2.5 or more) is such that in certain scenarios, an increase in capital expenditure, upto a point, could conceivably result in an increase in the contractor's share of profit petroleum, despite a reduction in the total profit petroleum as well as GoI's share of profit petroleum. Further, "front-ending" of capital expenditure (i.e. skewed towards the initial phases) decreases the IM, and postpones the movement to higher IM slabs; this results in a reduction in GoI share on a discounted cash flow basis, since the slabs involving higher GoI share come later, rather than earlier.

Operational control of E&P operations is largely with the private operators, and the GoI's oversight role is restricted essentially to its representation (through MoPNG and/ or DGH) in the Management Committee for the block, especially in approval of Annual Work Programmes and Budgets and Field Development Plans, as well as a few approval functions delineated in the PSC.

Ashok Chawla Committee Report

We are given to understand that the report of the Ashok Chawla Committee on allocation of natural resources also draws similar conclusions regarding the IM-based profit-sharing formula. This committee had, inter alia, representatives from MoPNG and the Ministry of Finance, so it can safely be presumed that its conclusions were well considered. However, the report is not currently available in the public domain.

According to media reports, the Committee has stated that the system ***"gives incentive (to an operator) to increase his investment, or front-end his work plan in order to see that the threshold where Government's profit take rises rapidly is not reached"***.

Citing the example of KG-DWN-98/3, the Committee has stated that "***the relationship between the pre-tax IM and the share of contractor profit petroleum changes dramatically once the pre-tax IM crosses 2.5, with the government's share increasing from 28 per cent to 85 per cent. It is useful to remember that this schedule is bid by the operator, and not determined by the Government."***

Further, according to the Committee, ***"a high share of some pre-tax IM will help to win the bid, depending on the financial mode of evaluation used, but it does raise concerns that such a radical change would provide very strong incentives for any operator to adopt all investment and strategies possible to ensure that the pre-tax IM stays within the 2.5 limit".***

The report clearly points out the risks associated with the IM-based formula for sharing of profit petroleum, especially with a steep jump in profit sharing from one slab to another. In our view, even the linearity introduced in the sliding scale for IM slabs from NELP-VII onwards does not fully address these risks.

The oversight/ control of GoI representatives on high value procurement decisions is also very limited in scope (largely restricted to prior intimation of the list of pre-qualified bidders). In fact, a comparison of the procurement procedure under PSCs in Bangladesh and India reveals that the clauses are similar, except that the Bangladesh PSCs require approval by the Management Committee for high value procurements (typically greater than US$ 500,000). This clause is, however, missing from the Indian PSCs in almost all its versions.

Our audit review also revealed that, by and large, the DGH and the Ministry through the Management Committee were ill equipped to pay adequate attentiion to protecting - at every stage of E&P, be it exploration, development or production - GoI's financial interests. Adequate attention was not paid as to how every proposal/ decision would potentially affect GoI's share of profit petroleum. In addition to their other inadequacies, the constraints of adequately skilled resources with MoPNG/ DGH for monitoring several hundred PSCs simultaneously cannot also be ignored. By contrast, it is inconceivable that the private contractor would fail to protect his financial interests, and assess every investment/ operational proposal to see whether it would result in incremental revenues for it both in terms of cost recovery and contractor's share of profit petroleum.

Given the similar conclusions that two independent agencies viz. the Chawla Committee and Audit have reached as regards the adverse impact of the profit sharing mechanism in protecting GoI's share (linked to the IM), designed in the late 1990s, there does seem to be enough ground to revisit the formula. The PSC as drawn up then, was with the limited expertise available with the GoI at that point of time. In view of the fact that, we have now gained the knowledge , there is need to conclusively address this issue in respect of future PSCs.

MoPNG stated (July 2011) that they were prepared to look at alternative formulas with an open mind and would consider the suggestion of the CAG and the Ashok Chawla Committee with an open mind and take a final view on merits.

8.2 Recommendations for Future PSCs

The stated strength of the profit sharing mechanism is the sharing of risks between the contractor and the Government – if the profits are low or non-existent, both parties suffer equally.

For future PSCs, we recommend that the IM-linkage with the profit sharing formula (even with the linear sliding scale introduced from NELP-VII onwards) be removed by the GoI. Instead, the biddable profit-sharing percentage should be a single percentage. This will reduce the incentive for skewed volume and timing of capital expenditure resulting in very low GoI share of PP. Further, in order to ensure a modicum of control, very high value procurement decisions above a specified limit should be subject to approval by the MC, more specifically the approval of the GoI representatives. Such a mechanism already exists in PSCs operating in Bangladesh.

8.3 Bid Evaluation Criteria

The bid evaluation criteria currently give weightage to technical/ financial ability and two biddable parameters - committed exploratory work and fiscal package (royalty + GoI share of profit petroleum). As regards fiscal package, the current evaluation model generally involves multiple scenarios of oil reserves and oil prices (typically high, medium and low) as well as a projected profile.

The assumptions based on which calculations of fiscal packages of different bidders are made are completely hypothetical. In the absence of high quality seismic data, let alone drilling and discovery findings, estimates of oil/ gas reserves and production profiles, as also projected capital and operating expenses and even crude oil and natural gas prices, is completely speculative. Admittedly, the evaluation model is applied consistently across all bidders. However, when the current system allows multiple bidding points (viz. different GoI shares of PP for different IM slabs), these hypothetical assumptions can not only make a significant difference as to who comes out as the winning bidder, but can also convey extremely unrealistic assumptions about what GoI's share of PP will be (e.g. when will GoI's share of PP reach the highest IM slab?).

Consequently, we recommend that the bidders should be allowed to only make a single point bid, which can be compared straightaway without resorting to hypothetical assumptions.

As regards the biddable exploratory work programme, we are generally in agreement with the bid evaluation process, except for the system of awarding points for well depth. As pointed out in Chapter 4 (relating to KG-DWN-98/3), it is unrealistic and impractical, without having accurate and reliable seismic data, to bid upfront how deep the well should be drilled, and then expect that, notwithstanding geological objectives, the well will be drilled to the committed depth even if it means a waste of money.

Consequently, in future, while considering the bid evaluation criteria, we recommend that either no weightage be allocated for well depth, or alternatively, well depth commitments be categorised into two groups – wells above and below a specified depth, e.g., 1500 or 2000 metres and points be awarded accordingly.

8.4 Management of existing PSCs

The vast majority of blocks with high prospects for hydrocarbon discovery have already been awarded through various pre-NELP/ NELP rounds, and GoI has no option but to work within the constraints of the existing PSC structure and clauses to the fullest extent possible.

8.4.1 Development Plans and Annual Work Programmes and Budgets

It is inconceivable that a private operator/ contractor will make investments in absolute as well as incremental terms, in petroleum operations under the PSC without assessing whether such investments would result in increased revenues for him in terms of cost recovery and contractor's share of profit petroleum. It is necessary for MoPNG and DGH to function in a similar manner, with regard to GoI's financial interests. Consequently we recommend the following:

- Review and approval of development plans should be considered not just from a "technical perspective" viz. how best can oil and gas be extracted from the reservoirs, but also from a financial perspective – not only overall (i.e. what is the project NPV, Rate of Return etc.), but specifically from GoI's point of view viz. what are the projections of royalty and GoI share of profit petroleum? What are the risks to these revenues? How will increases/ decreases in capital expenditure, reserves, reservoir productivity, prices etc. affect GoI's financial take?

- While reviewing and approving development plans, GoI representatives on the MC as well as DGH and MoPNG should ensure that detailed and appropriately validated estimates of GoI take and contractor take are included as an integral part of these plans at the approval stage. A suitable range for GoI take, say ± 15, 20 or 25 *per cent*, as considered appropriate by MoPNG, could be stipulated.

- Approval by MoPNG of such development plans should be on the clear stipulation that any changes in capital and operating expenditure, expenditure commitments, production quantities and other factors, which have the impact of reducing the Investment Multiple and GoI share of profit petroleum **beyond *the stipulated range*** must be submitted for prior approval by GoI representatives on the MC, with detailed justification.

- Annual Work Programmes and Budgets should be strictly in line with the approved development plans. Any deviations or changes vis-à-vis the development plan which have the impact of reducing the IM and GoI share of profit petroleum ***beyond the stipulated range*** must be submitted for prior approval of the MC. Similarly, any significant variations from the approved Work Programme and Budgets with similar impact ***beyond the stipulated range*** must also be subject to prior approval.

- Incurring of any costs which vary from the Development Plans and Annual Work Programmes & Budgets on an overall basis, as well as in terms of significant line items with significant adverse impact on IM and GoI share of profit petroleum **– *beyond the stipulated range*** - without prior approval of GoI representatives on MC should automatically be ineligible for cost recovery.

While some of these recommendations could be misconstrued as hampering operational flexibility in petroleum operations by the contractor, the importance of the overall objective of protecting GoI's revenue interests cannot be ignored under any circumstances.

8.4.2 Procurement Activities

The provisions relating to procurement procedures in the PSCs do not provide for adequate oversight / control by GoI representatives on procurement processes. However, given the existing provisions, we recommend the following measures for protecting GoI's financial interest.

- The objective of effective procurement is to ensure optimum, not necessarily lowest, prices through effective competition. As long as adequate number of 'responsive' financial bids, typically three or more, from reputed vendors, who are pre-qualified after following due process, are received and duly considered (*i.e.,* not withdrawn, disqualified on technical or other grounds, deviations/ non-responsiveness or otherwise not considered), generate adequate competitive tension, the probability of effective procurement at optimum costs remains high.

- However, when high value contracts are awarded on the basis of single 'responsive' financial bids, in our opinion, these are awarded without competition, effectively on nomination basis. In all such cases, prior approval of the MC should be necessary for such awards. Post facto approval, with appropriate justification, for emergent procurement decisions may also be considered. Similar provisions would also apply to all procurement decisions involving post-priced bid opening changes to scope, quantities, work, prices, conditions etc.

- Also, the practice of repeated extensions, subsequent substantial variations in scope etc. of existing contracts is also not in line with the existing PSC procurement provisions, which incidentally makes no mention of extensions. Extensions or scope variations for high value contracts, beyond the contractually stipulated extensions, should also be subject to prior MC approval, with provisions for post facto approval in emergent cases.

