Gaffney, Cline & Associates Ltd
Technical and Management Advisers to the Petroleum Industry Internationally Since 1962

Bentley Hall
Blacknest, Alton
Hampshire GU34 4PU
United Kingdom

Telephone: +44 (0) 1420 525366
Facsimile: +44 (0) 1420 525367

email: gcauk@gaffney-cline.com
www.gaffney-cline.com

Registered London No. 1122740

MIH/E2021/nxd/0271 **26th May, 2009**

Mr. Yogeshwar Sharma,
Hardy Oil and Gas Plc,
137-143 Hammersmith Road,
London,
W14 0QL.

Dear Mr. Sharma,

THE CONTINGENT RESOURCES AND PROSPECTIVE RESOURCES OF BLOCK D3 AND BLOCK D9,
KRISHNA GODAVARI BASIN, OFFSHORE INDIA

Further to the Gaffney, Cline & Associates (GCA) presentation to the Board of Hardy Oil and Gas plc (Hardy) on 6th May, 2009 and your subsequent request of a short summary letter report of GCA presented results, we are pleased to provide herewith this short summary letter report.

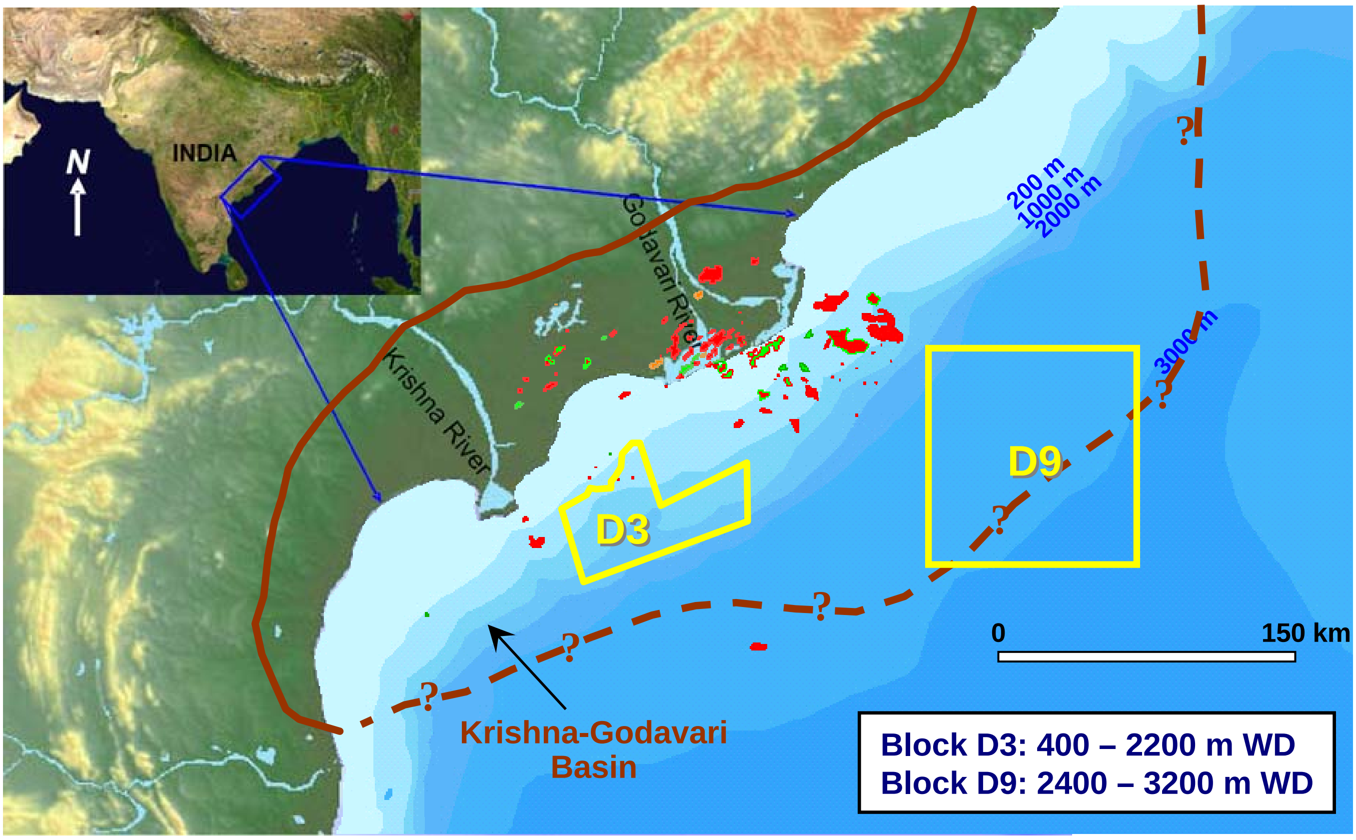
INTRODUCTION

In accordance with the instruction letter of Hardy dated 11th March, 2009, GCA has reviewed the petroleum interests owned by Hardy in Blocks D3 and D9, Krishna Godavari Basin, offshore India, the location of which is shown in Figure 1. These assets comprise two discoveries in Block D3 and duly licensed exploration interests in Blocks D3 and D9. Hardy's Net Working Interest (NWI) in these blocks is 10%. Reliance Industries (RIL) has the other 90% and is the Operator.

The principal objective was to perform a technical evaluation of the Contingent Resources in Block D3 and the Prospective Resources in Blocks D3 and D9, and to opine on the resource potential of Blocks D3 and D9. In addition, GCA was requested to provide a perspective on the prospectivity of Hardy's Assam asset.

