

PART III



COMPETENT PERSON'S REPORT

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21st November, 2007

Gentlemen,

EVALUATION OF THE ASSETS OF RODEO DEVELOPMENT LTD

In response to your request, RPS Energy ('RPS') has completed an independent evaluation of the Logbaba Asset, onshore Cameroon ('the Property') currently owned by Rodeo Development Ltd. ('RDL') and RSM Production Corporation ('RSM'). We have estimated reserves and resources as at 1 July 2007 based on data and information available up to that time. This work is in the context of Bramlin Limited's ('Bramlin') intention to acquire RDL. The attached report has been prepared in the form of a Competent Persons Report ('CPR') that meets the requirements of the Alternative Investment Market (AIM) of the London Stock Exchange (LSE) as specified in the LSE Guidance Note, dated March 2006, pertaining to such documents.

The AIM Guidance requires that resource estimates are prepared and described on the basis of a "Standard". The resource estimates shown in this report are based on the resource definitions jointly set out by the Society of Petroleum Engineers ('SPE'), the World Petroleum Congress ('WPC'), the American Association of Petroleum Geologists ('AAPG') and the Society of Petroleum Evaluation Engineers ('SPEE') in April 2007 in a document entitled Petroleum Resources Management System".

The work was undertaken by a team of professional petroleum engineers, geoscientists and economists and is based on data supplied by Bramlin. Our approach has been to prepare independent estimates of resources by determining, first, whether the hydrocarbon volumes in the Property can properly be classified as Reserves, then, secondly, what portions of those volumes can be assessed as Proved (1P), Proved plus Probable (2P) and Proved plus Probable plus Possible (3P). All of these volumes are Undeveloped.

In estimating the resource volumes and their value we have used standard petroleum engineering and economic evaluation techniques. These techniques combine geological and production data with detailed information concerning fluid characteristics and reservoir pressure. We have estimated the degree of uncertainty inherent in the measurements and interpretation of the data and have calculated a range of recoverable resources. We have constructed an economic model, on the basis of various contracts that have been made available to us, and we have calculated values for each of the reserves categories. We have taken the working interest that RDL has in the Properties as presented

by Bramlin and we have not investigated nor do we make any warranty as to RDL's interest in the fields.

RDL's interests can be summarised as follows:

- **Existing exploration permit:** an exploration well and three appraisal wells were drilled on the Logbaba permit, onshore Cameroon, between 1955 and 1957. All four wells encountered hydrocarbons. Under the terms of a farm-in agreement relating to RSM's interest in the Logbaba permit, RDL is committed to drilling at least two new wells on the permit, in order to retain a 60% working interest in the asset.

Reserves

Logbaba Field	Gross Estimate			Net Attributable			Operator
	Proved	Proved plus Probable	Proved plus Probable plus Possible	Proved	Proved plus Probable	Proved plus Probable plus Possible	
Condensate	0.17	1.78	3.42	0.12	1.12	2.09	RDL
NGL	0.20	2.05	3.95	0.14	1.29	2.41	RDL
Total for Liquids	0.37	3.83	7.37	0.26	2.41	4.50	RDL
Gas Reserves	10.04	104.88	202.39	7.00	65.87	123.71	RDL
Total for Gas	10.04	104.88	202.39	7.00	65.87	123.71	RDL

Table 1 - Reserves Estimates, (MMbbls, for liquids, and Bscf, for gas)

No Contingent or Prospective Resources have been identified.

Qualifications

RPS Energy is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. Except for the provision of professional services on a fee basis, RPS Energy does not have a commercial arrangement with any other person or company involved in the interests that are the subject of this report. Dr. Graeme Simpson, Director, Advisory of RPS Energy, has supervised the evaluation.

Dr. Simpson has thirty two years of oil and gas industry experience. He is a Director of RPS Energy, a Chartered Geologist, a Certified Petroleum Geologist, a Member of various professional societies, including the Energy Institute, the Geological Society, the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers. He is an Honorary Professor of Petroleum Geology in the University of Aberdeen, Scotland. Other RPS Energy employees involved in this work hold at least a Masters degree in geology, geophysics, petroleum engineering or a related subject or have at least five years of relevant experience in the practice of geology, geophysics or petroleum engineering.

Basis of Opinion

The evaluation presented in this report reflects our informed judgement based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, RPS Energy is not in a position to attest to the property title, financial interest relationships or encumbrances related to the property. Our estimates of potential resources

and values are based on data provided by Bramlin. We have accepted, without independent verification, the accuracy and completeness of these data.

The report represents RPS Energy's best professional judgement and should not be considered a guarantee or prediction of results. It should be understood that any evaluation, particularly one involving exploration and future petroleum developments may be subject to significant variations over short periods of time as new information becomes available. Our liability is limited solely to Bramlin as per the Letter of Engagement between Bramlin Ltd and RPS Energy Limited.

This report relates specifically and solely to the subject asset and is conditional upon various assumptions that are described herein. This report must, therefore, be read in its entirety. This report was provided for the sole use of Bramlin on a fee basis. This report in its entirety may be reproduced or redistributed to any other persons. However in instances where excerpts only are to be reproduced or published this cannot be done without the express permission of RPS Energy.

RPS Energy has given and not withdrawn its written consent to the issue of this document with its name included within it and with inclusion therein of its report and references thereto in the form and context in which they are included for the purposes of Annex I to the AIM PD Rules. RPS Energy accepts responsibility for the information contained in the RPS Energy Report set out in this part of this document and to the best knowledge and belief of RPS Energy, having taken all reasonable care to ensure that such is the case, the information contained in such report is in accordance with the facts and does not omit anything likely to affect the import of such information.

Yours faithfully,

RPS Energy,

A handwritten signature in black ink, appearing to read 'G Simpson', written over a horizontal line.

Dr. Graeme Simpson
Director, Advisory

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1. INTRODUCTION

1.1. ASSET AND METHOD OF EXTRACTION

The only asset on which RPS has been asked to report is the Logbaba gas-condensate field, onshore Cameroon.

The field was discovered and appraised between 1955 and 1957 by Elf Serepca, but as there was no market for the gas at that time, the four wells that Elf Serepca drilled, each of which encountered gas, were plugged and abandoned.

In 2001 the licence was re-awarded to 100% to RSM Production Corporation (RSM); Rodeo Development Ltd (RDL) farmed in to the licence in 2005, and the farm-in terms provide for RDL to earn a 60% interest. Bramlin now proposes to purchase all of the assets and liabilities of RDL.

The current plan is to drill at least two new wells, adjacent to the old wells, and to produce gas, condensate and Natural Gas Liquids (NGLs) to sell into the local market.

Permit	Operator	Interest (%)	Status ¹	Licence Expiry Date	Licence Area (km ²)	Comments
Logbaba	RDL	60	Exploration	2052*	64	Application for conversion to an Exploitation Licence is in progress

** note that this date assumes conversion to an Exploitation Licence*

Table 1 - Asset Summary (Source: RDL)

1.2. DATABASE

This Competent Persons Report has been based on a database comprising the following information sources:

- **Well data:** for the four wells drilled in 1955 by Elf Serepca. These data include logs (SP and resistivity curves only); pressure and flow rate data for the intervals tested; and well completion reports
- **RSM maps:** a set of structure and isopach maps prepared by RSM
- **Independent Assessment Report:** a report entitled "Evaluation of the Interests of Rodeo Development Ltd. In the Development of the Logbaba Gas-Condensate Field, Onshore Cameroon", dated February 8 2007, by Petrotech Engineering Ltd. For RPS's comments on this report, see section 3.2
- **A Market Study:** a short report entitled "Etude de Marche sur le Project d'Exploitation du Gaz Naturel de Logbaba"
- **A Power Plant Study:** a presentation prepared by RDL entitled "Power Plant Proposal"

No seismic data over the field have been made available.

¹ Exploration, Development or Production only, per AIM Guidelines, March 2006

2. OVERVIEW OF THE REGION LOCATION AND ASSETS

2.1. ASSETS AND LIABILITIES

Logbaba Field

The Republic of Cameroon is situated on the Gulf of Guinea and forms part of West Central Africa (Figure 1). The major cities are Douala - the economic metropolis; Yaounde, the political capital; Nkongsamba; and the port of Limbe where the refinery is located.

