This Prospectus (the "**Prospectus**") comprises a prospectus relating to Caracal Energy Inc. (the "**Company**") prepared in accordance with the Prospectus Rules of the Financial Conduct Authority (the "**FCA**") made under section 73A of the Financial Services and Markets Act 2000 (as amended) (the "**FSMA**"). This Prospectus has been filed with the FCA and has been made available to the public in accordance with section 3.2 of the Prospectus Rules.

Application has been made (i) to the FCA in its capacity as competent authority under the FSMA (the "**UK Listing Authority**") for all of the common shares in the Company (the "**Shares**") to be admitted to listing on the premium listing segment of the Official List of the FCA (the "**Official List**") and (ii) to the London Stock Exchange plc (the "**London Stock Exchange**") for such Shares to be admitted to trading on the London Stock Exchange's main market for listed securities (together, "**Admission**"). Admission to trading on the London Stock Exchange's main market for listed securities constitutes admission to trading on a regulated market. It is expected that Admission will become effective, and that unconditional dealings in the Shares will commence, on or around 5 July 2013. No application is currently intended to be made for the Shares to be admitted to listing or trading on any other exchange.

Prior to Admission, the Company will file a final non-offering prospectus (the "**Canadian Prospectus**") with the applicable Canadian securities regulatory authorities in each of the provinces of Canada other than Québec (the "**Applicable Jurisdictions**") (the "**Canadian Securities Regulators**") to enable the Company to become a "reporting issuer" in the Applicable Jurisdictions pursuant to securities legislation in the Applicable Jurisdictions (the "**Applicable Canadian Securities Laws**"). Once a receipt has been received for the Canadian Prospectus from the Canadian Securities Regulators, the Company will become a reporting issuer in the Applicable Jurisdictions, which means that the Company will be subject to ongoing public disclosure requirements under the Applicable Canadian Securities Laws. Admission will not occur until the Company has become a reporting issuer in the Applicable Jurisdictions.

THIS PROSPECTUS DOES NOT CONSTITUTE AN OFFER TO SELL OR AN INVITATION TO SUBSCRIBE FOR, OR THE SOLICITATION OF AN OFFER TO PURCHASE OR TO SUBSCRIBE FOR, ANY SHARES TO ANY PERSON IN ANY JURISDICTION.

This Prospectus has not been and will not be filed with any of the Canadian Securities Regulators as a prospectus under the Applicable Canadian Securities Laws. This Prospectus does not purport to include the information required of a prospectus under the Applicable Canadian Securities Laws. This Prospectus may not be issued or distributed in Canada or to a resident of Canada.

The Company and the directors of the Company, whose names and principal functions are set out in Part VIII: "Directors, Senior Managers and Corporate Governance" (the "**Directors**"), accept responsibility for the information contained in this Prospectus. To the best of the knowledge of the Company and the Directors (each of whom has taken all reasonable care to ensure that such is the case), the information contained in this Prospectus is in accordance with the facts and does not omit anything likely to affect the import of such information.

Investors should read the entire Prospectus and, in particular, investors are advised to examine all the risks that might be relevant in connection with the Shares. See Part II: "Risk Factors" for a discussion of certain risks and other factors relating to the Shares.

CARACAL ENERGY INC.

CARACAL ENERGY INC.

(incorporated under the Canada Business Corporations Act and registered in Canada with registered number 716005-4)

Prospectus

Introduction to admission of all Shares to listing on the premium listing segment of the Official List and to trading on the London Stock Exchange's main market for listed securities

RBC Capital Markets
Sponsor

RBC Europe Limited ("**RBC Capital Markets**" and the "**Sponsor**") has been appointed as Sponsor. The Sponsor is acting exclusively for the Company and no one else in connection with Admission. The Sponsor will not regard any other person (whether or not a recipient of this Prospectus) as a client in relation to Admission and will not be responsible to anyone other than the Company for providing the protections afforded to its clients nor for giving advice in relation to the Shares or Admission or any transaction or arrangement referred to in this Prospectus.

This Prospectus has been prepared solely in respect of Admission and is being made publicly available for information purposes only and does not require any action to be taken by holders of Shares. This Prospectus does not constitute an offer to sell or an invitation to subscribe for, or the solicitation of an offer to purchase or to subscribe for, any Shares to any person in any jurisdiction.

No person has been authorised to give any information or to make any representations other than the information and representations contained in this Prospectus and, if any other information is given or representations are made, such information or representations must not be relied upon as having been authorised by or on behalf of the Company, the Directors or the Sponsor.

Apart from the responsibilities and liabilities, if any, which may be imposed on the Sponsor by the FSMA or the regulatory regime established thereunder, the Sponsor does not accept any responsibility or liability whatsoever for the contents of this Prospectus, including its accuracy, completeness or verification, or for any other statement made or purported to be made by it, or on its behalf, in connection with the Company, the Group, the Shares or Admission. The Sponsor accordingly disclaims all and any liability whether arising in tort, contract or otherwise (save as referred to above) which it might otherwise have in respect of this Prospectus or any such statement.

Investors should read this Prospectus in its entirety.

Notice to overseas persons

The distribution of this Prospectus in certain jurisdictions may be restricted by law. No action has been or will be taken by the Company or the Sponsor to permit the possession, issue or distribution of this Prospectus in any jurisdiction where action for that purpose may be required. Accordingly, neither this Prospectus nor any advertisement nor any other material related to this Prospectus may be distributed or published in any jurisdiction except under circumstances that will result in compliance with any applicable laws and regulations. Persons into whose possession this Prospectus comes should inform themselves about and observe any such restrictions. Any failure to comply with these restrictions may constitute a violation of the securities laws of any such jurisdiction.

The Shares have not been, and will not be, registered under the U.S. Securities Act of 1933 or under the applicable securities laws of any state of the United States.

THE SHARES HAVE NOT BEEN APPROVED OR DISAPPROVED BY THE UNITED STATES SECURITIES AND EXCHANGE COMMISSION, ANY OTHER FEDERAL OR STATE SECURITIES COMMISSION IN THE UNITED STATES OR ANY OTHER REGULATORY AUTHORITY IN THE UNITED STATES, NOR HAVE ANY SUCH AUTHORITIES PASSED UPON OR ENDORSED THE ADEQUACY OF THIS PROSPECTUS.

Dated 27 June 2013.

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PART I

SUMMARY INFORMATION

Summaries are made up of disclosure requirements known as "Elements". These elements are numbered in Sections A-E (A.1—E.7).

This summary contains all the Elements required to be included in a summary for this type of securities and issuer. Because some Elements are not required to be addressed, there may be gaps in the numbering sequence of the Elements.

Even though an Element may be required to be inserted in the summary because of the type of securities and issuer, it is possible that no relevant information can be given regarding the Element. In this case a short description of the Element is included in the summary with the mention of "not applicable".

Section A—Introduction and warnings		
Element	**Disclosure requirement**	**Disclosure**
A.1	Warning	This summary should be read as an introduction to this Prospectus. Any decision to invest in the Shares should be based on consideration of this Prospectus as a whole by the investor. Where a claim relating to the information contained in this Prospectus is brought before a court, the plaintiff investor might, under the national legislation of the Member States of the European Economic Area, be required to bear the costs of translating this Prospectus before the legal proceedings are initiated. Civil liability attaches only to persons who have tabled this summary, including any translation thereof, but only if the summary is misleading, inaccurate or inconsistent when read together with the other parts of this Prospectus or it does not provide, when read together with the other parts of this Prospectus, key information in order to aid investors when considering whether to invest in the Shares.
A.2	Subsequent resale of securities or final placement of securities through financial intermediaries	Not applicable. The Company is not engaging any financial intermediaries for any resale of securities or final placement of securities in connection with this Prospectus.

Section B—Issuer		
Element	**Disclosure requirement**	**Disclosure**
B.1	Legal and commercial name	Caracal Energy Inc. (the "**Company**" and, together with its direct and indirect subsidiaries, the "**Group**").
B.2	Domicile and legal form	The Company is a company incorporated in Canada with its registered office situated in Calgary, Alberta, Canada. The Company operates under the Canadian Business Corporations Act.

Section B—Issuer		
Element	**Disclosure requirement**	**Disclosure**
B.3	Operations and principal activities	The Company is an independent oil and gas exploration, appraisal and development company which, together with Glencore, has exclusive rights to explore and develop oil and gas reserves and resources over an area of approximately 26,103 km^2 (6.4 million acres) in the south of the Republic of Chad ("**Chad**"). This area comprises three contractual zones (the "**Contractual Zones**"), the rights to which were granted to the Group in 2011 pursuant to three production sharing contracts (each, a "**PSC**") that it entered into with the Government of Chad. *DOB/DOI Contractual Zone* • The DOB/DOI Contractual Zone covers an area of approximately 2,865 km^2. It contains two discoveries of commercial interest that the Group is currently developing: the Badila Field and the Mangara Field. • The independent competent person's reports prepared by GLJ Petroleum Consultants Ltd. dated 29 January 2013 and 28 February 2013, each with an effective date of 31 December 2012 (the "**GLJ Reports**"), estimate that the gross lease reserves attributed to the Badila and Mangara Fields are 28.8 MMbbl (proved), 63.2 MMbbl (proved plus probable) and 135.2 MMbbl (proved plus probable plus possible) (14.4 MMbbl, 31.6 MMbbl and 67.6 MMbbl, respectively, on a Net Participating Interest basis). "**Net Participating Interest**" means the Group's participating interest multiplied by the gross lease reserves, resources or production, as applicable. • The GLJ Reports estimate that the gross lease unrisked prospective resources located in the DOB/DOI Contractual Zone are 239.6 MMstb (mean) (calculated by the Group to be 159.7 MMstb on a Net Participating Interest basis). When calculating Net Participating Interests in respect of prospective resources, the Group has assumed that it has a 66.67 per cent. participating interest. However, upon the approval of an EXA, the Government of Chad may elect to acquire up to a 25 per cent. participating interest in the relevant EXA and the Group's participating interest would be adjusted accordingly. • Exclusive exploitation authorisations (each, an "**EXA**") to develop and produce from the Badila and Mangara Fields were granted to the Group by the Government of Chad in August 2012 and June 2012, respectively and cover a combined area of 100 km^2. • The Group is targeting commencement of first production from the Badila and Mangara Fields in July 2013 and the third quarter of 2013, respectively. • The GLJ Reports forecast gross production, in the 2P case, of 23,000 bbl/d from the Badila and Mangara Fields by the end of 2013 and 36,000 bbl/d by the end of 2014 (11,500 bbl/d and 18,000 bbl/d, respectively, on a Net Participating Interest basis). *Doseo/Borogop Contractual Zone* • The Doseo/Borogop Contractual Zone covers an area of approximately 22,414 km^2 and contains four discoveries of commercial interest that the Group has identified as development priorities: the Kibea, Maku, Tega and North Sako Fields. • The Group submitted a feasibility study and an EXA application for the Kibea Field in April 2013. • The Group is currently undertaking feasibility studies on the Maku, Tega and North Sako Fields. The Group expects to submit an EXA application for the Maku Field during 2013.

Section B—Issuer		
Element	**Disclosure requirement**	**Disclosure**
		• The GLJ Reports estimate that the gross lease reserves attributed to the Kibea and Maku Fields are zero (proved), 26.0 MMbbl (proved plus probable) and 65.4 MMbbl (proved plus probable plus possible) (zero, 13.0 MMbbl and 32.7 MMbbl, respectively, on a Net Participating Interest basis)(1). The GLJ Reports estimate that the gross lease unrisked prospective resources located in the Doseo/Borogop Contractual Zone are 985.3 MMstb (mean) (calculated by the Group to be 656.9 MMstb on a Net Participating Interest basis). *DOH Contractual Zone* • The DOH Contractual Zone covers an area of approximately 824 km^2. It is subject to further exploration. The two wellbores drilled by previous operators within the DOH Contractual Zone have evidence of oil, but not in quantities of commercial interest that the Group would intend to develop. • The GLJ Reports estimate that the gross lease unrisked prospective resources located in the DOH Contractual Zone are 49.5 MMstb (mean) (calculated by the Group to be 33.0 MMstb on a Net Participating Interest basis). *Strategic partnership with Glencore* • The Group entered into a farm-in agreement with Glencore Xstrata plc ("**Glencore**") in December 2012 (the "**Farm-in Agreement**"). President Déby signed a decree approving the Farm-in Agreement on 4 February 2013, and such decree was ratified by the Chadian National Assembly on 26 April 2013. • Upon completion of the Farm-in Agreement on 13 June 2013 and pursuant to the Farm-in Completion Letter dated 13 June 2013 (the "**Farm-in Completion**"), Glencore acquired from the Group (i) a 33.33 per cent. participating interest in each of the PSCs, with the Group retaining a 66.67 per cent. participating interest and (ii) a 25 per cent. participating interest in the Badila and Mangara EXAs. At or around the same time, Glencore acquired a further 10 per cent. participating interest in the Badila and Mangara EXAs from the Government of Chad. As such, the Group has a 50 per cent. participating interest, Glencore has a 35 per cent. participating interest and the Government of Chad has a 15 per cent. participating interest, respectively, in each of these EXAs. The Group remains operator under each of the PSCs. • Pursuant to the Farm-in Agreement, Glencore agreed to pay the Group approximately U.S.$30.75 million in respect of historic unrecoverable costs incurred in relation to the PSCs. The Farm-in Agreement also obliges Glencore to carry a proportion of the Group's capital expenditure costs up to U.S.$100 million a year between July 2012 and June 2014 and U.S.$100 million for the period from July 2014 to June 2016, subject to an aggregate limit of U.S.$300 million. • Pursuant to the Farm-in Advance Agreement, U.S.$100 million and U.S.$50 million was advanced by Glencore to the Group on 4 March 2013 and 30 May 2013, respectively, as advance consideration for its obligations under the Farm-in Agreement (the "**Farm-in Advance**"). Upon the Farm-in Completion, Glencore paid the Group approximately U.S.$107 million as consideration for its obligations under the Farm-in Agreement, net of the repayment of the Farm-in Advance.

(1) GLJ has assumed, for the purposes of estimating the Group's participating interest in any future EXAs which may be granted under each PSC, that the Government of Chad will elect to acquire a 25 per cent. participating interest in each EXA. Accordingly, the participating interest of each of the Group and Glencore has been assumed by GLJ to be 50 per cent. and 25 per cent. respectively, of the gross lease interest.

Section B—Issuer		
Element	**Disclosure requirement**	**Disclosure**
		• In December 2012, the Group entered into an offtake agreement with Glencore, pursuant to which Glencore will purchase and market the Group's proportionate share of production under the PSCs (the "**Offtake Agreement**"). The Offtake Agreement provides that the price paid for the Group's oil will be set by reference to the average market prices for Dated Brent Crude and includes incentives relating to the performance of Glencore thereunder. • The Group believes that its strategic partnership with Glencore strengthens its investment case and further raises the Group's international profile. • In addition to providing the Group with development capital, the Group believes that Glencore also offers significant marketing expertise and the ability to maximise export proceeds. *Access to market* • Oil produced in Chad is exported by means of a pipeline (the "**Export Pipeline**") running from the Doba Basin fields in southern Chad to a marine shipping terminal located off the coast of Cameroon. • In October 2012, an Interconnection Agreement was entered into by the Group and the operator of the Export Pipeline in Chad, TOTCO, enabling the connection of the Group's transportation infrastructure to transport the Group's production from the Badila and Mangara Fields to the Export Pipeline. • In March 2013, a Facilities Modification Agreement was entered into by the Group and the operator of the Export Pipeline in Cameroon, COTCO, providing for certain modifications to the Cameroonian portion of the Export Pipeline to accommodate the transportation of the Group's oil. • There are two transportation agreements that the Group expects to enter into in relation to the export of oil produced in the Badila and Mangara Fields, one in respect of the Chadian portion of the Export Pipeline and the other in respect of the Cameroonian portion of the Export Pipeline (together, the "**Transportation Agreements**"). The Transportation Agreements are expected to govern the terms of use of the Export Pipeline for the transport of oil produced in the Badila and Mangara Fields, including the order of priority for access and the applicable fees payable for use of the Export Pipeline. The Transportation Agreements are in an advanced stage of negotiation and the Group expects that they will be entered into prior to targeted first production from the Badila Field in July 2013.
B.4a	Significant recent trends	Since the appointment of the current management team on and after 1 July 2011, the Group has advanced a number of significant initiatives and developments in respect of the PSCs and the Group's business, including: • EXAs have been granted in respect of each of the Badila and Mangara Fields; • drilling of each of the Badila-2, Badila-3 and Mangara-4 wells has been completed and drilling of the Mangara-5 well has commenced; • re-entry of two existing wells located in the Badila and Mangara Fields (Badila-1 and Mangara-2) drilled by the previous operator, achieving constrained test rates of up to 4,025 bbl/d and 800 bbl/d, respectively;

Section B—Issuer		
Element	**Disclosure requirement**	**Disclosure**
		• completion of a 147 km^2 3-D seismic shoot over the Mangara Field and adjoining Krim exploration prospect in April 2012 and analysis of the data produced; • completion of a 320 km^2 3-D seismic shoot over the Badila Field and Bitanda exploration prospect in May 2013 and analysis of the data produced commenced; • the lease of one drilling rig and one service rig, each of which is currently in operation on the Group's properties, with an additional drilling rig due to commence operation in July 2013; • appointment of an experienced technical team; • installation of four 12-inch pipeline segments crossing the Logone River, enabling the Mangara to Badila Pipeline to pass underneath; • completion of upgrades to public and private roads and bridges to enable all-weather access to both the Badila and Mangara Fields; • approval by the Government of Chad in July 2012 of an environmental impact assessment prepared by the Group in respect of operations in the DOB and DOI blocks; • acquisition of access to the land required for the development of the Badila and Mangara Fields and associated pipeline, processing and production facilities; • completion of construction and commissioning of the Early Production Facilities, Connection Pipe, LACT Unit and Hot Tap; • contracts awarded for the construction of the Blending Export Terminal, Mangara CPF and Mangara to Badila Pipeline, drilling services, camps and other related facilities; and • gross proceeds of over U.S.$295 million raised through the issuance of Shares and Convertible Bonds during 2012.
B.5	Group description	Pursuant to an amendment to the Company's articles of association filed on 23 May 2013, the Company changed its name from Griffiths Energy International Inc. to Caracal Energy Inc. Prior to Admission, the Company will file a final non-offering prospectus (the "**Canadian Prospectus**") with the applicable Canadian securities regulatory authorities in each of the provinces of Canada other than Québec (the "**Applicable Jurisdictions**") (the "**Canadian Securities Regulators**") to enable the Company to become a "reporting issuer" in the Applicable Jurisdictions pursuant to applicable securities legislation in the Applicable Jurisdictions (the "**Applicable Canadian Securities Laws**"). Once a receipt has been received for the Canadian Prospectus from the Canadian Securities Regulators, the Company will become a reporting issuer in the Applicable Jurisdictions, which means that the Company will be subject to ongoing public disclosure requirements under the Applicable Canadian Securities Laws. Admission will not occur until the Company has become a reporting issuer in the Applicable Jurisdictions.

<table>
<tr><th colspan="3">Section B—Issuer</th></tr>
<tr><th>Element</th><th>Disclosure requirement</th><th>Disclosure</th></tr>
<tr><td></td><td></td><td>The Company is the principal holding company of the Group, which comprises the following subsidiaries:
• PetroChad (Mangara) Limited, Griffiths Energy (Chad) Ltd. and Griffiths Energy (DOH) Ltd. are party to the DOB/DOI PSC, Doseo/Borogop PSC and DOH PSC, respectively and are each indirectly wholly-owned by the Company.
• Griffiths Energy (U.S.) Inc. is primarily used to facilitate logistics and associated accounting duties for sourcing, acquiring and shipping material needed to operate in Chad. It is wholly-owned by the Company.
• PetroChad Transportation Ltd. owns and operates facilities located in the Badila Field that will be used to process and transport the Group's production from the Badila and Mangara Fields to the Export Pipeline. It is indirectly wholly-owned by the Company, but Glencore is expected to acquire a 33.33 per cent. ownership interest in July 2013.
• Griffiths Energy Holdings Ltd. is an intermediate holding company. It is wholly-owned by the Company.</td></tr>
<tr><td>B.6</td><td>Notification interests; different voting rights; controlling interests</td><td>So far as the Company is aware, as at 24 June 2013 (being the latest practicable date prior to the publication of this Prospectus), the following person, directly or indirectly, had an interest of five per cent. or more in the Company's capital or voting rights:
<table>
<tr><th></th><th>Number of Shares as at 24 June 2013</th><th>Percentage of existing issued share capital as at 24 June 2013(1)</th><th>Percentage of voting rights as at 24 June 2013</th><th>Number of Shares immediately following Admission</th><th>Percentage of issued share capital immediately following Admission(1)</th><th>Percentage of voting rights immediately following Admission</th></tr>
<tr><td>The Bradley Griffiths BDG Trust . . . . . .</td><td>12,651,000</td><td>10.9%</td><td>10.9%</td><td>12,651,000</td><td>10.9%</td><td>10.9%</td></tr>
</table>
Note:
(1) As at 24 June 2013 and immediately following Admission, the outstanding fully diluted share capital of the Company was, and will be, 159,170,204 and the percentage of the outstanding fully diluted share capital of the Company held by The Bradley Griffiths BDG Trust was, and will be, 7.95%.

The Company is not aware of any person who directly or indirectly, jointly or severally, exercises or could exercise control over the Company.

The person referred to above does not have voting rights in respect of the share capital of the Company (issued or to be issued) which differ from any other shareholder of the Company.</td></tr>
</table>

Section B—Issuer		
Element	**Disclosure requirement**	**Disclosure**
B.7	Key financial information	The table below sets out summary financial information of the Company as derived from (i) the audited consolidated financial statements of the Company as of and for the years ended 2012, 2011 and 2010 and (ii) the unaudited interim consolidated financial statements of the Company as of and for the three months ended 31 March 2013 and 2012.