The Krishna-Godavari Basin is an emerging world class petroleum province. An unconventional biogenic gas petroleum system, proven in RIL's D1-D3 gas fields, is present in Blocks D3 and D9. This petroleum system has a source rock of microbial origin and is believed to be pervasive throughout the Miocene and younger sequences of the two Blocks. The prospectivity is predicated on identifying palaeo-gas hydrate occurrences in deep water that have expelled free gas that is subsequently entrapped in Miocene, Pliocene and Pleistocene clastic sequences. The older plays however, rely on a thermogenic source(s).

Reservoir is therefore the key play element to be investigated. Deepwater clastic depositional systems comprise stacked, amalgamated channel complexes, slope and basin floor fans. Major relative lowstands of sea-level e.g. Middle Miocene, associated with large influx of coarse clastics, are the principal play targets.



Location of Blocks D3 and D9		
Proj. E2021 May 09	Checked: MTH	Fig. 1

Traps are predominantly stratigraphic where effective updip, base and top seals are present. Structural traps are both fault-related and large anticlinal closures associated with toe thrusts. Combination stratigraphic /structural traps are also present.

The principal geological risks are reservoir presence, continuity and connectivity, and the presence of thermogenic hydrocarbon kitchens; the latter for Eocene, Palaeocene and Cretaceous plays, particularly in Block D9.

A play-based exploration methodology "Best Practice" is performed in the technical evaluation of Block D3. This approach addresses both the current prospect inventory and the "yet to find" resource potential i.e. as yet unidentified leads.

It is considered that this approach is more representative of the prospectivity of Block D3, than solely prospect summation. It is believed that a significant number of new leads will be generated in the future.

GCA has applied the Petroleum Resources Management System published by the Society of Petroleum Engineers / World Petroleum Council / American Association of Petroleum Geologists / Society of Petroleum Evaluation Engineers (SPE/WPC/AAPG/SPEE) in March, 2007 ("SPE PRMS"), as shown in Appendix I.

SUMMARY

GCA confirms Hardy's assessment of Contingent Resources for Block D3 as follows:

The A-1 discovery has a gross aggregate Best Estimate of 0.2 TCF with a range from 0.06 TCF (Low Estimate) to 0.5 TCF (High Estimate).

The B-1 discovery has a gross aggregate Best Estimate of 0.2 TCF with a range from 0.08 TCF (Low Estimate) to 0.4 TCF (High Estimate).

The Contingent Resources summary is shown in Table 1. The Chance of Economic Development (COED) i.e. the chance to move from Contingent Resources to Reserve, for these two discoveries, on their own, is considered low at this time.

A summary map of Block D3 discoveries, Hardy prospects and leads, and new features identified by GCA is shown in Figure 2.

The potential gross, risked Best Estimate resource for Block D3 is 9.5 TCF with a range from 1.5 TCF (Low Estimate) to 23 TCF (High Estimate) as shown in Table 2. This assessment uses a play-based exploration methodology with each play comprising currently identified prospects and leads and a number of postulated prospects based on the play area and field size distribution. Volumetric estimates are made at both the prospect and play level. In addition, a Geological Chance of Success (GCOS) is assigned to all the prospects and leads. For comparison, a prospect summation approach results in a gross risked Best Estimate of 2.5 TCF, as summarised in Table 3. A summary of the prospects/leads GIIP, gross, unrisked P90, P50 and P10 volume distribution, by play, for Block D3 is shown in Figure 3.

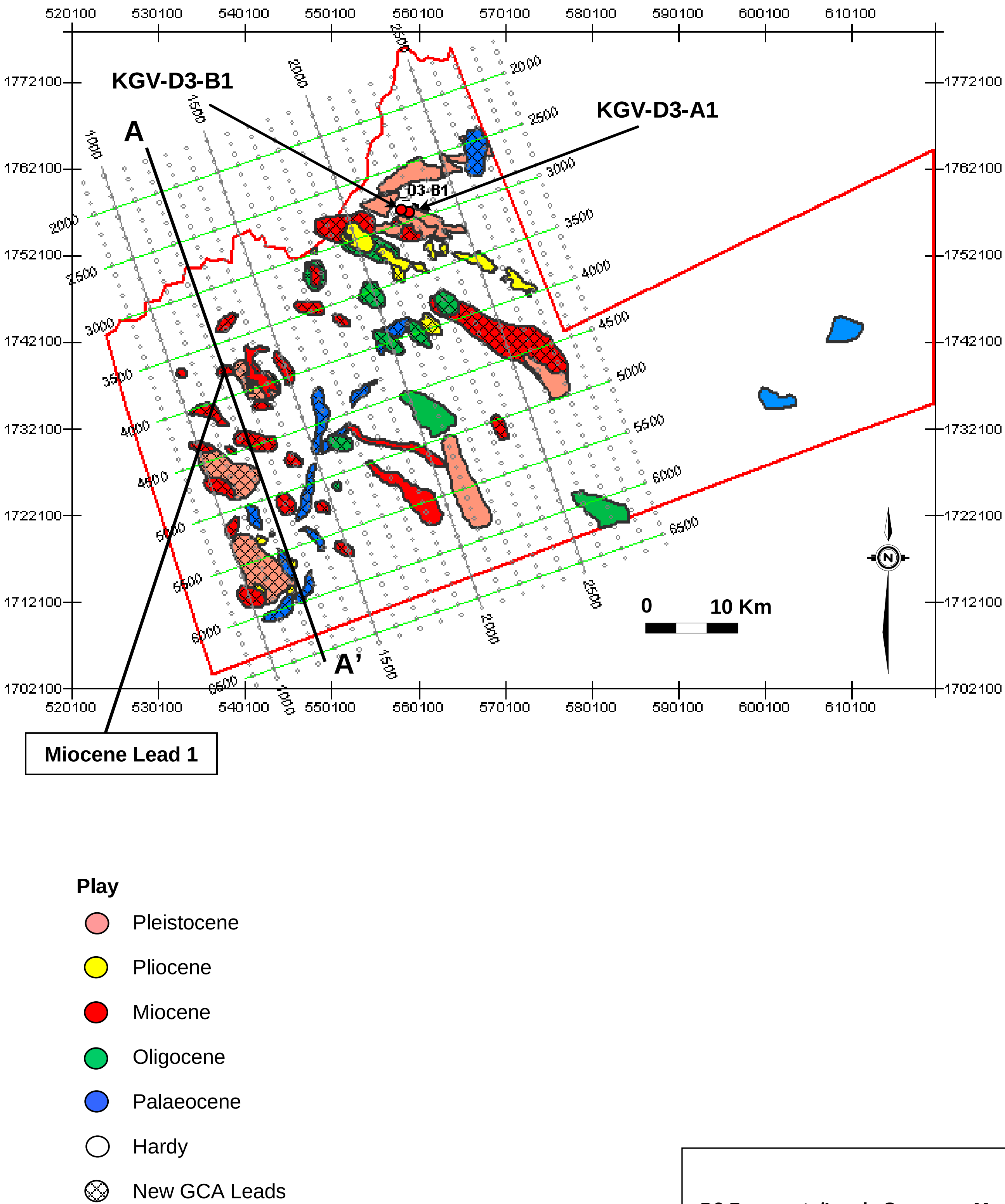
Hardy's identified prospects/leads in Block D9 are shown in Figure 4. The gross, risked Best Estimate Prospective Resources for gas in Block D9 is 11 TCF, with a range from 4 TCF (Low Estimate) to 23 TCF (High Estimate). The gross, risked Best Estimate Prospective Resources for oil in Block D9 is 143 MMBbl, with a range from 49 MMBbl (Low

