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4 May 2011

VALUATION OF PETROLEUM ASSETS IN BLOCKS O AND I, OFFSHORE EQUATORIAL GUINEA

In response to Glencore International AG's request of September 2010 and the Letter of Engagement dated 3rd December 2010 with Glencore International AG, RPS Energy Consultants Limited ("RPS") has completed an independent valuation of liquid hydrocarbons in Blocks O and I, offshore Equatorial Guinea (the "Properties") in which Glencore Exploration Limited and Glencore Exploration (EG) Limited respectively (collectively "Glencore") have an interest. The blocks are operated by Noble Energy EG Limited ("Noble", the "Operator").

The information contained in this section is issued by RPS at the request of Glencore International AG as part of the work detailed in the Letter of Engagement made on 3 December 2010 and is subject to the terms and conditions contained therein. This report has been prepared for the specific purpose of inclusion in the prospectus relating to the global offer. This report accords with the requirements set out in the United Kingdom Financial Services Authority's Prospectus Rules and has been prepared having regard to the recommendations for the consistent implementation of the European Commission's Regulation on Prospectuses No. 890/2004 (the European Securities and Markets Authority's ("ESMA") recommendations published by the Committee of European Securities Regulators (now the ESMA) as updated on 23 March 2011 following the publication of a consultation paper in April 2010 in relation to content of prospectuses regarding mineral companies.

The RPS work contained in this section is based on data and information available up to 30th September, 2010. An effective date of December 31st 2010 has been assumed for the valuation.

Both hydrocarbon liquids and gas are present in the discoveries in Blocks O and I and both phases are expected to be present in any future discoveries. The review of in-place hydrocarbon volumes includes both liquids and gas. However, in view of the immaturity of plans to monetise hydrocarbon gas from Equatorial Guinea waters the valuation presented herein was limited to the value of the liquids (both crude oil and condensate).

Where discoveries or prospects straddle the block boundary, RPS has assumed the same equity split as the Operator. These do not represent RPS' opinion on the relative prospects in each block.

The work has been performed by an RPS team of professional petroleum engineers, geoscientists and economists and is based on the Operator's data, supplied through Glencore. All Reserves and Resources definitions and estimates shown in this section are based on the 2007 SPE/AAPG/WPC/SPEE Petroleum Resource Management System ("PRMS").

Our approach has been to review the Operator's technical interpretation of their base case geoscience and engineering data for the field for reasonableness and to review the ranges of uncertainty for each parameter around this base case in order to estimate a range of petroleum initially in place and recoverable. For the prospects, Glencore's technical interpretation of geoscience data was reviewed.

QUALIFICATIONS

RPS is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. The provision of professional services has been solely on a fee basis. Mr Gordon Taylor, Director, Geoscience for RPS Energy, has supervised the evaluation. Mr Taylor is a Chartered Geologist and Chartered Engineer with over 30 years experience in upstream oil and gas.

Other RPS 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 results presented herein 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 Work has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, RPS is not in a position to attest to the property title, financial interest relationships or encumbrances related to the properties.

Our estimates of resources and value are based on the data set available to, and provided by Glencore. We have accepted, without independent verification, the accuracy and completeness of these data.

As the offshore fields are yet to be developed and there are no facilities in place on the blocks to date, a site visit was not deemed necessary.

The information in this section represents RPS' 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. As agreed in the Letter of Engagement, RPS cannot and does not guarantee the accuracy or correctness of any interpretation made by it. In particular, RPS does not warrant that the work will be any form of guarantee of geological or commercial outcome.

The information in this section relates specifically and solely to the subject assets and is conditional upon various assumptions a summary of which is included herein. Except with permission from RPS, the information in this section may not be reproduced or redistributed, in whole or in part, to any other person than the addressees or published, in whole or in part, for any purpose without the express written consent of RPS. In instances where excerpts only are to be reproduced or published, other than in relation to the circular and prospectus in connection with an initial public offering this cannot be done without the express permission of RPS.

RPS has given and not withdrawn its written consent to the issue of this prospectus, with its name included within it, and to the inclusion of this information and references to the information in this section in the prospectus. For the purposes of Prospectus Rule 5.5.3R(2)(f) RPS accepts responsibility for the information contained in this section set out in this section of the prospectus and those sections of the prospectus which include references to the information in this section and declares that to the best knowledge and belief of RPS, having taken all reasonable care to ensure that such is the case, the information contained herein is in accordance with the facts and does not omit anything likely to affect the import of such information

Yours faithfully,

RPS Energy

Gordon R Taylor, ***CEng, CGeol***
Director, Geoscience

SPE/WPC/AAPG/SPEE RESERVE/RESOURCE DEFINITIONS

The following is extracted from the SPE/WPC/AAPG/SPEE PRMS 2007 using the section numbering and spelling from PRMS.

1.0 Basic Principles and Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project's economic feasibility, its productive life, and its related cash flows.

1.1 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 sulphide and sulphur. 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 A1-1 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.