8.4.3 Relinquishment of area, and delineation of discovery and development areas

As pointed out in earlier chapters, the entire PSC process is designed to ensure that the private contractors fully explore the contract area within designated timelines, relinquish areas where hydrocarbon prospects appear poor in a phased manner, and retain only those areas where hydrocarbon discoveries are made, relinquishing the remaining area for re-allocation – through a competitive bidding process - to other potential bidders, whose hopes/ views in terms of hydrocarbon prospectivity differ (either on account of technical and other capabilities or in terms of their risk appetite) from the contract holders who have relinquished such area. We, therefore, recommend the following:

The stipulated timelines and processes in the PSC for relinquishment of contract area should, under no circumstances, be relaxed, and compliance with these provisions should be invariably ensured.

Further, the discovery and development areas should be rigorously delineated, keeping strictly to the discoveries made through exploratory and appraisal well drilling and proper delineation of reservoir boundaries. Attempts by contractors for delineation of excessively wide discovery/ development areas through elastic (and incorrect) interpretation of hydrocarbon discovery should be strongly rebutted.

8.4.4 Compliance with other PSC provisions

The PSC is a contractual document, and compliance with every contractual clause is of utmost importance. It would be inappropriate to distinguish between "major" and "minor" clauses, and neglect monitoring of compliance with so-called "minor" PSC clauses.

We recommend that DGH, and where necessary, MoPNG should put into place adequate and effective measures to ensure that compliance with all provisions of the PSC are fully monitored on a timely basis and appropriately documented, and action taken against operators on a timely and consistent basis, for non-compliance with PSC provisions. For such purposes, strengthening of the resource basis of DGH in terms of adequate quantity of skilled resources may be necessary.

DGH should also consider developing a comprehensive PSC monitoring system, which will not only provide details of compliance with PSC provisions for any block/ contract at a glance, but will also enable operators to "file" returns/ documents/ information electronically through the web and/or e-mail. The cost of developing (and maintaining) such an IT system will be miniscule, compared to the total GoI PP revenues as well as the potential (although not exactly quantifiable) gains from more effective and timely monitoring of compliance.

MoPNG has assured that conclusions and recommendations drawn by CAG would be considered for appropriate action.

ABajaj

(Anand Mohan Bajaj)
Principal Director of Audit
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New Delhi
Dated: 18-8-2011

Countersigned

Vinod Rai

(Vinod Rai)
Comptroller and Auditor General of India

New Delhi
Dated: 24-8-2011

ANNEXURES

Details of PSCs covered in Audit Sample

S. No.	Name of block/ field	Operator	Brief description
1	MB-OSN-97/3	RIL	MB-OSN-97/3 was a shallow water block located in Mumbai offshore. It was awarded under NELP-I round. The PSC, which was signed on 12 April 2000 with RIL and Niko with 90 and 10 percent Participating Interest respectively, was made effective from 7 June 2000. From July 2003, RIL held 100 percent PI. The total area of the block was 5740 sq. kms. The operator could not complete the Minimum Work Programme relating to drilling of two wells and relinquished the block at the end of Phase-I after availing two extensions of 12 months each. No discovery was made in the block.
2	NEC-DWN-2002/1	RIL	NEC-DWN-2002/1, an offshore deep water block located in North East Coast, was awarded to the Joint venture of RIL and HEPI under NELP-IV round. The PSC was signed on 6 February 2004 with RIL (with 90 percent PI) and HEPI (with 10 percent PI). The effective date of the PEL is 18 March 2004. HEPI transferred its PI to RIL, which was approved by MoPNG in July 2008. The total original area of the block was 25,565 sq. km. The block is under Exploration Phase-II and 25 percent area i.e. 6391 sq. km. has been relinquished by the operator at the end of Phase-I. No discovery has been made in the block.
3	MN-DWN-2004/3	RIL	MN-DWN2004/3, an offshore deep water block located in Mahanadi basin, was awarded to RIL under NELP-VI round. The PSC for the block was signed on 2 March 2007 with RIL. The effective date of the PEL is 15 May 2007. The total original area of the block is 11,316 sq. km. The block is under Exploration Phase-I. No discovery has been made in the block.
4	KG-OSN-2001/02	RIL	KG-OSN-2001/02 is a shallow water block located in Krishna Godawari basin, which was awarded under NELP-III round to the consortium of RIL and HEPI with 90 and 10 percent PI respectively. The PSC was signed on 4 February 2003. The effective date of the PEL is 3 April 2003. Presently, RIL holds 100 percent PI. The total original area of the block was 210 sq. km. Two discoveries have been made in the block. The operator opted not to enter Phase-II at the end of Phase-I, and had retained the whole area to carry out Appraisal Programme after availing two extensions - 6 and 5 ½ months.
5	KK-DWN-2003/1	RIL	KK-DWN-2003/1, a deep water block located in the Kerala Konkan basin, was awarded to RIL under NELP-V round. The PSC for the

S. No.	Name of block/ field	Operator	Brief description
			block was signed on 23 September 2005. The effective date of the PEL is 23 January 2006. The total original area of the block is 18,245 sq. km. The block is under Exploration Phase. No discovery has been made in the block.
6	CB-ON/1	RIL	The PSC for CB-ON/1, a pre-NELP (7th round) onshore block located at Cambay basin, was signed with M/s Okland International with 100 percent on 16 July 1998. With effect from 31 March 2005, M/s Okland assigned 50 percent PI to Tullow India Op. Ltd. (TIOL), 40 percent PI to RIL and remaining 10 percent PI to Okland Offshore Holding Ltd. (OOHL). ONGC is the licensee and has 30 percent pre-emptive right in case of commercial discovery. Presently, RIL is the operator. PEL for the block is effective from 5 September 2003. The block is under Exploration Phase-III and there is no discovery. In the third phase, the operator has retained 1533 sq. km. i.e. 25 percent of the total 6133 sq. km. original area.
7	KK-DWN-2000/2	ONGC	KK-DWN-2000/2, an offshore deep water block located in the Kerala Konkan basin was awarded under NELP-II round to a consortium of ONGC and GAIL with 85 and 15 percent PI respectively. Total area of the block measured 20,998 sq. km. The PSC was signed on 17 July 2001 and made effective from the date of issue of PEL i.e. 16 August 2001. After completing the committed MWP, ONGC relinquished the whole block at the end of Phase-I.
8	RJ-ONN-2002/1	OIL	RJ-ONN-2002/1 is an onshore block located in Rajasthan, which was awarded under NELP-IV round to a consortium of OIL and ONGC with 60 and 40 percent PI respectively. The PSC was signed on 6 February 2004. The effective date of the contract is 22 June 2004. The block was under Exploration Phase-II. An extension of 6 months was granted to the contractor at the end of Phase-I. After relinquishing 2475 sq. km. i.e. 25 percent of the original 9900 sq. km. area, the consortium had retained 7425 sq. km. area in the 2nd phase.
9	MB-OSN-2004/2	Petrogas	MB-OSN-2004/2 is a shallow water block located in Mumbai offshore, which was awarded under NELP-VI round to a consortium of Petrogas, GAIL, IOC, GSPC and HPCL each having 20 percent PI. The PSC was signed on 2 March 2007. The effective date of the contract is 21 May 2007. Total area of the block is 741 sq. km. The block is under Exploration Phase-I, and no discovery has been made.
10	CB-OS-2 Lakshmi	CEIL	CB-OS-2, a pre-NELP exploration offshore block, is located in the Gulf of Khambat on the West coast of India. The PSC for the block

S. No.	Name of block/ field	Operator	Brief description
11	CB-OS-2 Gauri	CEIL	was signed with the Joint Venture of ONGC (Licensee), Tata Petrodyne Limited (TPL) and Cairn Energy India Pty Ltd (CEIL-Operator) in June 1998 with initial PI of 10, 45 and 45 percent respectively. The total contract area of the block was 3534 sq. kms. There are two major discoveries i.e. Lakshmi Gas and Gauri Gas. Oil was also discovered subsequently in both the fields. Lakshmi and Gauri fields are producing gas since November 2003 and April 2004 respectively. Gauri field is producing oil from October 2006, and Lakshmi from July 2007.
12	CB-ONN-2000/1	GSPC	CB-ONN-2000/1, an onland block located at Cambay basin was awarded under NELP-II round to a consortium of GSPC, GAIL and JTI with 40, 40 and 20 percent PI respectively. The PSC was signed in July 2001 and the effective date was 7 January 2002. Presently, GSPC and GAIL hold 50 percent PI each. Two discoveries have been made in the block. Out of the original total contract area of 1424 sq. km., the operator has retained 14.1 sq. km. as development area.
13	Hazira	Niko Resources	Hazira is a small size producing field located in Cambay basin. The field was already discovered in 1969. The PSC for the field was signed on 23 September 1994 with Niko Resources (having 33.33 percent PI) and GSPCL (with 66.67 percent PI). Out of the total 50 sq. km area of the field, 22.7102 sq. km falls offshore and 27.0214 sq km falls onshore. Mining lease for the field was granted in October 2005.
14	PG-ONN-2001/1	ONGC	PG-ONN-2001/1 exploratory block under NELP-III round awarded to ONGC with 100% PI. It is an onland block located in KG-PG basin. The PSC was signed on 4.2.2003 and PEL was granted on 4.7.2003. The block is in exploration phase (June 2008).
15	CY-OSN-2000/1	ONGC	CY-OSN-2000/1 exploratory block under NELP-II round was awarded to ONGC with 100% PI. It is an offshore block located in Cauvery basin. The PSC was signed on 17.7.2001 and PEL was issued on 16.8.2001. The block was relinquished in Phase-II on 15.2.2007 without completing the committed one well. The cost for unfinished work progamme of one well was paid to the Government.
16	MB-DWN-2000/1	ONGC	MB-DWN-2000/1 exploratory deep water block in Mumbai Offshore Basin under NELP-II round was awarded to consortium of ONGC (85%) and IOC (15%). The PSC was signed on 17.7.2001. The block was relinquished in Phase-I without drilling the committed three wells. The cost for unfinished work progamme of one well was paid to the Government.

S. No.	Name of block/ field	Operator	Brief description
17	Ratna series	Premier Oil, UK	Ratna-R Series fields located in Western Offshore under second round of development bidding awarded (1993) to a consortium of M/s Essar Oil Limited and M/s Premier Oil Pacific Limited, UK (designed Operator) with a participating interest of 50% and 10% respectively in March 1996. ONGC is having participating interest of 40% in the Joint Venture. The Production Sharing Contract is yet to be signed between GOI and Joint Venture. The field still remains with ONGC and is at present lying in abandoned condition.