TABLE 1

D3: CONTINGENT RESOURCES SUMMARY AS AT 1ST MAY 2009

Prospect	Gross Contingent Resources (BCF)			Hardy Interest	Net Hardy Contingent Resources (BCF)		
	Low Estimate 1C	Best Estimate 2C	High Estimate 3C		Low Estimate 1C	Best Estimate 2C	High Estimate 3C
A1 Pleistocene Sand 0	28	**113**	274	10%	2.8	11.3	27.4
A1 Pleistocene Sand 1	33	**97**	209	10%	3.3	9.7	20.9
Total A-1	**61**	**210**	**483**	**10%**	**6.1**	**21.0**	**48.3**
B1 Pleistocene Sand 2 (Southern)	57	**146**	316	10%	5.7	14.6	31.6
B1 Well Pliocene Sand	27	**67**	125	10%	2.7	6.7	12.5
Total B-1	**84**	**213**	**441**	**10%**	**8.4**	**21.3**	**44.1**
Grand Total	**145**	**423**	**924**	**10%**	**14.5**	**42.3**	**92.4**

Checked: MIH Approved: GNLC



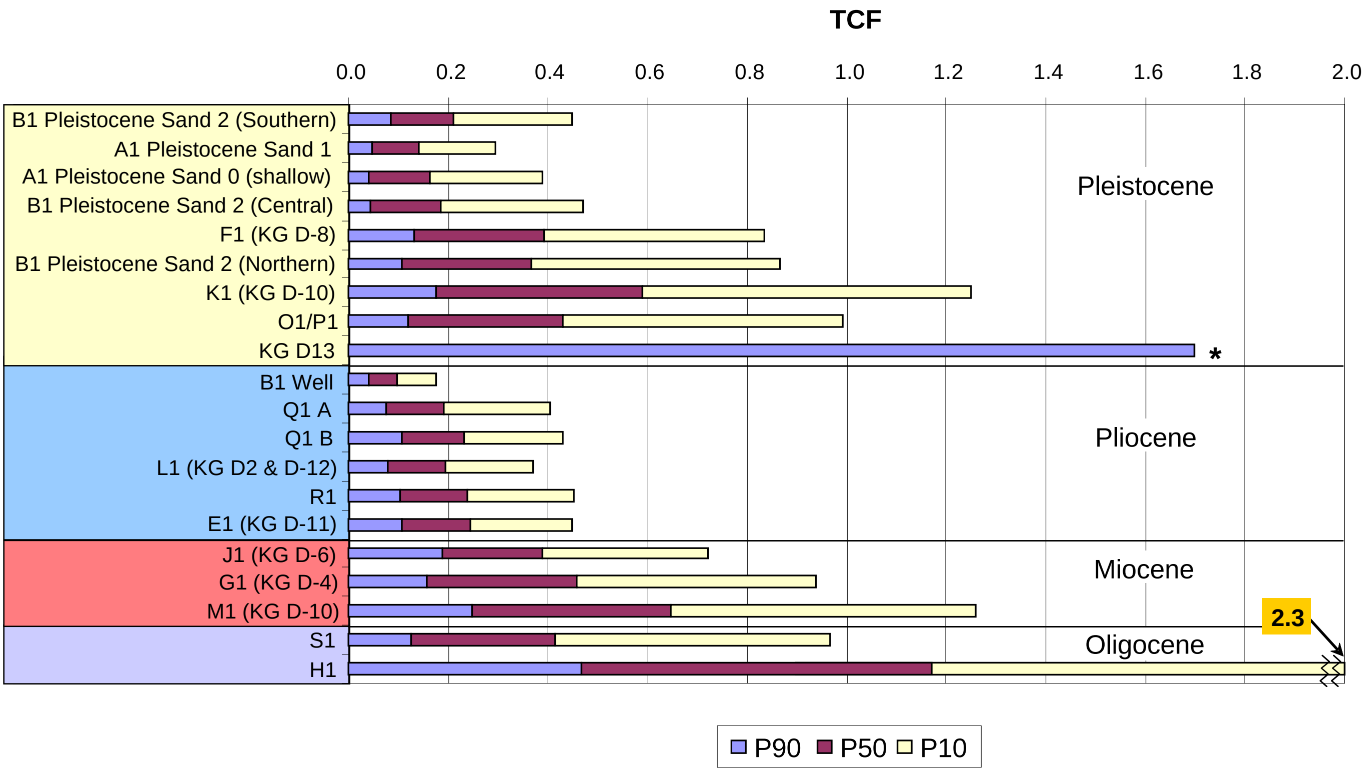
D3 Prospects/Leads Summary Map		
Proj. E2021 May 09	Checked: MIH	Fig. 2