	Three months ended 31 March 2013 (unaudited)	Three months ended 31 March 2012 (unaudited)	Year ended 31 December 2012 (audited)	Year ended 31 December 2011 (audited)	Year ended 31 December 2010 (audited)
			(U.S.$'000)		
Income statement:					
Revenues	—	—	—	—	—
Expenses	23,367	20,903	69,393	56,450	1,541
Deferred tax reduction	—	—	(5,381)	—	—
Net loss and comprehensive loss	23,367	20,903	64,012	56,450	1,541
Per Share data:					
Basic and diluted net loss and comprehensive loss per share	0.21	0.22	0.59	0.72	0.03
Basic and diluted weighted average number of shares outstanding	113,438	95,462	108,458	78,036	44,425
Cash flows:					
Operating activities	23,112	(9,663)	(55,186)	(24,443)	(1,941)
Investing activities	(61,799)	(6,246)	(161,299)	(106,728)	—
Financing activities	3,899	117,167	284,115	180,843	1,531

	As at 31 March 2013 (unaudited)	As at 31 March 2012 (unaudited)	As at 31 December 2012 (audited)	As at 31 December 2011 (audited)	As at 31 December 2010 (audited)
			(U.S.$'000)		
Statement of financial position:					
Current assets	97,424	154,664	132,121	52,909	822
Non-current assets	407,687	129,072	299,383	110,243	—
Total assets	505,111	283,736	431,504	163,152	822
Current liabilities	24,493	29,045	42,741	7,471	514
Non-current liabilities	246,076	2,015	137,590	1,995	—
Total liabilities	270,569	31,060	180,331	9,466	514
Total shareholders' equity	234,542	252,676	251,173	153,686	308
Total Shares outstanding	115,624,419	112,448,719	112,761,219	88,008,719	44,612,500

In the first quarter of 2011 and the second quarter of 2012, the Company raised net proceeds of approximately C$175 million and C$117 million, respectively, through private placements of Shares.

In September 2012, the Company raised net proceeds of approximately U.S.$167 million through the issuance of Convertible Bonds.

Pursuant to the Farm-in Advance Agreement, U.S.$100 million and U.S.$50 million was advanced by Glencore to PetroChad (Mangara) Limited (an indirect wholly-owned subsidiary of the Company) on 4 March 2013 and 30 May 2013, respectively, as advance consideration for its obligations under the Farm-in Agreement.

Section B—Issuer		
Element	**Disclosure requirement**	**Disclosure**
		Pursuant to the Farm-in Completion, approximately U.S.$107 million was paid by Glencore to certain direct wholly-owned subsidiaries of the Company as consideration for its obligations under the Farm-in Agreement, net of the repayment of the Farm-in Advance. Other than as set out above, there has been no significant change to the Group's financial condition and operating results during or subsequent to the period covered by the historical financial information contained in this Prospectus.
B.8	Key *pro forma* financial information	Not applicable. No *pro forma* financial information has been included in this Prospectus.
B.9	Profit forecast	Not applicable. No profit forecast has been included in this Prospectus.
B.10	Description of the nature of any qualifications in the audit report on the historical financial information	Not applicable. The audit report on the audited consolidated financial statements of the Company as of and for the years ended 2012, 2011 and 2010 is not qualified.
B.11	Explanation if there is insufficient working capital	Not applicable. In the opinion of the Company the working capital available to the Group is sufficient for the Group's present requirements, that is for the next 12 months following the date of this Prospectus.

Section C—Securities		
Element	**Disclosure requirement**	**Disclosure**
C.1	Type and class of securities	The securities to be admitted to listing on the premium listing segment of the Official List and to trading on the London Stock Exchange plc's main market for listed securities are common shares in the capital of the Company ("**Shares**"). When admitted to trading, the Shares will be registered with ISIN number CA1407561077 and SEDOL number BB97882.
C.2	Currency of the securities issue	Following Admission, the price of the Shares will be quoted on the London Stock Exchange in pounds sterling.
C.3	Issued share capital	As at 24 June 2013, the number of issued Shares was 115,657,752. The Shares do not have a nominal or par value.
C.4	Description of the rights attaching to the securities	The Shares rank *pari passu* in all respects. • Each Share ranks equally for voting purposes. On a show of hands each shareholder has one vote and on a poll each shareholder has one vote per Share held. • Each Share ranks equally for any dividend declared. Each Share ranks equally for any distributions made on a winding-up. • Each Share ranks equally in the right to receive a relative proportion of shares in case of a capitalisation of reserves.

Section C—Securities		
Element	**Disclosure requirement**	**Disclosure**
		Securities issued by non-UK companies, such as the Company, cannot be held or transferred electronically in the CREST system. The Company has established arrangements for the issuance of depositary interests to enable investors to settle interests in the Shares through the CREST system.
C.5	Restrictions on the free transferability of the securities	Not applicable. There are no restrictions on the free transferability of the Shares.
C.6	Admission	Application has been made (i) to the UK Listing Authority for all of the Shares to be admitted to listing on the premium listing segment of the Official List and (ii) to the London Stock Exchange plc for such Shares to be admitted to trading on its main market for listed securities (together, "**Admission**"). It is expected that Admission will become effective, and that unconditional dealings in the Shares will commence, at 8.00 a.m. (London time) on or around 5 July 2013.
C.7	Dividends and dividend policy	The Company has never declared or paid any dividends on the Shares and the Directors do not anticipate that the Company will pay dividends in the near future. The Directors will consider the Company's dividend policy as the Company advances the development of its operations. The Directors envisage that, at such time, the Company's dividend policy would be determined based on, and depend on, the results of the Company's operations, financial condition, cash requirements, future prospects, profits available for distribution and other factors deemed to be relevant at the time. The Company's current intention is that future dividends, if any, would be declared and paid in U.S. dollars, although the Company may choose to declare and/or pay dividends in another currency.

Section D—Risks		
Element	**Disclosure requirement**	**Disclosure**
D.1	Key information on the risks specific to the issuer or its industry	***Risks associated with early stage exploration and production*** • The Group is currently in an early stage of operations and has experienced operating losses in each year since the incorporation of the Company. The Group's success depends on its ability to locate, explore, appraise and develop oil reserves and to produce these reserves commercially. It has limited actual exploration and production data from which to draw upon when formulating its exploration and development strategy and may be unable to obtain commercially reasonable terms for its exploration, appraisal, development or production activities. • There is no assurance that the Group's expenditures on future exploration will result in new discoveries of oil in commercial quantities. The reserves and resources data, profiles and plans for the Group's assets contained in this Prospectus are estimates and actual production, revenues, development and operating expenditures with respect to reserves and resources will vary from estimates thereof, and such variations could be material.

Section D—Risks		
Element	**Disclosure requirement**	**Disclosure**
		Risks associated with project delivery • The Group's projects might be delayed or terminated as a result of several factors, many of which are not in its control. In particular, the viability of the Group's business is dependent upon gaining access to the Export Pipeline, in relation to which not all agreements required for access have been finalised. The Export Pipeline is the only means for the Group to transport its production to market, as there is no rail infrastructure or adequate road access that would allow the Group to cost-effectively transport oil by truck. • The Group's business requires significant capital expenditure, and the future expansion and development of the business could require future debt and equity financing. Project risks, such as interruptions, delays, cost over-runs and recovery, and increases in the cost of materials and services could impact the timing of expected revenues from operations, and significant cost over-runs and recovery could make a project uneconomic. ***Risks associated with dependence on third parties, including joint venture partners*** • The Group has joint venture partners and may be required to consult them on significant matters. In addition, the Group has agreed to sell all of its production to Glencore; if the Offtake Agreement was terminated the Group would need to enter into a new contract with another purchaser, which may delay the Group's ability to sell its oil. • The Group relies on third party contractors and providers of capital equipment. Some of the services required for the Group's operations and strategic developments are currently only available on commercially reasonable terms from a limited number of providers and the Group must compete with other oil exploration and production companies in Chad for such services. ***Risks associated with the terms of the PSCs*** • The Group is subject to certain risks related to the terms of the PSCs, including a minimum work programme that contains minimum work obligations. The Group has made assumptions in its business plans that rely on a certain portion of development cost recovery from the Government of Chad that is contingent on the Group's continued compliance with the terms of the PSCs. ***Risks associated with doing business in Chad*** • The Group is exposed to risks inherent in doing business in emerging markets, including political, legal, regulatory, social and economic risks. The Group's operations may be affected in varying degrees by government regulations with respect to restrictions on production, price controls, export controls, income taxes, expropriation of property or environmental legislation. Chad has a less developed legal system than exists in developed countries and the Group may have difficulty in obtaining effective legal redress in the courts of Chad.

Section D—Risks		
Element	**Disclosure requirement**	**Disclosure**
		• Chad suffers from under-developed infrastructure, chronic energy shortages and high energy costs. Due to the location of the Group's properties, there is no infrastructure, other than the Group's, currently available to refine and transport oil from the Group's existing and future wells to the Export Pipeline. • The Group is subject to environmental laws and regulations in connection with its operations and there are certain risks inherent in its activities, such as accidental spills, leakages, explosions, fires or other unforeseen circumstances that could expose the Group to significant liability. Environmental, health and safety laws may also become more complex and stringent or the subject of increasingly strict interpretation and/or enforcement.
D.3	Key information on the risks specific to the securities	***Risks associated with the Shares*** • An active trading market for the Shares may not develop, which may limit liquidity and/or cause the price of the Shares to fall, and the market price for the Shares may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond the Group's control. • The Company has never declared or paid any dividends on the Shares and currently the Company intends to retain future earnings, if any, for future operations, expansion and debt repayment, if necessary. Therefore, at present there is no intention to pay a dividend and a dividend may never be paid.

Section E—Offer		
Element	**Disclosure requirement**	**Disclosure**
E.1	Net proceeds and costs of offer	The Company will not receive any proceeds in relation to Admission. The estimated fees and expenses relating to Admission, including professional fees and expenses and the costs of printing of documents are estimated to amount to £3.4 million (U.S.$5.2 million) (including VAT) and are payable by the Company.
E.2a	Reasons for the offer, use of proceeds and net amount of proceeds	The Company will not receive any proceeds in relation to Admission. The Directors believe that Admission will better position the Company in the London market, which has numerous listed oil and gas companies that are focused in the African region. This should enable the Company to access a more receptive investor base and enhance liquidity for existing holders of the Shares. Admission is also expected to broaden the Company's access to institutional capital to support its operations and growth, if and when required.
E.3	Terms and conditions of the offer	Not applicable. This Prospectus does not constitute an offer to sell or an invitation to subscribe for, or the solicitation of an offer to purchase or to subscribe for, any Shares to any person in any jurisdiction.
E.4	Material interests	Not applicable. There are no interests known to the Company that are material to Admission or which are conflicting interests.

Section E—Offer		
Element	**Disclosure requirement**	**Disclosure**
E.5	Selling shareholder/ lock-up arrangements	No Shares are being sold by any shareholder of the Company pursuant to Admission. The Company is subject to a 120-day lock-up period following Admission, during which time it will not issue or dispose of any Shares, or securities convertible or exchangeable into Shares, without the consent of the Sponsor, subject to certain exceptions, including in respect of the conversion of the Convertible Bonds into Shares in accordance with their terms (and potentially any accrued but unpaid interest in relation thereto). Upon the occurrence of a qualifying public offer (a "**QPO**") under the terms of the Convertible Bonds, the Company will: • procure that no Director or Senior Manager will sell Shares, or any warrants or options relating to Shares, for a period of not less than 365 days following the effective date of the QPO; and • seek undertakings from holders of more than 5 per cent. of the outstanding Shares not to sell such Shares for a period of not more than 120 days following the effective date of the QPO. It is anticipated that, together, The Bradley Griffiths BDG Trust, BDG Capital Ltd. and Griffiths Energy and Resources Inc. may dispose of up to two million Shares or interests in up to two million Shares, upon terms to be determined, in the near- to medium-term following Admission.
E.6	Dilution	Not applicable. This Prospectus does not constitute an offer to sell or an invitation to subscribe for, or the solicitation of an offer to purchase or to subscribe for, any Shares to any person in any jurisdiction.
E.7	Estimated expenses charged to investor	Not applicable. No expenses relating to Admission will be charged to investors by the Company.

PART II

RISK FACTORS

Any investment in the Shares is speculative and subject to a high degree of risk. Prior to investing in the Shares, prospective investors should carefully consider the risks and uncertainties associated with any investment in the Shares, the Group's business and the industry in which it operates, together with all other information contained in this Prospectus including, in particular, the risk factors described below. Any of the risks described below, as well as other risks and uncertainties discussed in this Prospectus, could have a material adverse effect on the Group's business and could therefore have a negative effect on the trading price of the Shares. Prospective investors should note that the risks relating to the Group, its industry and the Shares summarised in Part I: "Summary Information" are the risks that the Group believes to be the most essential to an assessment by a prospective investor of whether to consider an investment in the Shares. However, as the risks which the Group faces relate to events and depend on circumstances that may or may not occur in the future, prospective investors should consider not only the information on the key risks summarised in Part I: "Summary Information" but also, among other things, the risks and uncertainties described below.

The following factors do not purport to be a complete list or explanation of all the risk factors involved in investing in the Shares and should be used as guidance only. Additional risks and uncertainties that are not currently known to the Group, or that it currently deems immaterial, may individually or cumulatively also have an adverse effect on the Group's business, results of operations, financial condition and prospects. If this occurs, the price of the Shares may decline and investors could lose all or part of their investment. Prospective investors should also consider carefully whether an investment in the Shares is suitable for them in light of the information in this Prospectus and their personal circumstances.

RISKS RELATING TO OUR BUSINESS AND OPERATIONS

The Group's success depends on its ability to locate, explore, appraise and develop oil reserves and to produce these reserves commercially

Oil exploration involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. Based on the interpretation of an extensive seismic database compiled by the previous operators on the Group's properties, the results of exploration wells drilled prior to 31 December 2012 and the recent well re-entry workover data, estimates in the GLJ Reports are that the Group's properties contain 28.8 MMbbl of gross lease proved reserves, 89.3 MMbbl of gross lease proved and probable reserves and 200.6 MMbbl of gross lease proved plus probable plus possible reserves (14.4 MMbbl, 44.6 MMbbl and 100.3 MMbbl, respectively, on a Net Participating Interest basis)[(2)]. However, these estimates are based upon data from only 16 wells having been drilled on more than 26,000 km^2 of land over the past 40 years. The previous operators drilled three wells in the Mangara Field, two wells in the Maku Field and one well in each of the Badila and Kibea Fields. Currently the Group has proved and probable reserves assigned to the Mangara, Badila, Kibea and Maku Fields. Furthermore, although other companies, including EEPCI, have been producing oil in Chad since 2003, the geology of those fields is not entirely comparable to the geology of the Group's fields. For example, the Group's current developments are within Lower Cretaceous clastic reservoirs, while EEPCI's production comes from Upper Cretaceous reservoirs. Therefore, the Group has limited actual exploration and production data from which to draw upon when formulating its exploration and development strategy. In addition, the Group may be unable to conduct its exploration, appraisal, development or production activities on commercially reasonable terms. Factors such as adverse weather conditions, natural disasters, equipment or services shortages, procurement delays or difficulties arising from the political, environmental and other conditions in the areas where the reserves are located or through which the Group's products are transported may increase costs and make it uneconomical to develop reserves and prospective and contingent resources. Without successful exploration, appraisal and development activities, the Group's reserves production and revenues are likely to decline over the longer term, and the failure of these activities would have a material adverse effect on the Group's business, financial condition and results of operations.

The Group believes that future increases in the Group's reserves will depend mainly on its ability to explore, appraise and develop its existing asset base. Therefore, the long-term success of the Group will

(2) GLJ has assumed, for the purposes of estimating the Group's participating interest in any future EXAs which may be granted under each PSC, that the Government of Chad will elect to acquire a 25 per cent. participating interest in each EXA. Accordingly, the participating interest of each of the Group and Glencore has been assumed by GLJ to be 50 per cent. and 25 per cent. respectively, of the gross lease interest.

also depend on its ability to find and develop additional oil reserves. If the Group is successful in exploiting its existing reserves, but is unsuccessful in locating and developing new reserves to replace its existing reserves, its reserves (and hence expected future production) would decline over time as its current reserves are depleted by production. It is difficult to accurately project the costs of implementing an exploratory drilling programme due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over-pressured zones, tools lost in the hole and changes in drilling plans and logistics. There is no assurance that the Group's expenditures on future exploration will result in new discoveries of oil, or in discoveries of oil in commercial quantities that can be economically developed.

The reserves and resources data, profiles and plans for the Group's assets contained in this Prospectus are estimates prepared by GLJ

Unless stated otherwise, the reserves and resources data and production estimates included in this Prospectus have been derived or extracted from the GLJ Reports, which have been prepared in accordance with the 2007 Petroleum Resources Management System (as defined by the Society of Petroleum Engineers, American Association of Petroleum Geologists, World Petroleum Council and Society of Petroleum Evaluation Engineers) ("**PRMS**"). There are numerous uncertainties inherent in estimating the quantity and the quality of reserves and prospective resources and in projecting future rates of production, including many factors beyond the Group's control.

The reserves and resources estimates contained in this Prospectus are derived from the interpretation of seismic and other geoscientific data and, where appropriate, well test results and logs. Such interpretation and estimates of the amounts of oil reserves and resources are subjective and the results of drilling, testing and production subsequent to the date of any particular estimate may result in substantial revisions to the original interpretation and estimates. The reserves and resources information set out in this Prospectus represent estimates only.

In general, estimates of economically recoverable oil reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. The Group's actual production, revenues and development and operating expenditures with respect to its reserves will vary from estimates thereof, and such variations could be material.

Estimates of proved and probable reserves that may be developed and produced in the future are often based upon volumetric estimates without the benefit of actual production history. Estimates based solely on volumetric methods are, in some cases, more uncertain than estimates also supported by actual production history. The estimates assume that the Group's assumptions as to its capital expenditure and operating costs are accurate and that the capital expenditure strategy of the Group is successfully implemented by it. There can be no assurance that actual capital expenditures will not vary significantly from current estimates or that the Group will be able to implement its capital expenditure strategy on the timetable currently envisaged.

Furthermore, there are also numerous uncertainties in estimating the timing and quantity of development expenditures and associated production projections. The production profiles and development plans in this Prospectus and in the GLJ Reports are based on a number of assumptions which, together with the estimates, may prove to be materially incorrect. As a result, investors should not place undue reliance on the forward-looking statements contained in this Prospectus and in the GLJ Reports concerning the Group's resources, production profiles and development plans. In addition, nothing in this Prospectus should be interpreted as assurances of the Group's reserves or resources, the production profiles of the Group's assets or the development plans of the Group.

Special uncertainties exist with respect to the estimation of prospective resources in addition to those set forth above that apply to reserves. Prospective resources are defined as 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. There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. Volumes associated with prospective resources included in the GLJ Reports should therefore be considered highly speculative, and there can be no guarantee that the Group will be able to develop these resources commercially.

The Group is currently in an early stage of operations and has experienced operating losses in each year since the Company's incorporation

The Group has a limited history of operations on which to assess its future expected performance, and the Group has not earned any revenue since the Company's incorporation in 2009. This is because, for the periods under review, the Group's projects have been in the developmental stage, as a result of which, the Group is subject to risks, expenses and uncertainties associated with the implementation of its business plan that are not typically faced by more mature companies. New operations must construct the necessary infrastructure, develop successful business relationships, establish operating procedures, hire staff, install management information and other systems and obtain licences, as well as take other measures necessary to conduct their intended business activities. It is common in new oil operations to experience unexpected problems and delays during construction, development and production start-up. The Group's projects might be delayed or terminated as a result of several factors, many of which are not in its control, including those noted above, political instability, adverse government regulatory action, an inability to raise sufficient capital, natural disasters and operational failures. Any of these factors may result in the Group's anticipated profitability not being achieved when expected, or at all, and its operations differing materially from the activities described in this Prospectus.

The Group will be dependent on the Export Pipeline to export its production

The Group will be entirely dependent on the Export Pipeline to export any oil out of Chad. In order to gain access to the Export Pipeline, the Transportation Agreements will need to be executed by the parties thereto, which include the Company. The Transportation Agreements are expected to govern the terms of use of the Export Pipeline for the transport of oil produced in the Badila and Mangara Fields, including the order of priority for access and the applicable fees payable for use of the Export Pipeline.

The Transportation Agreements are in an advanced stage of negotiation and the Group expects that they will be entered into prior to targeted first production from the Badila Field in July 2013. However, as the discussions to finalise the Transportation Agreements are complex and involve multiple parties, there can be no guarantee that these agreements will be entered into within the expected timeframe. Absent access to the Export Pipeline pursuant to the Transportation Agreements (or any interim agreements, if any, to provide temporary transportation rights pending finalisation of the Transportation Agreements), the Group's business would not be viable.

The fees payable by the Group to use the Export Pipeline are the subject of negotiation between the parties to the Transportation Agreements. These fees are expected to include payments in respect of a fixed and variable throughput charge, operating expenditure, capital expenditure and a utility rate of return for use of the Export Pipeline. Transit fees are also payable to the Government of Cameroon in respect of oil transported through the Cameroonian portion of the Export Pipeline. Based on negotiations to date, the Group believes that the anticipated fees to be payable by the Group to use the Export Pipeline will result in the continued economic viability of its planned development of the Badila and Mangara Fields. However, the exact charges to which the Group will be subject for use of the Export Pipeline will not be known until negotiations in respect of the Export Pipeline have been concluded and the transit fees have been agreed between the Governments of Chad and Cameroon. If the outcome of these discussions are materially different from the Group's current expectations, the Group's business, results of operations and financial condition could be materially adversely affected.

The Group's access to the Export Pipeline is subject to rights of priority access of other producers. The order of use of the Export Pipeline gives priority to crude oil produced by the operators of the Export Pipeline, followed by production from a defined geographical area (the "**Permit H Zone**"), within which the Group's Contractual Zones are located. Priority of access in respect of a particular field within the Permit H Zone is determined by the date of submission to the operators of the Export Pipeline of an official request for access (such request to be accompanied by the relevant field development plan approved by the Government of Chad). To date, the Group has been granted access requests relating to the Badila and Mangara Fields. However, such access requests were granted after access requests were

granted to one other operator in respect of certain of its fields in the Permit H Zone (the "**Third Party Fields**"). The Group's production from the Badila and Mangara Fields has lower priority access to the Export Pipeline than production from the operators of the Export Pipeline's current and future producing assets and the Third Party Fields (together, the "**Priority Fields**"). Based on current and anticipated medium-term production levels of the Badila and Mangara Fields and the Priority Fields (as provided by the operators of the Export Pipeline), and subject to the priority arrangements currently established, the Group believes that the Export Pipeline has sufficient capacity to service both the needs of the Priority Fields and those of the Badila and Mangara Fields. However, should production from the Priority Fields increase, there is a risk that there could be capacity constraints in the Export Pipeline, affecting the Group's ability to transport all or part of its oil.