Summary of blocks selected for supplementary scrutiny of operators' records

S. No.	Name of block/ field	Operator	Brief description
1	KG-DWN-98/3	RIL	The KG-DWN-98/3 Block (also referred to as KG-D6) was awarded in NELP-I in 2000 to the RIL-Niko consortium.
2	Panna-Mukta	BGEPIL (primary operator)	The fields Panna-Mukta and Tapti were discovered and operated by Oil and Natural Gas commission under nomination basis till 1994. In January 1994, the Government of India awarded the fields to a consortium of Enron Oil and Gas India Ltd (30 per cent), Reliance India Limited. (RIL) (30 per cent) and ONGC as Govt. nominee (40 per cent). The PSC was signed on 22 December 1994. In 2002, the PI of Enron was taken over by British Gas Exploration and Production India Limited (BGEPIL).
3	Mid and South Tapti		
4	RJ-ON-90/1	CEIL	The PSC for this Rajasthan block was signed between GOI, Shell India Production Development B.V. (SIPD) and ONGC in May 1995. Subsequently, SIPD assigned its 100 percent PI to Cairn Energy India Limited (CEIL) between September 1998 to June 2003.

Status of Discoveries (KG-DWN-98/3)

S. No	Name of discovery	Date of furnishing of particulars of the discovery, in writing, by the Contractor to the MC and to Government	Date of notification as Discovery of potential commercial interest and submission of report by the contractor to the MC, containing test data and its analysis	Date of submission of appraisal programme	Review of appraisal programme by MC	Date of submission of Commerciality proposal	Review of DoC proposal by MC	Declaration of commerciality by Contractor	Submission of FDP	Approval of FDP	Remarks
				As per PSC	As per PSC	As per PSC	As per PSC		As per PSC	As per PSC	
				Actual	Actual	Actual	Actual		Actual	Actual	
1	D-1	-	29.10.02	28.10.03	-	28.10.05	May 2003	02.04.03	01.04.04	22.12.04	Operator had submitted a combined FDP with D-3 discovery.
				Not submitted		Nov. 2002 Exact date not available, as the	24.03.03		26.5.04	05.11.04	

S. No	Name of discovery	Date of furnishing of particulars of the discovery, in writing, by the Contractor to the MC and to Government	Date of notification as Discovery of potential commercial interest and submission of report by the contractor to the MC, containing test data and its analysis	Date of submission of appraisal programme	Review of appraisal programme by MC	Date of submission of Commerciality proposal	Review of DoC proposal by MC	Declaration of commerciality by Contractor	Submission of FDP	Approval of FDP	Remarks
				As per PSC	As per PSC	As per PSC	As per PSC		As per PSC	As per PSC	
				Actual	Actual	Actual	Actual		Actual	Actual	
						process file was not furnished by DGH to audit					
2	D-2	-	29.10.02	28.10.03	-	28.10.05	17.11.03	17.03.04	16.03.05	09.02.09	• There was a delay of 1 ½ month in review of the DoC proposal. • There was a delay of more than than three years in submission of the FDP of this discovery. • FDP awaits approval since February 2009.
				Not submitted		21.05.03	07.01.04		14.07.08	Awaited	
3	D-3	-	29.10.02	28.10.03	-	28.10.05	17.11.03	17.03.04	16.03.05	22.12.04	There was a delay of 1 ½

S. No	Name of discovery	Date of furnishing of particulars of the discovery, in writing, by the Contractor to the MC and to Government	Date of notification as Discovery of potential commercial interest and submission of report by the contractor to the MC, containing test data and its analysis	Date of submission of appraisal programme	Review of appraisal programme by MC	Date of submission of Commerciality proposal	Review of DoC proposal by MC	Declaration of commerciality by Contractor	Submission of FDP	Approval of FDP	Remarks
				As per PSC	As per PSC	As per PSC	As per PSC		As per PSC	As per PSC	
				Actual	Actual	Actual	Actual		Actual	Actual	
				Not submitted		21.05.03	07.01.04		26.05.04	05.11.04	month in review of the DoC proposal.
4	D-4	-	24.01.03	23.01.04	-	23.01.06	22.06.06	21.01.08	20.01.09	09.02.09	• The MC reviewed DoC proposal in respect of eight satellite gas discoveries viz. Dhirubhai-4, 6, 7, 8, 16, 19, 22 and 23 after two years of submission of the DoC proposal. Initially, operator submitted (July 2008) a combined FDP for nine discoveries as satellite discoveries viz. D-2, D-4, D-6, D-7, D-8, D-16, D-19,
				Not submitted		24.12.05	04.01.08		14.07.08	Awaited	

S. No	Name of discovery	Date of furnishing of particulars of the discovery, in writing, by the Contractor to the MC and to Government	Date of notification as Discovery of potential commercial interest and submission of report by the contractor to the MC, containing test data and its analysis	Date of submission of appraisal programme	Review of appraisal programme by MC	Date of submission of Commerciality proposal	Review of DoC proposal by MC	Declaration of commerciality by Contractor	Submission of FDP	Approval of FDP	Remarks
				As per PSC	As per PSC	As per PSC	As per PSC		As per PSC	As per PSC	
				Actual	Actual	Actual	Actual		Actual	Actual	
											D-22 and D-23. As the proposal was found to be non-viable from the techno-economic point of view, DGH informed (March 2009) the operator to convene a meeting and address the issue. Subsequently, after holding of meetings and correspondence, RIL submitted (December 2009) an optimized FDP in respect of four discoveries viz. D-2, D-6, D-19 and D-22, which awaited approval.

S. No	Name of discovery	Date of furnishing of particulars of the discovery, in writing, by the Contractor to the MC and to Government	Date of notification as Discovery of potential commercial interest and submission of report by the contractor to the MC, containing test data and its analysis	Date of submission of appraisal programme	Review of appraisal programme by MC	Date of submission of Commerciality proposal	Review of DoC proposal by MC	Declaration of commerciality by Contractor	Submission of FDP	Approval of FDP	Remarks
				As per PSC	As per PSC	As per PSC	As per PSC		As per PSC	As per PSC	
				Actual	Actual	Actual	Actual		Actual	Actual	
5	D-5	-	10.07.03	09.07.04	-	09.07.06	-	-	-	-	Appraisal Programme awaited since 09.07.04
				Not submitted		-					
6	D-6	-	10.07.03	09.07.04	-	09.07.06	22.06.06	21.01.08	20.01.09	09.02.09	Same remarks as at S.No. 4 above.
				Not submitted		24.12.05	04.01.08		14.07.08		
7	D-7	-	08.05.04	07.05.05	-	07.05.07	22.06.06	21.01.08	20.01.09	09.02.09	
				Not submitted		24.12.05	04.01.08		14.07.08		
8	D-8	-	10.05.04	09.05.05	-	09.05.07	22.06.06	21.01.08	20.01.09	09.02.09	
				Not		24.12.05	04.01.08		14.07.08		

S. No	Name of discovery	Date of furnishing of particulars of the discovery, in writing, by the Contractor to the MC and to Government	Date of notification as Discovery of potential commercial interest and submission of report by the contractor to the MC, containing test data and its analysis	Date of submission of appraisal programme	Review of appraisal programme by MC	Date of submission of Commerciality proposal	Review of DoC proposal by MC	Declaration of commerciality by Contractor	Submission of FDP	Approval of FDP	Remarks
				As per PSC	As per PSC	As per PSC	As per PSC		As per PSC	As per PSC	
				Actual	Actual	Actual	Actual		Actual	Actual	
				submitted							
9	D-16	-	14.08.04	13.08.05	-	13.08.07	22.06.06	21.01.08	20.01.09	09.02.09	
				Not submitted		24.12.05	04.01.08		14.07.08		
10	D-18	-	14.04.05	13.04.06	-	13.04.08	-	-	-	-	Appraisal Programme awaited since 13.04.06
				Not submitted		-					
11	D-19	-	14.04.05	13.04.06	-	13.04.08	22.06.06	21.01.08	20.01.09	09.02.09	Same remarks as at Sl. No. 4 above.
				Not submitted		24.12.05	04.01.08		14.07.08		

S. No	Name of discovery	Date of furnishing of particulars of the discovery, in writing, by the Contractor to the MC and to Government	Date of notification as Discovery of potential commercial interest and submission of report by the contractor to the MC, containing test data and its analysis	Date of submission of appraisal programme	Review of appraisal programme by MC	Date of submission of Commerciality proposal	Review of DoC proposal by MC	Declaration of commerciality by Contractor	Submission of FDP	Approval of FDP	Remarks
				As per PSC	As per PSC	As per PSC	As per PSC		As per PSC	As per PSC	
				Actual	Actual	Actual	Actual		Actual	Actual	
12	D-22	-	01.08.05	31.07.06	-	31.07.08	22.06.06	21.01.08	20.01.09	09.02.09	
				Not submitted		24.12.05	04.01.08		14.07.08		
13	D-23	-	24.10.05	23.10.06	-	23.10.08	22.06.06	21.01.08	20.01.09	09.02.09	
				Not submitted		24.12.05	04.01.08		14.07.08		
14	D-26	24.06.06	26.06.06	25.10.06	-	25.12.08	17.02.07	09.02.07	28.08.07	February 2008	FDP was approved after a delay of two months.
				Not submitted		20.10.06	02.02.07		18.08.07	17.04.08	

S. No	Name of discovery	Date of furnishing particulars of the discovery, in writing, by the Contractor to the MC and to Government	Date of notification as Discovery of potential commercial interest and submission of report by the contractor to the MC, containing test data and its analysis	Date of submission of appraisal programme	Review of appraisal programme by MC	Date of submission of Commerciality proposal	Review of DoC proposal by MC	Declaration of commerciality by Contractor	Submission of FDP	Approval of FDP	Remarks
				As per PSC	As per PSC	As per PSC	As per PSC		As per PSC	As per PSC	
				Actual	Actual	Actual	Actual		Actual	Actual	
15	D-29	23.02.07	20.04.07	19.04.08	06.11.07	19.04.10	18.08.10	-	-	-	• Appraisal programme was reviewed after a delay of 5 ½ months • Review of DoC was pending since August 2010
				09.07.07	24.04.08	19.02.10	Not yet reviewed				
16	D-30	23.02.07	20.04.07	19.04.08	06.11.07	19.04.10	18.08.10	-	-	-	
				09.07.07	24.04.08	19.02.10	Not yet reviewed				
17	D-31	09.03.07	08.05.07	07.05.08	06.11.07	07.05.10	18.08.10	-	-	-	
				09.07.07	24.04.08	19.02.10	Not yet reviewed				

