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

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	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

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	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.

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	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.

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	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 2^{nd} 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.**

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	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.

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	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.	DGH no longer mentions any requirement other than 3D seismic coverage
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.	
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	

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	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.

Date	Event	Further Comments of Audit
	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

Date	Event	Further Comments of Audit
	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	

Date	Event	Further Comments of Audit
	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.	

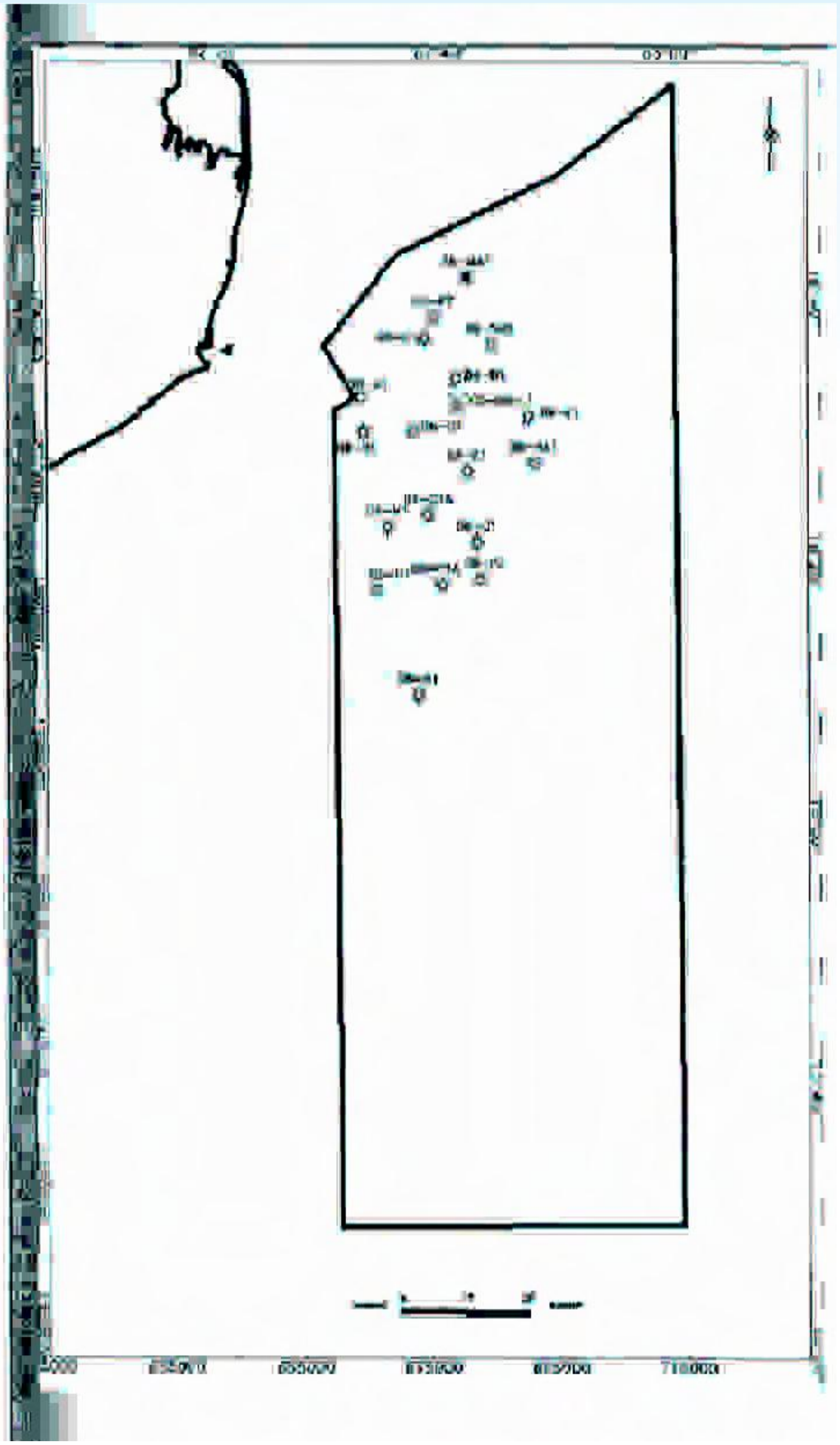
Date	Event	Further Comments of Audit
	Further while mentioning that there were timelines given in PSC on various activities that set in after discovery was announced, it was not clear to them whether those provisions had been complied with. DGH was further requested to intimate about the availability 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	

Date	Event	Further Comments of Audit
	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.	