The level of priority accorded to the Group's fields other than the Badila and Mangara Fields will depend upon the Group's ability to obtain approval of the relevant field development plans. Should any other producer in the Permit H Zone obtain approval of field development plans prior to the Group and subsequently be granted access requests by the operators of the Export Pipeline, any new fields (other than the Badila and Mangara Fields) developed by the Group would be accorded lesser priority of access to the Export Pipeline. Also, separate transportation agreements will need to be entered into to enable the transport of oil produced in any of the Group's properties not located within the Badila and Mangara Fields through the Export Pipeline. While it is expected that the terms of such additional transportation agreements would be substantially the same as those of the Transportation Agreements, there is no assurance that they would be the same. Consequently, the terms of such transportation agreements could adversely affect the economic viability of the development of the fields to which they relate.

Should the Group not be able to access adequate capacity in the Export Pipeline due to demand from other higher-priority producers or for any other reason (including mechanical malfunction), there is no other means by which the Group can transport its production from its fields to its contracted purchaser, Glencore, or any other potential purchaser, as there is no rail infrastructure or adequate road access that would allow the Group to transport material quantities of oil to market by truck cost-effectively over the long term.

Furthermore, the majority of the Export Pipeline runs through Cameroon. Therefore, the Group's access to and use of the Export Pipeline may be adversely affected by, *inter alia*, changes in the political or economic environment in Cameroon, changes in law, regulation or tariff structures, lack of adequate infrastructure, or criminal or terrorist activity.

The Group relies on its joint venture partners and may be required to consult them on significant matters

The Group operates all of its assets, but has entered a series of agreements with Glencore, one of the world's largest commodity traders, in respect of all three of the PSCs. The Government of Chad has also exercised its back-in rights in relation to the Badila and Mangara EXAs, which provided it, through SHT, with a 25 per cent. participating interest therein (reduced to 15 per cent. following the sale of a 10 per cent. participating interest to Glencore in June 2013 pursuant to the Glencore/SHT Transaction). As is common in joint ventures, the arrangements with Glencore provide that Glencore must be consulted or provide its consent in relation to significant matters. Accordingly, while the Group has control over the day-to-day management and operations of those assets, it may be required to undertake certain activities on a sole risk basis if Glencore elects to not participate in such operations. It may also experience delays in undertaking activities due to time taken to obtain the consent of Glencore. Any disagreement, absence of consent, delay, opposition, breach of agreement, or inability to undertake activities or failure to provide funding of the kind identified above could adversely affect the Group's business, prospects, financial condition and results of operations.

The Group has also entered into the Offtake Agreement to sell all of its entitlement of crude oil produced under the PSCs to Glencore. The Group will therefore be reliant on Glencore for substantially all of its revenues and hence subject to the increased risk of delayed payment for delivered production volumes, counterparty default or termination of the sales agreement by Glencore. The Group has no previous experience contracting with Glencore or as a counterparty in a joint venture agreement. If the Group were to seek to terminate the agreement with Glencore against its wishes, Glencore could delay any resolution of the matter for a significant period of time. Further, if the Offtake Agreement was terminated by action of either party, the Group would need to negotiate and enter into a new contract with another purchaser for the sale of its oil. During any such negotiations, which may take a significant amount of time to conclude, the Group may not be able to sell any of its oil, which would have an adverse effect on the

Group's business, results of operations and financial condition. The absence of alternative purchasers for the oil produced by the Group may also expose it to adverse pricing or other contractual terms. There can be no assurance that the Group would be able to negotiate and enter into agreements with purchasers for the sale of oil on equivalent terms to those with Glencore, or at all. Any such delays, defaults, reduction in oil volumes purchased or adverse pricing or other contractual terms could adversely affect the Group's business, results of operations and financial condition.

The Group's business requires significant capital expenditure, and the future expansion and development of the business could require future debt and equity financing

The Group's business requires substantial capital expenditures for the foreseeable future to finance the exploration, development and production of its existing oil reserves. The Group believes that its existing cash resources, together with the financial commitments of Glencore pursuant to the Farm-in Agreement and expected operating cash flow from production, will be sufficient to fund the Group's current capital expenditure plans for the next 12 months. If the revenues from the Group's reserves decrease as a result of lower oil prices and/or lower than projected production levels, its ability to expend the necessary capital to undertake its exploration and development programme, to replace its reserves and to maintain its production in the future will be adversely affected. Although the Group is of the opinion that it has sufficient working capital from its existing resources to fund itself for the next 12 months, there can be no assurance that in future periods beyond the next 12 months there will be any cash generated by operations or that debt or equity financing, if required, will be available or sufficient to meet the Group's future funding requirements. In addition, the Group competes with other oil exploration and production companies operating in emerging markets for funding. There can be no guarantee that there will be sufficient investor demand to meet the funding requirements of this sector and/or emerging market issuers, including those of the Group. The failure to obtain such additional funding could result in the delay or indefinite postponement of further exploration and development of the Group's properties, including the inability to drill certain prospects prior to their mandatory relinquishment to the Government of Chad under the terms of the PSCs, which could adversely affect the Group's business, results of operations and financial condition.

Project risks, such as interruptions, delays, cost over-runs and recovery, and increases in the cost of materials and services, could materially adversely affect the Group's business

The Group will be required to manage a variety of projects in the conduct of its business. Project delays would impact the timing of expected revenues from operations, and significant cost over-runs could make a project uneconomic. As at the date of this Prospectus, the Group has not yet realised any production from its assets. It has only completed the drilling of three new wells across the Badila and Mangara Fields, and there can be no guarantee that these or further wells drilled will lead to successful production. Assuming production from the Badila Field commences as targeted in July 2013, the Group's ability to successfully market oil depends upon numerous factors, some of which are beyond the Group's control, including: the availability of drilling and related equipment; the availability of processing capacity; the availability of storage capacity; the availability and proximity of Export Pipeline capacity; the availability and productivity of skilled labour; the supply of and demand for oil; the effects of inclement weather; the potential rate of increase in the cost of materials and services; unexpected cost increases; accidental events; currency fluctuations; changes in regulations; and the regulation of the oil industry by various levels of government and governmental agencies. As a result of these factors, the Group may be unable to execute its development projects on time, on budget or at all, and may not be able to effectively market its oil production.

The Group relies on third party contractors and providers of capital equipment

The Group relies to a large extent on external contractors to carry out drilling activities and seismic acquisition as well as the construction, operation and maintenance of its facilities and other capital expenditure projects. As a result, the Group is dependent on external contractors performing satisfactorily and fulfilling their obligations. Any failure by an external contractor to do so may lead to delays or curtailment of the production, transportation, refining or delivery of oil. In addition, the costs of third party operators may increase, leading to higher production and transportation expenses for the Group. Any failure in performance or increase in costs could have an adverse effect on the Group's results of operations.

Some of the services required for the Group's operations and strategic developments are currently only available on commercially reasonable terms from a limited number of providers. The Group competes for the services of these providers with other oil exploration and production companies in Chad, which can constrain the Group's negotiating position in setting the terms of the relevant contract. The Group's operations and developments may be interrupted or otherwise adversely affected by failure to supply or delays in the supply of services that meet the Group's quality requirements. If the Group is forced to change a provider of such services, there is no guarantee that this would not result in the Group experiencing additional costs, interruptions to supply continuity or other adverse effects on its business. There is also no guarantee that the Group will be able to find adequate replacement services on a timely basis or at all. Any failure in performance by third party services providers, external contractors or consultants, increase in costs or inability to find adequate replacement services on a timely basis, if at all, could have a material adverse effect on the Group's business, results of operation and financial condition.

The Group is dependent on key management and other personnel to help manage growth

The Group is dependent on a team of key management and other personnel with experience, knowledge and skill in oil exploration and development operations for its success, in particular its Chief Executive Officer, President and Executive Director, Gary Guidry. The contributions of the management team to the immediate and near term operations of the Group are likely to be of central importance. The Group has no key-man insurance policies. The departure of any of these key individuals, or any impediment to performance of their duties, may cause the Group serious operational difficulties, and the Group may not be able to locate suitable replacement personnel in a timely manner, or at all. There is no guarantee that the Group will retain members of its management team, and if the Group were to lose a member of its management team unexpectedly, its business, prospects, financial condition and results of operations may be adversely affected.

The Group's ability to manage growth will require it to continue to implement and improve its administrative, accounting and management systems, and to recruit, integrate and train new employees, including additional management, administrative, distribution, sales and marketing and, potentially, manufacturing personnel. There can be no assurance that the Group will be able to attract and retain skilled and experienced personnel.

The Group's business also requires skilled personnel and professional staff in the areas of exploration and development, operations, engineering, business development, oil marketing, finance and accounting, a significant portion of whom will be required to spend substantial amounts of time in Chad. Competition for such personnel is intense. The loss of such personnel and the failure to successfully recruit replacements would have a material adverse effect on its business, prospects, financial condition and results of operations.

Oil production companies, including the Group, may be adversely affected by current global economic conditions

The current global economic environment and the volatility of international markets have caused governments and central banks to undertake unprecedented intervention designed to stabilise global and domestic financial systems, stimulate new lending and support structurally important industries and institutions such as banks which are at risk of failing. Many developed economies have experienced recessions over the past several years and growth has slowed in many emerging economies with serious adverse consequences for asset values, employment levels, consumer confidence and levels of economic activity. Numerous governments and central banks have responded to these economic conditions by proposing programmes to make substantial funds and guarantees available to boost liquidity and confidence in their financial systems. It is not known whether these responses will be effective in addressing the economic and market conditions that exist at present. The impact of the reversal or withdrawal of such programmes is also uncertain. Any further deterioration of the global economic environment could have a material adverse effect on the Group's business, results of operations and financial condition, particularly to the extent it impacts upon the price of oil and/or affects the Group's ability to access the capital markets or obtain credit for future funding on commercially acceptable terms.

Oil prices have fluctuated significantly in the past and could significantly impact the Group

The Group's revenues, profitability and growth will depend substantially on prevailing oil prices, which can be volatile and subject to fluctuation. Changes in oil prices will directly affect the Group's revenues and net income because, under the terms of the Offtake Agreement, the Group will value its oil using a formula

which is based upon the spot price for Dated Brent Crude. Factors affecting the price of oil include, but are not limited to:

- changes in the global and regional supply and demand for oil and expectations regarding future supply and demand;
- the condition of the world economy and geopolitical events;
- the worldwide military and political environment and uncertainty or instability resulting from the escalation or outbreak of armed hostilities or acts of terrorism in oil producing countries;
- other actions taken by major oil producing or consuming countries or companies;
- governmental regulations and actions, including export restrictions, price regulation and taxes;
- the development, availability, price and acceptance of alternative fuels; and
- weather conditions and natural disasters in oil producing regions.

The Group's future profitability will be determined in large part by the difference between the income received for the oil the Group sells and its operating costs, as well as costs incurred transporting and selling its oil. Therefore, a decline in oil prices may reduce the amount of oil that the Group is able to produce economically, thereby reducing profitability, and to the extent that production costs exceed anticipated income from the sale of oil produced, may reduce the economic viability of the production levels of specific wells or of projects planned or in development.

In addition, should oil and/or gas prices increase significantly, governments or other counterparties may want to change their commercial terms with the Group. This may result in cancellation, termination or a unilateral change of terms (such as a change in oil pricing policy or the renegotiation or nullification of existing PSCs) by a government or counterparty, which could materially and adversely affect the Group's business, prospects, financial condition and results of operations.

The Group's insurance and indemnities may not adequately cover all risks or expenses

The Group's involvement in the exploration for and development of oil and gas reserves may result in the Group becoming subject to liability for, among other things, pollution, blow-outs, property damage, personal injury or other hazards. The Group can give no assurance that its existing insurance and indemnity cover will be sufficient to cover all the risks to which it may be subject or that the proceeds of insurance applicable to covered risks or recovery under indemnities will be adequate to cover expenses relating to losses or liabilities. In addition, risks may not in all circumstances be insurable or, in certain cases, such as political risk, the Group may elect not to obtain insurance with regard to specific risks due to the high premiums associated with such insurance or for other reasons. Accordingly, the Group may suffer material losses from uninsurable or uninsured risks or insufficient insurance and indemnity coverage. The occurrence of a significant event that the Group may not be fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on the Group's financial condition and results of operations.

The Group is subject to certain risks related to the terms of the PSCs

The PSCs contain certain obligations of the Group to provide a minimum work programme that contains minimum work obligations, in the form of minimum exploration expenditures. The minimum EEA obligations during the Initial Exploration Term amount to U.S.$115.0 million across all three PSCs, and as of 31 March 2013, U.S.$94.4 million remained to be spent. If the Group fails to satisfy the minimum work obligation of the applicable PSC (or if the applicable PSC is revoked or forfeited), it will be required to pay to the Government of Chad, in cash, an amount equal to 50 per cent. of the work obligations not completed during the applicable term. Any such payments could have a material adverse effect on the Group, its business, prospects, results of operations or financial condition.

The PSCs provide that if the Government of Chad elects to exercise its back-in rights in respect of an EXA (as it has done in respect of the Badila and Mangara EXAs and as the Group expects it to do in respect of future EXAs), it will be required to reimburse the Group for the Government of Chad's proportionate share of all exploration and development costs out of the Government of Chad's participating interest share of Cost Oil. However, this obligation for reimbursement only commences on the date of production of the first barrel of oil from the relevant EXA. If there is insufficient production over the term of the EXA to permit complete reimbursement of exploration costs, the Group will remain responsible for all costs of

the EXA without entitlement to reimbursement from the Government of Chad, which could have a material adverse effect on the Group, its business, prospects, results of operations or financial condition.

While the Group negotiates renewals of its exploration or appraisal periods and term contracts prior to their expiry, there can be no assurance that the Group will be able to enter into a new phase or obtain extensions to contracts with the governments or other suppliers or joint venture partners on commercially reasonable terms, prior to the end of an exploration period, following the end of the period or at all. In particular, pursuant to the terms of the PSCs, if the Group wishes to extend the term of an EEA beyond the Initial Exploration Term of five years (from the date of decree for each PSC), then it is required to relinquish 50 per cent. of the contract area (excluding any areas in which petroleum has been discovered in commercial quantities, as evidenced by the approval of an EXA). After expiry of the Initial Exploration Term (in 2016 for each of the PSCs), the Group will be eligible for a three year extension on 50 per cent. of the acreage in a contiguous block, which would also be subject to minimum work obligations and would require a bank guarantee in favour of the Government of Chad to be put in place for 50 per cent. of the minimum work obligation amount. There can be no assurance that the area proposed by the Group for relinquishment will be accepted by the Government of Chad, and there is a risk that such relinquishment may contain reserves already booked by the Group, leading to a restatement of its reserves.

The Group has made assumptions in its business plans that rely on development and exploration costs recovered from the Government of Chad, referred to as "Cost Recovery". Cost Recovery is contingent on the Group's continued compliance with the terms of its licence, including administrative matters which can be cumbersome, as well as the generation of sufficient quantities of production and related revenue. The Group is the first exploration and development company to go through this Cost Recovery process with the Government of Chad under its revised petroleum law. Therefore, the Group cannot predict the type of issues that may give rise to future cost disputes with the Government of Chad based on past experience and may as a result incur higher unrecoverable costs and, consequently, lower Cost Recovery, than might otherwise be the case.

It is also possible that an exploration or appraisal period set out in a PSC is insufficient to perform the necessary seismic, drilling or other exploration or appraisal activities required to determine whether it is appropriate for the Group to elect to move into the next phase and commit to additional work obligations. The Group may therefore seek to secure the necessary amendments, renewals, extensions or waivers prior to making an election to move into the next phase of operations, and could miss the deadline for election to the next phase, while discussions with the Government of Chad are pending. The necessary amendments, renewals, extensions or waivers also may not be forthcoming on terms commercially acceptable to the Group, giving rise to the risk that the Group's interest in the PSC may be terminated by the Government of Chad or the Group may be required to relinquish the contract area.

The Group faces the possibility of future decommissioning charges that it cannot anticipate

Upon the expiry or abandonment of a PSC, the Group and Glencore are required, under the PSCs and also potentially under the terms of other relevant agreements or local law, to remove equipment, installations, structures and pipelines on its fields in accordance with a prescribed abandonment plan and to restore the production sites and returned contract area generally. The obligation to set aside financing for these expenses under the terms of the PSCs and EXAs begins at the time of first production, although the Company made a provision in its audited consolidated financial statements as of and for the year ended 2012 in the amount of U.S.$2.1 million for such decommissioning expenses. The Group may also be exposed to decommissioning charges in relation to its use of the Export Pipeline. If the costs associated with decommissioning are higher than expected, or the Group otherwise incurs penalties for failure to decommission its properties as required, its business, prospects, financial condition and results of operations may be adversely affected.

Drilling, exploration, production and related activities can be dangerous, involving health, safety and environmental risks

Developing oil resources and reserves into commercial production involves a high degree of risk. The Group is subject to all of the operating risks normally associated with the exploration for, and the production, storage, transportation and marketing of, oil, including blowouts, explosions, fire, gaseous leaks, migration of harmful substances and oil spills, any of which could cause personal injury, result in damage to, or destruction of, oil wells or formations or production facilities and other property, equipment and the environment, as well as interrupt operations. In addition, the Group's operations are subject to all

of the risks normally incident to drilling of oil wells and the operation and development of oil properties, including encountering unexpected formations or pressures, differential sticking of drilling assemblages, premature declines of reservoirs, equipment failures and other accidents (including vehicle accidents during equipment and rig moves), sour gas releases, uncontrollable flows of oil, natural gas or well fluids, adverse weather conditions, diseases impacting the health of personnel, pollution and other environmental risks. If any of these events were to occur, they could result in environmental damage, injury to persons and loss of life and a failure to produce oil or gas in commercial quantities. They could also result in significant delays to drilling programmes, a partial or total shutdown of operations, significant damage to the Group's equipment and equipment owned by third parties and personal injury or wrongful death claims being brought against the Group. These events could also put at risk some or all of the Group's licences or PSCs which enable it to explore and develop, and could result in the Group incurring significant civil liability claims, significant fines or penalties as well as criminal sanctions potentially being enforced against the Group and/or its officers. In addition, the Group's operations, including the Group's drilling programme and other exploration activities as well as the transport and other logistics on which the Group is dependent, may be adversely affected and severely disrupted by climatic conditions. Natural disasters or adverse conditions may occur in those geographical areas in which the Group operates, including severe weather, earthquakes, cyclones, excessive rainfall, tropical storms, floods, bridge or road washouts, droughts or epidemic and disease.

Criminal or terrorist actions may have a material adverse effect on the Group's business

Oil companies, particularly foreign-owned companies operating in countries such as Chad, may be targets of criminal or terrorist acts. Such incidents could severely disrupt exploration, appraisal, development and production across a broad geographical area. If the Group or its employees are the subject of any attacks, kidnappings or other security threats, the Group may be required to incur additional expenditure through increased insurance premiums, hiring additional security personnel or equipment, replacement of assets and additional safety protections. Furthermore, any such event could have an adverse effect on the Group's ability to staff its operations adequately and could adversely affect the Group's reputation.

The occurrence of any of the above could result in a long-term delay to oil exploration, appraisal, development and production by the Group in the affected region and could restrict the Group's control over the nature and timing of its exploration, appraisal, development, production and other activities. Such interruptions, expenditure or delays could have a material and adverse effect on the Group's business, prospects, financial condition and results of operations.

Foreign Subsidiaries

The Company conducts most of its operations through its subsidiaries located outside of Canada. Therefore, the Company will be dependent on distributions from these subsidiaries to meet its obligations. The ability of a subsidiary to make payments to the Company may be constrained by, among other things: the level of taxation, particularly corporate profits and withholding taxes, in the jurisdiction in which it operates; and the introduction of exchange controls or repatriation restrictions or the availability of hard currency to be repatriated.

RISKS RELATING TO CHAD

The Group is exposed to risks inherent in doing business in Chad

The Group is currently entirely dependent upon its exploration and development properties covered by the PSCs in Chad, and any adverse development affecting those properties or the PSCs would have a material adverse effect on the Group, its business, prospects, results of operations and financial condition. Doing business in Chad brings with it a wide variety of risks, including political, legal, regulatory, social and economic risks.

Political Risks

Chad endured three decades of civil warfare, as well as invasions by Libya, before a cessation of conflict finally occurred in 1990. In 1998, a rebellion broke out in northern Chad, which has sporadically flared up despite several peace agreements between the Government of Chad and the rebels. Chad most recently suffered a period of political instability from 2005 to 2008, in connection with the Darfur crisis in neighbouring Sudan. Eastern Chad, where United Nations peacekeepers were deployed until 2011, remains less stable than the capital, N'Djamena. On and off throughout the current Chadian government's

20-year tenure, armed rebel groups have sought to overthrow President Idriss Déby and bring about regime change by force. Certain rebel groups received support in the course of 2009 from the Sudanese government. In 2006 and 2008, Chadian rebels entered the capital city of N'Djamena but were repelled by the Chadian military. In 2009, Chadian rebels clashed with the Chadian national army in eastern Chad. A January 2010 agreement between the Government of Chad and the government of Sudan has committed the two nations to ceasing support for rebels operating within their territories, and to ending the proxy war that Chad and Sudan had waged since 2005. Chad has also signed agreements with a number of rebels and several commanders, and many rebel soldiers returned to Chad in the course of 2009, although others continue to state that they intend to fight the regime. Meanwhile, inter-ethnic violence between nomadic and pastoral groups persists in south-eastern Chad, and tensions between local Chadian populations and refugees from Darfur and the Central African Republic continue, essentially over use of scarce natural resources. According to the Office of the United Nations High Commissioner for Refugees in September 2012, over 345,000 refugees resided in Chad; of these, almost 80 per cent. originated from Sudan.

In December 2012, upon the initiative of the Economic Community of Central African States (ECCAS), Chadian troops were sent into the Central African Republic as part of the Central African Multinational Force (FOMAC) to assist its government in resisting rebel groups attempting to enter the capital city of Bangui. In January 2013, a ceasefire was agreed between the Séléka rebel forces and the government of the Central African Republic. The ceasefire was broken in late January and, on 24 March 2013, Séléka forces entered Bangui and President François Bozizé fled the country and resigned. Although rebel leader Michel Djotodia has been declared president of the Central African Republic for an 18-month transitional period, his government is not recognised by other countries in the region and the situation remains unstable. The Group's assets are located in southern Chad, near the border with the Central African Republic. Any heightening of the current instability in this region could have an adverse impact on the Group's operations.

In addition, there can be no assurance that industries deemed of national or strategic importance to Chad, such as oil production, will not be subject to nationalisation, expropriation, requisition or confiscation, whether legitimate or not, by any authority or body. Similarly, the Group's operations may be affected in varying degrees by government regulations with respect to restrictions on production, price controls, export controls, income taxes, expropriation of property or environmental legislation, as more fully described below. There can be no assurance that the laws of Chad protecting foreign investments will not be amended or abolished or that existing laws will be enforced or interpreted to provide adequate protection against any or all of the risks set forth above.

