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

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[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.