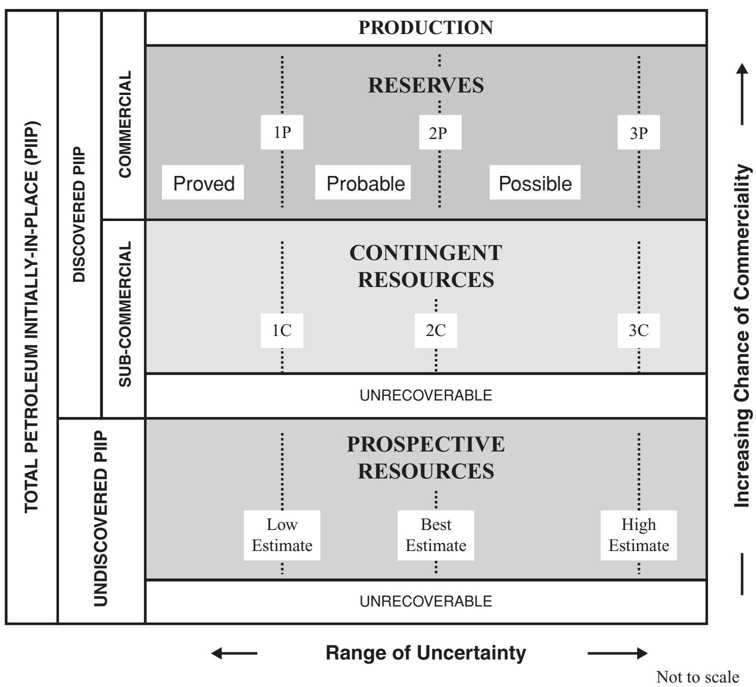

Figure B.1: Resources Classification Framework

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.

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 subclassified 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).

1.2 Project-Based Resources Evaluations

The resources evaluation process consists of identifying a recovery project, or projects, associated with a petroleum accumulation(s), estimating the quantities of Petroleum Initially-in-Place, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on its maturity status or chance of commerciality.

This concept of a project-based classification system is further clarified by examining the primary data sources contributing to an evaluation of net recoverable resources (see Figure A1-2) that may be described as follows:

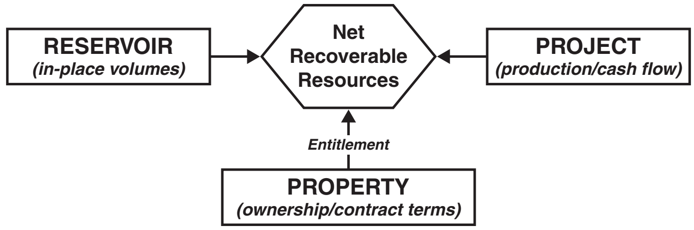

Figure B.2: Resources Evaluation Data Sources

- The Reservoir (accumulation): Key attributes include the types and quantities of Petroleum Initially-in-Place and the fluid and rock properties that affect petroleum recovery.
- The Project: Each project applied to a specific reservoir development generates a unique production and cash flow schedule. The time integration of these schedules taken to the project's technical, economic, or contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to Total Initially-in-Place quantities defines the ultimate recovery efficiency for the development project(s). A project may be defined at various levels and stages of maturity; it may include one or many wells and associated production and processing facilities. One project may develop many reservoirs, or many projects may be applied to one reservoir.
- The Property (lease or license area): Each property may have unique associated contractual rights and obligations including the fiscal terms. Such information allows definition of each participant's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations.

In context of this data relationship, "project" is the primary element considered in this resources classification, and net recoverable resources are the incremental quantities derived from each project. Project represents the link between the petroleum accumulation and the decision-making process. A project may, for example, constitute the development of a single reservoir or field, or an incremental development for a producing field, or the integrated development of several fields and associated facilities with a common ownership. In general, an individual project will represent the level at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for that project.

An accumulation or potential accumulation of petroleum may be subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resource classes simultaneously.

In order to assign recoverable resources of any class, a development plan needs to be defined consisting of one or more projects. Even for Prospective Resources, the estimates of recoverable quantities must be stated in terms of the sales products derived from a development program assuming successful discovery and commercial development. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be largely based on analogous projects. In-place quantities for which a feasible project cannot be defined using current, or reasonably forecast improvements in, technology are classified as Unrecoverable.

Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on a forecast of the conditions that will exist during the time period encompassed by the project's activities. "Conditions" include technological, economic, legal, environmental, social, and governmental factors. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms, and taxes.

The resource quantities being estimated are those volumes producible from a project as measured according to delivery specifications at the point of sale or custody transfer. The cumulative production from the evaluation date forward to cessation of production is the remaining recoverable quantity. The sum of the associated annual net cash flows yields the estimated future net revenue. When the cash flows are discounted according to a defined discount rate and time period, the summation of the discounted cash flows is termed net present value (NPV) of the project.

Licence Overview

The right of Glencore to conduct petroleum operations in Block O is defined in the Production Sharing Contract (the "Block O PSC") between the Republic of Equatorial Guinea and Glencore Exploration Ltd signed on the 13 July 2004.

The right of Glencore to conduct petroleum operations in Block I is defined in the Production Sharing Contract (the "Block I PSC") between the Republic of Equatorial Guinea Glencore Exploration (EG) Ltd signed on the 3 February 2000.

RPS does not opine on Glencore's rights under these PSC's.

Glencore has 23.75 per cent. equity (working interest) as a non-operating participating partner in the Block I PSC and 25 per cent. equity (working interest) as a non-operating participating partner in the Block O PSC. The following table summarises the partners and their respective equity interest in Blocks O and I.GEPetrol holds a 5 per cent. carried interest in Block I. In Block O GEPetrol has a 30 per cent. equity interest of which 10 per cent. is carried.

Glencore's Working Interest in Blocks O & I

Partner	Block I Interest	Block O Interest
	(%)	
Glencore Exploration (EG) Limited	23.75	
Glencore Exploration Limited		25
Noble Energy (Technical Operator)	38	45
Atlas Petroleum International Limited (Administrative Operator)	27.55	
Osborne Resources Limited	5.7	
GEPetrol	5	30

Within the blocks there are two government approved development projects Aseng and Alen; five discoveries, Carmen, Diega A-sand, Diega B-sand, Felicita and Yolanda; and a number of prospects.