The Douala / Kribi-Campo Basin comprises part of the greater West African Margin Basin System and is the northernmost of a series of genetically related basins that stretch from the Walvis Ridge to Cameroon. The main source rock sequence in the Douala Basin is Lower Cretaceous in age. Turbidites and deep sea fan deposits comprise the Upper and Lower Cretaceous reservoir sequences although in the latter fluvial and alluvial reservoirs have also been encountered. Shallow water deltaic Tertiary deposits are also potential reservoirs, in the shallow water areas of the basin. The Logbaba Field contains a series of stacked reservoirs of Campanian and Santonian (Upper Cretaceous) age. There may be additional deeper potential, but it has not been assessed by RPS.

The Logbaba Field is located in the northern Douala Basin within the eastern suburbs of Douala, in Cameroon, West Africa (Figure 2). The Douala Basin lies to the southeast of the Niger Delta, a prolific petroleum province. It is separated from the Niger Delta by a northeast-southwest trending Volcanic Complex (see Figure 3) which includes the active Mount Cameroon Volcano onshore and the islands of Bioko (formerly Fernando Po) and Principe offshore to the southwest. The thermally mature petroleum systems present in the Douala Basin include the Middle Cretaceous and Late Tertiary sequences. Tectonically, the Douala Basin is characterized by the development of listric growth faults; rollover into these faults generates lowside structural closures in addition to the highside closures (see Figure 4). There may be additional structuring due to movement on the underlying Aptian salt, but without seismic data it is not possible to comment further on this.

The French company Elf Serepca drilled the LA-101 well in late 1954, near the small village of Logbaba. Two highly over-pressured sandstone reservoirs were encountered in the Campanian (Upper Cretaceous) section between 1,600 and 1,800 m below sea level, and the well blew out. The well flowed out of control for 38 days but was eventually brought under control. Before being capped, the well flowed at an estimated 24 MMcf of gas per day, with an undetermined amount of condensate, producing a total of approximately 0.9 Bcf of gas. After the blow-out was brought under control, casing was set across the over-pressured reservoir and this casing was then perforated between 1,764-1,768 m measured depth. Tests of this reservoir yielded gas at a daily rate of 440,000 m³ (15.54 MMcf) of gas and 41 m³ (258 barrels) of condensate with a gas-oil ratio ('GOR') of 10,500 m³/m³ to 11,000 m³/m³ through a 3/4" choke for a period of three days, with a cumulative gas production of 1,770,000 m³ (62.5 MMcf).

The LA-102, LA-103, and LA-104 appraisal wells were drilled between 1955 and 1957, and they each found gas in various sand "lenses" (bodies of reservoir rock). The LA-102 and LA-103 wells both tested gas from Campanian sand lenses; LA-104 was not tested. There was no gas market at that time, so the wells were plugged and abandoned, and no further wells have been drilled since then.

RPS was supplied with a depth structure map for the top of the Campanian section, and this illustrates the nature of the inferred trapping mechanism in a dip closed structure associated with a north-south oriented listric fault, downthrown to the west. RPS believes that this is a reasonable representation of the Logbaba structure, given the regional context and the constraint of having no seismic data. Using this map, and data from the four wells, RPS constructed depth structure maps for each of the four sand packages (A, B, C and D), and used these in volumetric computations. Figure 5 is the Top Campanian C depth structure map, as an example, for illustration purposes. Figure 6 is a schematic cross section through three of the wells, again to illustrate the inferred trapping mechanism.

The licence area is illustrated in Figure 1, and the terms are discussed in Section 4 of this report.

2.2. INTERESTS IN THE ASSETS

RPS and its staff have no interest in any of the assets described in this report.

3. RESERVE AND RESOURCE ESTIMATES

3.1. LOGBABA FIELD

Licence	Logbaba
Operator	Rodeo Development Ltd
RDL Interest	60 per cent.
Partner	RSM 40 per cent.

Table 2 - Logbaba Field Data

Summary

The assessment of the volumes to be produced from the Logbaba Field uses, as a Standard, the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, as issued in April 2007. This, in turn, refers back to the SPE/WPC/AAPG Guidelines document of 2001.

In this system, in order for a volume of hydrocarbons contained within a reservoir to qualify as Reserves, it must be assessed as being:

- Discovered (i.e. have tested hydrocarbons to the surface in measurable quantities)
- Recoverable (i.e. not "in-place", but just those volumes that can be collected and sold at the surface, corrected to surface temperatures and pressures)
- Commercial (i.e. the owner(s) have shown a clear commitment to develop the accumulation within a reasonable timeframe)
- Remaining (i.e. excluding any volumes already produced by the "as of" date)

RPS believes that the Logbaba hydrocarbons do qualify as Reserves. Specifically, RPS regards the Marketing Study as establishing, with reasonable certainty, the existence of a market and of RDL's intention to deliver to that market.

Proved Reserves (1P)

To qualify as Proved Reserves, there should be "at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate".

The four wells drilled at Logbaba provide the only firm subsurface information for the assessment of the volumes that could be produced from the field. Specifically, there are no seismic data available, so there is no firm evidence as to the structural configuration of the reservoir(s), although the fact that hydrocarbons have been tested to the surface indicates that a working petroleum system exists, and particularly, a trapping mechanism exists. However, we do not know, with any reasonable certainty, whether that trapping mechanism is structural or stratigraphic, or what the extent and geometry of the reservoir(s) is. In particular, we cannot assess, with any reasonable certainty, the position, orientation and throw of faults, though it is likely that listric normal faults are present, and we cannot make any observations of salt tectonics or their influence on the reservoirs.

RPS therefore believes that, to a level of reasonable certainty, as required by the SPE Guidelines, the only data that can be used for the assessment of Proved Reserves are the well test data. There is sufficient pressure and produced volume data, in each of the three wells that were tested, to use the material balance method to give an estimate of the gas initially in-place (GIIP) that can be accessed from each of the wells.

On this basis, Proved Reserves have been assigned to the Campanian C reservoir in wells LA-101 and LA-102, and to the Campanian D reservoir in well LA-103.

The Campanian A sand was tested in LA-101, but did not flow at commercial rates (only traces of gas were recovered); the Campanian B sand was tested in LA-103 and recovered some gas, but insufficient volume and pressure data were recorded to estimate volumes. No Proved Reserves have been assigned to these intervals in these wells.

Proved plus Probable (2P), and Proved plus Probable plus Possible (3P) Reserves

The SPE Guidelines require that it can be said of the volumes assigned to the 2P and 3P categories, that with “50% and 10% certainty, respectively ... the quantities actually recovered will equal or exceed the estimate”.

RPS believes that the isopach and structure maps that it has generated from the well data do give sufficient confidence for the hydrocarbons that can be assessed from them, in terms of a geometric assessment of volumes, to qualify, at the 50% and 10% certainty level, as 2P and 3P Reserves respectively.

Isopach maps were constructed on the basis of top and base reservoir picks in each of the wells. These were then truncated downdip on the basis of a notional structure map, near the gas-down-to level in the segment around each of the wells for 2P Reserves, and down to the mapped closure for 3P Reserves. In the 3P case, the porosity and gas saturation were increased slightly relative to the values seen in the well logs.

Database

The database utilized includes analogue wireline log data, with SP and resistivity curves, from the four wells; well test data from the LA-101, 102 and 103 wells; and core data and well completion reports.

Reservoir

The reservoir appears to consist of a series of stacked sand lenses, of Upper Cretaceous age (Figure 7), encased in shales. They were probably deposited as marine turbidite or submarine fan-channel systems, sourced from the east and north and extending to the west into the expanding rift-basin. It is possible, though by no means certain on the basis of the available data, that the sands correlate between the wells, as shown in Figure 8.

RPS digitized and then analyzed each of the well logs, and derived reservoir average values for porosity (between 18% and 20%) and gas saturation (between 60% and 70%), along with net pay thickness.

No hydrocarbon-water contacts have been seen.