The Group cannot guarantee that its operations, properties or its facilities will be immune from the effects of these activities. If the Group's operations, properties or its facilities are affected by such activities, it could have a material adverse effect on the Group, its business, results of operations and financial condition.

Legal and Regulatory Risks

The Group is subject to extensive Chadian laws and regulations governing prices, taxes, royalties, allowable production, transport, waste disposal, pollution control and similar environmental laws, the export of oil and many other aspects of the oil business. Decision-making authority and power that impacts the Group's business is highly concentrated within the executive branch of the Government of Chad. There can be no assurance that the actions of present or future governments in Chad will not materially and adversely affect the business, financial condition or results of operations of the Group.

The DOH PSC was approved by an ordinance (the "**DOH Ordinance**") issued by the President of Chad on 17 August 2011. In accordance with Article 125 of the Constitution of Chad, a presidential ordinance must be ratified by a law passed by the Chadian National Assembly. The Chadian National Assembly did not pass a ratification law in respect of the DOH Ordinance within the required timeframe, meaning that the DOH PSC is required to be approved by a law adopted by the Chadian National Assembly in order for it to be valid. Until such law is passed, there is a risk the DOH PSC, and the Group's rights pursuant thereto, may be determined to be invalid. The Group has requested that the Ministry of Petroleum and Energy of the Government of Chad (the "**Ministry of Petroleum**") table the relevant legislation before the Chadian National Assembly in order that approval thereof may be obtained as soon as possible, and the Group understands that steps are being taken by the Ministry of Petroleum to achieve this. However, there can be no guarantee that the Chadian National Assembly (which is next due to convene in October 2013) will pass any such law on a timely basis or at all. According to the GLJ Reports, no reserves have been identified as

of 31 December 2012 in the DOH Contractual Zone and the estimated gross lease unrisked prospective resources are 49.5 MMstb (mean), or approximately 3.9 per cent., of the Group's total gross lease unrisked prospective resources (mean).

In order to perfect the transfer of the Glencore Transferred Interests (as defined below) from the Group to Glencore as per the terms of the PSCs, a fee is payable to the Government of Chad (the "**PSC Transfer Fee**"). The PSC Transfer Fee was set at U.S.$3 million for each EXA and U.S.$1 million for each EEA, for an aggregate of U.S.$9 million, in orders ("**the Transfer Fee Orders**") issued by the Minister for Petroleum of the Government of Chad (the "**Minister for Petroleum**") on 17 May 2013. On 7 June 2013, the Group paid U.S$8 million to the Public Treasury of Chad for the transfer of the DOB/DOI Transferred Interest and Doseo/Borogop Transferred Interest (each as defined below). According to the Transfer Fee Orders, upon ratification of the DOH PSC by the Chadian National Assembly, the Group will be required to pay U.S.$1 million to perfect the transfer of the DOH Transferred Interest (as defined below) to Glencore.

In order for the amount of the PSC Transfer Fee to have legal effect, the Chadian National Assembly must enact a law to confirm the PSC Transfer Fee (the "**Confirmatory Law**"), absent which there is a risk that the transfer of the Glencore Transferred Interests cannot be perfected. There can be no guarantee that the Chadian National Assembly (which is next due to convene in October 2013) will pass the Confirmatory Law on a timely basis or at all. Alternatively, the Confirmatory Law may be passed but set out a different PSC Transfer Fee. Therefore, pursuant to a letter agreement dated 13 June 2013 between Glencore and the Group (the "**Farm-in Completion Letter**"), the Group has agreed to indemnify Glencore from any loss which Glencore incurs if legal title to the DOB/DOI Transferred Interest and the Doseo/Borogop Transferred Interest does not pass to Glencore as a result of the Confirmatory Law not being passed, or being passed but not on terms that are consistent with the Transfer Fee Orders. Notwithstanding the above, Glencore is required to pay its working interest share of costs and will be entitled to its working interest share of production and associated revenue.

"**Glencore Transferred Interests**" means a 33.33 per cent. participating interest in each of the DOB/DOI PSC and DOB/DOI EEA (the "**DOB/DOI Transferred Interest**"), the Doseo/Borogop PSC and Doseo/Borogop EEA (the "**Doseo/Borogop Transferred Interest**") and the DOH PSC and DOH EEA (the "**DOH Transferred Interest**").

Chad has a less developed legal system than exists in developed countries. The Group may have difficulty in obtaining effective legal redress in the courts of Chad, whether in respect of a breach of law or contract, or an ownership dispute, as there may be a higher degree of discretion on the part of governmental authorities, a lack of judicial or administrative guidance on interpreting applicable laws, rules and regulations, inconsistencies or conflicts between and within various laws, regulations, decrees, orders and resolutions and/or relative inexperience on the part of the judiciary and courts in interpreting such matters, including, in particular, the Government of Chad's petroleum law, which was implemented in 2007 and only revised in 2010, and in respect of the application of tax legislation to oil and gas companies operating in Chad.

Chad has a score of 19 out of 100 from the 2012 Corruption Perceptions Index compiled by Transparency International (a global civil society organisation that monitors corporate and political corruption), ranking it 165 out of 176 nations. This rating is below other Sub-Saharan African oil producing nations such as Nigeria (27) and Gabon (35), broadly in line with Angola (22) and Equatorial Guinea (20) but above Sudan (13). On other governance measurements, the World Bank places Chad in the bottom 5 per cent. in relation to control of corruption.

Enforcement of laws in Chad will depend on and be subject to the interpretation by the relevant authority, and such authority may adopt an interpretation of an aspect of local law which differs from that of the Group. Any contracts, PSCs, joint ventures or other legal agreements that contain governing law and/or jurisdiction clauses implementing non-Chadian law or jurisdiction may not be enforceable under local laws. In certain cases, the commitment of government officials and agencies and the judicial system to abide by legal requirements and negotiated agreements may be more uncertain and may be susceptible to revision or cancellation, and legal redress may be uncertain or delayed. Any adverse interpretation of or action with respect to the Group's legal arrangements could have a material adverse effect on the Group, its business, results of operations and financial condition.

If a dispute arises in connection with operations in Chad, the Group may be subject to the exclusive jurisdiction of courts in Chad or arbitration tribunals in Chad or may not be successful in subjecting persons, especially those associated with the Ministry of Petroleum, to the jurisdiction of another country.

There can be no assurance that if the Group becomes involved in a dispute in Chad that it will be dealt with in a satisfactory manner or in a way in which the Group expects. The delay or results of such dispute settlement could have a material adverse effect on the Group, its business, prospects, results of operations and financial condition.

The Government of Chad exercises significant influence over domestic oil and gas exploration and production, as well as many other aspects of its economy. Any action by the Government of Chad concerning the economy, including the oil industry (such as a change in oil or gas pricing policy or taxation rules or practice, or renegotiation or nullification of existing concession contracts or oil exploration policy, laws or practice), could have a material adverse effect on the Group. For example, the Government of Chad did not adhere to the agreed terms that governed the World Bank's participation in the financing of the Export Pipeline, as a result of which the World Bank has withdrawn financial support from the country. The Government of Chad could also require the Group to grant to it larger shares of oil or revenues than previously agreed to, or postpone or review projects, nationalise assets, or make changes to laws, rules, regulations or policies, in each case, which could adversely affect the Group's business, prospects, financial condition and results of operations.

Infrastructure Risk

Oil exploration and production and the sale of such production depends on adequate infrastructure. Reliable roads, bridges, power sources and water supplies are important determinants which affect capital and operating costs. Generally speaking, Chad suffers from underdeveloped infrastructure, energy shortages and high energy costs. Transportation costs are high, and some of Chad's roads are difficult for large trucks to navigate during the rainy season.

Due to the location of the Group's properties, there is no infrastructure, other than the Group's, currently available to refine and transport oil from the Group's existing and future wells to the Export Pipeline. While the Group intends to construct and commission the Blending Export Terminal, Early Production Facilities Expansion, Mangara CPF and Mangara to Badila Pipeline, there is no guarantee that this infrastructure will be completed on a timely basis or at all. These projects are dependent on third parties, require significant capital expenditure, and require the transport of materials and personnel to the relevant sites. While the Group has taken several steps to improve local infrastructure, including building roads and bridges to improve access to its fields, there can be no assurance that the Group's operations, properties or its facilities will not be adversely impacted by the lack of developed infrastructure. Any significant delay to the execution of these projects would have a material adverse impact on the Group's business, results of operations and financial condition.

Exchange Controls

Currently there are no restrictions on transfers of funds into Chad, but any company intending to send more than U.S.$800,000 out of the country must seek approval from the Ministry of Finance of the Government of Chad (the "**Ministry of Finance**"). The Group has an exemption from this requirement pursuant to the terms of the PSCs. Similar restrictions also apply to individuals seeking to transfer money exceeding U.S.$1,000 out of Chad. Approvals are generally routine, although the Ministry of Finance has occasionally restricted capital outflows for temporary periods. Businesses can gain advance approvals for regular money transfers. If these restrictions are altered in a manner detrimental to the Group, if approval for any such transfer is not forthcoming, or if the PSCs are altered to remove this exemption, the Group, its business, prospects, results of operations or financial condition could be materially adversely affected, as would its ability to pay dividends on the Shares, should any be declared.

Environmental, Health and Safety Risks

The Group is subject to environmental laws and regulations in connection with its operations. Although the Group believes that it is in compliance in all material respects with all applicable environmental laws and regulations, there are certain risks inherent in its activities, such as accidental spills, leakages, explosions, fires or other unforeseen circumstances that could expose the Group to significant liability. Significant penalties could be imposed on the Group for clean up costs, or damages against it in the event of discharges into the environment, including environmental damage caused by previous owners of properties, acts of sabotage or non-compliance with regulation.

Environmental, health and safety laws may also become more complex and stringent or the subject of increasingly strict interpretation and/or enforcement. The terms of future PSCs or licences may include

more stringent environmental and/or health and safety requirements. Obtaining requisite licences and permits may also become more difficult or be the subject of delay by reason of governmental, regional or local consultation, approvals or other considerations or requirements.

In addition, the Group may be required to incur additional expenditure or could be required to hire or purchase additional equipment to comply with any new environmental and/or health and safety regulations. The impact of any such regulations or requirements could be to impose a constraint on long-term oil and gas production of the Group and restrict the Group's control over the nature and timing of its exploration, appraisal, development, production and other activities or its ability to undertake these activities at all may be materially and adversely affected, including by substantial delays or material increases in costs. Such additional costs, interruptions or delays could have an adverse impact on the Group's business, prospects, financial condition and results of operations.

Social and Economic Risks

The Group's workforce is not currently unionised, although the Group expects it to be in the medium-term. The Group generally enjoys good labour relations with its employees and, to date, has not been impacted by strikes or work stoppages. However, there can be no assurance that its operations may not be affected by labour disruptions involving its own employees and/or the employees of third parties, including employees of contractors retained by the Group and the employees of operators of transportation infrastructure needed to run the Group's operations in the future.

In addition, many of the Group's principal pieces of infrastructure are or will be located in close proximity to population centres. While all land acquisition and permitting has been carried out in compliance with local law and World Bank guidelines and all grievances reported to date have been successfully addressed in accordance with World Bank guidelines, there can be no assurance that this will continue to be the case.

RISKS RELATING TO THE SHARES

An active trading market for the Shares may not develop, which may limit liquidity and/or cause the price of the Shares to fall

The Company has established arrangements to enable investors to settle interests in the Shares through the CREST system. At the date of Admission, the Shares will either be held in certificated form or by means of a nominee account for the purposes of clearance through CDS. There is currently no public market for the Shares and there can be no assurance that a liquid, public market will develop or, if developed, will be maintained for the Shares and/or Depositary Interests. If an active public market does not develop or is not maintained, the Shares may be difficult to sell compared to the shares of companies with more liquid trading markets and the price of the Shares may be subject to greater fluctuations than might otherwise be the case.

Share price volatility

The market price for the Shares may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond the Group's control, including the following: (i) actual or anticipated fluctuations in the Group's quarterly results of operations; (ii) actual or anticipated changes in oil prices and/or in the capital markets; (iii) recommendations by securities research analysts; (iv) changes in the economic performance or market valuations of other companies that investors deem comparable to the Company; (v) addition or departure of the Company's executive officers and other key personnel; (vi) sales or perceived sales of additional Shares; (vii) significant acquisitions or business combinations, strategic partnerships, joint ventures or capital commitments by or involving the Group or its competitors; (viii) changes in laws, rules and regulations applicable to the Group and its operations; (ix) general economic, political and other conditions, in particular in Chad and Africa more broadly; and (x) news reports relating to trends, concerns, technological or competitive developments, regulatory changes and other related issues in the Group's industry or target markets.

Financial markets have experienced significant price and volume fluctuations in the last several years that have particularly affected the market prices of equity securities of companies and that have, in many cases, been unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of the Shares may decline even if the Group's operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause decreases in asset values that are deemed to be other than temporary, which may result in

impairment losses. Also, certain institutional investors may base their investment decisions on consideration of the Group's environmental, governance and social practices and performance against such institutions' respective investment guidelines and criteria, and failure to meet such criteria may result in a limited or no investment in the Shares by those institutions, which could adversely affect the trading price of the Shares. There can be no assurance that continuing fluctuations in the price and volume of publicly traded equity securities will not occur. If such increased levels of volatility and market turmoil continue, the Group's operations could be adversely impacted and the trading price of the Shares may be adversely affected.

Dividends

The Company has never declared or paid any dividends on the Shares. The Company currently intends to retain future earnings, if any, for future operations, expansion and debt repayment, if necessary. Therefore at present there is no intention to pay dividends and a dividend may never be paid. Any decision to declare and pay dividends will be made at the discretion of the Board of Directors and will depend on, among other things, the Group's results of operations, current and anticipated cash requirements and surplus, financial condition, contractual restrictions, financing agreement covenants, solvency tests imposed by corporate law and other factors that the Board of Directors may consider relevant.

In addition to the foregoing, the Company's ability to institute and pay dividends now or in the future may be limited by covenants contained in the agreements governing any indebtedness that the Group may incur in the future, including the terms of any credit facilities the Group may enter into with third party lenders. It is not uncommon that credit facilities will prevent a borrower from declaring or paying any dividends (excluding stock dividends) to any of its shareholders or returning any capital (including by way of dividend) to any of its shareholders.

As a result of the foregoing factors, purchasers of the Shares may not receive any return on an investment in the Shares unless they sell such Shares for a price greater than that which they paid for them.

The Company's current intention is that future dividends, if any, would be declared and paid in U.S. dollars, although the Company may choose to declare and/or pay dividends in another currency.

Dilution and further sales

The Group may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Group which may be dilutive. The Company has agreed to refrain from issuing or selling Shares, or securities convertible or exchangeable into Shares, for a period of 120 days commencing on the date of Admission without the consent of the Sponsor, subject to certain exceptions (such exceptions including in respect of the conversion of the Convertible Bonds into Shares in accordance with their terms (and potentially any accrued but unpaid interest in relation thereto)). The Convertible Bonds are convertible into Shares at any time up to 14 days prior to the Maturity Date (or 14 days prior to any earlier date fixed for redemption of the Convertible Bonds) at an initial conversion price of U.S.$6.07 per Share. 28,599,670 Shares would be issuable in the event that conversion of all the Convertible Bonds took place at such conversion price. At the end of this 120-day period, there will be no restrictions on the Company issuing or selling Shares, other than those pursuant to applicable securities laws and stock exchange policies. There are no restrictions on sales of Shares by any existing shareholders of the Company following the date of Admission, some of whom may wish to reduce their Share position in the Company and sell some or all of their Shares. The sale of a substantial number of the Shares in the public market after Admission, or the perception that such sales may occur, could adversely affect the prevailing market price of the Shares and negatively impact the Group's ability to raise equity capital in the future.

The market price of the Shares may be affected by fluctuations in exchange rates

The Group reports its results of operations and financial condition in U.S. dollars. Following Admission, the price of the Shares will be quoted on the London Stock Exchange in pounds sterling. As a consequence, shareholders may experience fluctuation in the market price of the Shares as a result of, amongst other factors, movements in the exchange rate between pounds sterling and U.S. dollars.

There is no guarantee that the Shares will be included in market indices as a foreign admitted company trading on the main market of the London Stock Exchange

The Company intends to make an application for the inclusion of the Shares in the FTSE UK Index Series. There can be no assurance that such application will be successful, or that any conditions applied by the FTSE Nationality Committee will be acceptable to the Company or capable of satisfaction, and that the Shares will be listed in the FTSE UK Index Series or any other such market index. The FTSE Nationality Committee exercises an element of discretion in determining whether a company is eligible for inclusion, and such discretion relates to matters outside of the Company's control. There is no certainty that the FTSE UK Index Series eligibility criteria will be achieved or that the benefits associated with FTSE UK Index Series inclusion will be available to the Company. Even if the Shares are ultimately included in the FTSE UK Index Series, there is no assurance that FTSE will not publish new guidance in the future regarding non-UK incorporated companies or that new laws and regulations, or amendments to existing laws and regulations, are not introduced that could result in the removal of the Shares from the FTSE UK Index Series.

RISKS RELATING TO THE DEPOSITARY INTERESTS

Holders of Depositary Interests must rely on the Depositary or the Custodian to exercise rights attaching to the underlying Shares for the benefit of the holders of Depositary Interests

The rights of holders of Depositary Interests will be governed by, among other things, the relevant provisions of the CREST Manual and the CREST Rules (as defined in the CREST Terms and Conditions issued by Euroclear UK & Ireland). The Depositary or the Custodian will hold the voting and other rights conferred by Canadian law and the Articles for the benefit of the relevant holder. Consequently, the holders of Depositary Interests must rely on the Depositary or the Custodian to exercise such rights for the benefit of the holders of Depositary Interests. Although the Company will enter into arrangements whereby Euroclear UK & Ireland will make a copy of the register of the names and addresses of holders of Depositary Interests available to the Company to enable the Company to send out notices of shareholder meetings and proxy forms to its holders of Depositary Interests and pursuant to Euroclear UK & Ireland's omnibus proxy arrangements, subject to certain requirements, the Custodian will be able to give each beneficial owner of a Depositary Interest the right to vote directly in respect of such owner's underlying Shares, there can be no assurance that such information, and consequently, all such rights and entitlements, will at all times be duly and timely passed on or that such proxy arrangements will be effective.

PART III

PRESENTATION OF FINANCIAL AND OTHER INFORMATION

General

No person has been authorised to give any information or to make any representations in connection with Admission other than the information and representations contained in this Prospectus and, if any other information is given or representations are made, such information or representations must not be relied upon as having been authorised by or on behalf of the Company, the Directors or the Sponsor. No representation or warranty, express or implied, is made by the Sponsor as to the accuracy or completeness of such information, and nothing contained in this Prospectus is, or shall be relied upon as, a promise or representation by the Sponsor as to the past, present or future.

The Company does not accept any responsibility for the accuracy or completeness of any information reported by the press or other media, nor the fairness or appropriateness of any forecasts, views or opinions expressed by the press or other media regarding Admission, the Shares, the Company or the Group. The Company makes no representation as to the appropriateness, accuracy, completeness or reliability of any such information or publication.

Without prejudice to any obligation of the Company to publish a supplementary prospectus pursuant to section 87G of the FSMA and paragraph 3.4.1 of the Prospectus Rules, the delivery of this Prospectus shall not, under any circumstances, create any implication that there has been no change in the business or affairs of the Company or of the Group taken as a whole since the date hereof or that the information contained herein is correct as of any time subsequent to its date.

The contents of this Prospectus are not to be construed as legal, business or tax advice. Each investor should consult his or her own lawyer, financial adviser or tax adviser for legal, financial or tax advice, as appropriate.

The Sponsor and any of its affiliates acting as an investor for its or his or her own account may hold Shares, any other securities of the Company or other related investments. Such persons do not intend to disclose the extent of any such investment otherwise than in accordance with any legal or regulatory obligation to do so.

Apart from the responsibilities and liabilities, if any, which may be imposed on the Sponsor by the FSMA or the regulatory regime established thereunder, the Sponsor does not accept any responsibility or liability whatsoever for the contents of this Prospectus, including its accuracy, completeness or verification, or for any other statement made or purported to be made by it, or on its behalf, in connection with the Company, the Group, the Shares or Admission. The Sponsor accordingly disclaims all and any liability whether arising in tort, contract or otherwise (save as referred to above) which it might otherwise have in respect of this Prospectus or any such statement.

No representation or warranty, express or implied, is made by the Sponsor as to the accuracy or completeness of information contained in this Prospectus, and nothing in this Prospectus is, or shall be relied upon as, a promise or representation by the Sponsor.

The Sponsor and any of its affiliates may have engaged in transactions with, and provided various investment banking, financial advisory and other services for, the Company for which they would have received customary fees.

Investors should read this Prospectus in its entirety.

Presentation of financial information

The historical financial information in this Prospectus has been prepared in accordance with the requirements of the Prospectus Directive Regulation, the Listing Rules and IFRS issued by the International Accounting Standards Board ("**IASB**") and as adopted for use in Canada. The basis of preparation is further explained in Part XI: "Historical Financial Information". The historical financial information presented in this Prospectus consists of (i) audited consolidated financial statements of the Company as of and for the years ended 2012, 2011 and 2010 and (ii) unaudited interim consolidated financial statements of the Company as of and for the three months ended 31 March 2013 and 2012.

Non-financial information operating data

The non-financial operating data included in this Prospectus has been extracted without material adjustment from the management records of the Company and is unaudited.

Currency presentation

Unless otherwise indicated, all references in this Prospectus to:

- "sterling", "pounds sterling", "GBP" or "£" are to the lawful currency of the United Kingdom;
- "U.S. dollars", "US$" or "U.S.$" are to the lawful currency of the United States; and
- "Canadian dollars", "CAD" or "C$" are to the lawful currency of Canada.

The basis of translation of foreign currency for the purpose of inclusion of the financial information is set out in Part XI: "Historical Financial Information". Information derived from this financial information set out elsewhere in this Prospectus has been translated on the same basis.

Following Admission, the price of the Shares will be quoted on the London Stock Exchange in pounds sterling.

The following table sets forth, for the periods indicated, the high, low, average and period-end noon (Eastern Standard Time (North America)) spot rates of exchange for one pound sterling, expressed in Canadian dollars, published by the Bank of Canada.