S. No	Name of discovery	Date of furnishing of particulars of the discovery, in writing, by the Contractor to the MC and to Government	Date of notification as Discovery of potential commercial interest and submission of report by the contractor to the MC, containing test data and its analysis	Date of submission of appraisal programme	Review of appraisal programme by MC	Date of submission of Commerciality proposal	Review of DoC proposal by MC	Declaration of commerciality by Contractor	Submission of FDP	Approval of FDP	Remarks
				As per PSC	As per PSC	As per PSC	As per PSC		As per PSC	As per PSC	
				Actual	Actual	Actual	Actual		Actual	Actual	
18	D-34	14.05.07	09.07.07	08.07.08	06.11.07	08.07.10	06.01.10	-	-	-	• Appraisal programme was reviewed after a delay of 5 ½ months • Review of DoC was pending since January 2010.
				09.07.07	24.04.08	10.07.09	Not yet reviewed				
19	D-42	07.07.08	11.07.08	10.07.09	11.11.08	10.07.11		-	-	-	• Appraisal programme was reviewed after a delay of 1 ½ months
				14.07.08	30.12.08	-					

Annexure 4.2

Non-compliance to PSC provisions regarding notification of discovery and submission of test reports

S.No.	Name of discovery	Date of written intimation of discovery	Date of notification regarding potential commerciality
1	Dhirubhai 1	-	29.10.2002
2	Dhirubhai 2	-	29.10.2002
3	Dhirubhai 3	-	29.10.2002
4	Dhirubhai 4	-	24.01.2003
5	Dhirubhai 5	-	10.07.2003
6	Dhirubhai 6	-	10.07.2003
7	Dhirubhai 7	-	08.05.2004
8	Dhirubhai 8	-	10.05.2004
9	Dhirubhai 16	-	14.08.2004
10	Dhirubhai 18	-	14.04.2005
11	Dhirubhai 19	-	14.04.2005
12	Dhirubhai 22	-	01.08.2005
13	Dhirubhai 23	-	24.10.2005
14	Dhirubhai 26	24.06.2006	26.06.2006
15	Dhirubhai 29	23.02.2007	20.04.2007
16	Dhirubhai 30	23.02.2007	20.04.2007
17	Dhirubhai 31	09.03.2007	08.05.2007
18	Dhirubhai 34	14.05.2007	09.07.2007
19	Dhirubhai 42	07.07.2008	11.07.2008

Annexure 4.3

Delays in submission /review or approval of Appraisal Programme / Declaration of Commerciality/ Development Plan

Issues	Audit Observations	Reply of MoPNG (July 2011)	Audit Remarks
Appraisal Programme	• There was a delay in review of Appraisal programme and work programme and budget in respect of Dhirubhai- 42 gas discovery (1½ month) and Dhirubhai- 29, 30, 31 and 34 gas discoveries (5½ months). • Timeline prescribed in Article 21.5.3 of PSC was not adhered to in this case.	• MoPNG stated that reviews of the discoveries were delayed as the contractor submitted the required data on piece meal basis. However, since the contractor had to carryout appraisal programme as per PSC timeline, the delayed review may not affect the timeline for submission of DOC. However, MoPNG stated that they had noted the audit observations for future course of action.	• Reply is not satisfactory. The timeline for submission of DOC is linked to the date of notification of a discovery and not to the date of review. The delayed review may affect the timeline for submission of DOC. Therefore, it does affect the objective of doing prompt exploration work.
Commercial Discovery	• The Management Committee reviewed (January 2008) the DoC proposal (December 2005) in respect of eight satellite gas discoveries viz. Dhirubhai-4, 6, 7, 8, 16, 19, 22 and 23 after two years of submission of the DoC proposal. • DoC proposals in respect of Dhirubhai-2 and 3 discoveries were reviewed (January	• While giving reasons for delays in review of DoC in respect of the discoveries, MoPNG stated that evaluation of DoCs took more time due to incomplete / partial / piecemeal submission of data by the contractor.	• The reply is not satisfactory, as non-adherence to the prescribed timelines indicates lack of coordination between DGH and contractor and also in view of the fact that such delays defeat the objective of achieving timely development/ production of petroleum resources of the country.

	2004) after a delay of 1½ month. • Reviews of DoC were awaiting in respect of Dhirubhai- 29, 30 and 31 (since August 2010) and Dhirubhai- 34 (since January 2010). • Timelines prescribed in Article 21.5.5 of PSC was not adhered to in these cases.		
Submission /approval of FDP	• The operator submitted (July 2008) a combined FDP for nine discoveries as satellite discoveries viz. D-2 (submitted three years after the due date of March 2005) D-4, D-6, D-7, D-8, D-16, D-19, D-22 and D-23. Since FDP proposal was found to be non-viable from the techno-economic point of view, DGH informed (March 2009) the operator to convene a meeting and address the issue. Subsequently, after holding of meetings/correspondences between RIL and DGH, RIL submitted	• MoPNG stated (July 2011) that the satellite discoveries were of small pools located in different water depth and scattered across the block. Due to sheer small size of the discoveries and considerable inter discovery distances it required a detailed technical and financial evaluation. After detailed in-house evaluation and series of deliberation, technical meetings with contractor besides engaging reputed consultant, the FDP had been finally evaluated at DGH. Evaluation of FDP took more time due to incomplete/partial/piecemeal submission of data by the contractor.	• The delays are not in consonance with PSC provisions. Further, the delay in submission of FDP in respect of D-2 discovery had not been explained by MoPNG.

	(December 2009) an optimized FDP in respect of four discoveries viz. D-2, D-6, D-19 and D-22, which awaited approval. • FDP of Dhirubhai-26 discovery was approved (April 2008) after 2 months of the due date on account of delay in submission of clarification by contractor and signing of Resolution by MC. • Timelines prescribed in Articles 21.5.6, 21.5.7 and 10.8 of PSC were not followed in these cases.	• As regards approval of FDP of Dhirubhai 26 discovery, MoPNG stated that evaluation of FDP was completed at DGH on 20.12.07 and the same day they communicated to the operator to convene MC Meeting on 28.02.08. After series of clarification / communication for finalisation of draft MC Resolution, MC Resolution was signed on 17.04.08. From this, it could be seen that evaluation of FDP at DGH, MC meeting to deliberate/approve the FDP was convened within PSC timeline but the MC Resolution was signed on 17.04.08.	

Annexure 4.4

Details of activities showing delay in taking action as per time line approved in the IDP for D-1 & D-3 Gas Fields

Major development related aspects to be completed as per approved plan and were as under:-

- Drilling of 14 wells in the initial phase till commencement of production to reach the plateau production of 40 millions cubic meter per day (MMSCMD).
- Installation of all subsea facilities, including well flow-lines, Subsea manifolds, Deepwater Pipelines End Manifold (DWPLEMS), Shallow Water Pipelines End Manifold (SWPLEMS), Gas Evacuation pipelines from DWPLEMS to SWPLEMS, Gas Evacuation pipelines SWPLEMS to onshore Terminal, infield Pipelines from manifold to Deepwater Pipelines End Manifold (DWPLEMS), MEG (Methanol E Glycols) lines.
- Onshore Terminal (OT) and Processing Trains.

Audit observed that major activities carried out by the contractor after approval of Development plan till October 2006 which were not in-line with the time schedule of the approved plan were as follows:

Concept and FEED

- Work for concept and FEED was completed in February 2004. However, instead of starting the work as per FEED and the approved development plan in November 2004, contractor initiated FEED up-dation in January 2006.

Project Consultancy

- RFQs for appointment of Project Management Consultant was issued in December 2005 and work awarded in January 2006.

Drilling of development wells

- Well proposal for drilling two development wells D6-A10 and D6-B7, was submitted to MC on 2nd April 2005, which was approved on 17th May 2005. Drilling of two development wells D6 A-10A and D6-B7 was completed on 25th October 2005 and 11th December 2005 respectively.
- Well proposals for drilling of four wells D6-A9, D6-A16, D6-A13 and D6-B13 was submitted to the MC and approved by the MC on 16th August 2006.
- Casings and Tubulars for Development drilling ordered in April 2006.

- Work for Design of Well Completions was awarded in April 2006 and design freeze for well completions was done in October 2006.

Onshore Terminal and Associated Facilities

- Work for dredging for extraction of fill material at Onshore Terminal (OT) site was awarded on 24th October 2005 and work commenced at the site on 30th March 2006 and major work was completed on 28th August 2006.
- RFQs for detailed engineering for OT were issued on 20th December 2005 and work for construction of On shore facilities and associated work was awarded on 29th May 2006.
- RFQs for MEG Regeneration/Reclamation and Slug Catchers were issued in May 2006 and work awarded in August 2006.
- RFQs Gas Dehyderation and TEG Regeneration issued in June 2006 and work awarded in September 2006
- RFQs for Turbine generators were issued in July 2006.

Offshore Production Facilities

- RFQs for long lead packages 1& 2 and package 3 (line pipes) were issued in January 2006 and work awarded in April 2006 and May 2006 respectively.
- RFQs for offshore installations were issued in March 2006 and work awarded in September 2006.
- Work for Reservoir Monitoring system was awarded in September 2006.
- Xmas Trees ordered in June 2006 with expected deliveries in October 2007-February 2008.
- Subsea control system, Umbilicals ordered in June 2006 with expected delivery in November 2007.
- Subsea structures and Tie-in including manifolds, valves and structures ordered with expected deliveries in end 2007 and early 2008.

D1-D3- IDP vs. AIDP: Development Cost Comparison of major elements

(Total cost and Spend figures in Million US$)

Sl. No	Descriptions	Cost Break-up of Major Cost elements as per IDP submitted by the Operator in May 2004					Cost Break-up of Major Cost elements as per Addendum to IDP submitted by the Operator in Oct'2006					Spend up to Mar'08	Spend Up to Mar'09	Spend Up to Jun'09	Cost Impact w.r.t. Quantity Revisions, Rate Revisions, Time Over Run, Tendering Process Deficiencies, Post Contract Award Revisions
		Unit Cost	No. of Units	UOM	Cost	Total cost	Unit Cost	No. of Units	UOM	Cost	Total cost	2007-08	Up to Mar'09	Up to Jun'09	
1	G&G Studies					24.5					34.67	19.63	24.57	25.53	
2	Reservoir and completion studies					10.9					22.66	9.27	12.98	13.75	
3	Development Wells					944.25					1164.6	423.45	978.89	1022.4	There was reduction in the number of wells from 34 to 22 in the revised FDP, but cost per well was increased from US$ 27.78 million to US$ 52.94 million. Further, 18 wells were actually drilled till Jun'09 with avarage cost per well US$ 56.8 million, i.e. actual cost more than double from FDP cost levels. Audit identified that one of the factors responsible for higher cost was non-finalisation of tenders, after bids invitation, for charter hire of deep drilling rig at lower day rates and also piece-meal hiring. Details of cost increases for other elements called for by Audit were not provided.