GIIP

Gas in place volumes have been computed as shown in Table 4, below

	Low Estimate P90	Best Estimate P50	High Estimate P10
RPS computation	12.6	136	260

Table 3 - Logbaba GIIP, 100 % Basis (Bcf)

Field Development Plan

RPS’s understanding of the Field Development Plan, to which the owners have stated they are committed, is as follows:

- Drill, test and complete four wells, each to be a “twin” of an existing well.
- The current plan is to drill extended-reach deviated wells from a central pad, due to dense population in the area. The central pad is to be located at site of Well LA 104, which is adjacent to the proposed gas plant.
- Perform production tests before bringing wells on-stream. The plan is to co-mingle completions in all the zones identified in the volumetrics work.
- Construct a gas plant and tie-in the wells.
- The gas plant is designed for 25 MMscfd operating load (the 2P case). In addition to lease (separator) condensate, the gas refrigeration plant will recover propane, butanes and pentanes (natural gas liquids, ‘NGL’).
- All products (sales gas, condensate, NGL) are to be delivered at the tailgate of the plant. Shipping of condensate will be by truck. There will be handling facilities for NGL in the plant.

- The gas refrigeration plant is designed to produce a NGL mix that will be sold at the plant tailgate. Additional facilities to fractionate propane and butane are not anticipated at this time. However, a separate company may be formed to strip the propane and butane using a de-propanizer and de-butanizer, downstream of the gas refrigeration plant, and to sell the pentane+ mix. This company can then distribute the propane and butane to the local markets and would be responsible for the capital and operating costs of such facilities to separate and distribute propane and butane.
- A power plant, adjacent to the gas plant, is planned, and will receive 17 MMscfd.
- Industrial users to receive 8 MMscfd, per the marketing study. A separate utilities company deals with the distribution of the sales gas to industrial customers.
- It is assumed that production from LA 103 and LA 101 offset wells will be on-stream in August 2009, following the completion of the gas plant. It is further assumed that, if wells LA 103 and 101 only indicate Proved Reserves volumes, then drilling will cease at this point. The Proved Reserves case valuation therefore is only burdened with the costs of two wells, and all of the production is sold to industrial users, at \$10 per Mcf. For the 2P case, production from LA 102 is assumed to be on-stream in December 2009. Production from LA 104 is assumed to be on-stream as soon as is required to maintain the 25 MMscfd plateau.
- It has been assumed that, as Logbaba Field production capacity declines, the power plant will receive supply in preference to industrial users. The power plant requires 19,000 MMBtu/day supply to stay on-stream (its "turndown" supply). It has further been assumed that as Logbaba field production capacity declines below 19,000 MMBtu/day, a third party supply of gas will become available to make up the load gap so that the power plant may be kept on line.
- Production will be via natural flow. The planned minimum flowing tubing-head pressure is 550 psig. Compression is not anticipated at this time.

Further notes:

The concession agreement requires the leaseholder to build a sales gas pipeline. The gas will be sold at the plant gate. A separate utilities company buys the gas and sells it to the industrial, residential and power generation customers.

There is no requirement to twin drill LA 104 to 14,000 ft and the drilling of the third and fourth well is not under any time restriction.

Drilling will take place from a central pad located close to the LA-104 well site. This will minimize costs of the relocation of local residents and ensure the security of the wells and future facilities. A centrally located pad will reduce future operating costs in regards to maintenance of locations, roads, and personnel requirements.

The cost assumptions shown below are in 2007 real terms:

- Twin drill LA 101, LA 102, LA 103, and LA 104 wells at US\$10 million per well for the first three, and US\$12.25 million for LA 104
- Gas processing plant cost = US\$10 million
- Tie-in well cost = US\$400,000 per well
- Total abandonment costs are estimated to be US\$150,000 per well, and US\$500,000 for the gas plant
- Gas price sold to industrial users US\$10 per Mcf
- Gas price sold to power plant US\$6.25 per Mcf
- Condensate price at US\$60 per barrel
- NGL price at US\$40 per barrel

After the first well is drilled and tested, the test results can be used for the specifications of the final design, and there would be sufficient time to fabricate refrigeration units for site installation prior to first production in the first quarter of 2009.

Marketing Study

A gas marketing study has been carried out by RDL, Tradex and Cameroon local academic consultants. The primary conclusions of this study are as follows:

- It is anticipated that a total of about 3 Bcf per year of demand exists, from conversion from current energy sources, and electrical power generation.
- The market is expected to grow by about 4.5% per year.
- These levels support an estimated sales price of US\$10.00 per Mcf.

The report on this study is regarded by RPS as justifying the commerciality of those volumes that, on a technical basis, are candidates to qualify as Proved Reserves.

Power Plant Study

RPS has been provided with a RDL presentation relating to a proposed power plant. The plans for this plant appear to be at a preliminary stage, but RPS accepts that, at a 50% confidence level, it is reasonable to assume that the plant will be built and gas volumes in excess of the Proved volume will be sold to it.

Reserves

It is assumed that, if the twins to the LA 101 and 103 wells only indicate the volumes that analysis of the test data on the original wells suggest, then drilling will cease at this point. The Proved case therefore includes only those volumes that the test data indicate were accessed by the LA-101 and 103 wells. Production and cost profiles were calculated on the basis of reaching a peak production, after three years, of 9.4 MMscfd, as indicated as an upper limit by the Marketing Study. The Proved case valuation is only burdened by the costs of two wells.

The Proved plus Probable case profiles were constructed on the basis of reaching a production plateau of 25 MMscfd after three years, and maintaining this plateau for approximately seven years.

The Proved plus Probable plus Possible case profiles were constructed on the basis of an assumed plateau production rate of 40 MMscfd, maintained for seven years.

Condensate and NGL yields derived from the test data and gas plant retention factors were used to calculate liquid recovery volumes.

Logbaba Field	Proved	Proved plus Probable	Proved plus Probable plus Possible
Gas (Bcf)	10.04	104.88	202.39
Condensate (MMbbls)	0.17	1.78	3.42
NGL (MMbbls)	0.20	2.05	3.95

Table 4 - Logbaba Reserves, 100% Basis

An economic evaluation of the Logbaba reserves is presented in Section 4, below.

3.2 THE PETROTECH ENGINEERING LTD REPORT

Under a cover letter dated February 8 2007, Petrotech Engineering Ltd delivered a report to the directors of RDL that was "considered as parts of the admission documents for a listing with the Alternate Investment Markets (AIM) of the London Stock Exchange. [sic]"

RPS reviewed this report in detail, but was unable to fully endorse the results reported, for the following reasons:

- RPS does not believe that the notional maps that are all that can be generated from the data supplied to RPS give sufficient confidence to be the basis for assessing Proved Reserves.
- The Petrotech report was completed before the Marketing Study was completed, and therefore does not include the volume and price constraints that this study reveals.
- The Petrotech report makes no reference to the potential for supplying gas to a power plant.

Discussions with the author of the report suggest that a map or maps were made available to him that were not made available, for whatever reason, to RPS, and that he used this map or maps as the basis for assessing Proved Reserves. This does not alter the RPS view that, in the absence of seismic data, only the well test data can be used in assessing Proved Reserves volumes.

It is also worth noting that it is not possible to reconcile the 2P reserves quoted in the Petrotech report with the work sheets that appear to set out the input to the detailed volumetric calculations. A set of maps was supplied to RPS by RDL, but these do not lead to the Petrotech volumes either, and the Petrotech author has stated that he did not use them.

Nevertheless, it is important to emphasise that the RPS 2P (i.e. most likely) volumes are broadly similar to those given in the Petrotech report, and the fact that they were derived completely independently lends further credibility to them.

4. ECONOMIC EVALUATION OF RESERVES

4.1. FISCAL AND ECONOMIC CONDITIONS

4.1.1. Fiscal Assumptions

On May 31, 2001, the Government of Cameroon entered into a Concession Contract with RSM, giving RSM a 100% interest in the Logbaba Licence. The exploration phase consists of a primary term of two years and two possible two-year extensions, for a maximum of six years. In the Development and Exploitation phase, there is a thirty-five year development production period with one possible ten year extension for a maximum of forty-five years.