TABLE 2

D3: PLAY SUMMARY; GROSS RISKED RESOURCES

Play	**Gross Risked Resources (TCF)**		
	Low Estimate	**Best Estimate**	**High Estimate**
Pleistocene	0.3	3.2	8.1
Pliocene	0.4	1.9	4.1
Miocene	0.6	3.6	9.4
Oligocene	0.1	0.4	0.9
Eocene	0.03	0.1	0.2
Palaeocene	0.1	0.3	0.8
Total Gross Aggregate Risked Best Estimate = 9.5 TCF			

Checked: MIH Approved: GNLC



Note: Lead KG-D13 is in the 2D area and due to limited data, GCA adopted Hardy's best estimate volume

D3: Prospects/Leads GIIP Gross UNRISKED P90-P50-P10 Volume Distribution by Play

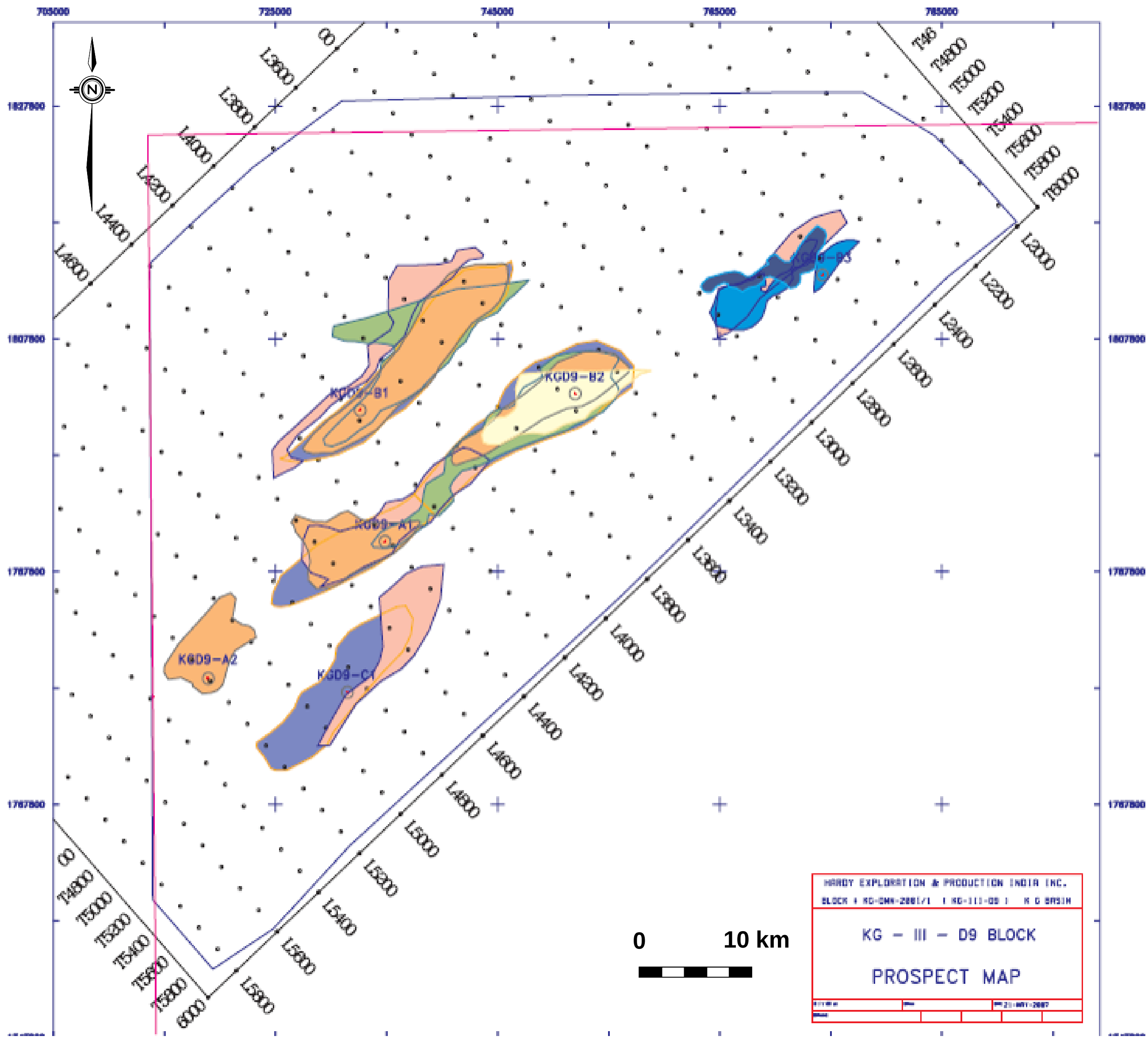
Proj. E2021	May 09	Checked: MTH	Fig. 3

TABLE 3

D3: SUMMARY OF GROSS PROSPECTIVE RESOURCES AS AT 1ST MAY, 2009

Prospect / Lead	Play	Gross Prospective Resources (BCF)			GCOS (frac)
		Low Estimate	Best Estimate	High Estimate	
B1 Pleistocene Sand 2 (Central)	Pleistocene	30	127	330	0.80
F1 (KG D-8)	Pleistocene	88	272	589	0.80
B1 Pleistocene Sand 2 (Northern)	Pleistocene	73	255	614	0.80
K1 (KG D-10)	Pleistocene	123	410	879	0.80
O1/P1	Pleistocene	83	300	691	0.80
KG D13	Pleistocene/Mio	1,190	1,190	1,190	0.05
Q1 A	Pliocene	52	134	291	0.70
Q1 B	Pliocene	74	161	306	0.70
L1 (KG D2 & D-12)	Pliocene	53	134	262	0.70
R1	Pliocene	72	166	318	0.70
E1 (KG D-11)	Pliocene	75	169	319	0.70
J1 (KG D-6)	Miocene	135	281	524	0.48
G1 (KG D-4)	Miocene	112	328	675	0.48
M1 (KG D-10)	Miocene	175	464	904	0.48
S1	Oligocene	89	300	703	0.24
H1	Oligocene	334	840	1,641	0.24
Gross Aggregate Risked Prospective Resources (TCF)		**0.9**	**2.5**	**5.2**	

Checked: MIH Approved: GNLC



Legend:

- Cretaceous
- Palaeocene/Cretaceous
- Lr. Miocene
- Mid. Miocene
- Up. Miocene
- Pliocene
- Pliocene

D9: Hardy Identified Prospects/Leads		
Proj. E2021 May 09	Checked: MTH	Fig. 4

Estimate) to 322 MMBbl (High Estimate). This assessment is summarised for gas and for oil in Tables 4 and 5 respectively. Summaries of the pprospects/leads GIIP and STOIIP gross, unrisked, P90, P50 and P10 volume distributions, per play, for Block D9 are shown in Figures 5 and 6 respectively.

With respect to Hardy's onshore Assam licence, GCA confirms that a challenging, potentially attractive play extension and possible new play(s) opportunity is expected. Neighbouring oil discoveries on trend may provide viable analogues.

CONCLUSIONS

- The Krishna-Godavari Basin is an emerging world class petroleum province with an unconventional biogenic gas petroleum system, and a conventional thermogenic petroleum system, the latter for Early Tertiary & Mesozoic plays.

- Attractive acreage holdings in Blocks D3 and D9 are confirmed as follows:

  Block D3:

  - Contingent Resources: gross, aggregate A-1 and B-1 Best Estimate of 0.4 TCF, with a range of 0.14 TCF (Low Estimate) to 0.9 TCF (High Estimate); and
  - Potential gross, risked Best Estimate resources of 9.5 TCF with a range from 1.5 TCF (Low Estimate) to 23 TCF (High Estimate).

  Block D9:

  - The gross risked Prospective Resources Best Estimate of 11 TCF + 143 MMBbl with a range from 4 TCF + 49 MMBbl (Low Estimate) to 23 TCF + 322 MMBbl (High Estimate).

- GCA considers the current Hardy/RIL prospect generation and resource assessment methodology is currently sub-optimal, and does not reflect industry "Best Practice". Therefore, the Hardy/RIL assessment does not reveal the full resource potential of the assets, in particular in Block D3.

- Multiple play opportunities exist. The Pleistocene and Pliocene plays are proven. However, the Miocene play(s) is considered to have the best undiscovered potential. (The results of the G-1 well are unknown at the time of this study.)

- Risk mitigating technologies (e.g. AVO, fluid substitution modelling, EM) are in place. However, Hardy, was not able to provide sufficient analytical results, within the timeframe of this study, to permit a thorough uncertainty and risk analysis to be performed.

- With respect to Hardy's onshore Assam licence, GCA confirms that a challenging, potentially attractive play extension and possible new play(s) opportunity is expected.

TABLE 4

D9: SUMMARY OF GROSS PROSPECTIVE RESOURCES AS AT 1ST MAY 2009

Prospect / Lead	Play	Gross Prospective Resources (TCF)			GCOS (frac)
		Low Estimate	Best Estimate	High Estimate	
Channel 2 (near #B3)	Lr Pliocene	0.3	0.9	1.8	0.30
Channel 1 (near #B3)	Up Pliocene	0.2	0.7	1.5	0.30
Central Anticline (near #A1)	U. Miocene	1.4	3.6	7.6	0.20
Northern Anticline (NW Flank B1)	U. Miocene	0.8	2.5	5.6	0.20
Central Anticline (near #B3)	U. Miocene	1.0	2.5	5.3	0.25
Southern Anticline (SE Flank C1)	U. Miocene	1.1	2.9	6.2	0.10
Central Anticline A1 & B2	M. Miocene	1.2	2.8	5.6	0.25
Northern Anticline B1	M. Miocene	2.7	5.2	12.0	0.25
Central Anticline A1 & B2	M. Miocene	2.9	6.6	12.9	0.25
Southern Anticline C1	M. Miocene	1.8	5.2	12.0	0.15
Northern Anticline (Near #B1)	L. Miocene	1.8	6.3	15.0	0.15
Central Anticline (near #A1)	L. Miocene	1.5	4.0	8.7	0.15
Central Anticline (near #B2)	L. Miocene	1.3	2.8	5.5	0.25
Central Anticline (near #A2)	L. Miocene	0.8	2.3	4.9	0.15
Central Anticline #A1 Channel	L. Miocene	1.4	4.2	9.2	0.15
Central Anticline #A2 Channel	L. Miocene	0.8	2.3	5.0	0.15
Gross Aggregate Risked Prospective Resources (TCF)		**4.1**	**10.8**	**23.0**	