Sl. No	Descriptions	Cost Break-up of Major Cost elements as per IDP submitted by the Operator in May 2004					Cost Break-up of Major Cost elements as per Addendum to IDP submitted by the Operator in Oct'2006					Spend up to Mar'08	Spend Up to Mar'09	Spend Up to Jun'09	Cost Impact w.r.t. Quantity Revisions, Rate Revisions, Time Over Run, Tendering Process Deficiencies, Post Contract Award Revisions
		Unit Cost	No. of Units	UOM	Cost	Total cost	Unit Cost	No. of Units	UOM	Cost	Total cost	2007-08	Up to Mar'09	Up to Jun'09	
4	**Production Facilities**					**1348.79**					**3735.5**	**2047.32**	**3664.17**	**3890.03**	**Abnormal upward revision in cost from US$ 1.349 Billion (FDP level) to US$ 3.735 Billion (Revised FDP level) and also actual spend till Jun'09 further increased by US$ 155 million. Basis of estimations for each cost element with supporting documents used at FDP stage and the revised FDP stage were not provided to Audit. However, Audit observed issues relating to tendering, award and execution of contracts for Engineering, Design, EPIC, CRP, Sub-sea Control System, X-Mas Trees, Umbilicals, MEG Plant, Pipelines, On-Shore Terminal, Jetty, etc.**
a.	*Surveys and environmental clearance*					*9.14*					*13.82*	*10.603*	*10.603*	*10.603*	***• Actual spend increase by US$ 1.46 million from FDP levels. Details of cost increase w.r.t. FDP levels called for by Audit were not provided.*** ***• Geo-technical Investigations estimated Cost almost double w.r.t. FDP levels. Actual spend under this sub-head and details of cost increase requested for by Audit were not intimated.***
b.	*Manifolds*		*10*			*46.85*		*6*	*11.8*		*70.81*	*37.93*	*78.25*	*78.25*	***There was reduction in number of manifolds from 10 to 6, but cost per manifold increased from US$ 4.7 million to US$ 11.8 million. Also actual spend further increased to US$ 13.04 million per manifold, i.e. cost almost triple than FDP levels. Details of cost increase were not provided to Audit.***

Sl. No	Descriptions	Cost Break-up of Major Cost elements as per IDP submitted by the Operator in May 2004					Cost Break-up of Major Cost elements as per Addendum to IDP submitted by the Operator in Oct'2006					Spend up to Mar'08	Spend Up to Mar'09	Spend Up to Jun'09	Cost Impact w.r.t. Quantity Revisions, Rate Revisions, Time Over Run, Tendering Process Deficiencies, Post Contract Award Revisions
		Unit Cost	No. of Units	UOM	Cost	Total cost	Unit Cost	No. of Units	UOM	Cost	Total cost	2007-08	Up to Mar'09	Up to Jun'09	
c.	*Pipelines and PLEM's*					*232.5*					*906.9*	*386.19*	*703.47*	*819.65*	***• Revised Estimated Cost almost triple than cost as initially approved FDP.*** ***• 24" pipelines: There was upward revision in the quantity of pipes, tonnage of pipes, time required for pipelines laying as well as rates for purchases as well as laying the lines. Overall, there was cost increase by more than triple, excluding the cost of third 24" pipeline.*** ***• 6" MEG Pipelines - 1,2 &3 : Cost increase by more than six times from FDP levels. Details of cost increase were not provided to Audit.*** ***• 12" Effluent Pipelines: Cost increase by five times from FDP levels. Details of cost increase were not provided to Audit.*** ***• Deepwater PLEM: Cost increase more than double from FDP level. Details of cost increase were not provided to Audit.***
d.	*Subsea Control System and Umbilical's*					*358.01*					*722.9*	*353.51*	*642.05*	*667.64*	***• Estimated cost increase by more than double from FDP level. Details of cost increase from FDP level were not provided to Audit. However, Audit observed post bid revisions and post-award cost escalation as one of the reasons for higher spend.*** ***• Jumpers/Connections: Cost increase more than eight times from FDP level. Details of cost increase were not provided to Audit.*** ***• Tooling: Cost increase more than double from FDP level. Details of cost increase were not provided to Audit.***
e.	Deepwater Pipeline					142.14					323.82	85.67	298.535	310.691	**Cost increase by more than double from FDP levels. Details of quantity, rate, time and total spend for Deepwater pipelines were not provided to Audit. However, Audit observed that one of the reasons for cost increase was delay in placement of order for pipelines, after bids invitation and also purchase of pipes at higher cost.**

Sl. No	Descriptions	Cost Break-up of Major Cost elements as per IDP submitted by the Operator in May 2004					Cost Break-up of Major Cost elements as per Addendum to IDP submitted by the Operator in Oct'2006					Spend up to Mar'08	Spend Up to Mar'09	Spend Up to Jun'09	Cost Impact w.r.t. Quantity Revisions, Rate Revisions, Time Over Run, Tendering Process Deficiencies, Post Contract Award Revisions
		Unit Cost	No. of Units	UOM	Cost	Total cost	Unit Cost	No. of Units	UOM	Cost	Total cost	2007-08	Up to Mar'09	Up to Jun'09	
f.	Onshore Terminal including site grading					192.08					550.87	437.75	713.308	773.035	• Cost almost triple in the revised FDP in comparison to the FDP approved cost in Nov'04. Further, actual spend till June 2009 was more than four times the initial FDP approved cost. Audit observed that one of the reasons for cost increase was award of contracts for Onshore Terminal at non-competitive prices on the basis of single priced bid and also on cost plus basis. Audit also observed post contract award revisions/ change orders having cost as well as time impact. • OT Equipments: Cost increase more than triple from FDP levels. Details of cost increase were not provided to Audit. • Slug Catcher: Cost almost triple w.r.t. FDP levels. Audit observed non-placement of repeat order for a Slug catcher was one of the reasons for cost increase. • Other Cost (including piping, instrumentation, spares, installation costs, OT compression facilities etc): Cost increase more than two and a half times. Details of quanity, rate, time and total spend for different cost elements under the sub-head were not provided to Audit.
g.	Compressions					196.46					0	0	0	0	Redesign at revised FDP stage.

Sl. No	Descriptions	Cost Break-up of Major Cost elements as per IDP submitted by the Operator in May 2004					Cost Break-up of Major Cost elements as per Addendum to IDP submitted by the Operator in Oct'2006					Spend up to Mar'08	Spend Up to Mar'09	Spend Up to Jun'09	Cost Impact w.r.t. Quantity Revisions, Rate Revisions, Time Over Run, Tendering Process Deficiencies, Post Contract Award Revisions
		Unit Cost	No. of Units	UO M	Cost	Total cost	Unit Cost	No. of Units	UOM	Cost	Total cost	2007-08	Up to Mar'09	Up to Jun'09	
h.	Control cum riser platform					0					446.83	392.14	539.211	539.872	**• New facility added. As per FDP approved in Nov'2004, there was no plan to create CRP and production was planned without the CRP facility. Further, actual spend till June 2009 increased by another 20% from the cost approved in the revised FDP.** **• Engineering: Audit observed that there were post award revisions/change orders, having impact of cost escalation. As against the price of US$23.92 million indicated in the contract, actual billed amount till 1st March 2008 was US$ 36.72 million, showing 53.51 percent increase.** **• Project management: Audit observed that there were post contract award revisions/change orders, having impact of cost escalation. Percentage increase noticed for man-hours spent till February 2008 for different project management activities w.r.t. the man-hours indicated there-against in the contract ranged from 15 percent upto 108 percent.** **• Procurement of steel and bulks for jacket/ Piles & Appurtenances/ Decks and Procurement of tagged items & equipments: Audit observed that there were post contract award revisions/change orders, having impact of cost escalation. Percentage increase noticed in the amount billed till 1st March 2008 for different procurement activities vis-à-vis the price indicated there-against in the contract ranged from 14 percent upto 97 percent.** **• Fabrication loadout and seafastening: Audit observed that there were post award revisions/change orders, having impact of cost escalation. As against the price of US$ 46.70 million indicated in the contract, actual billed amount till 1st March 2008 was US$ 94.02 million, showing 101 percent increase.** **The Operator was asked to provide the details of quantity, rates, time and total spend under each cost element, which was, however, not provided.**

Sl. No	Descriptions	Cost Break-up of Major Cost elements as per IDP submitted by the Operator in May 2004					Cost Break-up of Major Cost elements as per Addendum to IDP submitted by the Operator in Oct'2006					Spend up to Mar'08	Spend Up to Mar'09	Spend Up to Jun'09	Cost Impact w.r.t. Quantity Revisions, Rate Revisions, Time Over Run, Tendering Process Deficiencies, Post Contract Award Revisions
		Unit Cost	No. of Units	UOM	Cost	Total cost	Unit Cost	No. of Units	UOM	Cost	Total cost	2007-08	Up to Mar'09	Up to Jun'09	
i.	Vent system					0					12.85	4.19	42.213	42.213	**New element added, which was not required as per FDP approved in Nov'04.**
j.	Vessel MOB-DEMOB					91.18					366.89	134.08	297.17	293.81	**Cost increase more than four times. Details of quantity, rates, time and total spend under the cost element were not provided to Audit.**
k.	Engineering cost					40.04					59.53	45.03	49.36	49.7	**Actual spend till June 2009 increase by US$ 9 million w.r.t. FDP approved cost in Nov'2004. Audit observed post award revisions having cost escalation impact.**
l.	CVA cost					17.16					47.63	4.77	7.02	8.99	**Reasons for lower spend under the cost element were not provided to Audit.**
m.	Project Management cost					114.4					212.62	155.46	282.97	295.57	**Increase in the cost approved in Dec'2006 by more than 85% w.r.t. FDP cost approved in Nov'2004. Further, actual spend was 39% more than the revised FDP cost.**
5	**Eco-protection**					**1.58**					**4.3**	**0.96**	**2.63**	**2.73**	
6	**G&A**					**13.5**					**20.5**	**19.71**	**79.06**	**80.07**	**Cost increase by more than five times from FDP level and more than three times from revised FDP levels. Basis of estimation at FDP and revised FDP levels and also details of abnormally higher spend were not provided to Audit.**
7	**Abandonment**					**0**					**0**	**0**	**0**	**0**	
8	**Information Technology**					**0**					**9.46**	**0.61**	**3.11**	**3.45**	