	3 months ended 31 March	Year ended 31 December		
	2013	2012	2011	2010
	C$	C$	C$	C$
Highest noon rate during the period	1.6025	1.6187	1.6332	1.7268
Lowest noon rate during the period	1.5263	1.5502	1.5297	1.4876
Average noon spot rate for the period	1.5641	1.5840	1.5861	1.5918
Noon rate at the end of the period	1.5417	1.6178	1.5799	1.5513

On 25 June 2013 (being the latest practicable date prior to the publication of this Prospectus), the noon (Eastern Standard Time (North America)) buying rate for one pound sterling, expressed in Canadian dollars, as published by the Bank of Canada was C$1.62.

The following table sets forth, for the periods indicated, the high, low, average and period-end closing spot rates of exchange for one pound sterling, expressed in U.S. dollars, as listed on Bloomberg.

	3 months ended 31 March	Year ended 31 December		
	2013	2012	2011	2010
	U.S.$	U.S.$	U.S.$	U.S.$
Highest closing spot rate during the period	1.6255	1.6279	1.6707	1.6362
Lowest closing spot rate during the period	1.4903	1.5318	1.5343	1.4334
Average closing noon spot rate for the period	1.5523	1.5852	1.6041	1.5458
Closing spot rate at the end of the period	1.5198	1.6255	1.5543	1.5612

On 25 June 2013 (being the latest practicable date prior to the publication of this Prospectus), the closing spot rate of exchange for one pound sterling, expressed in U.S. dollars, as listed on Bloomberg was U.S.$1.54.

The following table sets forth, for the periods indicated, the high, low, average and period-end noon (Eastern Standard Time (North America)) spot rates of exchange for one U.S. dollar, expressed in Canadian dollars, published by the Bank of Canada.

	3 months ended 31 March	Year ended 31 December		
	2013	2012	2011	2010
	C$	C$	C$	C$
Highest rate during the period	1.0343	1.0418	1.0604	1.0778
Lowest rate during the period	0.9815	0.9710	0.9449	0.9946
Average noon spot rate for the period	1.0103	0.9996	0.9891	1.0299
Rate at the end of the period	1.0160	0.9949	1.0170	0.9946

On 25 June 2013 (being the latest practicable date prior to the publication of this Prospectus), the noon (Eastern Standard Time (North America)) buying rate for one U.S. dollar, expressed in Canadian dollars, as published by the Bank of Canada was C$1.05.

The Company prepares its financial statements in U.S. dollars. Unless otherwise indicated, the financial information contained in this Prospectus has been expressed in U.S. dollars.

Rounding

Percentages and certain amounts in this Prospectus, including financial, statistical and operating information, have been rounded to the nearest whole number or single decimal place for ease of presentation. As a result, the figures shown as totals may not be the precise sum of the figures that precede them. In addition, certain percentages and amounts contained in this Prospectus reflect calculations based on the underlying information prior to rounding, and accordingly may not confirm exactly to the percentages or amounts that would be derived if the relevant calculations were based upon the rounded numbers.

Conversions

The following table sets forth certain standard conversions from Standard Imperial Units to the International System of Units (or metric units).

To convert from	To	Multiply by
cubic feet	cubic metres	0.02832
cubic metres	cubic feet	35.315
barrels (bbls)	cubic metres	0.159
cubic metres	barrels (bbls)	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
square kilometres (km^2)	acres	247.105
acres	square kilometres (km^2)	0.00405

Market, economic and industry data

Unless otherwise identified, market data, statistics and information in this Prospectus in respect of the oil industry in Chad have been extracted from a Wood Mackenzie report entitled "Chad Country Overview" dated May 2013.

The Company confirms that all third party information contained in this Prospectus has been accurately reproduced and, so far as the Company is aware and is able to ascertain from information published by that third party, no facts have been omitted that would render the reproduced information inaccurate or misleading.

Mineral reserve and mineral resource reporting

Unless stated otherwise: (i) the reserves and resources data and production estimates included in this Prospectus have been derived or extracted from the GLJ Reports; (ii) GLJ has compiled the GLJ Reports in accordance with PRMS; and (iii) the GLJ Reports give effect to the Farm-in Completion.

Investors should not place undue reliance on the forward-looking statements in the GLJ Reports or on the ability of GLJ to predict actual reserves or resources. Contingent resources relate to undeveloped accumulations and may include non-commercial resources. It should be noted that prospective resources relate to inferred, undiscovered and/or undeveloped mineral resources and accordingly by their nature are highly speculative. A possibility exists that the prospects will not result in the successful discovery of economic resources, in which case there would be no commercial development.

Statements relating to reserves and resources are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future. Readers should refer to paragraph 13—"Summary of key information from the GLJ Reports" in Part VI: "Information on the Group" for information regarding the assumptions related to the reserves and resources reported herein. There is no assurance that forecast price and cost assumptions will be attained, and variances could be material. See "Forward-looking statements" in this Part III. The GLJ Reports employ GLJ's pricing assumptions as at 1 January 2013, which may differ from the pricing assumptions used in prior reserves and resources evaluations.

Proved reserves are those reserves which are most certain to be recovered. There is at least a 90 per cent. probability that the quantities actually recovered will equal or exceed the estimated proved reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. There is at least a 50 per cent. probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10 per cent. probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

Contingent resources disclosed herein were assigned in the GLJ Reports. All such contingent resource estimates are not currently classified as reserves primarily due to economic considerations. See paragraph 13—"Summary of key information from the GLJ Reports" in Part VI: "Information on the Group" for information on the specific contingencies that prevent the classification of the contingent resources as reserves. Contingent resources entail more commercial risk than reserves and adjustments for commercial risks have not been incorporated in the summaries of contingent resources set forth in this Prospectus. Although discovered, there is no certainty that it will be commercially viable to produce any portion of the contingent resources. Moreover, the volumes of contingent resources reported herein are very sensitive to economic assumptions, including capital, operating costs and commodity pricing. Removal of the contingency that allows classification of reserves may have a material effect on the assignability of the Company's contingent resources.

UPIIP and prospective resources disclosed herein were assigned in the GLJ Reports based on gross volumes and are not affected by the Farm-in Completion. Prospective resources entail more commercial and exploration risks, as they are not yet discovered, than those relating to reserves and contingent resources. Due to the nature of the exploration and commercial risks associated with the prospects evaluated in the GLJ Reports, UPIIP and prospective resources are considered the most specific assignable categories for such prospects. The risked UPIIP and prospective resources reported herein are partially risked resources that have been risked for the chance of discovery and a minimum economic field size threshold, but have not been risked for chance of development. If a discovery is made, there is no certainty that it will be developed or, if it is developed, there is no certainty as to the timing of such development.

The information on resources in this Prospectus and in the GLJ Reports is based on economic and other assumptions that may prove to be incorrect. The basis of preparation for the GLJ Reports is set out in more detail therein.

The estimates and projections in the GLJ Reports in respect of individual properties may not reflect the same confidence level as estimates for all properties, due to the effects of aggregation. Barrel(s) of oil equivalent ("**boe**") may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Additional information with respect to the

Company's reserves and resources can be found under paragraph 13—"Summary of key information from the GLJ Reports" in Part VI: "Information on the Group".

Any references in this Prospectus to initial and/or final raw test or production rates and/or "flush" production rates may be useful in confirming the presence of hydrocarbons; however, such rates are not determinative of the rates at which the relevant wells will commence productions and decline thereafter. Test results are not necessarily indicative of long-term performance or of ultimate recovery.

When calculating Net Participating Interests in respect of prospective resources, the Group has assumed that it has a 66.67 per cent. participating interest. However, upon the approval of an EXA, the Government of Chad may elect to acquire up to a 25 per cent. participating interest in the relevant EXA and the Group's participating interest would be adjusted accordingly.

GLJ has assumed, for the purposes of estimating the Group's participating interest in any future EXAs which may be granted under each PSC, that the Government of Chad will elect to acquire a 25 per cent. participating interest in each EXA. Accordingly, the participating interest of each of the Group and Glencore has been assumed by GLJ to be 50 per cent. and 25 per cent. respectively, of the gross lease interest.

Forward-looking statements

Certain information contained in this Prospectus, including any information as to the Group's strategy, market position, plans or future financial or operating performance, constitutes "forward-looking statements". All statements, other than statements of historical fact, are forward-looking statements. The words "believe", "expect", "anticipate", "contemplate", "target", "plan", "intend", "continue", "budget", "project", "aim", "estimate", "may", "will", "could", "should", "schedule" and similar expressions or, in each case, their negative or other variations or comparable terminology, or by discussions of strategy, plans, objectives, goals, future events or intentions identify forward-looking statements. They appear in a number of places throughout this Prospectus and include statements regarding the intentions, beliefs or current expectations of the Group concerning, amongst other things, the Company's results of operations. In particular, this Prospectus contains forward-looking statements pertaining to the following: the reserve and resource potential of the Group's properties; the estimated quantity and value of the Group's proved, probable and possible reserves, contingent resources, prospective resources and UPIIP; the Group's growth strategy and opportunities; the timing and scope of certain of the Group's operations and the timing and level of production from the Group's properties; the Group's expectations and plans for successful construction and commissioning of the Blending Export Terminal, the Early Production Facilities Expansion, the Mangara CPF, the Mangara to Badila Pipeline and the Doseo/Borogop Pipeline; the Group's expectations regarding its access to the Export Pipeline and its ability to successfully transport and sell future production; the timing and scope of the Group's plan to submit an EXA application for the Maku Field; the timing of entering into the Transportation Agreements; the timing of entering into the Inland Transportation Agreement; the timing and completion of the assignment and transfer of PetroChad's transportation rights under the DOB/DOI PSC to PCT; the timing and completion of the assignment and transfer of PetroChad's rights and obligations under the Interconnection Agreement to PCT; the timing of Glencore's expected acquisition of an ownership interest in PCT; the potential for production disruption and constraints; supply and demand fundamentals for crude oil and natural gas; the anticipated quality characteristics of crude oil to be produced from the Group's properties and the crude oil price differential to be realised by the Group as a consequence thereof; the Group's drilling plans; industry and market conditions pertaining to the oil and gas industry; the Group's plans for, and results of, exploration and development activities; the Group's expected generation of internal funds to be used to undertake exploration and development plans; the timing for receipt of regulatory and Government of Chad approvals; the timing and potential effects of any unionisation of the Group's workforce; the Group's treatment under the Government of Chad's governmental and regulatory regimes and the application to the Company of tax laws of the Government of Chad; the Group's expectation of no further action in respect of the matters which were the subject of the Special Committee Investigation; the expected impacts of the Group's strategic partnership with Glencore; the Group's future general and administrative expenses; the Group's future capital spending plans; the Group's future exploration and development expenses; the Group's insurance coverage; the timing of Admission; the Group's expected abandonment and reclamation costs; the Company's dividend policy; the possible disposition of up to two million Shares or interests in up to two million Shares, in aggregate, by the Bradley Griffiths BDG Trust, BDG Capital Ltd. and Griffiths Energy and Resources Inc.; the Group's estimates relating to the net oil pay of the Badila-1 well; and the compensation that is expected to be paid to the Directors and Senior Managers in

2013 and thereafter. See also "Mineral reserve and mineral resource reporting" in this Part III. Readers are cautioned that the foregoing list of forward-looking statements should not be construed as being exhaustive.

With respect to forward-looking statements contained in this Prospectus, assumptions have been made regarding, among other things: the political, economic and business stability of Chad; a common understanding and interpretation of the terms of the PSCs between the Group and the Government of Chad, including Cost Recovery; the Government of Chad's participation in the Group's development activities; the timeframe within which the Group expects to receive payment for its production; the Group's ability to obtain and retain qualified staff in a timely and cost-efficient manner; the Group's ability to obtain and retain necessary equipment in a timely and cost-efficient manner; the Group's ability to gain access to the Export Pipeline and transport production from its properties through the Export Pipeline and the terms and timing thereof; future crude oil and natural gas prices; the application to the Group of the regulatory framework governing royalties, taxes and environmental matters in Chad; the Group's ability to market, sell and receive payment for its production and the prices to be received for such production sales; the Group's future production levels; the recoverability of the Group's reserves and resources; future capital expenditures to be made by the Group; future cash flows from production; future sources of funding for the Group's capital programme; the Group's future debt levels, if any; the Group's future use of derivative instruments, if any; geological and engineering estimates in respect of the Group's reserves and resources; the Group's estimates in relation to net oil pay of the Badila-1 well; the geography of the areas in which the Group is conducting exploration and development activities; the intentions of the Board with respect to the executive compensation plans and corporate governance programmes currently established; the impact of competition on the Group; and the Group's ability to obtain required financing on acceptable terms. Readers are cautioned that the foregoing list of assumptions should not be construed as being exhaustive.

Forward-looking statements and other information contained in this Prospectus concerning the oil and natural gas industry in Chad and the Group's general expectations concerning this industry are based on estimates prepared by the Group using data made available by the Ministry of Petroleum as well as from reserve and resource reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Group believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Group is not aware of any material misstatements regarding any industry data presented herein, the oil and natural gas industry, particularly in Chad, involves numerous risks and uncertainties and is subject to change based on various factors.

Forward-looking statements are necessarily based upon a number of estimates and assumptions that, while considered reasonable by the Group, are inherently subject to significant business, economic and competitive uncertainties and contingencies. Known and unknown factors could cause actual results to differ materially from those projected in the forward-looking statements. In addition, even if the Group's results of operations and financial condition, and the development of the industry in which the Group operates, are consistent with the forward-looking statements contained in this Prospectus, those results or developments may not be indicative of results or developments in subsequent periods.

Investors are cautioned that forward-looking statements are not guarantees of future performance. Forward-looking statements may, and often do, differ materially from actual results. Any forward-looking statements in this Prospectus speak only as at the date of this Prospectus, reflect the Group's current view with respect to future events and are subject to risks relating to future events and other risks, uncertainties and assumptions relating to the Group's operations, results of operations, growth strategy, liquidity and the availability of new credit. Investors should specifically consider the factors identified in this Prospectus that could cause actual results to differ. All of the forward-looking statements made in this Prospectus are qualified by these cautionary statements. Specific reference is made to Part II: "Risk Factors", Part VI: "Information on the Group" and Part X: "Operating and Financial Review".

Subject to the requirements of the Prospectus Rules, the Disclosure and Transparency Rules and the Listing Rules, or applicable law, the Company explicitly disclaims any intention or obligation or undertaking publicly to release the result of any revisions to any forward-looking statements in this Prospectus that may occur due to any change in the Group's expectations or to reflect events or circumstances after the date of it.

No incorporation of website information

The contents of the Company's website, any website mentioned in this Prospectus or any website directly or indirectly linked to these websites have not been verified and do not form part of this Prospectus and investors should not rely on such information.

Definitions and glossary

Certain terms used in this Prospectus, including all capitalised terms and certain technical and other terms, are defined and explained in Part XVII: "Definitions" and Part XVIII: "Glossary of Technical Terms".

Times

All times referred to in this Prospectus are, unless otherwise stated, references to the time in London, UK.

Enforceability of Canadian judgments

As the material assets of the Company are located outside of Canada, it may be difficult or impossible to enforce judgments granted by a Canadian court against its assets located outside of Canada, against its subsidiaries or against Directors and Senior Managers who are resident outside of Canada.

PART IV

DIRECTORS, COMPANY SECRETARY, REGISTERED AND HEAD OFFICE AND ADVISERS

Directors	Gary Guidry	President, Chief Executive Officer and Executive Director
	Robert B. Hodgins	Independent Non-Executive Chairman
	Carol Bell	Independent Non-Executive Director
	John Bentley	Independent Non-Executive Director
	Peter Dey	Independent Non-Executive Director
	Ronald W. Royal	Independent Non-Executive Director
	Brooke Wade	Independent Non-Executive Director
Company Secretary	Diane Phillips	
Registered and head office of the Company	Suite 2100 555 – 4th Avenue S.W. Calgary, Alberta Canada, T2P 3E7	
Sponsor	RBC Capital Markets Riverbank House 2 Swan Lane London, EC4R 3BF United Kingdom	
English and U.S. legal advisers to the Company	Linklaters LLP One Silk Street London, EC2Y 8HQ United Kingdom	
Canadian legal advisers to the Company	Stikeman Elliot LLP 4300 Bankers Hall West 888 – 3rd Street S.W. Calgary, Alberta Canada, T2P 5C5	
English legal advisers to the Sponsor	White & Case LLP 5 Old Broad Street London, EC2N 1DW United Kingdom	
Canadian legal advisers to the Sponsor	Blake, Cassels and Graydon LLP 3500 Bankers Hall East Calgary, Alberta AB, Canada, T2P 3V4	
Auditors	KPMG LLP 2700 205 – 5th Avenue S.W. Calgary, Alberta Canada, T2P 4B9	

Registrar[3]	Computershare Investor Services Inc. 600, 530 – 8th Avenue S.W. Calgary, Alberta Canada, T2P 3S8
Depositary	Computershare Investor Services plc The Pavilions Bridgwater Road Bristol, BS99 6ZZ United Kingdom
Independent Competent Person	GLJ Petroleum Consultants Ltd. 4100, 400 – 3rd Avenue S.W. Calgary, Alberta Canada, T2P 4H2

[3] The Company expects to appoint Computershare Investor Services Inc. as its registrar prior to the date of Admission. However, as at the date of this Prospectus, the registrar of the Company is Olympia Trust Company of 2300, 125 - 9th Avenue S.E., Calgary, Alberta, Canada, T2G 0P6.

PART V

EXPECTED TIMETABLE OF PRINCIPAL EVENTS RELATED TO ADMISSION

Event	Time and Date
Prospectus published	27 June 2013
Admission and commencement of unconditional dealings on the London Stock Exchange	8.00 a.m. on or around 5 July 2013
CREST accounts available to be credited in respect of Depositary Interests	On or around 5 July 2013

References to times are to London, UK times. Each of the times and dates in the above timetable is subject to change without further notice.

A supplementary prospectus will be published in accordance with Section 87G of FSMA and paragraph 3.4.1 of the Prospectus Rules in case of any significant new event, material mistake or inaccuracy relating to the information included in this Prospectus which is capable of affecting the assessment of the Shares and which arises or is noted between the time when this Prospectus is approved and Admission.

PART VI

INFORMATION ON THE GROUP

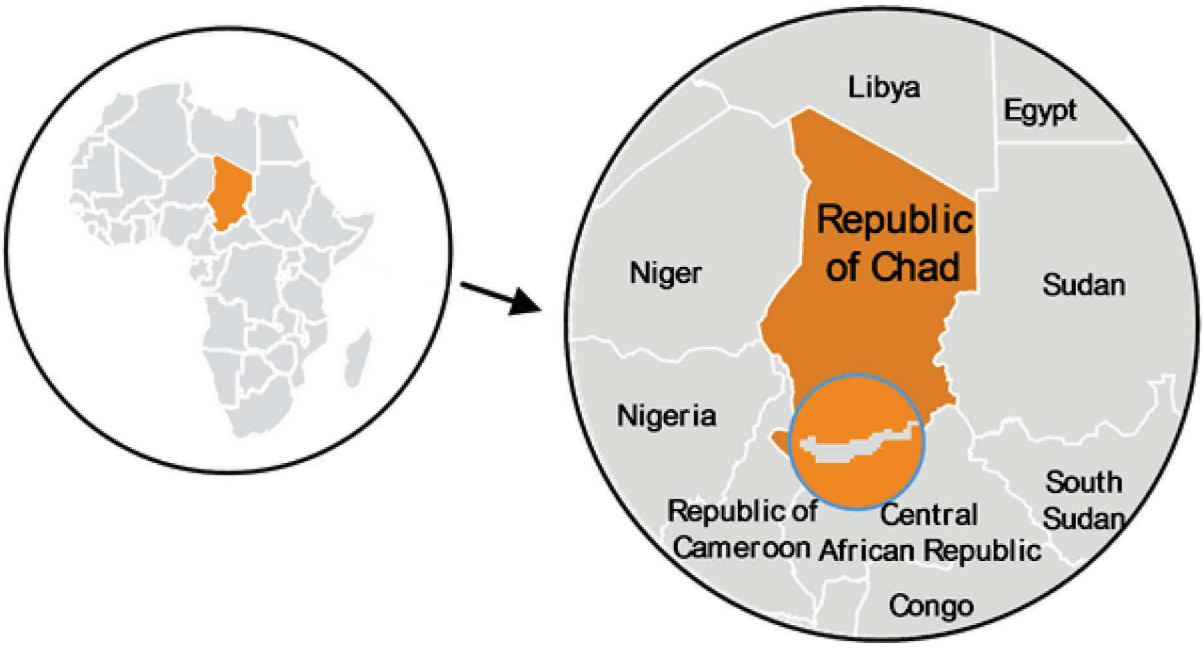
*Unless the context otherwise requires, references in this Part VI to (i) the "**Company**" mean Caracal Energy Inc. and (ii) the "**Group**" mean the Company and its direct and indirect subsidiaries on a consolidated basis.*

1 Business overview

Introduction

Founded in 2009, the Company is an independent oil and gas exploration, appraisal and development company which, together with Glencore, has exclusive rights to explore and develop oil and gas reserves and resources over an area of approximately 26,103 km^2 (6.4 million acres) in southern Chad. This area is comprised of three Contractual Zones, the rights to which were granted to the Group in 2011 pursuant to three production sharing contracts (each, a "**PSC**") that it entered into with the Government of Chad.

Location of the Group's properties in Chad



DOB/DOI Contractual Zone (DOB/DOI PSC)

- The DOB/DOI Contractual Zone covers an area of approximately 2,865 km^2. It contains two discoveries of commercial interest that the Group is currently developing: the Badila Field and the Mangara Field.
- The independent competent person's reports prepared by GLJ Petroleum Consultants Ltd. ("**GLJ**") dated 29 January 2013 and 28 February 2013, each with an effective date of 31 December 2012 (the "**GLJ Reports**"), estimate that the gross lease reserves attributed to the Badila and Mangara Fields are 28.8 MMbbl (proved), 63.2 MMbbl (proved plus probable) and 135.2 MMbbl (proved plus probable plus possible) (14.4 MMbbl, 31.6 MMbbl and 67.6 MMbbl, respectively, on a Net Participating Interest basis). "**Net Participating Interest**" means the Group's participating interest multiplied by the gross lease reserves, resources or production, as applicable.
- The GLJ Reports estimate that the gross lease unrisked prospective resources located in the DOB/DOI Contractual Zone are 239.6 MMstb (mean) (calculated by the Group to be 159.7 MMstb on a Net Participating Interest basis). When calculating Net Participating Interests in respect of prospective resources, the Group has assumed that it has a 66.67 per cent. participating interest. However, upon the approval of an EXA, the Government of Chad may elect to acquire up to a 25 per cent. participating interest in the relevant EXA and the Group's participating interest would be adjusted accordingly.