Rodeo Resources Inc (RRI) was brought into the project by RSM, and a subsidiary, Rodeo Development Ltd (RDL) was set up to hold the project. Originally, RDL shares were owned by RRI, but as the project required further funding, the share ownership changed. A Reserve Bonus and Contingent Payment Agreement provide for payments to be made to RRI in the event that the project is successful and produces gas.

On December 6 2005, Logbaba Development Ltd. (now RDL) signed a Farm-in agreement with RSM, under which RDL has an interest in the Logbaba Licence. Under the farm-in agreement, the RDL will assume 100% of the Initial and Optional Work Commitment costs in return for which it will retain a 100% working interest before recovery and 60% working interest after recovery of these costs.

The Initial Work Commitment is the drilling and completing of twin wells to the original LA 101 and LA 103 wells. The Optional Work Commitment entails the twinning of two additional wells, LA 102 and LA 104. Gas gathering, tie-ins, production, and gas processing plant facility costs are not included in the work commitments and RDL will have a 60% working interest in these.

RDL was assigned its interest and the operatorship in 2006. During the cost recovery period, RSM will receive a 2% overriding royalty on gross production. After cost recovery, RSM will receive 100% of production attributable to the LA 101, 102, 103 and 104 wells, until recovery of US\$800,000 of their initial investment. Once RSM recovered this sum, the working interests will be 60% RDL and 40% RSM.

The Logbaba Licence is governed by concession terms. Royalty is paid on production and the standard Cameroon Corporate Income tax rate applies to net profits.

RPS extracted the main fiscal terms described in the farm-in Agreement between RSM and RDL which contains, in Annex 1, the original Concession contract between the Republic of Cameroon and RSM. RPS also extracted additional terms from the Contingent Payment and Reserves Bonus agreements entered on December 6 2005 between RDL and Rodeo Resources.

Under the Concession agreement, the gross production is subject to an 8% royalty payable to the government. In addition, under the Contingent Payment agreement, RDL agrees to pay Rodeo Resources a contingent payment equal to 1.2% of gross production.

Additionally, RDL, according to the Reserves Bonus Agreement, agrees to pay a reserve bonus of US\$500,000 per million BOE, up to US\$10,000,000, to Rodeo Resources, where one BOE is defined as being equal to six Mcf. The reserve bonus is based on the gross field reserves, as calculated at the end of the fourth year after commencement of production by RDL under the farm-in Agreement with RSM. In the calculation of the reserve bonus, the BOE reserves shall not be reduced as a result of production during the reference period under the farm-in Agreement.

The Reserve Bonus Agreement states that the reserve classification for the calculation is based on Proved plus Probable plus Possible. However, since the current reserves uncertainty range will almost certainly be reduced after four years of production, RPS has assumed that the reserves base to calculate the reserve bonus is the total recoverable volume that corresponds to the case being evaluated (i.e. 1P, 2P and 3P).

The payment of the reserve bonus can be made in five equal instalments per year, but is subject to accrued interest of 6% per annum of the unpaid balance. It is assumed, in RPS's economic assessment, that the maximum payment is made as soon as possible, to avoid interest payment.

Société Nationale des Hydrocarbures ('SNH', the National Oil Company of Cameroon) will continue to monitor operations as the official representative of the Government. SNH has a right, pursuant to the License Contract, to acquire a 5% interest in the Project by reimbursing RSM 5% of all costs incurred

by RSM during the development and exploitation phase to the time of election. Thereafter, SNH will pay their 5% share of all operating costs and receive their share of production in kind or revenue generated from its sale. RPS has assumed that SNH does not exercise this 5% back-in option.

Under Article 13 of the Contract, the royalty payable to the State is 8%. Under Article 15, additional petroleum levy is exempt but production bonuses are payable as per Article 16, as follows:

1. US\$500,000 for reaching 500,000 m³ (17.658 MMcf) of gas per day of production for 60 consecutive days, or reaching a cumulative production of 365,000,000 m³ (12.9 Bcf) of gas.
2. US\$1,000,000 for reaching 1,000,000 m³ (35.317 MMcf) of gas per day of production for 60 consecutive days, or reaching a cumulative production of 730,000,000 m³ (25.8 Bcf) of gas.

For training of local professionals, the Operator has to provide an annual budget of US\$25,000 during the Development and Exploitation phase of the Contract.

Article 22 of the Contract states that the Contractor is required to open, and make deposits to, an escrow account in a Cameroonian banking institution for the purpose of financing, on a timely basis, the abandonment operations. The Contract does not specify the timing and amount of these deposits. RPS has assumed that deposits to this fund are made on a yearly basis in proportion to the depletion of reserves starting in the year in which the production commences.

Under Article 14 of the Contract, the net profits that the Operator receives from Petroleum Operations in the territory of the Republic of Cameroon are subject to company tax at the rate of 38.50%.

The fiscal terms applicable to the valuation of the stated reserves are summarised below.

Royalties

Proportional Royalty	8%
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Overriding Royalty (paid to RSM during payout and proportionately reduced to 60% assigned to farmee)	2%
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Corporate Income Tax	38.5%
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Training fee (paid yearly during development and exploitation phase)	US \$ 25,000
---	--------------

State Participation (Option – assumed not exercised)	5%
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Cost Recovery

Farmee WI during payout (not including non initial and optional work capex)	100%
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Farmee WI after payout (not including the first US\$ 800,000 of gross revenue)	60%
--	-----

Production bonuses

When production is higher than 500,000 m ³ /d or Cumulative production of natural gas reaches 365,000,000 m ³ , whichever occurs the first.	US\$ 500,000
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When production is higher than 1,000,000 m ³ /d or Cumulative production of natural gas reaches 730,000,000 m ³ , whichever occurs the first.	US\$ 1,000,000
---	----------------

Other payments

Contingent Payment (calculated over 1.2% of total area gross production)	1.2%
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Reserves Bonus Payment	US\$ 500,000 per million BOE up to US\$ 10,000,000
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4.1.2. Economic Assumptions

Inflation Rate

Annual inflation of 2 per cent has been applied to all 2007 US\$ cost and product price estimates.

Gas, Condensate and NGL Price Assumptions

Potential supply of gas to industrial users is documented in the Market Study, dated May 2007. This study supports, at the proposed production levels, a gas price of US\$10.00 per Mcf, and a condensate sales price of US\$60 per barrel.

RPS has assumed an NGL sales price of US\$40 per barrel.

Additionally the, Power Plant Proposal provided by RDL suggests a selling price of US\$ 5.34 per MMBtu (US\$ 6.25 per Mcf).

As a result of the above, RPS has assumed constant hydrocarbon prices, in real terms, of US\$60 per barrel condensate produced, US\$40 per barrel NGL produced, and US\$ 6.25 per Mcf and US\$10.00 per Mcf for gas sold to the Power Plant and industrial users, respectively. These price forecasts have been escalated using the annual inflation rate stated above.

4.2. ECONOMIC VALUATION

4.2.1. Logbaba

RPS has computed NPV10 values, in nominal terms, based on the RPS forecast production. The effective date used is 1 January 2007.

RPS has applied an economic limit test to all calculations. The economic limit is here defined as the point at which the gross before income tax operating cash flow of the project becomes negative (for the last time), and hence continued production beyond this point would result in a net cash loss.

RPS's estimates of post tax net present value are based on cash flow analysis that does not include overhead, management, and administrative fees.