Sl. No	Descriptions	Cost Break-up of Major Cost elements as per IDP submitted by the Operator in May 2004					Cost Break-up of Major Cost elements as per Addendum to IDP submitted by the Operator in Oct'2006					Spend up to Mar'08	Spend Up to Mar'09	Spend Up to Jun'09	Cost Impact w.r.t. Quantity Revisions, Rate Revisions, Time Over Run, Tendering Process Deficiencies, Post Contract Award Revisions
		Unit Cost	No. of Units	UOM	Cost	Total cost	Unit Cost	No. of Units	UOM	Cost	Total cost	2007-08	Up to Mar'09	Up to Jun'09	
9	Kakinada Captive Berth					0					54.96	18.67	19.86	20.71	Details of cost approved in the revised FDP and reasons for lower spend were not provided to Audit.
10	Owned Support, Intervention Vessel and Helicopter					0					150	20.31	9.58	9.58	Details of cost approved in the revised FDP and details of US$ 20.31 million spend upto March 2008 were not provided to Audit.
11	Overhead @ 2%					46.87					0	0	0	0	Details of FDP and revised FDP approved costs and actual spend under the sub-head were not provided to Audit.
12	Exchange Loss/Gain					0					0	-2.17	-6.57	-2.79	
13	ML/Licence Fee/Dead Rent					0					0	0.14	0.14	0	
Grand Total						2390.38					5196.6	2557.9	4788.42	5056.46	

Details of discoveries

S.No.	Name of the Discovery	Date of Discovery	Date of intimation (Article 9.1 b of PSC)		Date of completion of test to determine whether discovery is of potential commercial interest Article 9.1 c of PSC)	Date of drilling of last appraisal well (Article 9.3 of PSC)	Date of advice by operator in writing by notice about commerciality of discovery to MC after completion of last appraisal well (Article 9.4 of PSC)	Date of DoC	Submission of FDP	Approval of FDP
			Due	Actual						
1	Guda	23.07.1999	22.08.1999	01.08.1999	10.09.1999	28.09.2005	Not available			
2	Saraswati	29.10.2001	28.11.2001	16.11.2001	21.11.2001	28.03.2004	11.01.2002	15.10.2004	30.12.2005	27.05.2006
3	Raageshwari Oil	25.12.2002	24.01.2003	04.02.2003	07.02.2003	02.04.2005	28.03.2003	15.10.2004	30.12.2005	27.05.2006
	GRF-1 (part of Guda)			01.11.2003	15.01.2004		06.02.2004			
4	Kameshwari	21.09.2003	21.10.2003	13.10.2003	14.11.2003	No appraisal well drilled	05.12.2003			
5	Mangala	20.01.2004	19.02.2004	23.01.2004	31.01.2004	06.01.2006	10.03.2004	15.10.2004	30.12.2005	27.05.2006
6	Aishwariya	05.03.2004	04.04.2004	09.03.2004	13.03.2004	15.04.2005	30.04.2004	15.10.2004	30.12.2005	27.05.2006
7	Vijaya	28.08.2004	27.09.2004	07.09.2004	23.09.2004	08.10.2005	17.10.2005			
8	Bhagyam	07.08.2004	06.09.2004	10.08.2004	25.08.2004	14.02.2006	21.10.2004	14.11.2006	11.10.2007	18.03.2008
9	Shakti	18.04.2004	18.05.2004	21.04.2004	22.04.2004	17.11.2004	04.06.2004	14.11.2006	Not submitted	-

10	Raag Deep gas	25.12.2002	24.01.2003	11.01.2005	07.02.2003	15.03.2006	28.03.2003	15.10.2004	30.12.2005	27.05.2006
11	Vandana	07.08.2004	06.09.2004	19.05.2005	24.11.2004	03.09.2005	21.06.2005			
12	N-I	18.05.2005	17.06.2005	16.06.2005	09.06.2005	21.08.2005	24.01.2006			
13	GSV	04.07.2005	03.08.2005	08.11.2005	20.10.2005	06.08.2006	24.01.2006			
14	N-C-West	04.07.2005	03.08.2005	08.11.2005	11.08.2005	No appraisal well drilled	24.01.2006			
15	Bhagyam South	03.12.2005	02.01.2006	27.12.2005	12.12.2006	No appraisal well drilled	22.02.2007			
16	N-E	09.01.2006	08.02.2006	19.01.2006	12.01.2006	31.01.2006	16.06.2006			
17	N-P	06.04.2006	06.05.2006	20.04.2006	22.04.2006	26.06.2006	06.02.2007			
18	Mangala Barmer Hill	20.01.2004	19.02.2004	20.04.2006	15.07.2006	20.01.2009	Not submitted			
19	Shakti-NE-1	21.10.2006	20.11.2006	13.11.2006	19.11.2006	No appraisal well drilled	22.01.2007			
20	K-W-2	21.11.2006	21.12.2006	16.12.2006	27.11.2006	26.06.2007	06.07.2007	24.12.2008	08.07.2009	Not approved
21	N-I-North	21.11.2005	21.12.2005	14.02.2007	04.12.2006	No appraisal well drilled	09.03.2007			
22	K-W-3	13.12.2006	12.01.2007	09.05.2007	24.12.2006	14.08.2007	06.07.2007	24.12.2008	08.07.2009	Not approved
23	Saraswati-Crest-1	05.05.2007	04.06.2007	17.05.2007	12.05.2007	No appraisal well drilled	13.07.2007			
24	K-W-6	20.07.2007	19.08.2007	10.08.2007	22.07.2007	No appraisal well drilled	13.09.2007	24.12.2008	08.07.2009	Not approved
25	Raageshwari-East-1z/Tukaram	24.11.2008	24.12.2008	16.12.2008	29.11.2008	19.03.2010	Not submitted			

Annexure 5.2

Cost estimates as per original and revised FDP

(US$ million)

Item No.	Description	Original FDP Approved	Revised FDP approved	Variance
DO1	Seismic	26.70	32.75	6.5
DO3	Development Studies	27.37	43.57	16.20
DO4	Well construction	433.08	698.80	265.72
DO5	Project management	67.25	167.52	100.27
DO7	Engineering	59.93	91.37	31.44
DO8	Surface facilities	513.40	1038.03	524.63
D10	Commissioning	15.80	13.51	-2.29
D12	Re-operations	18.53	76.30	57.77
D21	Land	4.81	5.47	0.66
D94	Insurance	3.67	5.28	1.61
D95	Base Office cost	14.11	18.41	4.30
D98	G&A	34.76	42.31	7.55
Sub total		**1219.41**	**2233.31**	**1013.90**
UAP	CONTINGENCY	22.20	111.67	89.47
Sub total		**1241.61**	**2344.98**	**1103.37**
D99	PCO	-	22.33	22.33
	Mangala field Dev.cost	-	**2367.31**	**2367.31**
	Mangala pipeline cost	-	941.05	941.05
	Mangala EOR pilot cost	-	35.61	35.61
Grand total		1241.61	3343.97	2102.36

Observations on award of contracts

Contracts awarded on nomination / single source basis

Sl No	Brief of observation	Amount Paid till 31.03.2008 (US$ million)
1	The operator issued (May 2007) tenders for supply, erection and commissioning of steam system package (shop fabricated skid mounted integral package boilers) to seven parties shortlisted on the basis of expression of interest, to which ten parties had responded. Four of the seven bidders, however, declined with only three remaining in the fray. Bids were evaluated technically. Thermax emerged as the sole technically qualified bidder to undertake the scope of work. Operator awarded (October 2007) the contract (s) to Thermax at **Rs 683,531,100** for supply and **Rs 101,348,720** for erection and supervision services during commissioning. Amount paid till 31 March 2008 was US$ 6,039,993.	6.04
2	The operator received only one bid from JP Kenny, against the tender issued to 8 bidders, for provision of Oil Export Pipeline Conceptual Design Study for Barmer Salaya Pipeline (BSPL) Project. The bid of JP Kenny was accepted and the contract was awarded for Pre-Front End Engineering Design (Pre-FEED)/BSPL Project. The expenditure incurred on pre-FEED was US$ 1.30 million. Thereafter, two more contracts viz: (i) FEED+ (basically a detailed design development sufficient to prepare Long Lead Item procurement Packages); and (ii) for supply of Project Personnel to the proposed Pipeline Integrated Project Management Team were awarded to JP Kenny for US$ **15.18** million and US$ **10** million respectively, inter-alia, stating that the contractor was involved since early concept stages. The approval / review of OC/MC were required for contracts on single source/nomination basis for awards in excess of US$ 0.50 million, which was not obtained. Further, by splitting work, the advantage of economies of scale was not availed.	14.50
3	Contract for Detailed Design & Engineering (DDE) for Mangala Oil & Raageshwari Gas Development Project was awarded to Mustang Engineering (Mustang) for US$ **62.6** million for a three year period, Mustang being the only bidder. The operator sent a team to Mustang's location in America to assess their capability, and the team assessed that Mustang, with a very experienced Project Management Team, had a very clear view of how the project could be organized to complete it on a fast track basis. However, subsequently, due to slow progress of work (little more than 60%), the contract was terminated, as slippage in progress would have a detrimental impact on construction operations.	68.91
Total		**89.45**

Contract awarded without assessing reasonability of rates

Sl No	Brief of observation	Amount (US$ million)
1.	The operator issued tenders for Supply of High Capacity Pump Packages to six bidders. Four parties declined, one did not respond and the remaining one (DMW) requested for extension of bid submission date, which was extended to 23 March 2007. However, no response was received from them also. Operator approached GE Oil & Gas-Kirloskar (GE) and DMW for their interest in submitting proposal. GE submitted (May 2007) their bid and award was made (September 2007) on them for US$ **19.45** million (revised budgeted cost estimated at US$ 9.00 million). Reasons for wide difference between the revised estimated cost and awarded cost were not available in the records.	1.94
Total		1.94