Licence Status

The effective dates of the initial exploration licence in Block I was 3rd February 2000 and of Block O was 13th July 2004. The Aseng area of development is currently in an exploitation period (25 years) from the date when the PoD was approved (29 June 2009). Similarly the Alen area of development is in an exploitation period (25 years) from the date when the PoD was approved (11 January 2011).

In Block I, the contractor group has completed all work commitments for the first and second initial exploration sub periods (three years each) and extension periods, as shown in the following table. The second extension period has been extended and will expire on the 3 October 2013. The full activity in Block I to date includes acquisition of 3D seismic over the whole block and drilling of six exploration wells I-1 to I-6.

Block I Work Commitments

Block I PSC	Commitment	
First initial sub-period	Purchase approximately 1,000 km of 2D seismic	Fulfilled
Second initial sub-period	Drill one exploration well to minimum depth of 3,000m kb	Fulfilled
First extension period	Drill one exploration well	Fulfilled
Second extension period	Drill one exploration well	Fulfilled

In Block O, the contractor group has completed all work commitments as shown in the following table. Block O is now held as an appraisal area until 10 May 2013 with no future firm obligations. The full activity in Block O to date includes acquisition of 3D seismic and drilling of five exploration wells O-1 to O-5.

Block O Work Commitments

Block O PSC	Commitment	
First initial sub-period	Acquire 800 km(2) of 3D. Drill one exploration well	Fulfilled
Second initial sub-period	Drill one exploration well	Fulfilled
First extension period	Drill one exploration well	Fulfilled
Second extension period	Drill one exploration well	Fulfilled

Geological Overview

Blocks O and I are located in the Douala Basin which is located offshore Equatorial Guinea to the southeast of the Cameroon Volcanic Line (CVL), a chain of Cenozoic basaltic volcanoes which creates a sea-floor ridge separating the Douala Basin from the prolific Niger Delta Basin to the northwest. Sediment input to the Douala Basin is sourced from the Sanaga River drainage system in Cameroon. The Douala Basin lies on a passive margin which has witnessed little deformation since the Early Cretaceous.

To date hydrocarbon exploration within Blocks O & I has focussed on the Miocene section. Sands of this age were laid down across a slope environment as a repetitive series of isolated, laterally discontinuous channel-fill deposits derived from very low sinuosity turbidites. These sands tend to have high net to gross ratios with very good intergranular porosity and high pore connectivity values.

Oil seeps onshore in Cameroon, plus reservoired oil and gas in Blocks O and I in Equatorial Guinea suggest both Cretaceous and Tertiary petroleum systems are present.

The Alen and Aseng sands are Miocene in age. The Aseng and Alen reservoir sandstones were deposited in a deepwater setting on the continental slope in a relatively confined system which allowed for high net-to-gross sand ratios. Well and seismic data suggest that reservoirs are linear, relatively constant thickness sandstone bodies that appear to have the geometry of a feeder channel, and form a sequence of stacked channel sandstones. Up-dip seal is likely to be produced by a shale infill after the channel was abandoned due to avulsion.

Overview of Discoveries and Prospects

The Aseng discovery is in water depths ranging from 879m to 1,024m and lies wholly within the Block I PSC license area. The reservoir is stratigraphically trapped Miocene channel sands. The wells across the field have intersected gas, oil and water columns providing good control on the depths of the gas-oil (GOC) and oil-water (OWC) contacts. Over 20 well penetrations have been drilled on the Aseng reservoir.

The Alen Field is predominately in Block O although a small portion of the down dip part of the field extends into Block I. Water depths range from 76m to 679 m. Four wells penetrate the stratigraphically trapped Miocene channel sand. It is believed the field is purely a gas condensate field with no oil leg present.

The Felicita discovery is in Block O at a water depth of 63m. One well penetrates the stratigraphically trapped Miocene channel sand reservoir. The discovery contains gas condensate over water.

The Diega (A-Sand) discovery is in Block I at a water depth of 631m. One well penetrates the stratigraphically trapped Miocene channel sand reservoir. The discovery contains gas condensate over water. The Diega (B-Sand) was also penetrated by the same well. The well encountered gas over oil at this level but did not encounter a water contact. The Diega B-Sand accumulation straddles Blocks O and I.

The Carmen is in Block O at a water depth of 50m. One well penetrates the stratigraphically trapped Miocene channel sand reservoir. The well encountered the wet gas over an oil leg.

The Yolanda discovery is in Block I at a water depth of 895m. One well penetrates the stratigraphically trapped Miocene channel sand reservoir. The discovery contains gas. No water contacts were observed.

A large number of prospects have been identified in Blocks O and I in various sands of Early Miocene age.

Resources and reserves

Reserves and Resources Methodology

Reserves and Resources Classification

All reserves and resources definitions and estimates, and also risk factors, shown are based on the 2007 SPE/AAPG/WPC/SPEE Petroleum Resource Management System ("PRMS") and as reported to Glencore by RPS.

In estimating the following reserves and resources RPS have used standard petroleum engineering techniques. These techniques combine geological and production data with detailed information concerning fluid characteristics and reservoir pressure. RPS has estimated the degree of uncertainty inherent in the measurements and interpretation of the data and has calculated a range of recoverable resources. RPS has assumed that the working interest in the assets advised by Glencore is correct and RPS has not investigated nor does it make any warranty as to the Glencore interest in these properties.