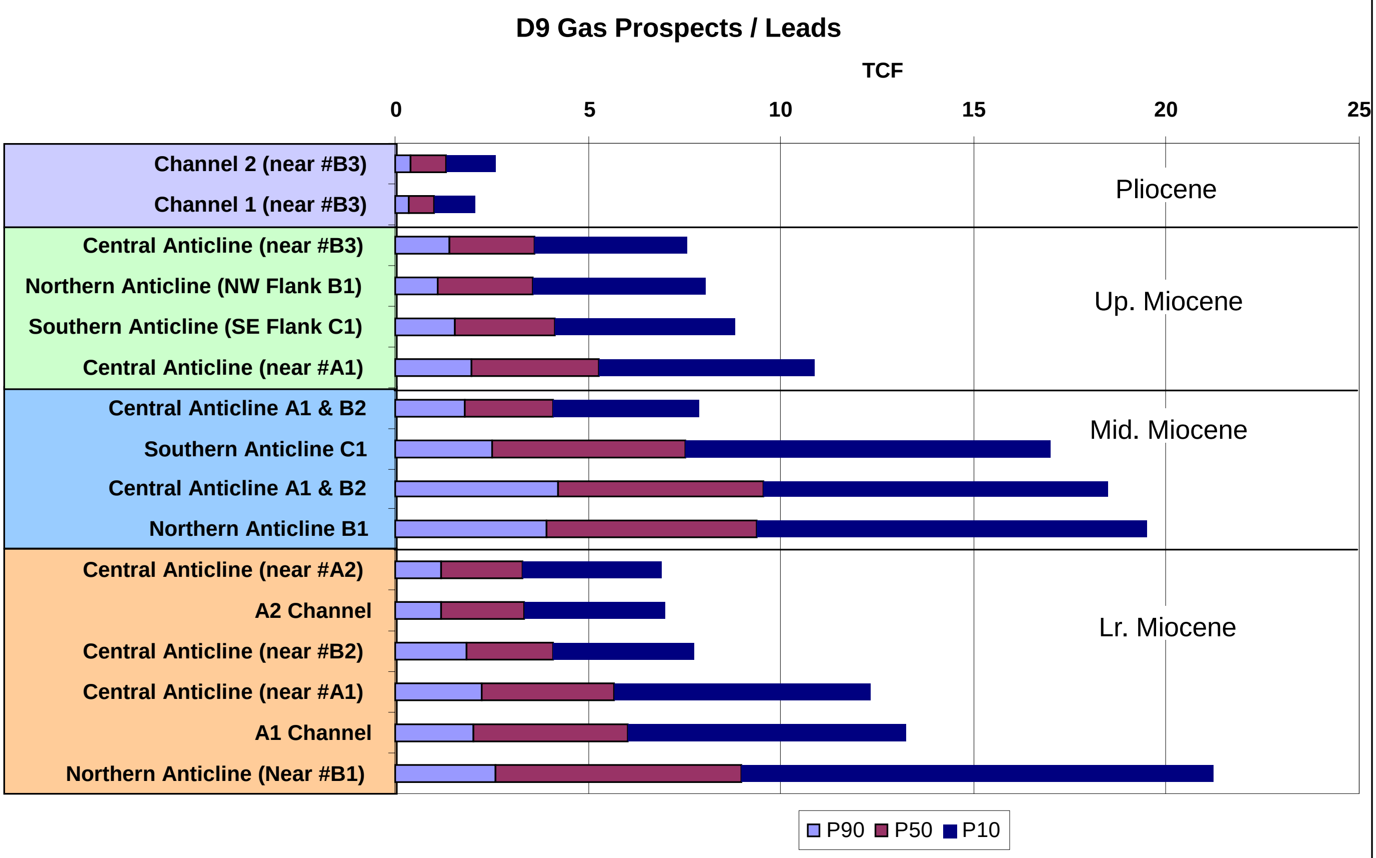
Checked: MIH Approved: GnLe

TABLE 5

D9: SUMMARY OF PROSPECT/LEAD GROSS PROSPECTIVE RESOURCES AS AT 1ST MAY 2009

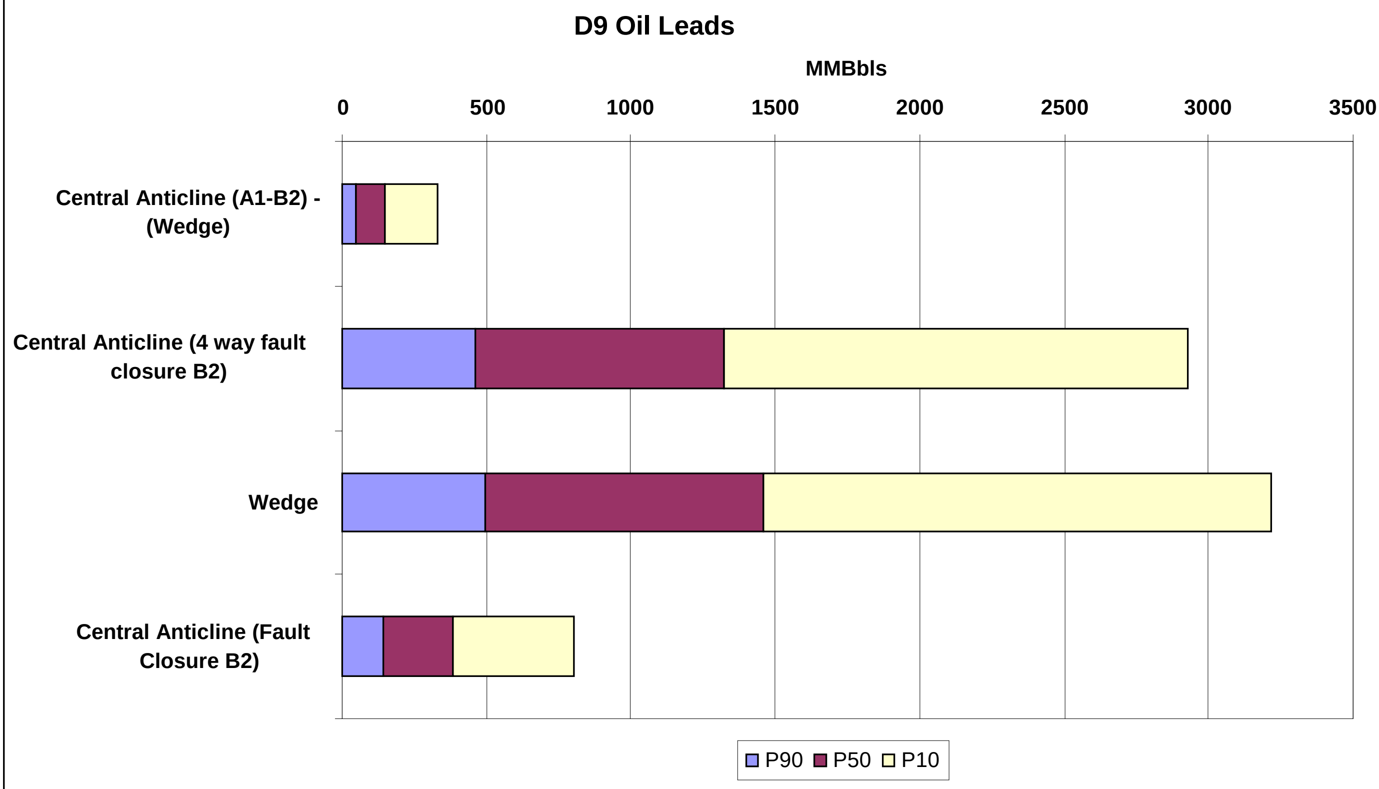
Prospect / Lead	Age	Prospective Resources (MMBbl)			GCOS (frac)
		Low Estimate	**Best Estimate**	**High Estimate**	
Central Anticline (4 way fault closure B2)	Palaeocene	142	420	961	0.18
Wedge	Palaeocene	156	456	1,040	0.18
Central Anticline (A1-B2) - (Hardy Wedge)	Palaeocene	15	47	107	0.08
Central Anticline (Fault Closure B2)	Cretaceous	44	122	260	0.18
Gross Aggregate Risked Prospective Resources (MMBbl)		**49**	**143**	322	

Checked: MIH Approved: GWE



D9: Prospects/Leads GIIP Gross UNRISKED P90-P50-P10 Volume Distribution by Play

Proj. E2021 May 09	Checked: MIH	Fig. 5



D9: Prospects/Leads Gross Unrisked STOIIP P90-P50-P10 Volume Distribution by Play

Proj. E2021 May 09	Checked: MIH	Fig. 6

<u>RECOMMENDATIONS</u>

- The current Hardy prospect and lead portfolio does not fully describe the ultimate Prospective Resources potential of the Blocks D3 and D9. It is recommended to perform a new, updated technical evaluation using a play analysis approach to include:

    - o Establishing a detailed sequence stratigraphic framework;
    - o Constructing regional environment of deposition maps (EOD) per play; and
    - o Developing AVO and EM risking and ranking methodologies.

- It is recommended to request RIL, as Operator, to perform a strategic exploration programme study to monetise assets, underpinned by:

    - o Economic analysis scenarios based on future development and production considerations (e.g. cluster/hub developments);
    - o Timing of first production and subsequent "ullage fillers' to extend the duration of plateau production; and
    - o Specific geographic infrastructure considerations to optimise commercial development.