- Exclusive exploitation authorisations (each, an "**EXA**") to develop and produce from the Badila and Mangara Fields were granted to the Group by the Government of Chad in August 2012 and June 2012, respectively, and cover a combined area of 100 km^2.
- The Group is targeting commencement of first production from the Badila and Mangara Fields in July 2013 and the third quarter of 2013, respectively.
- The GLJ Reports forecast gross production, in the 2P case, of 23,000 bbl/d from the Badila and Mangara Fields by the end of 2013 and 36,000 bbl/d by the end of 2014 (11,500 bbl/d and 18,000 bbl/d, respectively, on a Net Participating Interest basis).

Doseo/Borogop Contractual Zone (Doseo/Borogop PSC)

- The Doseo/Borogop Contractual Zone covers an area of approximately 22,414 km^2 and contains four discoveries of commercial interest that the Group has identified as development priorities: the Kibea, Maku, Tega and North Sako Fields.
- The Group submitted a feasibility study and an EXA application for the Kibea Field in April 2013.
- The Group is currently undertaking feasibility studies on the Maku, Tega and North Sako Fields. The Group expects to submit an EXA application for the Maku Field during 2013.
- The GLJ Reports estimate that the gross lease reserves attributed to the Kibea and Maku Fields are zero (proved), 26.0 MMbbl (proved plus probable) and 65.4 MMbbl (proved plus probable plus possible) (zero, 13.0 MMbbl and 32.7 MMbbl, respectively, on a Net Participating Interest basis)[(3)]. The GLJ Reports estimate that the gross lease unrisked prospective resources located in the Doseo/Borogop Contractual Zone are 985.3 MMstb (mean) (calculated by the Group to be 656.9 MMstb on a Net Participating Interest basis).

DOH Contractual Zone (DOH PSC)

- The DOH Contractual Zone covers an area of approximately 824 km^2.
- The DOH Contractual Zone is subject to further exploration. The two wellbores drilled by previous operators within the DOH Contractual Zone have evidence of oil, but not in quantities of commercial interest that the Group would intend to develop.
- The GLJ Reports estimate that the gross lease unrisked prospective resources located in the DOH Contractual Zone are 49.5 MMstb (mean) (calculated by the Group to be 33.0 MMstb on a Net Participating Interest basis).

Farm-in Agreement

The Group entered into a farm-in agreement with Glencore in December 2012 (the "**Farm-in Agreement**"). President Déby signed a decree approving the Farm-in Agreement on 4 February 2013, and such decree was ratified by the Chadian National Assembly on 26 April 2013.

Upon assignment and transfer of the Transferred Interests and payment of the Farm-in Consideration pursuant to the Farm-in Agreement and the Farm-in Completion Letter on 13 June 2013 (the "**Farm-in Completion**"), Glencore acquired from the Group (i) a 33.33 per cent. participating interest in each of the PSCs, with the Group retaining a 66.67 per cent. participating interest and (ii) a 25 per cent. participating interest in the Badila and Mangara EXAs. At or around the same time, Glencore acquired a further 10 per cent. participating interest in the Badila and Mangara EXAs from Société des Hydrocarbures du Tchad ("**SHT**"), the national oil company of Chad (the "**Glencore/SHT Transaction**"). As such, the Group has a 50 per cent. participating interest, Glencore has a 35 per cent. participating interest and SHT has a 15 per cent. participating interest, respectively, in each of these EXAs. The Group remains operator under each of the PSCs.

The Group entered into an advance agreement with Glencore on 1 March 2013 (the "**Original Farm-in Advance Agreement**" and, together with an amendment agreement dated 29 May 2013, the "**Farm-in Advance Agreement**"). Pursuant to the Farm-in Advance Agreement, U.S.$100 million and U.S.$50 million was advanced by Glencore to the Group on 4 March 2013 and 30 May 2013, respectively, as advance

(3) GLJ has assumed, for the purposes of estimating the Group's participating interest in any future EXAs which may be granted under each PSC, that the Government of Chad will elect to acquire a 25 per cent. participating interest in each EXA. Accordingly, the participating interest of each of the Group and Glencore has been assumed by GLJ to be 50 per cent. and 25 per cent. respectively, of the gross lease interest.

consideration for its obligations under the Farm-in Agreement (the "**Farm-in Advance**"). Upon the Farm-in Completion, Glencore paid the Group approximately U.S.$107 million as consideration for its obligations under the Farm-in Agreement, net of the repayment of the Farm-in Advance.

The Group and Glencore have agreed pursuant to the Farm-in Agreement to develop jointly the necessary pipeline transportation system and related facilities to transport crude oil produced under the Badila and/or Mangara EXA from the boundary of the relevant Contractual Zone to the connecting flange with the Export Pipeline (the "**ITA Project**").

Offtake Agreement

The Group entered into an offtake agreement with Glencore in December 2012 (the "**Offtake Agreement**"), pursuant to which Glencore will purchase and market the Group's proportionate share of production under the PSCs. The Offtake Agreement provides that the price paid for the Group's oil will be set by reference to the average market prices for Dated Brent Crude and includes incentives relating to the performance of Glencore thereunder.

Access to market

Oil produced in Chad is exported by means of a 1,070-kilometre, 30-inch pipeline (the "**Export Pipeline**") running from the Doba Basin fields in southern Chad to a marine shipping terminal located approximately 11 kilometres off the coast of Cameroon, near Kribi (the "**Kribi Terminal**"). Based on current and anticipated medium-term production levels of the Badila and Mangara Fields and the Priority Fields (as provided by the operators of the Export Pipeline), and subject to the priority arrangements currently established, the Group believes that the Export Pipeline has sufficient capacity to service both the needs of the Priority Fields and those of the Badila and Mangara Fields.

In October 2012, an interconnection agreement (the "**Interconnection Agreement**") was entered into by the Group and the operator of the Export Pipeline in Chad, Tchad Oil Transportation Company S.A. ("**TOTCO**"), enabling the connection of the Group's transportation infrastructure (including a 16-kilometre dry oil pipeline (the "**Connection Pipe**")) to transport the Group's production from the Badila and Mangara Fields to the Export Pipeline.

On 18 March 2013, a facilities modification agreement (the "**Facilities Modification Agreement**") was entered into by PetroChad (as operator of the DOB/DOI PSC) with Cameroon Oil Transportation Company S.A. ("**COTCO**"), the operator of the Export Pipeline in Cameroon, providing for certain modifications to the Cameroonian portion of the Export Pipeline to accommodate the transportation of the Group's oil.

There are two transportation agreements that the Group expects to enter into in relation to the export of oil produced in the Badila and Mangara Fields, one in respect of the Chadian portion of the Export Pipeline (the "**TOTCO Transportation Agreement**") and the other in respect of the Cameroonian portion of the Export Pipeline (the "**COTCO Transportation Agreement**" and, together with the TOTCO Transportation Agreement, the "**Transportation Agreements**"). The Transportation Agreements are expected to govern the terms of use of the Export Pipeline for the transport of oil produced in the Badila and Mangara Fields, including the order of priority for access and the applicable fees payable for use of the Export Pipeline. The Transportation Agreements are in an advanced stage of negotiation and the Group expects that they will be entered into prior to targeted first production from the Badila Field in July 2013.

For more information on the Export Pipeline, see "The Group will be dependent on the Export Pipeline to export its production" in Part II: "Risk Factors", paragraph 12—"Access to market" in this Part VI and paragraph 10—"Material contracts" in Part XVI: "Additional Information".

Summary of the PSCs

The following table summarises certain information relating to each of the PSCs:

	DOB/DOI PSC	Doseo/Borogop PSC	DOH PSC
Area (km^2)	2,865	22,414	824
Expiry date of Initial Exploration Term of current exclusive exploration authorisation (each, an "EEA")	4 April 2016	26 January 2016	25 August 2016
EXA status	EXAs granted in June 2012 (Mangara) and August 2012 (Badila)	N/A[3]	N/A
EXA Initial Exploitation Term	25 years	N/A	N/A
Area of EXA (km^2)	100	N/A	N/A
2P Reserves (MMbbl)[1][2]	63.2	26.0	N/A
3P Reserves (MMbbl)[1][2]	135.2	65.4	N/A
Royalty rates			
— Crude oil	14.25%	14.25%	14.25%
— Natural gas	5%	5%	5%
— Cost Oil to Contractor	70%	70%	70%
Profit Oil to Contractor	Between 40-60%	Between 40-60%	Between 40-60%
PSC/EEA participating interest[4]	66.67%	66.67%	66.67%
EXA participating interest[5]	50%	N/A	N/A
Maximum Government of Chad participating interest	25%	25%	25%

Notes:

(1) Gross.

(2) Derived from the GLJ Reports.

(3) The Group submitted an EXA application for the Kibea Field in April 2013 and expects to submit an EXA application for the Maku Field during 2013.

(4) Upon the Farm-in Completion, Glencore acquired a 33.33 per cent. participating interest from the Group.

(5) SHT exercised its back-in rights to secure its maximum participating interest of 25 per cent. in the Badila and Mangara EXAs. Following the Glencore/SHT Transaction, SHT has a 15 per cent. participating interest and Glencore has a 35 per cent. participating interest, respectively, in the Badila and Mangara EXAs.

Seizure of the Relevant Shares

Pursuant to a negotiated settlement, the Company pleaded guilty on 22 January 2013 to one count of bribing a foreign public official to induce the official to use his position to influence any acts or decisions of the foreign state for which the official performs duties or functions, contrary to Section 3(1)(b) of Canada's Corruption of Foreign Public Officials Act. Pursuant to the guilty plea, the Company paid a fine of C$10,350,000. The plea was made in relation to conduct occurring between 30 August 2009 and 9 February 2011 (prior to the appointment of the existing management team and election of the Board of Directors) involving two consulting agreements entered into by the Company.

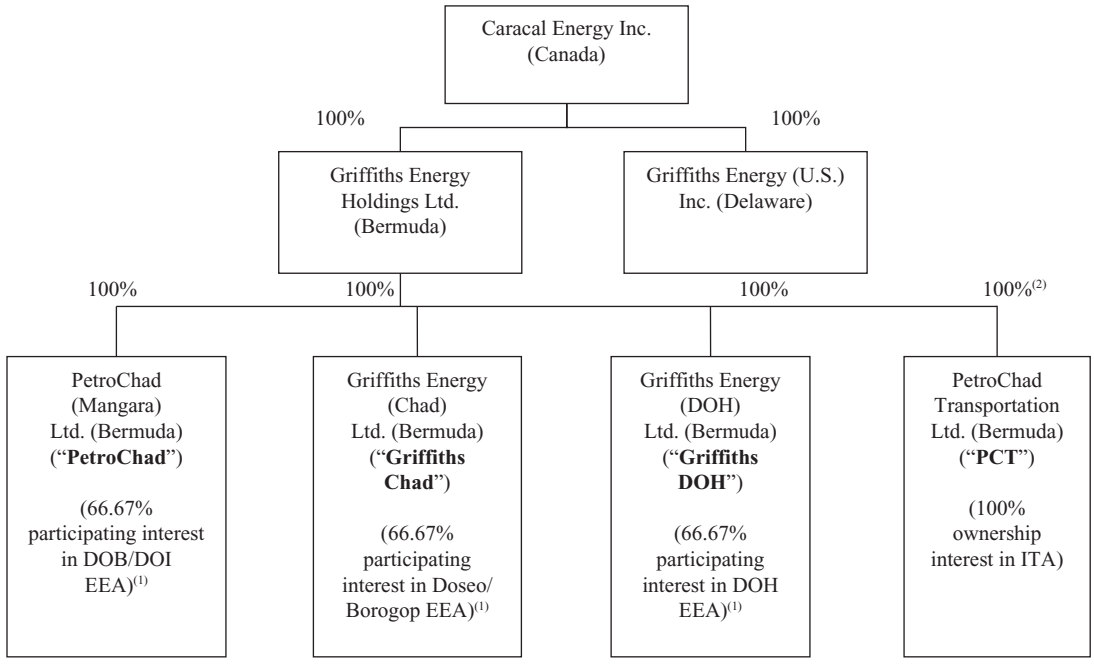
On 15 September 2009, (i) Nouracham Niam, the spouse of Chad's Ambassador to Canada (the "**Ambassador**"), was given, and took, the opportunity to purchase 1,600,000 Shares at U.S.$0.001 per Share and (ii) Ikram Saleh and Adoum Hassan (each nominated by Nouracham Niam) also purchased a total of 2,400,000 Shares at U.S.$0.001 per Share (together, the "**Relevant Shares**"). Each of Nouracham Niam, Ikram Saleh and Adoum Hassan remain the registered holders of the Relevant Shares. The Relevant Shares were part of a larger issuance of Shares and were purchased by these individuals at the same price and time as the founders, former management and former directors of the Company.

Following the Company's guilty plea, the Crown made application for forfeiture of the Relevant Shares on the basis that they may be assets flowing from the commission of the offence of bribery. Between 19 February 2013 and 3 April 2013, all of the certificates representing the Relevant Shares were seized by the Royal Canadian Mounted Police (the "**RCMP**"). The Public Prosecution Service of Canada ("**PPSC**") has confirmed that the Relevant Shares will be retained by the Canadian authorities until the conclusion of the proceedings relating to the application for their forfeiture. While retained by the Canadian authorities, the Relevant Shares can not be transferred or dealt with in any manner until the court proceedings in respect of their forfeiture is completed.

See paragraph 14—"Special Committee Investigation" in this Part VI.

2 Group structure

The following diagram illustrates the organisational and ownership structure of the Group and identifies the subsidiaries that are parties to each of the PSCs.



Notes:

(1) Upon the Farm-in Completion, Glencore acquired a 33.33% participating interest in the EEA from the Group.

(2) Glencore is expected to acquire a 33.33% ownership interest in PCT from the Group in July 2013.

The Company has entered into a technical services agreement with each of PetroChad, Griffiths Chad and Griffiths DOH. The purpose of these technical services agreements is to allow each of PetroChad, Griffiths Chad and Griffiths DOH to benefit from the Company's skill and expertise in further developing and operating the properties in Chad.

Pursuant to an amendment to the Company's articles of association filed on 23 May 2013, the Company changed its name from Griffiths Energy International Inc. to Caracal Energy Inc.

3 History

2009	
April	Company incorporated as First Dune Oil and Gas Inc. for the purpose of identifying oil exploration, development and production opportunities in Chad.
August	Change of name to Griffiths Energy International Inc.
2010	Commenced negotiations with the Government of Chad in relation to the PSCs.
2011	
January	Griffiths Chad signs the Doseo/Borogop PSC.
March	PetroChad signs the DOB/DOI PSC.
July – August	Appointment of new management team by the Board and appointment of Gary Guidry as the Chief Executive Officer, President and an Executive Director of the Company.
August	Griffiths DOH signs the DOH PSC.
October – November	Special Committee formed by the Company to investigate certain consulting agreements entered into by the Company and payments made to a foreign public official between August 2009 and February 2011, and self-reporting of such matters to the RCMP and the U.S. Department of Justice (the "**U.S. DoJ**"). See paragraph 14—"Special Committee Investigation" in this Part VI.
2012	
June	EXA to develop the Mangara Field granted.
July	DOB/DOI Environmental Impact Assessment approved by the Government of Chad.
August	EXA to develop the Badila Field granted.
October	Interconnection Agreement signed with TOTCO.
December	Farm-in Agreement and Offtake Agreement signed with Glencore.
2013	
February	Settlement of matters relating to the Special Committee Investigation with the PPSC and the U.S. DoJ. See paragraph 14—"Special Committee Investigation" in this Part VI.
March	Original Farm-in Advance Agreement signed with Glencore and U.S.$100 million advanced to the Group in relation thereto.
March	Facilities Modification Agreement signed with COTCO.
April	Farm-in Agreement ratified by the Chadian National Assembly.
May	Change of name to Caracal Energy Inc.
May	Amendment agreement relating to the Original Farm-in Advance Agreement (the **"Farm-in Advance Amendment Agreement"**) signed with Glencore and U.S.$50 million advanced to the Group in relation thereto.
June	Farm-in Completion occurred on 13 June 2013 and approximately U.S.$107 million paid to the Group by Glencore in relation thereto.

4 Key Strengths

The Directors believe that the Group has the following key strengths:

First independent exploration and production company to be granted PSCs under revised petroleum law, providing exclusive rights, together with Glencore, to explore and develop approximately 6.4 million acres in a hydrocarbon basin in Chad

The Group is one of a small number of independent exploration and production companies operating in Chad. The Group entered into three PSCs with the Government of Chad between January 2011 and August 2011, which cover approximately 6.4 million acres in southern Chad adjacent to the Doba Basin fields held by Esso Exploration and Production Chad Inc. ("**EEPCI**"), a consortium comprising Exxon

Mobil Corporation ("**ExxonMobil**"), Petroliam Nasional Berhad ("**PETRONAS**") and Chevron Corporation ("**Chevron**"). The Doseo/Borogop PSC and the DOB/DOI PSC were the first two PSCs signed by any person or company following revisions to the Government of Chad's petroleum law in 2010 (see "Legal Framework and Process in Chad" in Part VII: "Industry Overview"). Beginning in 1969, the areas in Chad subject to and governed by the terms and conditions of the PSCs (the "**Contractual Zones**") were evaluated by a number of the world's largest independent oil and gas companies (most recently, EEPCI) prior to their mandatory relinquishment between 2009 and 2011.

Fully funded to forecast gross production of 36,000 bbl/d, in the 2P case

During 2012, the Group raised gross proceeds of over U.S.$295 million through the issuance of Shares and Convertible Bonds. See Part X: "Operating and Financial Review". In addition, pursuant to the Farm-in Agreement, Glencore agreed to pay approximately U.S.$30.75 million to the Group in respect of historic unrecoverable costs incurred in relation to the PSCs. The Farm-in Agreement also obliges Glencore to carry a proportion of the Group's capital expenditure costs up to U.S.$100 million a year between July 2012 and June 2014 and U.S.$100 million for the period from July 2014 to June 2016, subject to an aggregate limit of U.S.$300 million.

Pursuant to the Farm-in Advance Agreement, U.S.$100 million and U.S.$50 million was advanced by Glencore to the Group on 4 March 2013 and 30 May 2013, respectively, as advance consideration for its obligations under the Farm-in Agreement. Upon the Farm-in Completion, Glencore paid the Group approximately U.S.$107 million as consideration for its obligations under the Farm-in Agreement, net of the repayment of the Farm-in Advance. See paragraph 10—"Material contracts" in Part XVI: "Additional Information".

The Group believes that its existing funding, together with the financial commitments of Glencore pursuant to the Farm-in Agreement and expected operating cash flow from production, will be sufficient to allow the Group to reach the gross production forecast by GLJ, in the 2P case, of 23,000 bbl/d from the Badila and Mangara Fields by the end of 2013 and 36,000 bbl/d by the end of 2014 (11,500 bbl/d and 18,000 bbl/d, respectively, on a Net Participating Interest basis).

Under-utilised Export Pipeline and related infrastructure in place

The Group expects to be the first third party not affiliated with EEPCI to export oil through the Export Pipeline. The Export Pipeline was built by a consortium led by ExxonMobil between 2000 and 2003. Based on the nameplate throughput capacity of 250,000 bbl/d, and EEPCI production of 105,000 bbl/d as reported by EEPCI, the Export Pipeline had utilisation of less than 50 per cent. as at 30 June 2012. Furthermore, according to EEPCI, as at 30 June 2012, EEPCI's production had declined by approximately 52 per cent. from a peak of 220,000 bbl/d in 2004. The Group believes that EEPCI's production is unlikely to increase and that, based on current and anticipated medium-term production levels of the Badila and Mangara Fields and the Priority Fields (as provided by the operators of the Export Pipeline), and subject to the priority arrangements currently established, the Export Pipeline has sufficient capacity to service both the needs of the Priority Fields and those of the Badila and Mangara Fields. Furthermore, the Group believes that the proximity of certain of its properties to the Export Pipeline presents an opportunity to transport and sell the Group's production in an efficient and cost-effective manner.

Strategic partnership with Glencore

Under the terms of the Farm-in Agreement, Glencore acquired from the Group a 33.33 per cent. participating interest in each of the PSCs and a 25 per cent. participating interest in the Badila and Mangara EXAs. In June 2013, Glencore purchased a further 10 per cent. participating interest in the Badila and Mangara EXAs from SHT pursuant to the Glencore/SHT Transaction. In addition, Glencore will purchase and market the Group's proportionate share of production under the PSCs pursuant to the Offtake Agreement. The Group believes that its strategic partnership with Glencore strengthens its investment case and further raises the Group's international profile. In addition to providing the Group with development capital, Glencore also offers significant marketing expertise and the ability to maximise export proceeds.

Glencore is an integrated commodities producer and marketer and its Energy Products division is a leading global oil trader handling the physical supply of approximately 3 per cent. of the world's oil consumption (850 MMbbl in 2011).

See paragraph 8—"Glencore Farm-in" and paragraph 11—"Offtake arrangements with Glencore" in this Part VI.

Production from existing discoveries is expected to generate sufficient cash flow to fund the Group's exploration and development programmes

The Group is targeting commencement of first production from the Badila and Mangara Fields in July 2013 and the third quarter of 2013, respectively. The Group anticipates using cash flow from these production operations to undertake its exploration and development programmes.

The Group expects to (i) drill all of its currently identified prospects and leads located within the Contractual Zones prior to the final relinquishment of the Contractual Zones in 2019 and (ii) develop the Badila, Mangara, Kibea and Maku Fields, without needing to obtain additional funding. The Group anticipates starting the exploration campaign in the second half of 2013 and is planning to spud three exploration wells by the end of 2013.

Access to significant prior technical work

The previous operators drilled 16 wells on the Contractual Zones and carried out extensive technical work and seismic evaluation, including approximately 25,000 lineal kilometres of two-dimensional seismic lines – of which 17,000 lineal kilometres covered the Contractual Zones. Pursuant to the terms of the PSCs, the Group has obtained substantially all such prior technical and seismic data, including both the raw seismic data as well as the previous operators' interpretation and analysis thereof. The Contractual Zones have been extensively mapped by the Group and a large database of leads and prospects have been compiled.