Hydrocarbon resource and reserve estimates are expressions of judgement based on knowledge, experience and industry practice and are restricted to the data made available. They are, therefore, imprecise and depend to some extent on interpretations, which may prove to be inaccurate. Estimates that were reasonable when made may change significantly when new information from additional exploration or appraisal activity becomes available.

Risk Assessment

For all prospects and appraisal assets estimates of the commercial chance of success for Contingent Resources, and estimates of geological chance of success for Prospective Resources, have been made. In PRMS the former is called Chance of Development (CoD) and the latter Chance of Discovery (also CoD) in the PRMS system. To avoid confusion with acronyms we have used the term Geological Probability of Success (GPoS) in this document synonymously with Chance of Discovery.

Contingent Resources

The chance of success in this context means the estimated chance, or probability, that the volumes will be commercially extracted. A Contingent Resource includes both proved hydrocarbon accumulations for which there is currently no development plan or sales contract and proved hydrocarbon accumulations that are too small or are in reservoirs that are of insufficient quality to allow commercial development at current prices. As a result the estimation of the chance that the volumes will be commercially extracted may have to address both commercial (i.e. contractual or oil price considerations) and technical (i.e. technology to address low deliverability reservoirs) issues.

Prospective Resources (Exploration Prospects)

Unlike risk assessment for Contingent Resources, when dealing with undrilled prospects there is a more accepted industry approach to risk assessment for Prospective Resources. It is standard practice to assign a Geological Probability of Success (GPoS) which represents the likelihood of source rock, charge, reservoir, trap and seal combining to result in a present-day hydrocarbon accumulation. RPS assesses risk by considering both a play risk and a prospect risk. The chance of success for the play and prospect are multiplied together to give a Geological Probability of Success (GPoS). We consider three factors when assessing play risk: source, reservoir, seal and we consider four factors when assessing prospect risk: trap, seal, reservoir and charge. The result is the chance or probability of discovering hydrocarbon volumes within the range defined (as set out in the paragraph below "Uncertainty Estimation"). It is not an estimation of commercial chance of success.

Uncertainty Estimation

The estimation of expected hydrocarbon volumes is an integral part of the evaluation process. It is normal practice to assign a range to the volume estimates because of the uncertainty over exactly how large the discovery or prospect will be. Estimating the range is normally undertaken in a probabilistic way (i.e. using Monte Carlo simulation), using a range for each input parameter to derive a range for the output volumes. Key contributing factors to the overall uncertainty are data uncertainty, interpretation uncertainty and model uncertainty.

Volumetric input parameters, gross rock volume (GRV), porosity, net-to-gross ratio (N:G), water saturation (S_w), fluid expansion factor (B_o or B_g) and recovery factor, are considered separately. RPS has internal guidelines on the best practice in characterising appropriate input distributions for these parameters.

Systematic bias in volumetric assessment is a well-established phenomenon. There is a tendency to estimate parameters to a greater degree of precision than is warranted[1] and to bias pre-drill estimates to the high side. Rose and Edwards observe the tendency towards assessing volumes in too narrow a range with overly large low-side and mean estimates. RPS uses benchmarked P90/P10 ratios and known field size distributions to check the reasonableness of estimated volumes.

Audit Method

RPS has performed the audit of Reserves and Resources estimates in accordance with generally accepted petroleum engineering evaluation principles as set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers ("SPE Audit Standards").

As with any audit RPS reviewed the Operator's interpretation and information and proceeded to perform the tests and procedures deemed necessary to confirm the reasonableness of the Operator's Reserves or Resources estimates. In this case the Operator's work that has been reviewed was confined to the Aseng and Alen fields. The work that RPS audited on the other discoveries in Blocks O and I and the prospect inventory was undertaken by Glencore.

The RPS approach in this instance has been to review the technical interpretation of the geoscience and engineering data for reasonableness. Where necessary RPS has undertaken independent re-interpretation to produce a technically reasonable base case interpretation. RPS then reviewed the Operator's ranges of uncertainty for each parameter around this base case which have been used to estimate a range of petroleum initially in place and recoverable for each field. Production profiles have then been developed for each model. Furthermore, RPS has reviewed the Operator's estimates of operating costs (Opex) and capital expenditure (Capex) for reasonableness.

The following tables show the estimated reserves and resources for Blocks O & I as determined by RPS.

Reserves as of 31 December 2010 (Exclusive of Resources)

	Reserves								
	Gross Field			Glencore Working Interest[2]			Glencore net Entitlement[1]		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
					(MMstb)				
Aseng[3]	97	113	131	23	27	31	27	30	32
Alen[4]	45	82	128	11	20	32	10	17	26

Notes:

(1) Contractor's net entitlement is their share of Cost Oil and Profit Oil calculated using the Production Sharing Contract (PSC) terms. Aseng reserves include carry repayment from Atlas Petroleum

(2) Glencore working interest in Block O is 25 per cent. Glencore working interest in Block I is 23.75 per cent.

(3) Includes oil and condensate

(4) The Operator's assumption that Alen is 95 per cent. in Block O and 5 per cent. in Block I has been used in this valuation. RPS does not opine on this split for equity determination purposes.

(1) Rose, P.R., 1987. Dealing with Risk and Uncertainty in Exploration: How Can We Improve? AAPG Bulletin, 71 (1), pp. 1-16.