- It is recommended that a post-well analysis of the wells already drilled should be performed. This will allow the pre- and post-drill volumes and input parameters to be compared and contrasted on a play by play basis. This work should include wells from outside of the Blocks but within each of the play fairways. This approach will allow the blocks to be placed within their regional basin context and may lead to the identification of potential that is not immediately obvious from study only within the Blocks.

This short-form report is a pre-cursor to GCA's Final Report, to be issued in the near future. We shall be pleased to clarify any issues as required.

The cooperation of Hardy staff throughout this project is appreciated.

Yours Sincerely,
GAFFNEY, CLINE & ASSOCIATES

G.W.L. Cull
Regional Director

APPENDIX I

SPE PRMS

Society of Petroleum Engineers, World Petroleum Council, American Association of Petroleum Geologists and Society of Petroleum Evaluation Engineers

Petroleum Resources Management System

Definitions and Guidelines ([1])

March 2007

Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

International efforts to standardize the definition of petroleum resources and how they are estimated began in the 1930s. Early guidance focused on Proved Reserves. Building on work initiated by the Society of Petroleum Evaluation Engineers (SPEE), SPE published definitions for all Reserves categories in 1987. In the same year, the World Petroleum Council (WPC, then known as the World Petroleum Congress), working independently, published Reserves definitions that were strikingly similar. In 1997, the two organizations jointly released a single set of definitions for Reserves that could be used worldwide. In 2000, the American Association of Petroleum Geologists (AAPG), SPE and WPC jointly developed a classification system for all petroleum resources. This was followed by additional supporting documents: supplemental application evaluation guidelines (2001) and a glossary of terms utilized in Resources definitions (2005). SPE also published standards for estimating and auditing reserves information (revised 2007).