Significant reserve and resource base enable low-cost, scalable business model focussed on onshore conventional oil development

The GLJ Reports assigned reserves and/or contingent resources to each of the Badila, Mangara, Maku and Kibea Fields. As at 31 December 2012, the GLJ Reports estimated gross lease proved reserves to be 28.8 MMbbl, gross lease proved plus probable reserves to be 89.3 MMbbl and gross lease proved plus probable plus possible reserves to be 200.6 MMbbl (14.4 MMbbl, 44.6 MMbbl and 100.3 MMbbl, respectively, on a Net Participating Interest basis)[(4)]. The GLJ Reports also estimated gross lease unrisked prospective resources to be 1,274.3 MMstb (mean) and gross lease partially risked prospective resources to be 307.4 MMstb (mean) (calculated by the Group to be 849.5 MMstb and 204.9 MMstb, respectively, on a Net Participating Interest basis). A total of 83 prospects and leads have been evaluated by the GLJ Reports throughout the Contractual Zones.

The Group's management and operational personnel has extensive experience in delivering oil production projects globally. Oil production has been ongoing in Chad since 2003 and a developed oilfield services industry now exists within the country. A combination of significant reserves and resources identified by the GLJ Reports, attractive PSC terms and readily available infrastructure contribute to Chad's positioning as a relatively low-cost operating environment for the Group.

Internationally experienced management team and Board of Directors

The Group's management team has an average of over 22 years each of experience working within the oil and gas industry.

The Group's management team is led by Gary Guidry, the Company's President and Chief Executive Officer. Mr Guidry has over 30 years of experience advancing and maximising the exploration and development opportunities of international oil and gas assets, including holding the position of Chief Executive Officer of Tanganyika Oil Company Ltd. ("**Tanganyika**"), which operated principally in Syria and Egypt. During Mr Guidry's tenure between May 2005 and December 2008, Tanganyika grew production from approximately 6,000 bbl/d to approximately 21,000 bbl/d. Mr Guidry has also held the position of Senior Vice President of Alberta Energy Company International Ltd., where he oversaw oil and gas operations in Chad and has held the position of country manager of Canadian Occidental Petroleum Ltd., where he oversaw operations in Nigeria and business development throughout west Africa.

The Group's management team has significant financial and technical expertise in the oil and gas industry through their involvement with UK and Canadian publicly listed oil and gas companies, operating both domestically and internationally. The management team includes qualified accountants, engineers,

(4) GLJ has assumed, for the purposes of estimating the Group's participating interest in any future EXAs which may be granted under each PSC, that the Government of Chad will elect to acquire a 25 per cent. participating interest in each EXA. Accordingly, the participating interest of each of the Group and Glencore has been assumed by GLJ to be 50 per cent. and 25 per cent., respectively, of the gross lease interest.

geologists and scientists and, collectively, its members have held a number of senior management and directorial positions within the energy, exploration and production and financial sectors. A number of the management team have experience working for corporations with interests in Africa and/or other emerging markets. Members of the management team have expertise overseeing large oil production projects in accordance with closely controlled budgets.

Strong operational progress to date

Since the appointment of the current management team on and after 1 July 2011, the Group has advanced a number of significant initiatives and developments in respect of the PSCs and the Group's business:

- EXAs have been granted in respect of each of the Badila and Mangara Fields;
- drilling of each of the Badila-2, Badila-3 and Mangara-4 wells has been completed and drilling of the Mangara-5 well has commenced;
- two existing wells (Badila-1 and Mangara-2) drilled by the previous operator have been re-entered, achieving constrained test rates of up to 4,025 bbl/d and 800 bbl/d, respectively;
- a 147 km^2 3-D seismic shoot over the Mangara Field and adjoining Krim exploration prospect has been undertaken and analysis of the data produced completed;
- a 320 km^2 3-D seismic shoot over the Badila Field and Bitanda exploration prospect has been completed and analysis of the data produced commenced;
- the lease of one drilling rig and one service rig (each of which is currently in operation on the Group's properties), with an additional drilling rig due to commence operation in July 2013;
- an experienced technical team has been put in place;
- four 12-inch pipeline segments crossing the Logone River have been installed, enabling the Mangara to Badila Pipeline to pass underneath;
- upgrades to public and private roads and bridges to enable all-weather access to the Badila and Mangara Fields have been completed;
- an environmental impact assessment in respect of operations in the DOB and DOI blocks was approved by the Government of Chad on 13 July 2012 (the "**DOB/DOI Environmental Impact Assessment**");
- access has been acquired to all land required for the development of the Badila and Mangara Fields, the Blending Export Terminal, the Connection Pipe and the right-of-way for the Mangara to Badila Pipeline;
- the Early Production Facilities, Connection Pipe, LACT Unit and Hot Tap have been completed and commissioned;
- contracts have been awarded for the construction of the Blending Export Terminal, Mangara CPF and Mangara to Badila Pipeline, drilling services, camps and other related facilities; and
- gross proceeds of over U.S.$295 million were raised through the issuance of Shares and Convertible Bonds during 2012.

5 Strategy

Following commencement of first production, the business strategy of the Group is to increase shareholder value through sustained growth in production, cash flow and reserves. The Group intends to lead the development and control of infrastructure in the regions in which it operates. The Group believes that the PSCs offer significant near-term production and long-term exploration opportunities with substantial resource potential. The Group believes that the combination of its existing asset base and technical management team will contribute significantly to the Company's growth and aim of being a leading independent international oil company. The key elements of the Group's strategy to achieve these goals are set out below.

First production from the Badila and Mangara Fields

The Group intends to use its existing cash and cash equivalents, along with proceeds from the Farm-in Agreement, to develop the Badila and Mangara Fields. Following commencement of first production, the Group believes that the cash flow generated from the Badila and Mangara Fields will provide the Group

with sufficient funding to undertake the development of those two fields and other known discoveries (subject to approval by the Government of Chad) and to undertake the drilling of exploration wells throughout the Contractual Zones.

Increase reserves through exploration drilling

Concurrently with the development plans relating to the existing discoveries, the Group also plans to advance its exploration strategy by reviewing approximately 17,000 lineal kilometres of seismic data over the Contractual Zones gathered by previous operators and high-grading prospects and leads located within the Contractual Zones. The Group anticipates starting the exploration campaign in the second half of 2013 and is planning to spud three exploration wells by the end of 2013 and approximately twelve exploration wells in 2014.

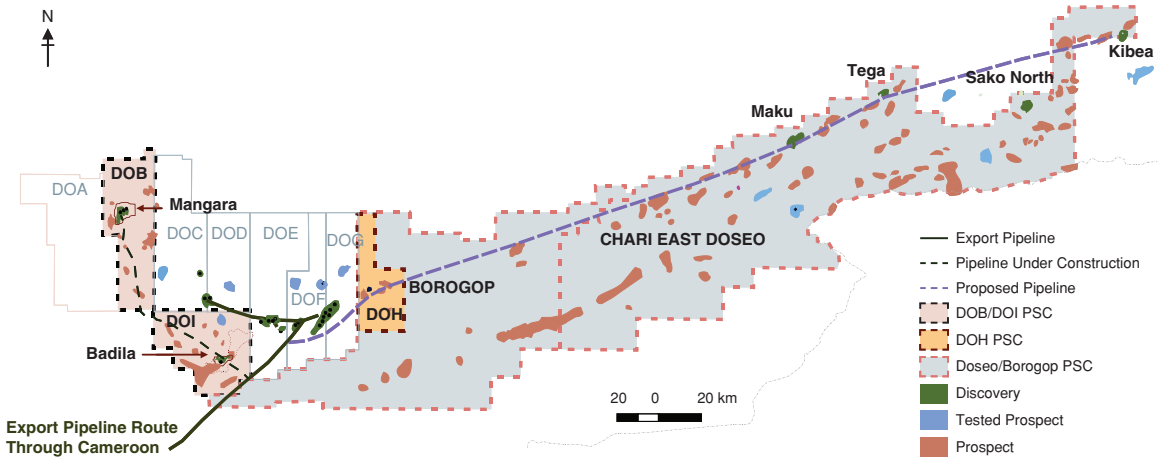
Long-term growth strategy

In the longer-term, the Group's strategy is to seek further exploration and development opportunities in Africa, both onshore and in shallow water. The Group's focus will be on areas in which it believes it can demonstrate a competitive advantage, such as regional experience, geologic deposition or synergies with its operations in Chad. The Group will focus on regions or assets which enable it to act as operator, lead the development and control of infrastructure and receive world market prices for the product.

6 Description of business and operations

Principal properties

The Group has entered into three PSCs covering three Contractual Zones in southern Chad comprising approximately 26,103 km^2 (6.4 million acres). The largest Contractual Zone is the Doseo/Borogop Contractual Zone, followed by the DOB/DOI Contractual Zone and the DOH Contractual Zone, as shown in the map below.



Geology

The Doba and Doseo Basins are part of the Central African Rift system and are separated by the Borogop uplift. Both interior rift basins share a similar depositional history with a fluvial/deltaic/lacustrine sediment infill that is primarily Cretaceous in age. The primary reservoir targets in the Doseo Basin are found within the Lower Cretaceous C, D and E depositional sequences. These sequences are represented by shale deposition in a deep lake, deposition of fluvial-deltaic sequences around the margins of the lake and slope fans/turbidites extending into deeper parts of the lake.

Reservoirs: The fluvial, deltaic and turbidite sands are the tested reservoirs in the Doseo Basin. The sands have porosities ranging from 8 per cent. to 26 per cent. and range in thickness from a few metres to tens of metres.

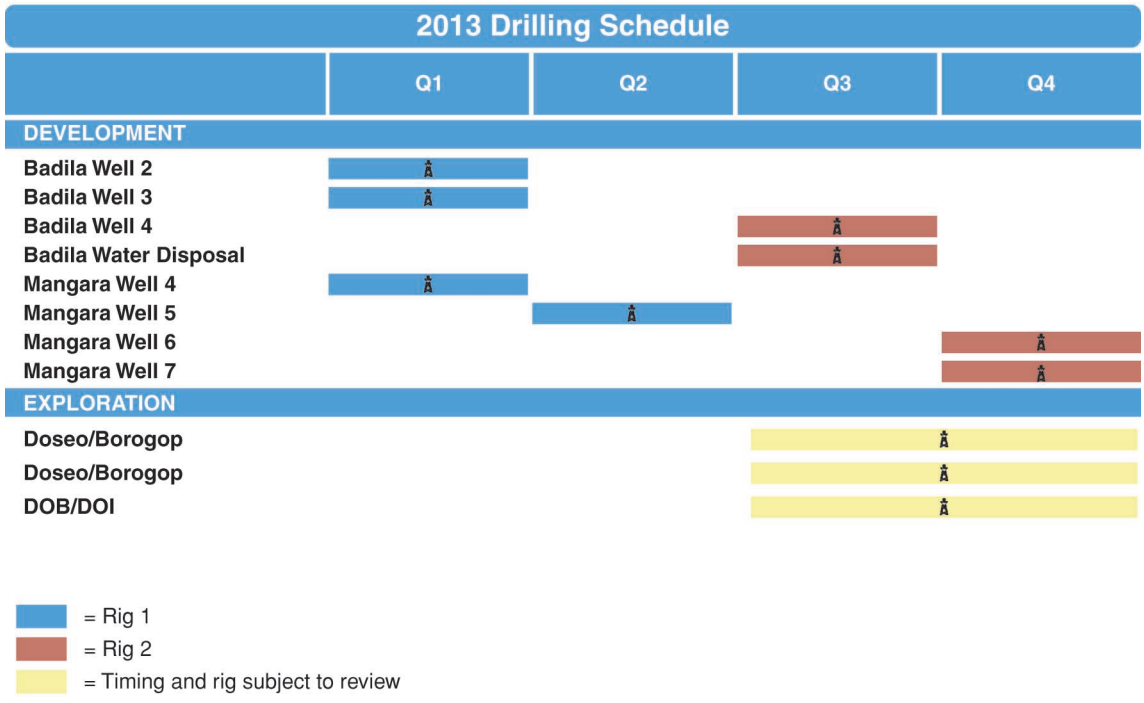
Source Rocks: The lacustrine shales of the C, D and E sequences are the source rocks for the hydrocarbon system with the highest quality source in the C and D intervals.

Seal: As the C sequence in the Doseo Basin is dominated by shale, except for the margins of the basin, the C shale forms the regional seal for the Lower Cretaceous play. Interbedded shales within the C, D and E sequences act as independent seals between reservoirs.

Play/Trap Types: There are four trap types recognised to date: structural 4-way closure, which is the most common trap type, and 3-way closure (fault bounded, stratigraphic and a combination of structural and stratigraphic).

2013 Drilling Schedule

Set out below is the Group's intended drilling schedule for 2013.



The Group's drilling schedule is expected to accelerate in 2014, with approximately twenty development wells and approximately twelve exploration wells planned. The Group intends to have approximately eight rigs in operation on its properties by the end of 2014.

DOB/DOI Contractual Zone

DOB/DOI PSC

The DOB/DOI PSC provides the Group and Glencore with the exclusive right to explore and develop oil and gas reserves and resources in an area of approximately 2,865 km^2 contained within the DOB and DOI blocks (the "**DOB/DOI Contractual Zone**").

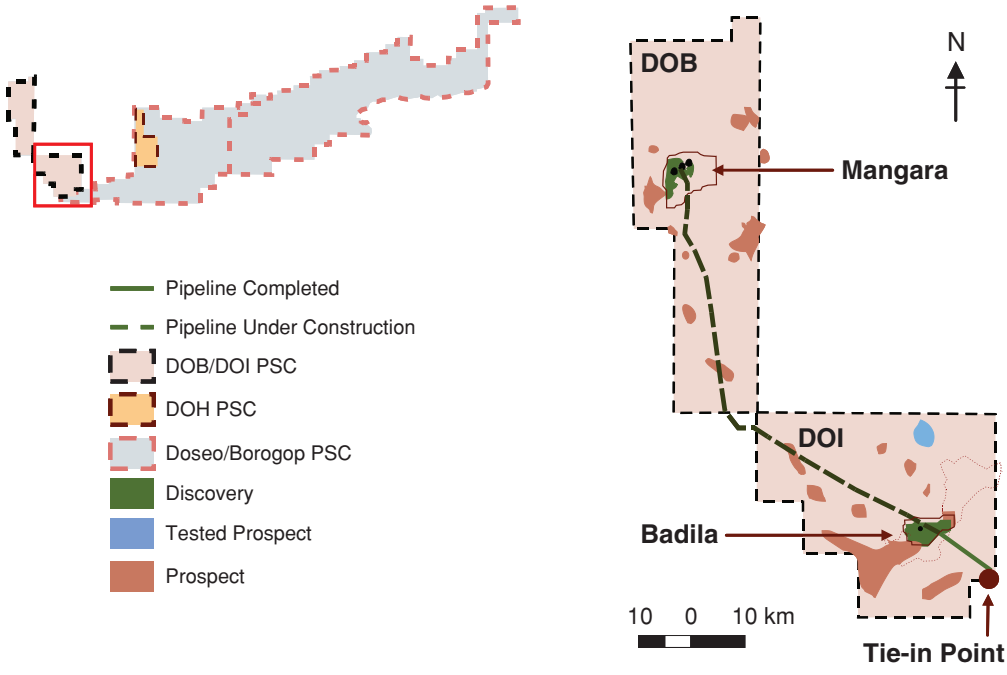
The Group is the operator of the DOB/DOI Contractual Zone, with a 66.67 per cent. participating interest in the EEAs, while the remaining 33.33 per cent. participating interest is held by Glencore. The Group has a 50 per cent. participating interest in the Badila and Mangara EXAs, with Glencore holding a 35 per cent. participating interest and SHT holding a 15 per cent. participating interest, respectively.

Under the terms of the DOB/DOI PSC, the Group was required to pay a signing bonus of U.S.$40 million to the Government of Chad. The DOB/DOI PSC states that the payment of the signing bonus does not constitute recoverable petroleum costs. As required by the DOB/DOI PSC, the Group also paid U.S.$3.2 million in relation to the Government of Chad's legal expenses.

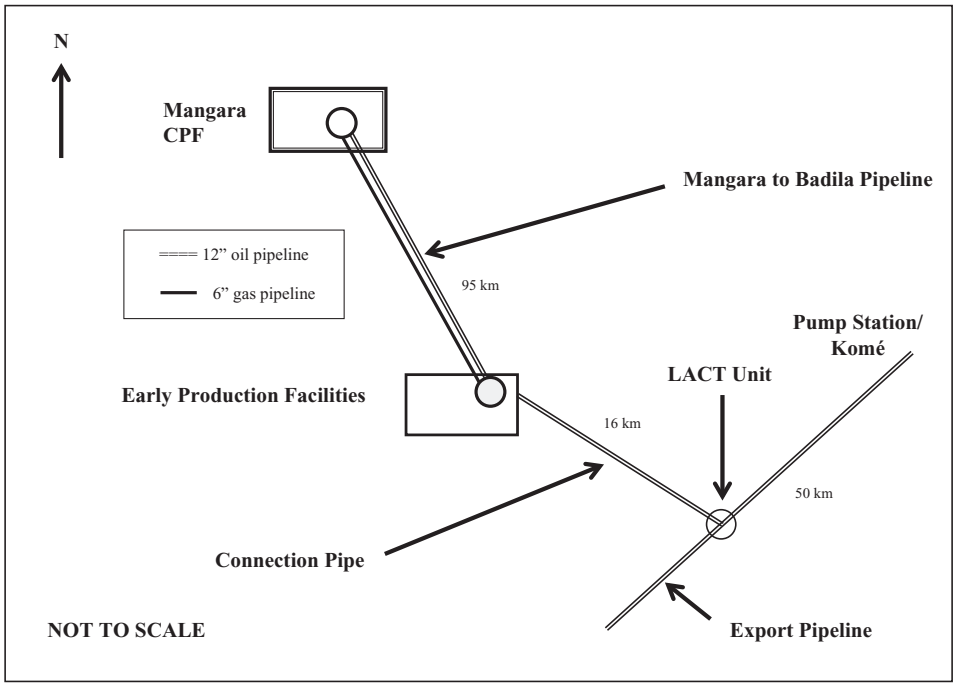
See paragraph 7—"PSCs" in this Part VI for a description of the other terms of the DOB/DOI PSC.

Badila and Mangara Fields

There are two discoveries of commercial interest that the Group is currently developing within the DOB/ DOI Contractual Zone: the Badila Field and the Mangara Field, located in the DOI and DOB blocks, respectively, as shown in the map below.



The illustrative map below identifies the location of the principal facilities and pipeline infrastructure in relation to the Badila and Mangara Fields.



Estimated reserves and resources

The GLJ Reports estimate that the gross lease reserves attributed to the Badila and Mangara Fields are 28.8 MMbbl (proved), 63.2 MMbbl (proved plus probable) and 135.2 MMbbl (proved plus probable plus possible) (14.4 MMbbl, 31.6 MMbbl and 67.6 MMbbl, respectively, on a Net Participating Interest basis). The GLJ Reports estimate that the gross lease unrisked prospective resources located in the DOB/DOI Contractual Zone are 239.6 MMstb (mean) (calculated by the Group to be 159.7 MMstb on a Net Participating Interest basis). See paragraph 13—"Summary of key information from the GLJ Reports" in this Part VI and "Mineral reserve and mineral resource reporting" in Part III: "Presentation of Financial and Other Information".

Badila Field

Overview

The Badila Field is an anticlinal structure with approximately 9 km^2 of closure and is located approximately 18 kilometres from the Export Pipeline. The Badila EXA covers approximately 29 km^2. The GLJ Reports forecast gross production, in the 2P case, of 20,000 bbl/d from the Badila Field by the end of 2014 (10,000 bbl/d on a Net Participating Interest basis).

Geology of the Badila Field

The Badila Field is located in the south-west of the Doba Basin. Hydrocarbons are present in both Upper and Lower Cretaceous reservoirs in the Badila structure. These strata consist of stacked fluvial, deltaic and lacustrine sediments with interbeds of shale dominated lacustrine and lake margin intervals that form top-seals. The A2 Upper Cretaceous sandstone reservoir contains gas and a possible thin oil leg. Oil reserves have been assigned to the C2, C3, D3 and D8 intervals.

Hydrocarbons are trapped at the Badila Field within an anticline created by contractional inversion of a Cretaceous rift fault that is located to the south-west of the field. Although seismic coverage is limited to only nine 2-D lines, the structure is a reasonably well-defined four-way closure. No faults are mapped within the prospective regions of the closure, although it is possible that a fault may be present along the western edge of the structure at deeper levels. The structural relief is approximately 40 metres at the A2 level, approximately 75 metres at the C3 level and approximately 80 metres at the D8 level.

The initial wells drilled in the Badila Field have targeted the Lower Cretaceous C and D oil-bearing reservoirs. Based on test results from the Badila-1, Badila-2 and Badila-3 wells, log and seismic interpretation, the Group expects these reservoirs to be the most productive zones.

In May 2013, the Group obtained 320 km^2 of 3-D seismic over the Badila Field and Bitanda exploration prospect. Processing of this seismic is currently in progress.

Badila D&E Plan

The Group submitted a development and exploitation plan (the "**Badila D&E Plan**") to the Government of Chad in June 2012 and, on 10 August 2012, the Group received a decree from the Ministry of Petroleum granting the Badila EXA. Any revisions to the Badila D&E Plan are subject to the approval of the Ministry of Petroleum.

The consultative process of land acquisition for the development of the Badila Field has been completed by the Group. Through a combination of open communication, fair and transparent compensation, and an accessible grievance management process, the Group was able to acquire permissions for all land required without any major work stoppages. As such, the Group complied with the principles set out by the World Bank for such land acquisition and damages compensation using industry rates based on fair replacement value.

The principal elements of the Badila D&E Plan are set out below.

Badila-1 well re-entry

The Badila-1 well, which was drilled by the previous operator of the Badila Field, was re-entered and tested by the Group in April 2012. The results of the multi-rate well test operations on Badila-1 have been analysed and indicate a natural flow of light sweet 31°-32° API crude oil at a rate of approximately 3,100 bbl/d over a period of 24 hours with zero water-cut. The maximum flow rate achieved was 4,025 bbl/d, with well bore pressure still increasing. The production rates were constrained by the physical testing and flaring equipment at the surface. During the well test period, which lasted approximately

55 flowing hours, a total of 5,050 barrels of crude were produced (equivalent to 2,200 bbl/d) with a gas-oil ratio in the range of 150 to 250 scf/bbl. There was no evidence of depletion and the well continued to clean-up throughout the test, with improving rates and flowing pressures. The Badila-1 well reaches a total depth of 2,438 metres and GLJ has estimated that it contains approximately 57.1 metres of net oil pay in the C and D reservoirs (2P Case). The Group has estimated that the Badila-1 well has 79 metres of net oil pay in the C sands and 44 metres of net oil pay in the D sands (a total of 123 metres), however, only 23.5 metres in the C sands was perforated for the test due to mechanical conditions of the well.