Block O and I Contingent Resources as of 31 December 2010 (on-block) (Exclusive of Reserves)

	Contingent Resources								
	Gross Field			Glencore Working Interest[1]			Glencore net Entitlement		
	1C	2C	3C	1C	2C	3C	1C	2C	3C
Liquids (MMstb)[3]									
Yolanda[4]	3.3	5.2	7.5	0.8	1.2	1.8	—[2]	—[2]	—[2]
Felicita[4]	1.8	3.2	5.5	0.4	0.8	1.4	—[2]	—[2]	—[2]
Diega (A-Sand)[4]	3.3	6	10	0.8	1.4	2.4			
Diega (B-Sand)[4][5]	24	52	99	5.7	12	24	4	8	14
Carmen (B-Sand)[4]	5.1	10	20	1.3	2.0	4.9	—[2]	—[2]	—[2]
Gas (Bscf)									
Aseng	419	519	640	100	123	152	—[2]	—[2]	—[2]
Alen	471	850	1,326	118	213	332	—[2]	—[2]	—[2]
Yolanda	393	506	640	93	120	152	—[2]	—[2]	—[2]
Felicita	49	71	104	12	18	26	—[2]	—[2]	—[2]
Diega (A-Sand)	122	176	249	29	42	59	—[2]	—[2]	—[2]
Diega (B-Sand)	46	94	193	11	22	46	—[2]	—[2]	—[2]
Carmen (B-Sand)	24	39	64	6	10	16	—[2]	—[2]	—[2]

Notes:

(1) Glencore working interest in Block O is 25 per cent. and Glencore working interest in Block I is 23.75 per cent.

(2) Valuation of gas and accumulations with minor liquid volumes not undertaken therefore net Entitlement not estimated

(3) Includes oil and condensate

(4) Yolanda & Diega A are 100 per cent. in Block I: Felicita & Carmen 100 per cent. in Block O: Diega B is approximately 90 per cent. in Block I & 10 per cent. in Block O. These approximations have been used in the valuation where appropriate. RPS does not opine on those splits for equity determination purposes.

Block O and I Prospective Resources as of 31 December 2010 (on-block) (Exclusive of Reserves)

	Prospective Resources (Unrisked)									
	In-Place			Recoverable						
	Gross			Gross			Glencore Working Interest[1]			
	P90	P50	P10	P90	P50	P10	P90	P50	P10	GPoS
										(%)
Oil (MMstb)										
Arabella[2][3]	0	0	0	0	0	0	0	0	0	
Adriana NE[2]	0	0	0	0	0	0	0	0	0	
Sarah A[2]	53	78	111	16	31	56	3.8	7.4	13.3	29
Isidora[2]	33	58	99	10	23	50	2.4	5.5	11.9	33
Regina A[2]	24	49	97	7	20	49	1.7	4.8	11.6	42
Sofia[2]	26	58	126	8	23	63	1.9	5.5	15	47
Carla[2][3]	210	400	749	63	160	375	15.4	39	91	23
Condensate (MMstb)										
Arabella	13	23	39	3.9	9.2	20	1	2.3	5	44
Adriana NE	5.2	14	36	1.6	5.6	18	0.4	1.4	4.5	47
Sarah A	6.7	10	15	2.0	4.0	7.5	0.5	1.0	1.8	29
Isidora	4.6	8.1	14	1.4	3.2	7.0	0.3	0.8	1.7	33
Regina A	3.3	6.8	14	1.0	2.7	7.0	0.2	0.6	1.7	42
Sofia	3.6	8.2	18	1.1	3.3	9.0	0.3	0.8	2.1	47
Carla	29	56	107	8.7	22	54	2.1	5.4	13.2	23
Gas (Bscf)[4]										
Arabella	189	325	553	142	260	470	35	65	117	44
Adriana NE	76	198	514	57	158	437	14	40	109	47
Sarah A	118	173	245	89	138	208	21	33	49	29
Isidora	58	102	175	44	82	149	10	19	35	33
Regina A	42	86	172	32	69	146	8	16	35	42
Sofia	46	103	224	35	82	190	8	19	45	47
Carla	369	707	1327	277	566	1,128	68	138	275	23

Notes:

(1) Glencore working interest in Block O is 25 per cent. and in Block I is 23.75 per cent.

(2) Sarah A, Isidora, Regina A, Sofia are 100 per cent. in Block I; Adriana NE is 100 per cent. in Block O; Arabella is 90/10 Block O/Block I, and Carla is 50/50 Block O/Block I. These approximations have been used in the valuation where appropriate. RPS does not opine on these splits for equity determination purposes.

(3) Glencore Interest for Arabella and Carla are weighted averages of block working interests.

(4) Gas volumes include inerts.

Alen Development Plan

The Alen development plan is split into two phases. During the first phase, the condensate will be produced with the gas recycled to maintain pressure. Gas will be produced from three wells located updip in the field, condensate will be stripped at the platform and dry gas will be re-injected into the reservoir down dip. It is assumed this phase would last a minimum of three years. The second phase of gas production would commence when the infrastructure for gas sales becomes available and other gas sales commercial arrangements are in place. The produced condensate will be stabilised for export through a subsea pipeline to the Aseng FPSO for storage and sales offload. This will save costs associated with a separate storage and offloading facility for the condensate.

The Operator's concept selection calls for two fixed platforms a well protector platform and a production platform. The production platform will consist of a large jacket and topsides with processing equipment, utilities systems, and quarters. Both fixed platforms will be new build structures. This concept offers an opportunity for Alen Field to become a future gas hub for the area after a staged development of Alen. Alen can be developed first, and then more facilities/satellite platforms can be added as other gas is routed to Alen for processing.