These definitions and the related classification system are now in common use internationally within the petroleum industry. They provide a measure of comparability and reduce the subjective nature of resources estimation. However, the technologies employed in petroleum exploration, development, production and processing continue to evolve and improve. The SPE Oil and Gas Reserves Committee works closely with other organizations to maintain the definitions and issues periodic revisions to keep current with evolving technologies and changing commercial opportunities.

The SPE PRMS document consolidates, builds on, and replaces guidance previously contained in the 1997 Petroleum Reserves Definitions, the 2000 Petroleum Resources Classification and Definitions publications, and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources"; the latter document remains a valuable source of more detailed background information.,

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that SPE PRMS will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

The full text of the SPE PRMS Definitions and Guidelines can be viewed at:
www.spe.org/specma/binary/files/6859916Petroleum_Resources_Management_System_2007.pdf

[1] These Definitions and Guidelines are extracted from the Society of Petroleum Engineers / World Petroleum Council / American Association of Petroleum Geologists / Society of Petroleum Evaluation Engineers (SPE/WPC/AAPG/SPEE) Petroleum Resources Management System document ("SPE PRMS"), approved in March 2007.

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.

Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

On Production

The development project is currently producing and selling petroleum to market.

The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project “chance of commerciality” can be said to be 100%. The project “decision gate” is the decision to initiate commercial production from the project.

Approved for Development

A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.

At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity’s current or following year’s approved budget. The project “decision gate” is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

Justified for Development

Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.

In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity’s assumptions of future prices, costs, etc. (“forecast case”) and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project “decision gate” is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.

Proved Reserves

Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes:

(1) the area delineated by drilling and defined by fluid contacts, if any, and

(2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that the locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.

Probable Reserves

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.

It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Possible Reserves

Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves

The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.

Probable and Possible Reserves

(See above for separate criteria for Probable Reserves and Possible Reserves.)

The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Developed Reserves

Developed Reserves are expected quantities to be recovered from existing wells and facilities.

Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves

Shut-in Reserves are expected to be recovered from:

(1) completion intervals which are open at the time of the estimate but which have not yet started producing,

(2) wells which were shut-in for market conditions or pipeline connections, or

(3) wells not capable of production for mechanical reasons.

Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Undeveloped Reserves

Undeveloped Reserves are quantities expected to be recovered through future investments:

(1) from new wells on undrilled acreage in known accumulations,

(2) from deepening existing wells to a different (but known) reservoir,

(3) from infill wells that will increase recovery, or

(4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to

(a) recomplete an existing well or

(b) install production or transportation facilities for primary or improved recovery projects.

CONTINGENT RESOURCES

Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.

Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

Development Pending

A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.

The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to “On Hold” or “Not Viable” status. The project “decision gate” is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.

Development Unclarified or on Hold

A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.

The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a reclassification of the project to “Not Viable” status. The project “decision gate” is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

Development Not Viable

A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.

The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project “decision gate” is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.

PROSPECTIVE RESOURCES

Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.

Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.

Prospect

A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.

Lead

A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.

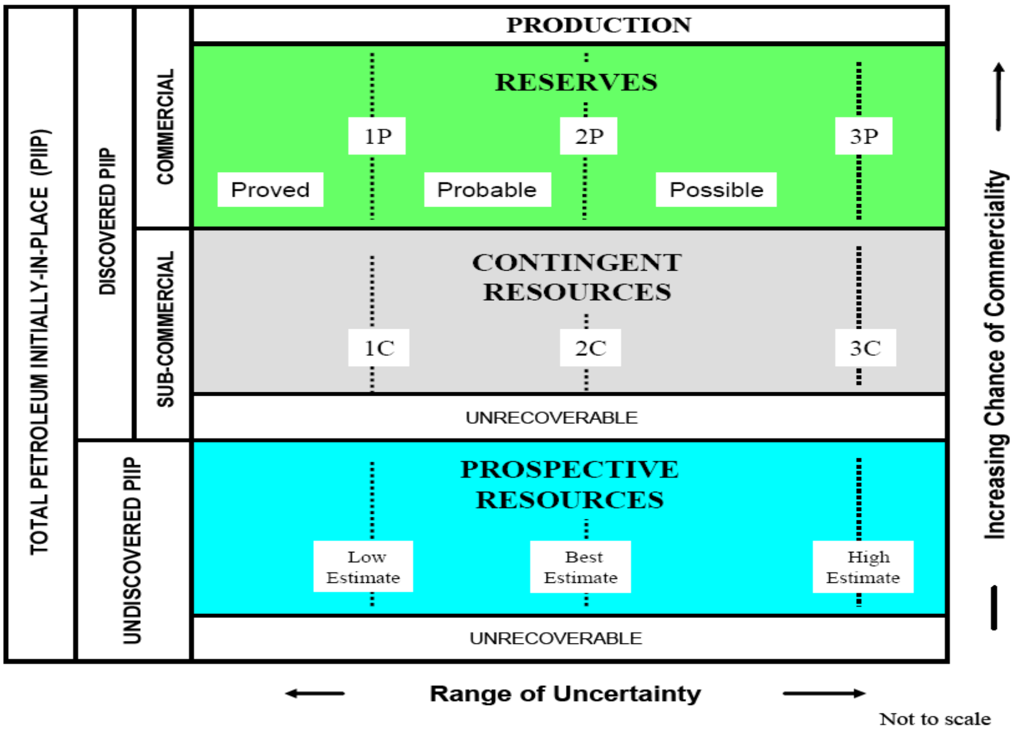
Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.

Play

A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

RESOURCES CLASSIFICATION



PROJECT MATURITY