Date	Event	Further Comments of Audit
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.

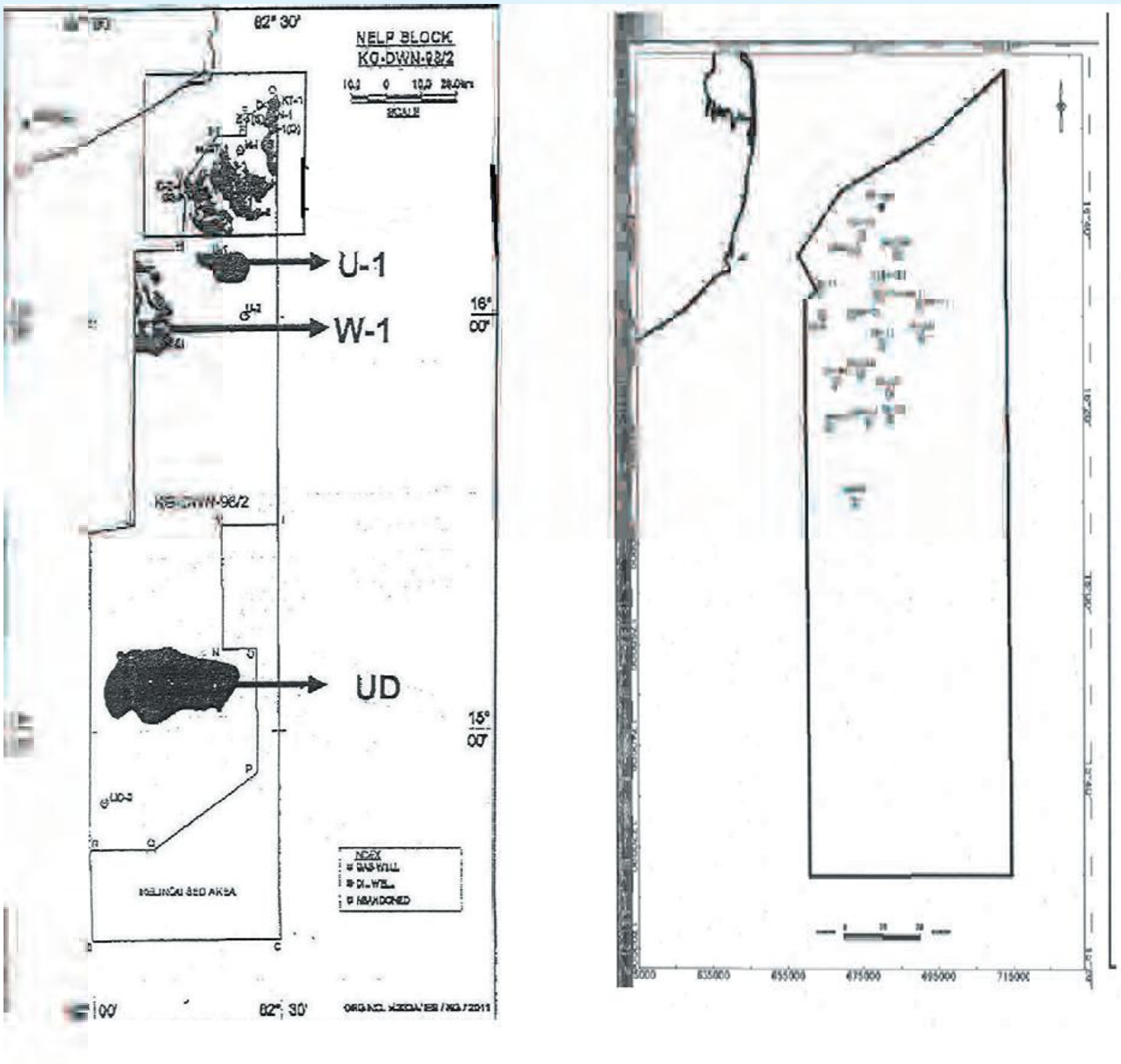
The reply of MoPNG is not tenable, and merely restates the opinions of the contractor, DGH and MoPNG summarized in the chronology indicated at Table 4.1.

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.

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[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.