The Alen Field will be produced from surface wells at the fixed platform site with gas re-injected into subsea trees and wellhead systems. The remote subsea wells will be connected to the host fixed platforms with seabed flowlines. Umbilicals will also be provided to support the required control and maintenance functions associated with the subsea systems.

The fixed platforms will incorporate installation and handling aids required for these various lines (pull-in systems, I-tubes, etc.). The fixed platforms will also incorporate the subsea control systems and support utility equipment required to operate the subsea systems (e.g. control stations and panels, hydraulic power units, umbilical termination units, etc.).

First production from Alen is expected from 1 January 2014.

The following table outlines the estimated production profile for the Alen field daily production of condensate and illustrates the expected plateau duration, peak production timings, and anticipated decline and field life.

Average Yearly Production Rate and Cumulative Recovery for Alen

	Low Case (P90)		Base Case (P50)		High Case (P10)	
Year	**Cumulative Production**	**Annualised Daily Production**	**Cumulative Production**	**Annualised Daily Production**	**Cumulative Production**	**Annualised Daily Production**
	(MMstb)	*(stb/d)*	*(MMstb)*	*(stb/d)*	*(MMstb)*	*(stb/d)*
2014	11.9	32,643	12.0	32,832	12.2	33,482
2015	23.8	32,570	24.0	32,832	24.5	33,482
2016	34.1	28,186	36.0	32,878	36.7	33,573
2017	40.3	17,020	47.1	30,359	48.9	33,444
2018	43.4	8,295	56.0	24,313	60.7	32,152
2019	44.7	3,623	63.3	20,109	70.8	27,581
2020	45.3	1,597	69.1	15,796	79.3	23,362
2021	45.6	789	73.3	11,630	87.1	21,335
2022	45.7	459	76.3	8,275	94.2	19,630
2023	45.8	307	78.5	5,771	100.5	17,196
2024	45.9	226	79.9	4,092	105.8	14,435
2025	46.0	178	81.0	2,997	110.0	11,575
2026	46.0	148	81.9	2,293	113.4	9,127
2027	46.1	128	82.5	1,817	116.0	7,304
2028	46.1	114	83.1	1,479	118.2	6,047
2029	46.2	103	83.5	1,216	120.1	5,110
2030	46.2	95	83.9	1,012	121.7	4,384
2031	46.2	88	84.2	848	123.1	3,775
2032	46.3	83	84.5	719	124.3	3,264
2033	46.3	78	84.7	611	125.3	2,816
2034	46.3	74	84.9	526	126.2	2,453
2035	46.3	70	85.1	456	127.0	2,154

Aseng Development Plan

Aseng will be developed by five producers and one water injector that have been drilled and completed subsea from two drill centres. In addition to this, two further water injectors have been drilled and I-1 and I-2 will be completed as gas injectors, I-2 will only be utilised if deemed necessary once production and injection performance has been assessed. These wells will then be tied back to an FPSO, which will be a converted VLCC tanker. Oil export will be by tanker offtake.

The reservoir management plan consists of injecting water (as required) and gas to maintain voidage replacement (and thus maintain reservoir pressure). Later in field life, gas lift can be added (gas lift valves will be included in the initial well completions).

First production from Aseng is expected from 1 January 2012.

The following table outlines the estimated production profile for the Alen field daily production of condensate and illustrates the expected plateau duration, peak production timings, and anticipated decline and field life.

Aseng Field Liquid Production Rate and Cumulative Recovery after 20 Years (Gross, 100 per cent. Basis)

	Low Case (P90)		Base Case (P50)		High Case (P10)	
Date	Cumulative Production	Annualised Daily Production	Cumulative Production	Annualised Daily Production	Cumulative Production	Annualised Daily Production
	(MMstb)	*(stb/d)*	*(MMstb)*	*(stb/d)*	*(MMstb)*	*(stb/d)*
2012	18	50,000	18	50,000	18	50,000
2013	36	48,821	37	50,000	37	50,000
2014	50	36,952	52	41,920	53	45,934
2015	60	29,628	65	35,093	66	35,667
2016	68	21,748	74	26,673	78	31,000
2017	75	17,560	82	19,858	87	24,470
2018	80	14,100	88	16,726	94	20,291
2019	84	11,005	93	13,985	100	17,379
2020	88	10,397	97	10,830	106	15,373
2021	91	9,567	101	10,362	110	11,488
2022	94	7,160	104	9,792	114	10,838
2023	95	3,215	107	9,156	118	10,367
2024	96	2,641	109	5,255	121	9,847
2025	97	2,828	110	3,019	125	9,167
2026	97	1,381	111	2,647	127	5,849
2027			112	2,756	128	3,260
2028			113	2,400	129	2,685
2029					130	2,666
2030					131	2,923
2031					132	1,685

Note:

Liquid rates oil plus condensate.

Diega B Notional Development Plan

The notional development for Diega B sands has been based on a subsea tie-back to the Aseng FPSO some 20km away. Diega B sand has an excellent reservoir quality, so the initial average 10,000 stb/d per horizontal well from Aseng is maintained for all cases. To minimise the amount of subsea piping, drilling from a subsea template has been assumed. This will necessitate pre-drilling all the producers. Three production wells and one water injector will be required to reach a possible 30,000bopd plateau. The field is timed to come on stream in 2014 when it is thought that sufficient ullage will be available in the Aseng system.

Similar to Aseng a 2-3 years plateau period has been assumed. The forecast is for a 25-year period.