Unit operating costs (Opex) have been provided by RDL and have been accepted, without being independently audited, by RPS. Operating costs applied are as follows:

- Fixed Opex per well: US\$ 25,000/well/month
- Fixed Opex production facilities: US\$ 15,000/month
- Fixed Opex gas plant: US\$ 20,000/month
- Variable Opex production: 1 US\$/Mcf
- Variable Opex processing: 3 US\$/Mcf
- Variable Opex handling: 5 US\$/bbl
- Cameroon nationals training program: US\$ 25,000/year

The following table is a summary of the value, pre- and post-tax (net to RDL), for the Proved, Proved plus Probable, and Proved plus Probable plus Possible reserves cases:

MM\$ NPV @10%	Reserves Category		
	Proved	Proved plus Probable	Proved plus Probable plus Possible
Pre Tax	21.19	192.06	438.75
Post Tax	12.23	117.06	269.23

Table 5 - Net Present Value – RDL

5. CONCLUSIONS

RDL's Logbaba Asset contains Undeveloped Reserves, the volumes and values for which are tabulated below:

Gross Volumes:

Logbaba Field	Proved	Proved and Probable	Proved, Probable and Possible
Gas (Bcf)	10.04	104.88	202.39
Condensate (MMbbl)	0.17	1.78	3.42
NGL (MMbbl)	0.20	2.05	3.95

Table 6 - Logbaba Reserves, 100% Basis

Net to RDL Volumes:

Logbaba Field	Proved	Proved and Probable	Proved, Probable and Possible
Gas (Bcf)	7.00	65.87	123.71
Condensate (MMbbl)	0.12	1.12	2.09
NGL (MMbbl)	0.14	1.29	2.41

Table 7 - Logbaba Reserves (Net to RDL Basis)

Net pre-tax value, in US\$ MM, RDL share:

Logbaba Field	Proved	Proved and Probable	Proved, Probable and Possible
NPV @ 10.00%	21.19	192.06	438.75
NPV @ 12.25%	18.82	161.64	366.49
NPV @ 15.00%	16.72	137.14	309.54

Table 8 - Logbaba pre-tax NPVs (Net to RDL Basis)

Net post-tax value, in US\$ MM, RDL share:

Logbaba Field	Proved	Proved and Probable	Proved, Probable and Possible
NPV @ 10.00%	12.23	117.06	269.23
NPV @ 12.25%	10.63	98.17	224.68
NPV @ 15.00%	9.20	82.94	189.56

Table 9 - Logbaba post-tax NPVs (Net to RDL Basis)

Gross pre-tax value, in US\$ MM:

Logbaba Field	Proved	Proved and Probable	Proved, Probable and Possible
NPV @ 10.00%	38.28	339.03	758.56
NPV @ 12.25%	34.30	286.02	634.00
NPV @ 15.00%	30.76	243.31	535.78

Table 10 - Logbaba pre-tax NPVs (Gross)

APPENDIX A: GLOSSARY OF TECHNICAL TERMS

B		Billion
Barg		gauge pressure in Bar
Bbls		Barrels
Bopd		barrels of oil per day
Bscf		billion standard cubic feet
Condensate		Condensates are a mixture of hydrocarbons (mainly pentanes and heavier) that exist in the gaseous phase at original temperature and pressure of the reservoir, but when produced, are in the liquid phase at surface pressure and temperature conditions.
FBHP		Flowing Bottom Hole Pressure
FTHP		Flowing Tubing Head Pressure
FWHP		flowing well head pressure
GDT		Gas Down To
GIIP		Gas Initially In Place
GOC		Gas-Oil Contact
GRV		Gross Rock Volume
GWC		Gas Water Contact
M		Metres
M		Thousand
Mbbls		thousand barrels
MD		measured depth
mD		permeability in millidarcies
MM		Million
MMbbls		million barrels
MMscm		million standard cubic metres
MMscm/d		million standard cubic metres per day
MMscf/d		million standard cubic feet per day
Mscm/d		thousand standard cubic metres per day
Mstb		thousand stock tank barrels
Natural Gas Liquids (NGL)		Natural Gas Liquids are a mixture of light hydrocarbons that exist in the gaseous phase and are recovered as liquids in gas processing plants.
OWC		Oil Water Contact
Scf		standard cubic feet measured at 14.7 pounds per square inch and 60° F
Scm		standard cubic metres measured at 14.7 pounds per square inch and 60° F
scm/d		standard cubic metres per day
TVDSS		true vertical depth (sub-sea)

APPENDIX B: FIGURES

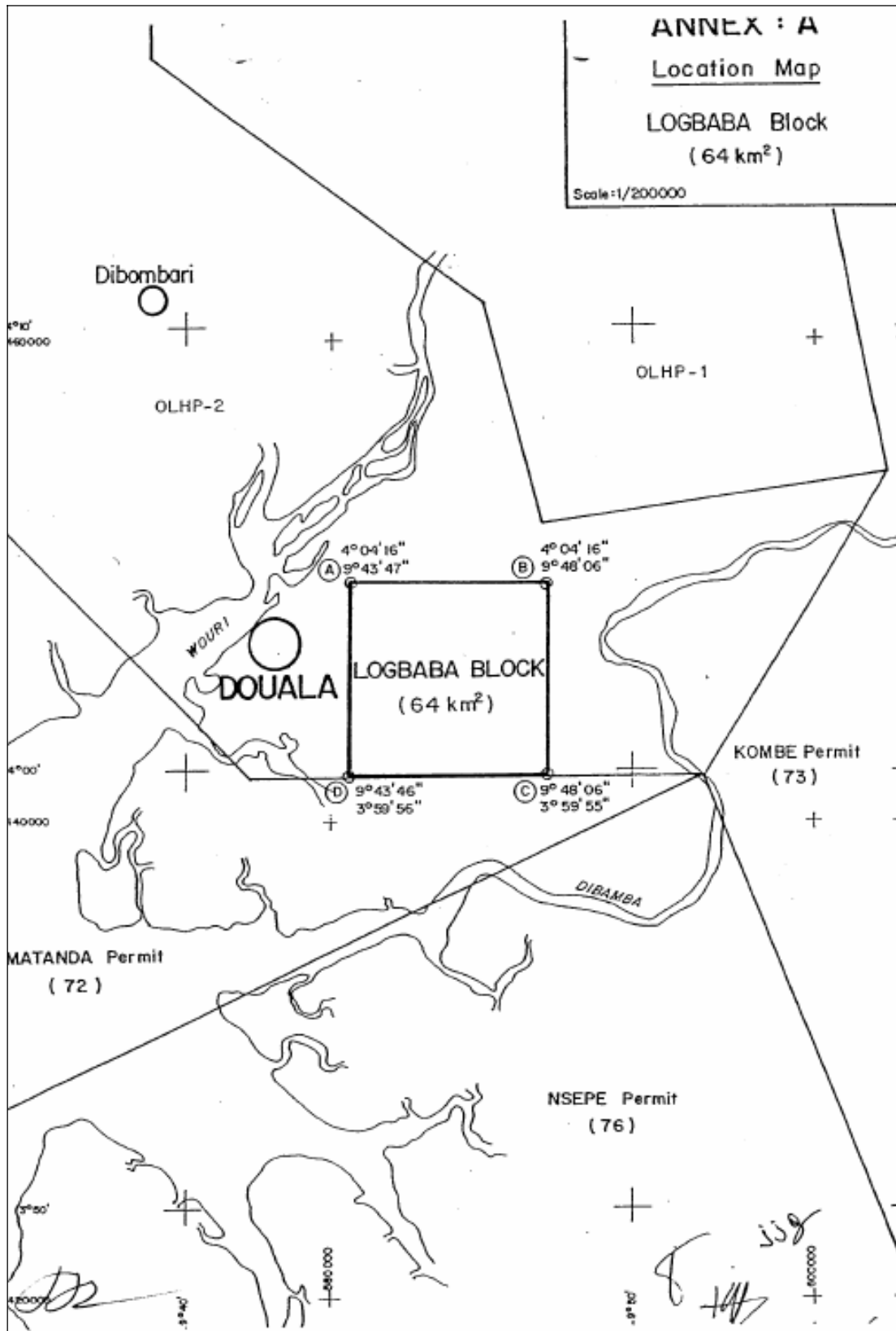
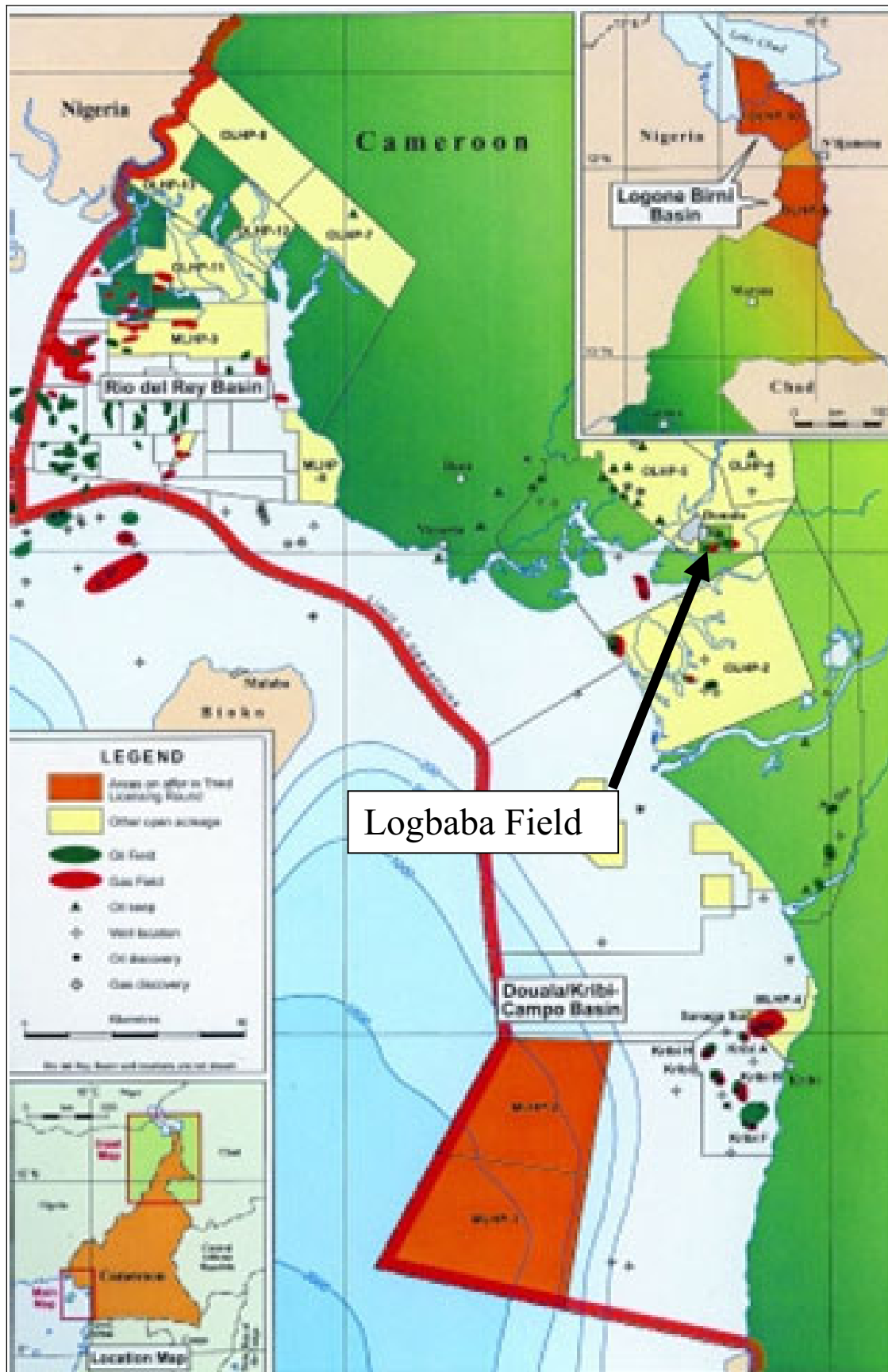