Extensions beyond contractual provisions/non-availing of economies of scale

Sl No	Brief of observation	Amount (US$ million)
1	A contract for work over/service rigs was awarded (May 2004) to John Energy for a primary period of twelve months at a cost of US$ 2.20 million. The contract was extended five times till 14 April 2007, in contravention of contractual provisions which provided for only two extensions of six months each.	7.12
2	Against tender for provision of drilling and completion fluids and solid control equipments and services, four bids were received and were found technically qualified. Price bids were opened, with Baker Hughes emerging the lowest bidder and contract at a cost of US$ 5.72 million was awarded on 26 July 2004 for six months with option of three extensions of six months each. It was observed that the contract was extended eight times, besides 11 variations, till 25 January 2008. Total payment made to Baker was US$ 13.51 million. Thus benefit of economies of scale, which were likely to accrue for a contract/extension of longer duration, remained to be availed. The total cost of contract including extensions and variations was US$ 20.22 million.	13.51
Total		20.63
Grand Total		112.02

Deficiencies regarding submission of reports

S. No	Name of block	• Deficiencies regarding submission of reports
1	KK-DWN-2003/1	• Out of nine quarterly reports, which were due for submission during April 2006 to April 2008, only two reports were found on record. • Annual local procurement statement for 2006-07 was not found on record.
2	MB-OSN-97/3	• Only one local procurement statement for 2002-03 was found on record, which was also submitted after a delay of one year. • Only one End of Year statement was found on record, which was submitted after a delay of 23 days. • Only a few quarterly reports pertaining to the block were found on record, some of which were also submitted after delays ranging between 1 ½ to 5 months.
3	KG-DWN-98/3	• There were delays in submission of annual reports outlining contractor's achievement in utilizing Indian resources (3 and 4 months for 2004-05 and 2006-07 respectively).
4	KG-OSN-2001/2	• There were delays in submission of annual reports outlining contractor's achievement in utilizing Indian resources (4 and 1 ½ months for 2006-07 and 2007-08 respectively).
5	MN-DWN-2004/3	• There was a delay in submission of annual reports outlining contractor's achievement in utilizing Indian resources (1 ½ month for 2007-08)
6	NEC-DWN-2002/1	• There were delays of 1 ½ to 4 months in submission of annual report outlining contractor's achievement in utilizing Indian resources. • Due to non-production of cost recovery statements, statements of cost, expenditure/receipts etc. to audit timely submission thereof could not be verified.
7	CB-OS/2	• Only 2 to 15 percent of contracts were awarded to Indian Vendors during 2001-02, 2002-03 and 2004-05 (records for 2003-04 were not furnished). In August 2005, the contractor had reported that he would take necessary steps to improve its achievements, however, compliance in this regard could not be verified in audit, as no further reports were submitted by the contractor for the years 2005-06 and 2006-07 as on April 2008.
8	Hazira	• Compliance regarding submission of annual local procurement statements could not be verified, as relevant records were not made available to audit.
9	CB-ONN-	

S. No	Name of block	• Deficiencies regarding submission of reports
	2000/1	
10	CB-ON/1	• Timely submission of quarterly and annual reports could not be verified in respect of these blocks, due to non-production of relevant records to audit.
11	KK-DWN-2000/2	
12	MB-OSN-2004/2	
13	RJ-ONN-2002/1	

Annexure 7.2

Statement showing delays in submission of Annual Audited Accounts

Name o f the block	Year	Date of submission	Delay in submission
KG-OSN-2001/2	2004-05	12.07.05	42 days
	2006-07	16.07.07	45 days
	2007-08	23.06.08	23 days
KK-DWN-2003-1	2006-07	26.6.07	25 days
	2007-08	23.6.08	22 days
NEC-DWN-2002/1	2004-05	12.7.05	42days
	2005-06	23.6.06	23 days
	2006-07	19.7.07	49 days
	2007-08	23.6.08	23 days
MN-DWN-2004/3	2007-08	20.6.08	20 days

Annexure 7.3

Statement showing Delays in approval of Audited Accounts

Name o f the block	Year	Date of submission	Date of approval	Delay in approval
KG-OSN-2001/2	2003-04	25.05.04	6.08.05	1 ½ month
	2004-05	12.07.05	8.12.05	4 months
	2006-07	16.07.07	3.06.08	9 ½ months
KK-DWN-2003-1	2005-06	30.5.06	7.9.06	2 months
	2006-07	26.6.07	24.9.07	2 months
NEC-DWN-2002/1	2004-05	12.7.05	18.11.05	3 months
	2006-07	19.7.07	15.10.07	2 months
MN-DWN-2004/3	2007-08	20.6.08	20.8.08	1 month
KG-DWN-98/3	2000-01	21.9.02	29.12.03	14 months
	2001-02	21.9.02	29.12.03	14 months
	2002-03	28.5.03	17.3.05	20 ½ months
	2003-04	25.5.04	7.1.06	18 months
	2004-05	12.7.05	10.4.06	8 months
	2006-07	16.7.07	14.11.08	15 months

Delays in submission of Annual Work Programmes and Budget

Name of the block	Exploration/ Appraisal/ Development/Production Budget	Year	Date of submission	Delay in submission
KG-DWN-98/3	Exploration	2004-05	5.2.04	1 month
		2005-06	14.2.05	1 ½ month
		2006-07	31.3.06	3 months
	Development	2005-06	27.10.05	10 months
		2007-08	23.2.07	2 months
Hazira	Development/ Production	2003-04	6.5.03	4 months
		2004-05	27.7.04	7 months
		2005-06	17.2.05	1 ½ months
		2006-07	31.3.06	3 months
CB-OS-2	Development/ Production	2004-05	4.3.04	2 months
		2005-06	8.4.05	3 months
		2006-07	9.3.06	2 months
		2007-08	9.3.07	2 months
KG-OSN-2001/2	Exploration	2004-05	26.2.04	2 months
		2005-06	1.3.05	2 months
		2006-07	18.2.06	1 ½ months
MB-OSN-97/3	Exploration	2005-06	14.2.05	1 ½ months
NEC-DWN-2002/1	Exploration	2005-06	31.1.05	1 month
		2006-07	17.5.06	4 ½ months
CB-ONN-2000/1	Exploration	2003-04	15.04.03	3 ½ months
		2004-05	21.06.04	5 ½ months
		2005-06	01.04.05	3 months
		2006-07	24.07.06	6 ½ months
CB-ON/1	Exploration	2004-05	4.03.04	2 months
		2005-06	8.06.05	5 months

		2006-07	14.06.06	5 ½ months
		2007-08	13.03.07	2 ½ months
KK-DWN-2000/2	Exploration	2002-03	11.02.02	1 ½ month
RJ-ON-90/1	Development	2006	5.4.06	6 months
		2007	8.12.06	2 months
				(In these cases, due date of submission was 30 September)
Panna-Mukta	Production Operations	2006-07	21.02.06	2 months
RJ-ONN-2002/1	Exploration	2007-08	28.2.07	2 months

Delays in review/approval of Annual Work Programme and Budget

Name of block	Nature of WP&B	Year	Delay in review/approval
KG-OSN-2001/2	Exploration	2004-05 (RE)	6.8.05 (reviewed after closure of the financial year)
		2005-06 (RE)	5.5.06 (reviewed after closure of the financial year)
KG-DWN-98/3	Exploration	2004-05 (RE)	25.5.05 (reviewed after closure of the financial year)
		2006-07 (RE)	23.7.07 (reviewed after closure of the financial year)
	Development	2006-07 (RE)	23.7.07 (approved after closure of the financial year)
CB-ONN-2000/1	Exploration	2003-04 (BE)	21.06.04 (reviewed after closure of the financial year)
		2004-05 (BE)	02.06.05 (reviewed after closure of the financial year)
		2005-06 (BE)	22.3.06 (reviewed in the last month of financial year)
		2006-07 (BE)	Not reviewed as of July 2008

Glossary

3D Seismic	A petroleum exploration method that shows the seismic reflectors in three dimensions. It is usually displayed on a computer monitor. The record can be rotated and slices (time or horizontal slices) taken out at various levels.
4C Seismic	A seismic survey that records not only the usual compressional waves (P waves) but also shear waves (S waves). It is used to better determine rock types and locate fractures.
4D Seismic	The seismic difference between several 3D seismic surveys run at different times over the same reservoir during production from that oil field. Changes in seismic responses from the reservoir such amplitude can show the flow of fluids through the reservoir.
Appraisal Well	A well drilled out from the side of a discovery well to determine the area of a new field.
Associated gas	Natural gas that is in contact with crude oil in the reservoir.
Barrel	A quantity or unit equal to 158.9074 litres (42 United States gallons) liquid measure, at a temperature of sixty degrees Fahrenheit and under one atmosphere pressure.
Barrels of oil equivalent	The amount of natural gas that has the same heat content as an average barrel of oil. It is about 6000 cf of gas.
Basement rock	Unproductive rocks underlying sedimentary rocks. It is usually an igneous or metamorphic rock.
Christmas tree	A subsea production system similar to a conventional land tree except it is assembled complete for remote installation on the sea floor with or without diver assistance. The marine tree is installed from the drilling platform; it is lowered into position on guide cables anchored to foundation legs implanted in the ocean floor. The tree is then latched mechanically or hydraulically to the well head by remote control.
Condensate	A hydrocarbon mixture composed primarily of molecules with 5, 6 and 7 carbon atoms. It is liquid under surface conditions but is a gas mixed with natural gas under subsurface reservoir conditions. Condensate is very light in density and is transparent to yellowish in color. It is almost pure gasoline in composition.
Crude Oil	A liquid composed of over one hundred different types of hydrocarbon molecules. The molecules range from 5 to more than 60 carbon atoms in length. Crude oil colors range from black to