Valuation of reserves

Valuation Assumptions

General

The effective date for the purpose of the valuation is 1 January 2011 and this has been used as the discount date for the valuation. All values are post-tax and have been expressed over a range of discount rates. An annual inflation rate of 2 per cent. has been assumed and is applied to both costs and revenues.

Oil Prices

The valuation has been based on the long term forecast for Brent (long term price of U.S.$83.75/stb in real 2010 dollars) as shown in the following table. A Low Price Case ($65/stb in real 2010 dollars) and High Price Case ($100/stb in real 2010 dollars) are also shown in the Table in Money of the Day (MoD) and have been used for price sensitivity purposes.

Brent Price Forecasts

	Low Price Case	Base Price Case	High Price Case
	(U.S.$/stb, MoD)	*(U.S.$/stb, MoD)*	*(U.S.$/stb, MoD)*
2010	77.84	78.59	79.09
2011	74.00	85.00	95.00
2012	71.50	87.00	102.00
2013	70.00	88.00	106.00
2014	70.36	90.65	108.24
2015	71.77	92.47	110.41
2016	73.20	94.32	112.62
2017	74.66	96.20	114.87
2018	76.16	98.13	117.17
2019	77.68	100.09	119.51
2020	79.23	102.09	121.90
2021 onwards	+2% p.a.	+2% p.a.	+2% p.a.

The RPS Price Forecast comprises of two components: (i) a near term price forecast for 2011-2013 which is based on the RPS near term MoD price forecast (as set out in the table above) and (ii) from 2014 onwards an equivalent long term 2010 real price of U.S.$65/U.S.$83.75/U.S.$100 for low price case/mid price case/high price case respectively inflated at 2 per cent. p.a. to derive MoD prices. The final low/mid/high price forecasts are a combination of the near and long term price forecasts. They are expressed in the table above and applied in the valuation in MoD terms.

Money of the day prices, sometimes also referred to as nominal or current prices, incorporate the effects of annual inflation and reflect the time value of money. For example, the mid case oil price of U.S.$83.75 in 2010 would be equivalent to U.S.$85.43 one year in the future (2011) assuming that annual inflation was 2%. The figure of U.S.$85.43 would be described as the price in MoD terms. Conversely if the price in one year (2011) was forecast to be U.S.$83.75 in MoD terms this would be equivalent to U.S.$82.11 (i.e. U.S.$83.75/1.02) in (2010). The figure of U.S.$82.11 would be described as the price in real terms. Thus the U.S.$83.75 mid case oil price in 2010 would be equivalent to U.S.$90.65 in 2014 in MoD terms as shown in the table above. The forecast price in every subsequent year after 2014 will increase by 2% over the previous year's forecast price.

The effect of inflation is illustrated below:

	2010	2011	2012	2013	2014	2015
			(U.S.$)			
Price in real terms	83.75	83.75	83.75	83.75	83.75	83.75
Price in MoD terms	83.75	85.43	87.13	88.88	90.65	92.47
Price in real terms	83.75	82.11	80.50	78.92	77.37	75.85
Price in MoD terms	83.75	83.75	83.75	83.75	83.75	83.75

The Aseng crude price is assumed to have a differential to Brent crude prices of −3 per cent., and this assumption has been applied to the Diega discovery. Alen condensate price is assumed at parity with the Brent price.

Gas Prices

The Plans of Development for both Aseng and Alen do not feature gas sales and in view of the immaturity of plans to monetise hydrocarbon gas from Equatorial Guinea waters this valuation does not include possible future gas sales.

Valuation Methodology

Aseng and Alen

The Aseng Field is within the "Block I" PSC area (the PSC for the D15 Block offshore Bioko Island). The Alen Field straddles Blocks O and I PSC contract areas. For valuation purposes RPS has assumed that 95 per cent. of Alen is within Block O and subject to the Block O PSC terms and 5 per cent. of Alen is in Block I and subject to the Block I PSC terms. As a first pass approximation the valuation assumes that the field will be unitised on this basis. RPS is not opining on the unitisation of the field. The relative proportion in each block has been taken from the Alen PoD and is not necessarily the opinion of RPS. The 5 per cent. of Alen assumed to lie within Block I is valued on an incremental basis relative to the Aseng field P50 development case. Spreadsheet based discounted cashflow models were created to honour each of the Block I and O PSC contract terms.

Fiscal Regime and Contract Terms

The PSCs in which Glencore has an interest are typical for Equatorial Guinea. There are royalties payable to the state based on production rates, cost recovery from a percentage of net revenue and contractor profit share based on production. Production bonuses and an abandonment reserve fund also apply. The contractor is subject to Corporation Tax on contractor income. As advised by Glencore, and consistent with both Aseng and Alen PoD submissions, the tax rate on income from Blocks I and O is 25 per cent.

Valuation Summary

Valuation of Aseng

After applying economic limits and deriving entitlement income from Block I PSC, the 1P, 2P and 3P Reserves for the Aseng Field are summarised in the following table.

Aseng Field Reserves Summary (Net Glencore Share)

	Gross Reserves	Net Entitlement Reserves
	(MMstb)	*(MMstb)*
Proved Reserves (1P)	97	27
Proved plus Probable Reserves (2P)	113	30
Proved plus Probable plus Possible Reserves (3P)	131	32

The valuation of the Aseng reserves at the 1P, 2P and 3P levels on a 2011 point forward basis over a range of discount factors is shown in the following table.