Figure 1 - Location of the Logbaba Block

Figure 2 - Regional Location Map



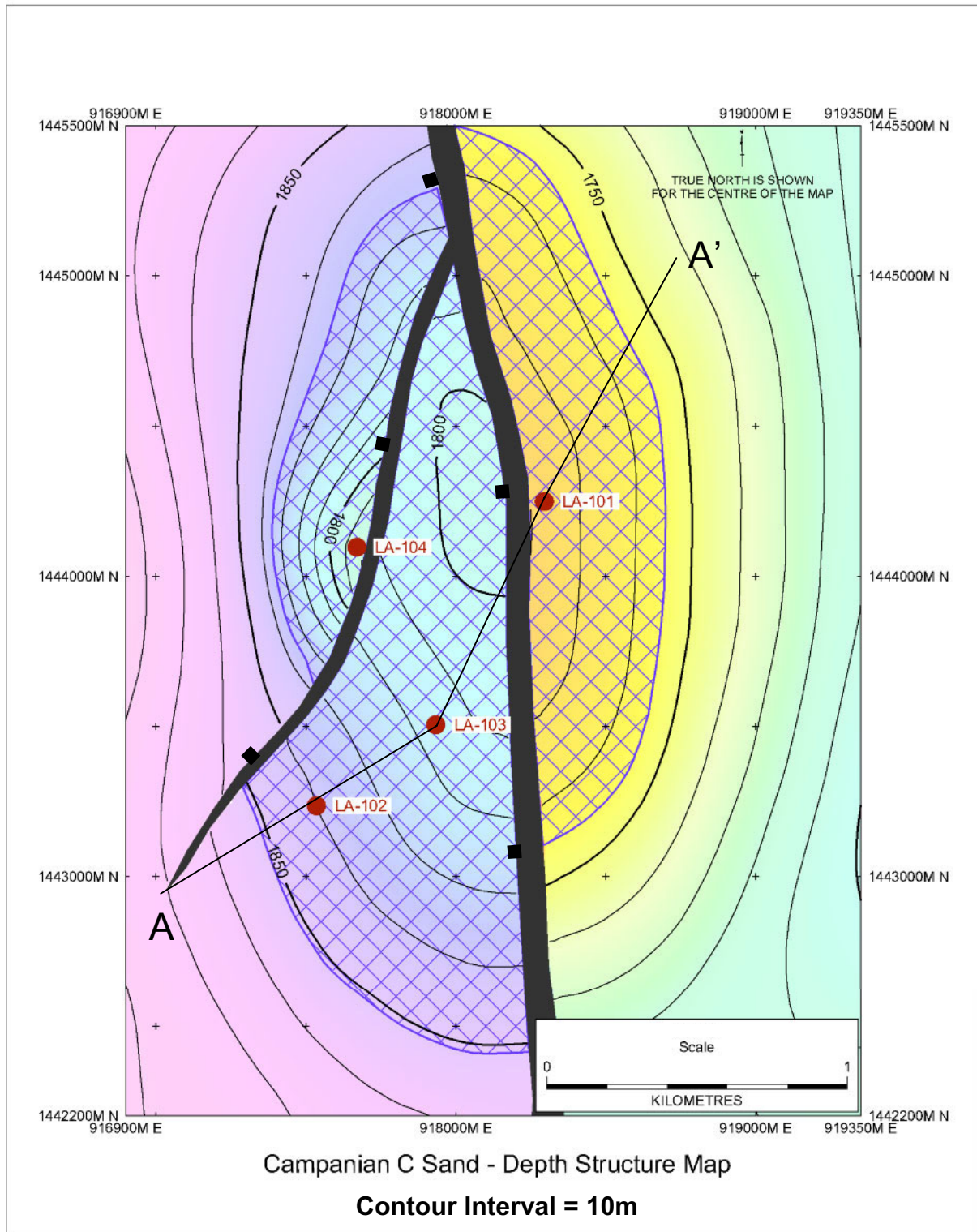


Figure 5 – Campanian C Sand, Depth Structure Map

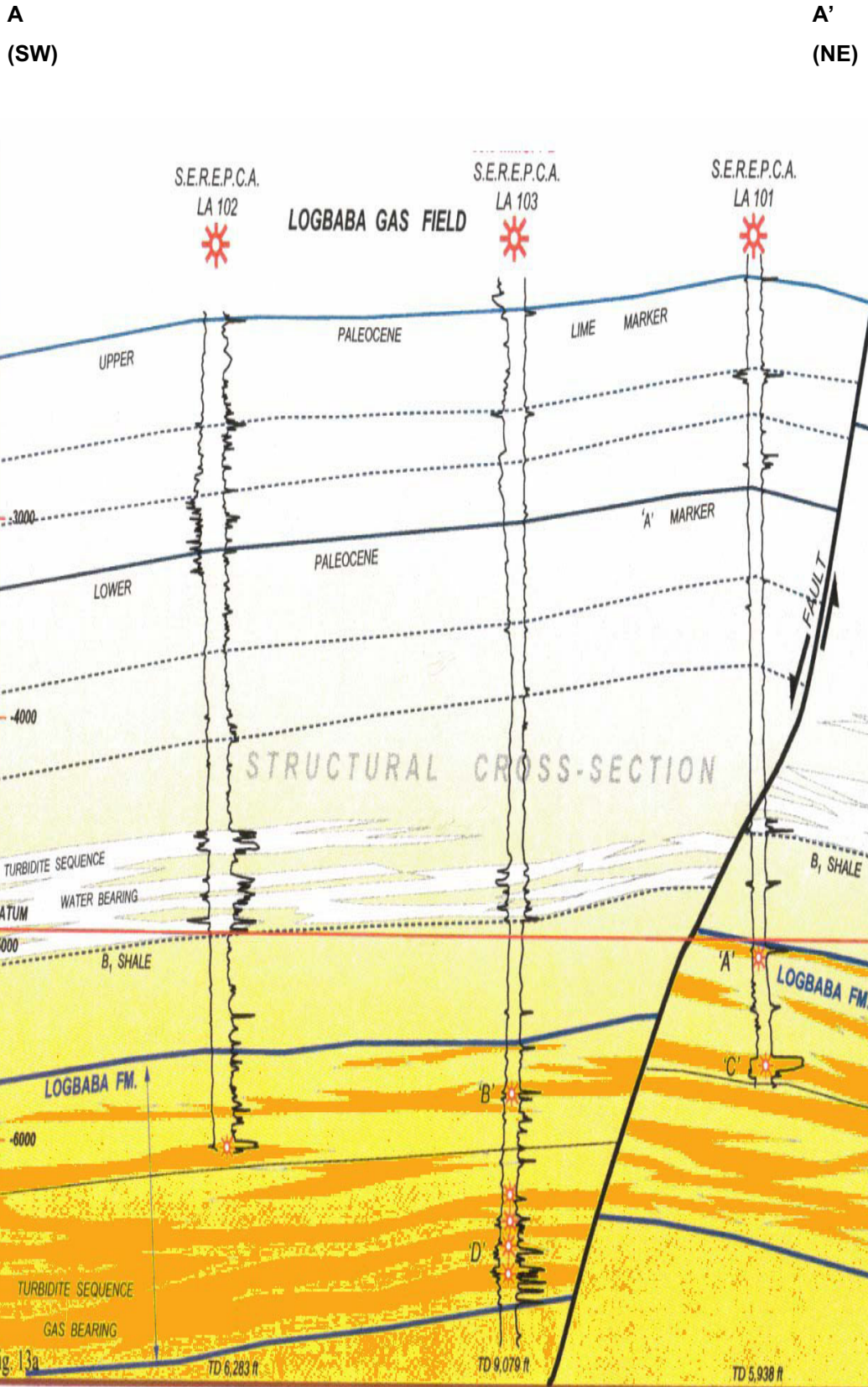


Figure 6 – Schematic South West-North East Cross-Section

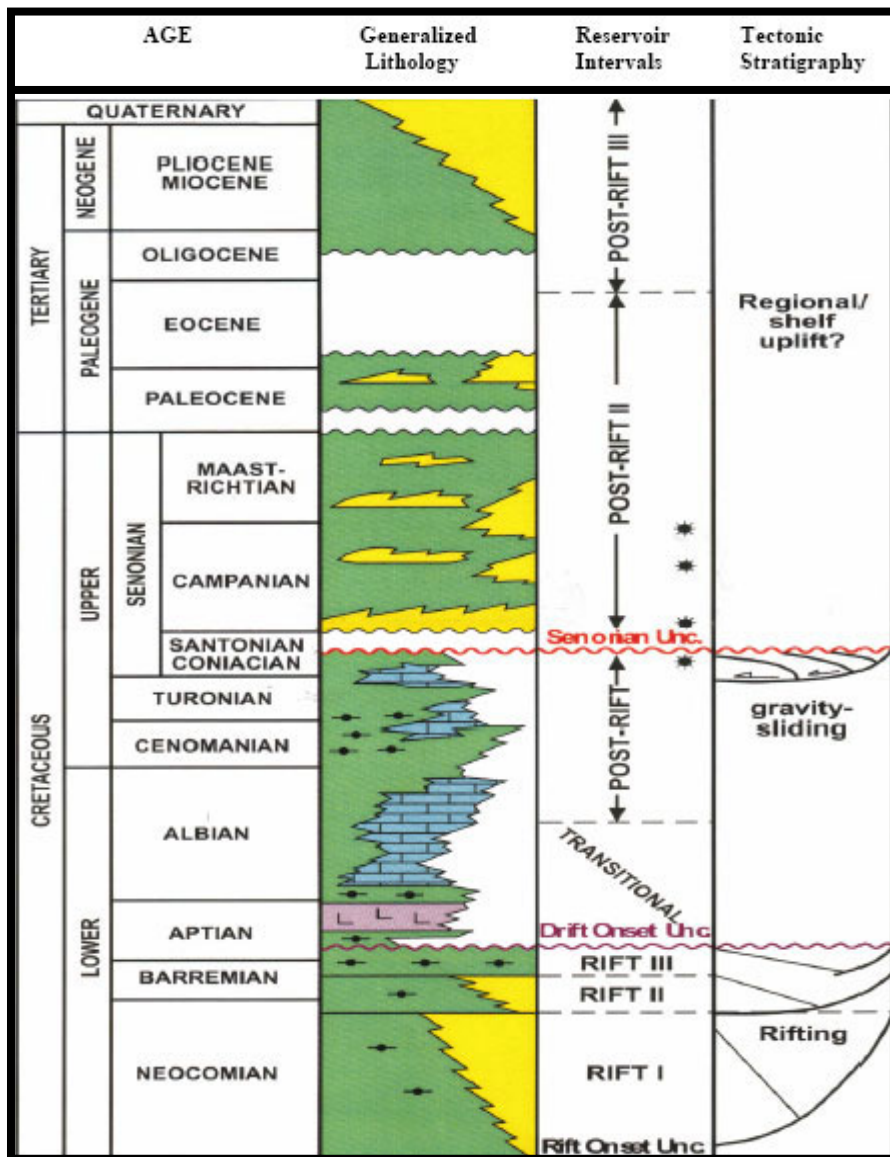


Figure 7 - Stratigraphy of the Douala Basin Sediments

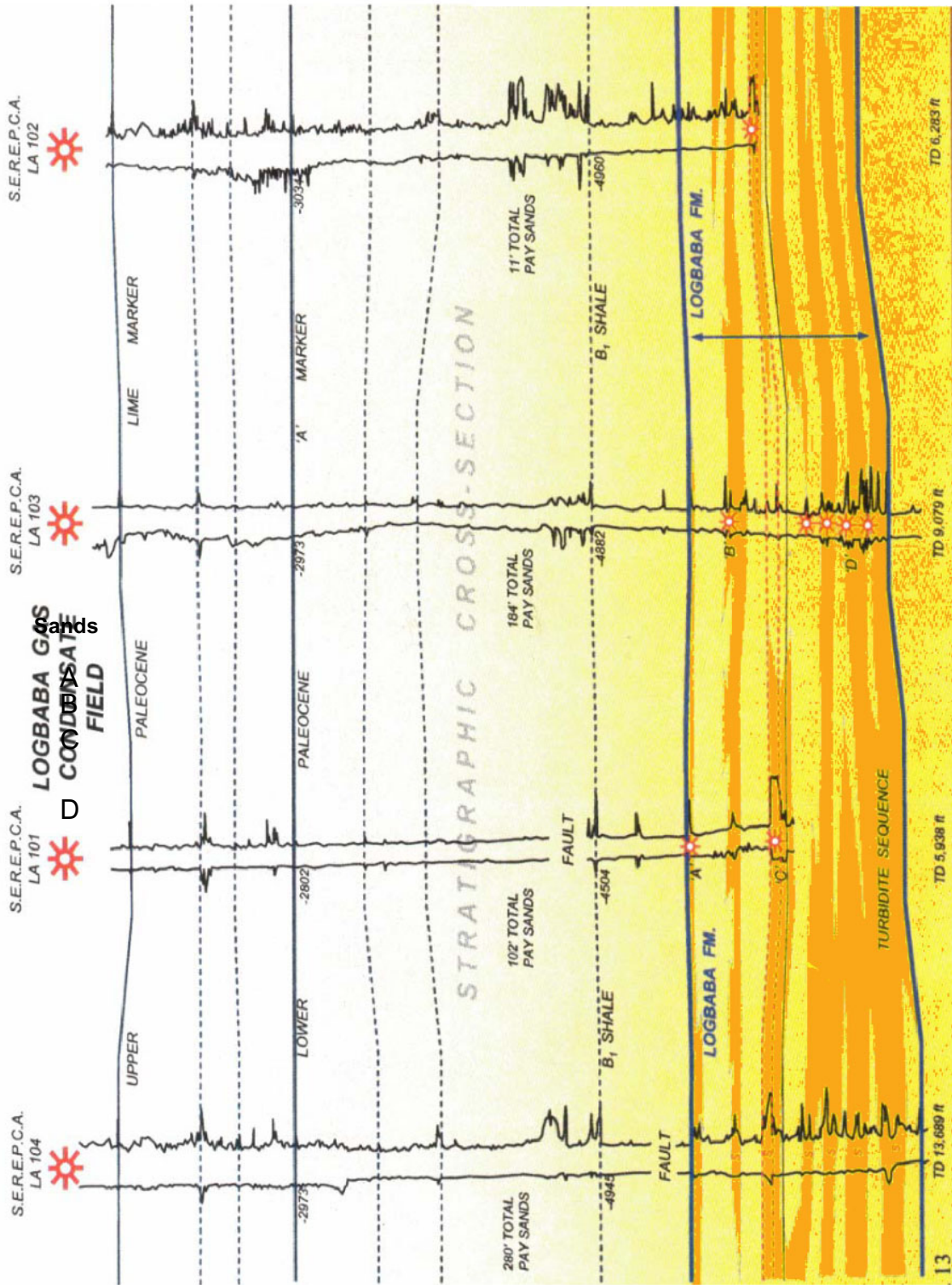


Figure 8 - Well Correlation, Logbaba Field

APPENDIX C: SPE/WPC/AAPG/SPEE RESERVE DEFINITIONS

Petroleum Resources Classification Framework

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide and sulfur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term “resources” as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth’s crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered “conventional” or “unconventional.”

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

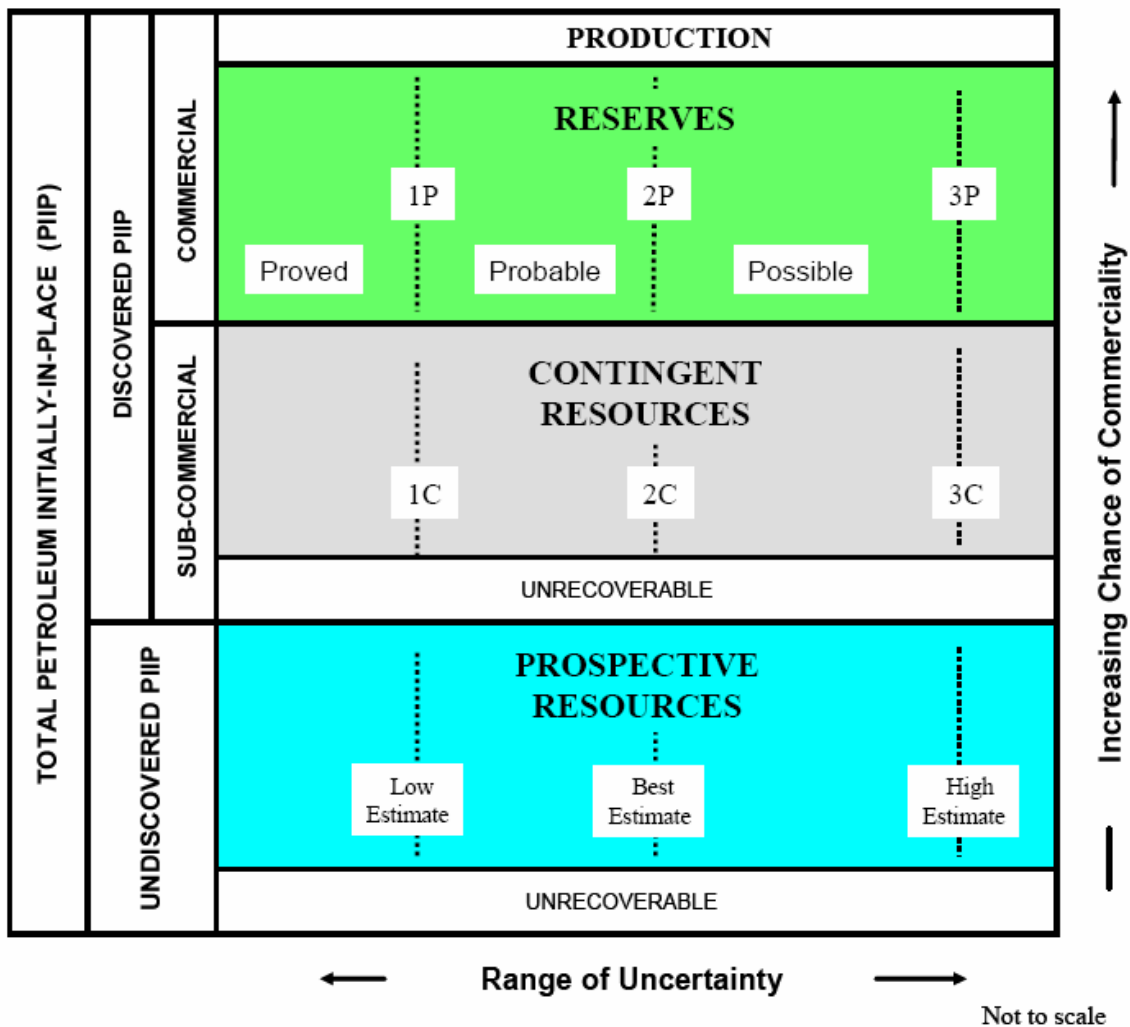


Figure 1-1: Resources Classification Framework.

The “Range of Uncertainty” reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the “Chance of Commerciality, that is, the chance that the project that will be developed and reach commercial producing status.