	greenish to yellowish to transparent.
Deepwater	Beyond 400 metre bathymetry.
Delineation well	A well drilled to the side of a discovery well to determine the extent of the new field.
Development well	A well drilled in the known extent of a field.
Discovery well	An exploratory well that encounters a new and previously untapped hydrocarbon deposit; a successful wildcat well.
Electrical log	A wireline resistivity log. It is often run with a spontaneous potential or natural gamma ray log.
Exploration	The phase in which a possible hydrocarbon region is being investigated, either by geological or geophysical surveys or by exploratory drilling. Successful exploration is followed by appraisal and development.
Exploration operations	Operations conducted in the contract area pursuant to the contract in searching for Petroleum and in the course of an Appraisal Programme and shall include but not be limited to aerial, geological, geophysical, geochemical, palaeontological, palynological, topographical and seismic surveys, analysis, studies and their interpretation, investigations relating to the subsurface geology including structural test drilling, stratigraphic test drilling, drilling of Exploration Wells and Appraisal Wells and other related activities such as surveying, drill site preparation and all work necessarily connected therewith that is conducted in connection with Petroleum exploration.
Exploration well	A well drilled for the purpose of searching for undiscovered Petroleum accumulations on any geological entity (be it of structural, stratigraphic, facies or pressure nature) to at least a depth or stratigraphic level specified in the Work Programme.
Facies	A distinctive part of a rock layer such as a sandstone facies.
Fault	A break in the rocks along which there has been movement of one side relative to the other side. Faults are either dip-slip or strike slip.
Field	The surface area directly above one or more producing reservoirs on the same trap such as an anticline.
FPSO vessel	A ship that is stationed above or near an offshore oil field. Produced fluids from subsea completion wells are brought by flowlines to the

	vessel where they are separated and treated.
Gas in place	The amount of gas in the pores of a reservoir.
Geologist	A scientist who identifies and studies rocks. A petroleum geologist searches for and exploits oil and gas deposits.
Geology	The science that deals with the history of the earth and its life as recorded in the rocks.
Geophysical exploration	The search for geological structures favourable to the accumulation of hydrocarbons by means of geophysical devices, such as the gravimeter, the magnetometer and the seismometer.
Geophysics	The application of certain familiar physical principles: magnetic attraction, gravitational pull, speed of sound waves, the behavior of electric currents - to the science of geology.
Hydrate	A snow-like substance that can form from water in a flowline as the temperature of natural gas falls. It is composed of ice with methane in the ice crystals.
Hydrocarbons	Organic chemical compounds of hydrogen and carbon atoms. There are a vast number of these compounds and they form the basis of all petroleum products. They may exist as gases, liquids or solids. An example of each is methane, hexane and asphalt.
Improved oil recovery	The methods of water flood and enhanced oil recovery that are used to produce more oil from a depleted reservoir.
Infill drilling	Drilling between producing wells in a developed field to produce petroleum at a faster rate.
Joint venture	A business or enterprise entered into by two or more partners. Joint venture leasing is a common practice. Usually the partner with the largest interest in the venture will be the operator.
Mesozoic	An era of geological time from 248 to 65 million years ago.
Methane	A hydrocarbon composed of CH_4. It is a gas under surface conditions and is a major component of natural gas (C_1).
Miocene	An epoch of time from 24 to 5.3 million years ago. It is part of the Tertiary Period.
Natural gas	Gaseous forms of petroleum consisting of mixtures of hydrocarbon gases and vapors, the more important of which are methane, ethane, propane, butane, pentane, and hexane; gas produced from

	a gas well.
Oligocene	An epoch of time from 34 to 24 million years ago. It is part of the Tertiary Period.
Operator	The Company who (a) is responsible for maintaining a producing lease & (b) is in charge of operations in working interest area.
Paleocene	An epoch of geological time from 65 to 55 million years ago. It is part of the Tertiary Period.
Pleistocene	An epoch of time, from about 1.8 million years ago to 10,000 years ago, during which glaciers occupied much of the land area. It is part of the Quaternary Period.
Pliocene	An epoch of geological time from 5.3 to 1.8 million years ago. It is a part of Tertiary Period.
Production Sharing Contract	The contract between Government and International/National E&P Company. The E&P Company bears the entire cost of exploration, drilling and production. The E&P Company is reimbursed for expenditures from the oil/gas that is produced. After reimbursement, the oil/gas proceed is split by an agreed formula.
Profit oil	Produced oil that split between a host company and a multinational company by an agreed formula after the multinational company has been reimbursed for expenditure.
Prospect	A location where both geological and economic conditions favor drilling a well.
Recoverable oil	The amount of oil that can be produced from a reservoir under current economic conditions. It is a fraction of the oil in place.
Recovery factor	The percentage of oil and/or gas in place that will be produced from a reservoir.
Reserves	The calculated amount of gas and/or oil that is expected to produced from a well /wells or a field. Proven reserves are calculated with reasonable certainty. Developed reserves can be produced from existing wells whereas undeveloped reserves cannot. Unproven reserves are not as certain due to technical and economic reasons as proven reserves. Probable and possible reserves are even less certain.
Reservoir	A porous and permeable sedimentary rock (sandstone, limestone, dolomite, etc.), containing quantities of oil and/or gas enclosed or surrounded by layers of less permeable or impervious rock; a

	structural trap; a stratigraphic trap.
Royalty	Usually a fixed percentage of a specified crude or gas value per unit produced, to be paid to the host government. It is a fixed charge independent of profit or loss.
Shale	A very common sedimentary rock composed of clay-sized particles. Black shales are source rocks for petroleum.
Shallow water	Upto 400 metre bathymetry.
Tertiary	A period of geological time from 65 to 1.8 million years ago. It is part of the Cenozoic Era.
Well	A hole drilled or bored into the earth, usually cased with metal pipe for the production of gas or oil. Also, a hole for the injection under pressure of water or gas into a subsurface rock formation.
Well log	A continuous record of rock properties measured in a well. Some types are sample, mud and wireline.
Wellhead	The forged or cast steel fitting on the top of a well. It consists of casing heads located on the bottom and a tubing head on the top. It is bolted or welded to the top of the surface casing.
Work over	To have a service Company do work (a workover) such as pullrods or sand cleanout on a producing well. A production rig, either a workover rig or a smaller service or pulling unit is used.

List of Abbreviations

2D	Two dimensional
3D	Three dimensional
4C	Four Channel
4D	Four Dimensional
ABO	Aker Borgestad Operations
AFP	Aker Floating Production
AIDP	Addendum to Initial Development Plan
AKAP	Aker Kvaerner Australia Pty Ltd.
AM	Audit memoranda
ANG	Associated Natural Gas
API	Acquisition, Processing and Interpretation of seismic data
APM	Administered Price Mechanism
BEC	Bid Evaluation Criteria
BGEPIL	British Gas Exploration and Production (India) Limited
BLPD	Barrels of Liquid Per Day
BOPD	Barrels of Oil Per Day
BPCL	Bharat Petroleum Corporation Limited
BWPD	Barrels of Water Per Day
CA	Chartered Accountant
CAPEX	Capital expenditure
CCEA	Cabinet Committee on Economic Affairs
CEHL	Cain Energy Hydrocarbons Limited
CEIL	Cairn Energy India Limited
CoA	Chart of Accounts
COSA	Crude Oil Sales Agreement
CRF	Cost Recovery Factor
CRL	Cost Recovery Limit
CRP	Control-cum-Riser Platform
DA	Development Area
DGCA	Directorate General of Civil Aviation
DGH	Directorate General of Hydrocarbon
DoC	Declaration of Commerciality

E&P	Exploration and Production
EC	Essentiality Certificate
EOI	Expression of Interest
EP	Exploration Phase
EPIC	Engineering, Procurement, Installation and Commissioning
EPOD	Expanded Plan of Development
FDP	Field Development Plan
FDPSO	Floating Drilling, Production, Storage and Offloading Vessel
FEED	Front End Engineering Design
FI	Financial
FIFO	First In First Out
FPSO	Floating Production, Storage and Offloading Vessel
G&G	Geological & Geophysical
GAIL	Gail (India) Limited
GIIP	Gas initial in place
GIPIP	Good International Petroleum Industry Practices
GoI	Government of India
GWC	Gas water Contact
HC	Hydrocarbon
HPCL	Hindustan Petroleum Corporation Limited
HSE	Health Safety and Environment
IDP	Initial Development Plan
IM	Investment Multiple
INR	Indian Rupee
IOC	Indian Oil Corporation
IOGPT	Institute of Oil and Gas Petroleum Technology
IPOD	Initial Plan of Development
JOA	Joint Operating Agreement
JS	Joint Secretary
L&T	Larsen and Toubro
LD	Liquidated damages
LKM	Line Kilo Metre
LNG	Liquified Natural Gas

LOA	Letter of Acceptance
LOI	Letter of intent
LSTK	Lump Sum Turnkey
LWD	Logging while drilling
MAT	Minimum Alternative Tax
MC	Management Committee
MCM	Management Committee Meeting
MEG	Mono Ethylene Glycol Regeneration & Reclamation
ML	Mining Lease
MMBBL	Million barrel
MMBOE	Million barrels of oil equivalent
MMBTU	Million Metric British Thermal Unit
MMSCF	Million standard cubic feet
MMSCMD	Million Standard Cubic Meter Per Day
MOD	Ministry of Defence
MoPNG	Ministry of Petroleum and Natural Gas
MPF	Mobile Production Facility
MPSC	Model Production Sharing Contract
MT	Metric Tonne
MWD	Measurement while drilling
MWP	Minimum Work Programme
NAA	Northern Appraisal Area
NANG	Non Associated Natural Gas
NELP	New Exploration and Licensing Policy
NIO	Notice Inviting Offer
NOC	National Oil Companies
NPV	Net Present Value
NRPOD	New Revised Plan of Development
NW	North West
O&M	Operation & Maintenance
OB	Operator Board
OC	Operating Committee
ODR	Operating day rate

OF (RD)	Oil Fields (Regulation & Development)
OGIP	Original Gas in Place
Oil	Oil India Limited
ONGC	Oil & Natural Gas Corporation
OPEX	Operating Expenditure
OT	Onshore Terminal
PEL	Petroleum Exploration License
PI	Participating Interest
PMT JV	Panna-Mukta Tapti Joint Venture
PNG Rules	Petroleum and Natural Gas Rules
PO	Purchase Order
POM	Preliminary observation memoranda
PP	Profit Petroleum
PSC	Production Sharing Contract
PTRR	Post tax Rate of Return
RFP	Request for Proposal
RIL	Reliance Industries Limited
S$	Singapore Dollars
SCADA	Supervisory Control & Data Acquisition
SE	South East
SIPD	Shell India Production and Development
TCF	Trillion Cubic Feet
US	Under Secretary
US$	United States Dollars
VLCC	Very Large Crude Carrier
VQC	Vendor Qualification criteria
WIP	Work in Progress
WP&B	Work Programme & Budget
XMT	Christmas tree