Aseng Field Post-Tax Valuation (Net Glencore Share)

	Post-Tax Net Present Value			
Discount Rate	0.0%	5.0%	10.0%	15.0%
		(U.S.$m, MoD)		
Proved Reserves (1P)	1,355	1,133	966	836
Proved plus Probable Reserves (2P)	1,496	1,234	1,041	893
Proved plus Probable plus Possible Reserves (3P)	1,649	1,333	1,108	941

The sensitivity of these values to oil price uncertainty was calculated using the low and high price scenarios described above and is shown below.

Sensitivity of Aseng NPV_{10} to Oil Price (Net Glencore Share)

	Net Present $Value_{10}$ of Future Net Revenue		
Price Case	1P	2P	3P
		(U.S.$m, MoD)	
Low Price ($65)	800	860	912
Base Price ($83.75)	966	1,041	1,108
High Price ($100)	1,117	1,207	1,288

Valuation of Alen

After applying economic limits and deriving entitlement income from Block O and Block I PSCs, the 1P, 2P and 3P Reserves for the Alen Field are summarised in the table below.

Alen Field Reserves Summary

	Gross Reserves	Net Entitlement Reserves
	(MMstb)	*(MMstb)*
Proved Reserves (1P)	45	10
Proved plus Probable Reserves (2P)	82	17
Proved plus Probable plus Possible Reserves (3P)	128	26

The valuation of the Alen field Reserves at the 1P, 2P and 3P levels on a 2011 point forward basis over a range of discount rates are in the following table.

Alen Field Post-Tax Valuation (Net Glencore Share)

	Post-Tax Net Present Value			
Discount Rate	0.0%	5.0%	10.0%	15.0%
	(U.S.$m, MoD)			
Using RPS Cost Estimates				
Proved Reserves (1P)	259	151	73	17
Proved plus Probable Reserves (2P)	665	419	255	144
Proved plus Probable plus Possible Reserves (3P)	1,148	687	412	240
Using Operator Cost Estimates				
Proved Reserves (1P)	290	182	104	48
Proved plus Probable Reserves (2P)	691	447	284	173
Proved plus Probable plus Possible Reserves (3P)	1,174	715	441	270

The sensitivity of these values to oil price uncertainty was calculated using the Low and High price scenarios described above and is shown below.

Sensitivity of Alen Field NPV_{10} to Oil Price (Net Glencore Share)

	Net Present $Value_{10}$ of Future Net Revenue		
Price Case	1P	2P	3P
	(U.S.$m, MoD)		
Low Price ($65)	(15)	126	233
Base Price ($83.75)	73	255	412
High Price ($100)	167	368	542

After applying economic limits and deriving entitlement income from Block I and Block O PSCs, the 1C, 2C and 3C Contingent Resources for the Diega B Field are summarised in the following table.

Diega B Field Contingent Resources Summary

	Gross Resources	Net Entitlement Resources
	(MMstb)	*(MMstb)*
1C Resources	23	4
2C Resources	49	8
3C Resources	91	14

Environmental and Facilities

Environmental Permits and Status

A summary of the health and safety review carried out by RPS is given below. The review of both the Alen and Aseng field development projects, based on the interpretation of the data, which was made available to RPS, confirms that both projects are in full compliance with the applicable laws and regulations of Equatorial Guinea and recognised best oilfield practice.

Laws of Equatorial Guinea

The following table provides an overview of Equatorial Guinea's key laws that are of potential relevance to the project.

Law	Description
Law Regulating the Environment in the Republic of Equatorial Guinea: Ministry of Fishing and Environment (Issued January 2004)	Provides the legal and philosophic basis concerning the basic norms of conservation, protection and recovery of the environment, promoting the sustainable use of natural resources, while achieving sustainable human development in the Republic of Equatorial Guinea.
Hydrocarbon Law. Ministry of Mines, Industry and Energy. 8/2006 (November 2006, "The Hydrocarbon Law")	Provides the framework for the licensing and awarding of exploration and production rights and authorizes the MMIE to enter into contracts with oil companies. The legal framework of the Hydrocarbon Law was updated to provide the necessary coverage for elements within the hydrocarbon sector that were previously nonexistent or did not adequately meet the needs of the Government.
Law of Territorial Seas and Exclusive Economic Zone (November 1984)	Defines the sovereignty of EG over its territorial sea and defines its rights over the marine resources therein. This sovereignty is exercised, in accordance with international law, over the water column, seabed, subsoil, and resources of the sea, and the superjacent airspace.

Social and Environmental Impact Assessment

Both projects are subject to environmental regulations under the legal framework of the environmental management of Equatorial Guinea and as such, the Operator provided the Equatorial Guinea regulatory authorities with a Social and Environmental Impact Assessment ("SEIA") pursuant to which relevant environmental protection, management standards and procedures which will be continually enforced during the project.

The SEIA sufficiently assesses the potential impact that the proposed project could have on the environment and social community. The SEIA also offers proposed mitigation measures to lower the risk / impact to as reasonably possible. The SEIA exceeds the requirements for an environmental impact study.

In summary, the SEIA for each project demonstrates that operations are in full compliance with the applicable laws and regulations of Equatorial Guinea and also sufficiently assesses / mitigates any potential impacts that could be caused by the project.

Oil Spill Contingency Plan

Both fields have been included on one approved Oil Spill Contingency Plan ("OSCP"), which covers operations and responsibility in the event of an oil spill.

The Operator OSCP gives clear directions and identifies responsibility in the event of a spill. It also provides project specific modelling data, which estimates the position of the oil spilt and also gives an estimated beaching location.

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