The following definitions apply to the major subdivisions within the resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated,

as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to “total resources”).

DISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Production Measurement, section 3.2). Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

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 further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves 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 development and production status.

CONTINGENT RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development 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.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

UNRECOVERABLE is that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Estimated Ultimate Recovery (EUR) is not a resources category, but a term that may be applied to any accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable under defined technical and commercial conditions plus those quantities already produced (total of recoverable resources).

APPENDIX D: SUMMARY TABLE OF ASSETS

Asset	Operator	Interest (%)	Status	Licence Expiry Date	Licence Area (km²)	Comments
Logbaba Field, Douala, Cameroon	RDL	60%	Exploration/Exploitation	16 March 2052*	64	Commencement of development drilling in 15 months

** note that this date assumes conversion to an Exploitation Licence*

APPENDIX E: SUMMARY OF RESERVES BY STATUS

Oil & Gas – Reserves

Logbaba Field	Gross Estimate			Net Attributable			Operator
	Proved	Proved plus Probable	Proved plus Probable plus Possible	Proved	Proved plus Probable	Proved plus Probable plus Possible	
Condensate	0.17	1.78	3.42	0.12	1.12	2.09	RDL
NGL	0.20	2.05	3.95	0.14	1.29	2.41	RDL
Total for Liquids	0.37	3.83	7.37	0.26	2.41	4.50	RDL
Gas Reserves	10.04	104.88	202.39	7.00	65.87	123.71	RDL
Total for Gas	10.04	104.88	202.39	7.00	65.87	123.71	RDL

(all figures in bbls or scf)

Source: RPS Energy

Note: “Operator” is name of the company that operates the asset

“Gross” are 100% of the **reserves** and/or **resources** attributable to the licence whilst “Net attributable” are those attributable to the **AIM company**