Measurements from the test indicate a productivity index estimated at approximately 15 bbl/d/psia and the sandface absolute open flow potential estimate ranges from 25,000-40,000 bbl/d. Measurements from the test also indicate a flowing wellhead pressure of 345 psia and a flowing bottomhole pressure of 1,872 psia. Based on the well test data, the stabilised flow rate after three to six months with electric submersible pump ("**ESP**") lift assistance is estimated at 7,500-9,000 bbl/d. Oil samples were obtained for laboratory testing and for tariff and commercial pricing adjustment agreements required to utilise the Export Pipeline.

Well-flow test results are not necessarily indicative of long-term performance or of ultimate recovery.

Badila drilling and completion operations

The Group commenced drilling on the Badila-2 well to a depth of 2,075 metres in November 2012. The Badila-2 well was completed as a production well in January 2013. The focus of testing on the Badila-2 well was the Cretaceous D reservoirs. Based on extensive coring and wireline logging, the Group has estimated that the Badila-2 well has 195 metres of net oil pay, which includes 101 metres in the Lower Cretaceous C zone across 5 sands, 92 metres in the Lower Cretaceous D zone across 8 sands and 2.5 metres in the Lower Cretaceous E sands. A maximum restricted natural flow rate of 3,300 bbl/d was achieved over six hours. During this six-hour period the gas-oil ratio was 105 scf/stb, API gravity was 28° to 30°, wellhead flowing pressure was 253 psi and the water-cut was 5 per cent. Well-flow test results are not necessarily indicative of long-term performance or of ultimate recovery.

Drilling commenced on the Badila-3 well to a depth of 2,150 metres in January 2013. The Badila-3 well was completed as a production well in March 2013.

The Group anticipates that there will be either one or two drilling rigs in operation throughout the development of the Badila Field, as well as one service rig to complete and test the wells. This service rig will also be used to perform any future workovers and repairs that may be required. After the drilling rig has set the production well casing, it will be released to the next location to be drilled. The Group has secured the lease of one drilling rig and one service rig, each of which are currently in operation on the Group's properties, with an additional drilling rig due to commence operation in July 2013.

During 2013, the Group expects to drill and test three development wells in the Badila Field (including Badila-2 and Badila-3), in addition to the completion of the Badila-1 wellbore as an oil production well. As production information becomes available, the location and timing of further infill drilling will be determined. The Group expects to drill a total of 29 development wells (24 producers and 5 water injectors) for full development of the Badila Field. The location and number of these wells will be optimised once production information has been gathered; reservoir simulation will be a key input for this. The Lower Cretaceous C and D reservoirs at Badila will require wells drilled to approximately 2,100 to 2,200 metres.

While the Group expects the wells will be capable of flowing initially without the need for artificial lift, the Group will install ESPs at the time of initial production. The Group believes that this will enable the potential for higher/optimised flow rates sooner in the production phase. The Group estimates a combined initial production capability of 15,000 bbl/d to 16,500 bbl/d for the Badila-1 and Badila-2 wells, based on a range of 7,500 bbl/d to 9,000 bbl/d for Badila-1 and a rate of 7,500 bbl/d for Badila-2. However, initial production will be constrained by the 14,000 bbl/d processing capacity of the Early Production Facilities.

Wellsites and gathering system

Engineering design and procurement has been completed for the associated surface facilities required for each wellsite in the Badila Field. As each well will be completed with an ESP artificial lift system, it will also have variable frequency drives ("**VFDs**") installed to optimise productivity. Additional wellsite surface equipment includes the installation of pig sending capability to manage wax deposition.

Six-inch flowlines will be installed between wells and central satellite facilities which have associated manifolds, pig receiving capability and test separators to enable well production testing for each well. Once tested, all production fluids will be recombined and sent via a 12-inch group line to the Early Production Facilities and, once commissioned, to the Early Production Facilities Expansion and the Blending Export Terminal for blending with Mangara crude.

Early Production Facilities

The two processing facilities that have been designed to treat initial oil production from the Badila Field (the "**Early Production Facilities**") are expected by the Group to execute the following key processes:

- primary separation of gas, oil and water;
- secondary separation of oil and water;
- gas incineration (for further information, see paragraph 16—"Health, Safety and Environment" in this Part VI);
- power generation for onsite use;
- provision of combined tankage for 24,000 barrels of oil meeting Export Pipeline specifications ("**Spec Oil**"); and
- pumping of Spec Oil to the LACT Unit via a 12-inch pipeline.

Construction and commissioning of the Early Production Facilities was completed in April 2013, each of which has a processing capacity of 7,000 bbl/d (14,000 bbl/d combined).

Construction of an expansion of the Early Production Facilities (the "**Early Production Facilities Expansion**"), providing for a further 10,000 bbl/d of processing capacity, is expected to commence in late 2013, with commissioning expected by the Group to take place in the first quarter of 2014. This will expand processing capacity of oil produced in the Badila Field to 24,000 bbl/d.

Inland transport authorisation

The Group has the right to use the ITA Facilities (as defined below) to transport oil to the Export Pipeline pursuant to the transportation rights granted to PetroChad under the DOB/DOI PSC. However, in due course, the Group intends to transfer such transportation rights from PetroChad to PCT. The timing of such transfer does not impact upon the Group's ability to utilise the ITA Facilities.

In August 2012, PetroChad submitted an application to the Government of Chad for the issuance of an inland transport authorisation in respect of the ITA Facilities. By presidential decree on 30 May 2013, PetroChad was (i) granted the rights to construct, maintain and operate the ITA Facilities and (ii) authorised to transfer such rights, in addition to the transportation rights that it holds pursuant to the DOB/DOI PSC, to PCT. In addition, the Group (via PCT) intends to enter into an agreement (the "**Inland Transportation Agreement**") with the Government of Chad, which is expected to set out the terms and conditions in respect of the operation of the ITA Facilities by PCT. The Group expects the Inland Transportation Agreement to be approved by presidential ordinance in July 2013.

The following infrastructure comprises the "**ITA Facilities**":

- *Blending Export Terminal:* The Blending Export Terminal will be located close to the Badila Field. Production will be received from the Mangara CPF, the Early Production Facilities and the Early Production Facilities Expansion where the crude will be blended to attain Spec Oil for delivery to the Export Pipeline. The Blending Export Terminal will utilise the fuel gas transported from the Badila and Mangara Fields to generate onsite power. Onsite storage will be installed for both oil (capacity 20,000 barrels) and water disposal. High pressure pumps will be located onsite to enable shipping of Spec Oil to the Export Pipeline. Construction of the Blending Export Terminal is underway, with many major components secured, and commissioning is expected to take place in the third quarter of 2013. Completion of the Blending Export Terminal is not required to enable first production from the Badila Field to commence.
- *Connection Pipe:* Construction and commissioning of this single, 16-kilometre, 12-inch dry oil pipeline running from the Blending Export Terminal to the Export Pipeline was completed in May 2013.
- *LACT Unit:* A lease automatic custody transfer unit (the "**LACT Unit**") will act as the final oil measurement point prior to the Group's production from the Badila and Mangara Fields entering the Export Pipeline. The LACT Unit was completed and commissioned in May 2013.

- *Hot Tap:* A flow valve connected to the side of the Export Pipeline (the "**Hot Tap**") will allow oil to flow into it. The Hot Tap was completed and commissioned in June 2013.

Expected 2013 work plan

The Group has scheduled the following key workstreams relating to the development of the Badila Field to be undertaken during the 2013 calendar year:

- drilling of three development wells (two of which, Badila-2 and Badila-3, have already been completed);
- completion of the Badila-1 wellbore as an oil production well;
- gathering system and pipeline installation;
- construction and commissioning of the Blending Export Terminal and commencement of construction of the Early Production Facilities Expansion; and
- completion of the processing of the 320 km^2 3-D seismic survey covering the Badila Field and Bitanda exploration prospect.

Mangara Field

Overview

The Mangara Field is located approximately 110 kilometres from the Export Pipeline and the Mangara EXA covers approximately 71 km^2. GLJ has forecast gross production of 16,000 bbl/d, in the 2P case, from the Mangara Field by the end of 2014 (8,000 bbl/d on a Net Participating Interest basis).

The Mangara EXA was granted in June 2012. Three wells were previously drilled in the Mangara Field (in 1978, 2003 and 2007), all encountering oil, with test and calculated rates in Mangara-1 and Mangara-2 ranging from 19 bbl/d to 1,875 bbl/d of light sweet crude (37° API), despite incurring formation damage during the drilling operations. The Group believes, based on review of the three well files and the results from the Mangara-2 re-entry performed by the Group in March 2012, that future development well productivity can be enhanced with the use of improved drilling mud designs that will minimise formation damage during drilling operations.

Geology of the Mangara Field

The Mangara Field is located in the north-west part of the Doba Basin. It is comprised of a faulted anticline that overlies an uplifted basement block. A NW-SE trending normal fault intersects the field and creates a high eastern side and a low western side. A thick interval of lacustrine shale overlies the reservoirs forming the top-seal.

The oil bearing Lower Cretaceous stacked clastic reservoirs are divided into three intervals named "C", "D" and "E". The C and D reservoirs were deposited in a fluvial-deltaic setting and are interbedded with shale prone intervals of lacustrine and lake margin sediments. The E interval was deposited in a fluvial-deltaic setting with periods of alluvial sedimentation. The E interval comprises the initial deposits into the expanding rift valley and contains coarser immature sediments. Reserves have been assigned to both the C and E intervals.

The main development targets in the Mangara Field are the C reservoirs. At the C level the anticline produces a 4-way dip closure. There is a high probability of trapping oil when the trap is a four way structural closure independent of the fault. The C interval is subdivided into the "C1a", "C1b", "C2" and "C3" reservoir packages. These four packages have been correlated across the existing wells and tied back to seismic. The C reservoirs appear continuous throughout the field and have all tested oil. The Group re-entered the Mangara-2 wellbore in March 2012 and flowed oil to surface from this interval.

The secondary target is the E interval. Because the E reservoir appears to be dependent on the fault for closure there is a risk of containment. This interval has successfully tested oil and will be tested with the first wells.

The D reservoirs have not been tested and will be evaluated with the first wells drilled in the Mangara Field.

In April 2012, the Group obtained 147.5 km^2 of 3-D seismic over the Mangara Field and neighbouring Krim exploration prospect. The Group has processed the 3-D seismic and the data will be used to determine the location of the new wells to be drilled. The previous wells drilled in the Mangara Field were drilled on the basis of 2-D seismic. The data obtained from 3-D analysis was of excellent quality and has now been integrated into the reservoir modelling to augment both the understanding of the geologic model and assist in optimising the depletion plan for the Mangara Field.

Mangara D&E Plan

The Group submitted a development and exploitation plan (the "**Mangara D&E Plan**") to the Government of Chad in August 2011 and, on 1 June 2012, the Group received a decree from the Ministry of Petroleum granting the Mangara EXA. Any revisions to the Mangara D&E Plan are subject to the approval of the Ministry of Petroleum.

The consultative process of land acquisition for the development of the Mangara Field has been completed by the Group. Through a combination of open communication, fair and transparent compensation, and an accessible grievance management process, the Group was able to acquire permissions for all land required without any major work stoppages. As such, the Group complied with the principles set out by the World Bank for such land acquisition and damages compensation using industry rates based on fair replacement value.

The principal elements of the Mangara D&E Plan are set out below.

Mangara-2 well re-entry

During March 2012, well servicing operations commenced on the Mangara-2 wellbore to obtain oil samples required for production and oil export planning. Due to the mechanical configuration the previous operator used to suspend the Mangara-2 wellbore, GLJ estimates that 54.1 metres of net oil pay were accessible for perforating in the Mangara C reservoir. Surface and reservoir samples were obtained and their physical properties are being used for tariff and commercial pricing adjustment agreements required to utilise the Export Pipeline.

A multi-rate flow and build-up test was conducted on the Mangara-2 wellbore in the C reservoirs to understand the un-stimulated wellbore delivery potential. During the maximum rate component of the test, the well flowed naturally at an average rate of approximately 800 bbl/d of light 37° API crude oil, with zero water-cut, gas-oil ratio of 600-1,200 scf/bbl and with a flowing wellhead pressure of up to 120 psia.

The purpose of the build-up test was to determine reservoir properties, including the mechanical skin damage. Measured rates and pressures were within the Group's expected range and confirmed significant skin damage from the initial well drilling. Engineering estimates suggest that, with successful removal of skin damage using conventional small-scale stimulation, the well will be capable of a sustained initial production rate of 1,500 to 2,000 bbl/d using an ESP for artificial lift. The Group is encouraged by the results, which validate forecast models for this area of the Mangara Field development.

Well-flow test results are not necessarily indicative of long-term performance or of ultimate recovery.

Mangara drilling and completion operations

The Group completed drilling on the Mangara-4 well to a depth of 2,472 metres in May 2013 and the well is currently in the process of completion. The Mangara-4 well has been targeted as a development well for the Cretaceous C and D reservoirs, and as an exploration test of the Cretaceous E reservoirs. Drilling commenced on the Mangara-5 well to a depth of approximately 3,300 metres in May 2013. The Group anticipates that there will be either one or two drilling rigs in operation throughout the development of the Mangara Field, as well as one service rig to complete and test the wells. This service rig will also be used to perform any future workovers and repairs that may be required. After the drilling rig has set the production well casing, it will be released to the next location to be drilled.

During 2013, the Group expects to drill four development wells (including Mangara-4 and Mangara-5) in the Mangara Field, in addition to the completion of the Mangara-2 wellbore as an oil production well. Depending on results, certain flank wells may be converted to water injection wells to provide pressure support, following a short period of oil production. However, this conversion and the timing thereof will depend on individual well performance as well as feasibility of water flood for pressure maintenance and

effective reservoir sweep. The Group expects to drill a total of approximately 70 development wells for full development of the Mangara Field.

While the first wells drilled in the Mangara Field will be vertical, the Group's future plans include the potential for drilling wells from pad locations. The Group expects that the wells will be capable of flowing initially without the need for artificial lift, however the Group will install ESPs at the time of initial production. The Group believes that this will enable the potential for higher/optimised flow rates sooner in the production phase.

Wellsites and gathering system

Engineering design and procurement has been completed for the associated surface facilities required for each wellsite in the Mangara Field. As each well will be completed with an ESP artificial lift system, it will also have VFDs installed to optimise productivity. Additional wellsite surface equipment includes the installation of pig sending capability to manage wax deposition.

Six-inch flowlines will be installed between wells and central satellite facilities which have associated manifolds, pig receiving capability and test separators to enable well production testing for each well. Once tested, all production fluids will be recombined and sent via a 12-inch group line to the Mangara CPF for separation and fluid processing.

Mangara CPF

The Mangara Central Production Facility (the "**Mangara CPF**") has been designed as the main production facility for the Mangara Field and is expected by the Group to execute the following key processes:

- primary separation of gas, oil and water;
- gas dehydration and compression for use as fuel;
- temporary oil and produced water storage, disposal and re-injection (initial water processing capability will be 5,000 bbl/d);
- power generation for onsite use and for future power distribution back to wellsites;
- high pressure pumping to transfer production to the Blending Export Terminal; and
- gas incineration to manage any excess gas production not consumed onsite or re-injected (for further information, see paragraph 16—"Health, Safety and Environment" in this Part VI).

The Mangara CPF has been designed as a phased installation to allow initial processing capability of 10,000 bbl/d, with expansion capability on a modular basis to between 25,000 and 40,000 bbl/d. The Group expects the Mangara CPF to be installed and commissioned in the third quarter of 2013.

Mangara to Badila Pipeline

The Mangara D&E Plan provides for the construction of (i) one 12-inch emulsion pipeline and (ii) one six-inch pipeline to transport fuel gas, both of which will be installed in a single trench (the "**Mangara to Badila Pipeline**"). Once initial separation of produced fluids has been conducted at the Mangara CPF, the emulsion will be sent approximately 95 kilometres to the Blending Export Terminal, located close to the Badila Field. All line pipe fabrication has been completed. The Group expects the Mangara to Badila Pipeline to be installed and commissioned in the third quarter of 2013.

Expected 2013 work plan

The Group has scheduled the following key workstreams relating to the development of the Mangara Field to be undertaken during the 2013 calendar year:

- drilling of four development wells in the Mangara Field (one of which, Mangara-4 has already been drilled and another, Mangara-5, is in process);
- completion of the Mangara-2 wellbore as an oil production well; and

- construction and commissioning of the Mangara CPF and the Mangara to Badila Pipeline, including the construction of a terminal at the expected tie-in point and other in-field infrastructure such as gathering systems, manifolds, satellites and flowlines.

Doseo/Borogop Contractual Zone

Doseo/Borogop PSC

The Doseo/Borogop PSC provides the Group and Glencore with the exclusive right to explore and develop oil and gas reserves and resources in an area of approximately 22,414 km^2 within the Chari East-Doseo and Borogop blocks (the "**Doseo/Borogop Contractual Zone**"). The Group is the operator of the Doseo/Borogop Contractual Zone, with a 66.67 per cent. participating interest in the EEA. Pursuant to the Farm-in Agreement Glencore has a 33.33 per cent. participating interest in the EEA.

Under the terms of the Doseo/Borogop PSC, the Group was required to pay a signing bonus of U.S.$40 million to the Government of Chad. As required by the Doseo/Borogop PSC, the Group also paid U.S.$3.2 million in relation to the Government of Chad's legal and other advisory fees. The Doseo/Borogop PSC states that the signing bonus shall be recognised as a petroleum cost that is recoverable for up to 25 per cent. of its total amount.

Between 1978 and 2007, nine wells were drilled in the Chari East-Doseo and Borogop blocks by the previous operators. The Chari East-Doseo block contains eight of the nine wells drilled, four of which were tested and recovered hydrocarbons. However, the previous operators did not place any of the discoveries on production. Extensive well records exists for all wells drilled, some of which were provided to the Group by the Government of Chad. The well records indicate that the maximum production rate for each of the tested wells ranged from approximately 135 bbl/d to 2,200 bbl/d of medium and light sweet crude oil, and often had multi-zone potential. None of the prior testing conducted by the previous operators involved artificial lift and little or no stimulation was used. The Group intends to re-enter some of these wells but will principally focus on drilling of new wells.

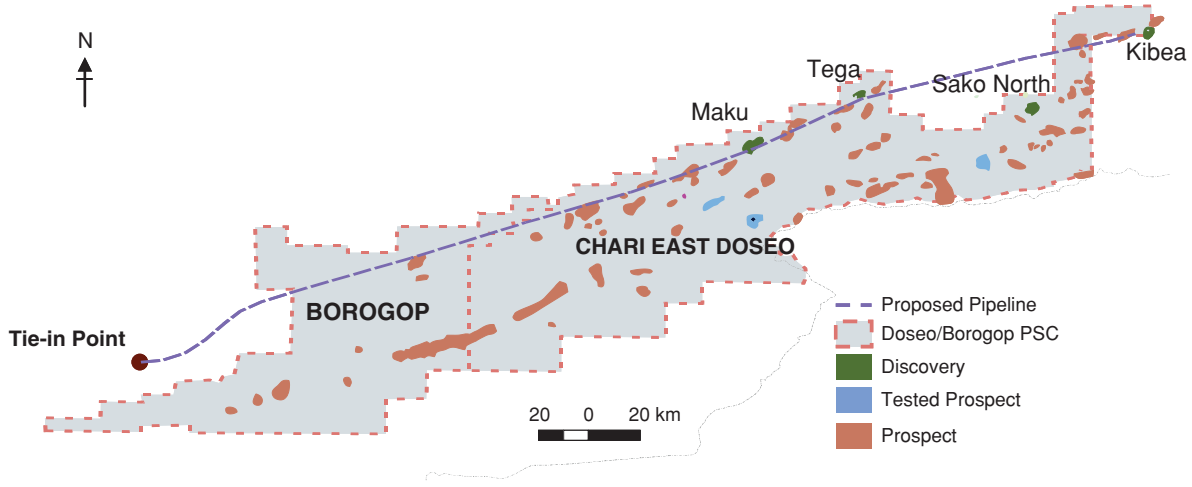
The Group provided notice of a declaration of discovery to the Government of Chad for the four tested prospects in the Chari East-Doseo block in August 2011. The four declared discoveries are the Kibea, North Sako, Tega and Maku Fields. The Group submitted an EXA application (together with the related declaration of commerciality and feasibility study, the "**Kibea EXA Application**"), covering, amongst other things, construction and sizing alternatives of the Doseo/Borogop Pipeline (as defined below) and related facilities, to the Government of Chad to establish commerciality for the Kibea Field on 22 April 2013.

The Group is familiar with the EXA application process having successfully obtained approval for each of the Badila and Mangara EXAs during 2012. The Group anticipates that the approval process for the Kibea EXA Application will be the same as that followed in relation to the Badila and Mangara EXAs. On 25 April 2013, the Kibea EXA Application was presented to the Doseo/Borogop Management Committee (consisting of members of the Government of Chad and the Group), which raised no objections in relation thereto. Pursuant to the terms of the Doseo/Borogop PSC, the Government of Chad had 30 days to respond to the Kibea EXA Application from the date of its presentation to the Doseo/Borogop Management Committee. Following the expiry of such period, the Kibea EXA Application was deemed approved. Pursuant to the terms of the Doseo/Borogop PSC, following the granting of express or tacit approval, and once the necessary arrangements have been established, the Government of Chad will issue an official decree granting the authorisation of the Kibea EXA Application.

The Kibea EXA Application includes details in relation to the requirement to construct a minimum 6-inch pipeline from the Kibea Field to the tie-in point on the Export Pipeline, via the Group's production assets within the Doseo/Borogop Contractual Zone (the "**Doseo/Borogop Pipeline**"). Approval of the Kibea EXA Application would constitute approval to construct the Doseo/Borogop Pipeline and all associated production, processing and transport infrastructure which is described therein. The Doseo/Borogop Pipeline Concept Study (as defined below) suggests an optimum 16-inch oil transportation pipeline and a 6-inch natural gas pipeline for the transportation of hydrocarbons from the Group's production assets within the Doseo/Borogop Contractual Zone to the Export Pipeline. The Kibea EXA Application is not limited to a specific diameter of pipeline, and final sizing of the Doseo/Borogop Pipeline will be determined as part of the Doseo/Borogop Pipeline Engineering Study (as defined below). The size of the Doseo/Borogop Pipeline will be stated in an inland transport authorisation application that is due to be submitted in the second half of 2013.

The Group anticipates delivering an EXA application, declaration of commerciality and feasibility study to the Government of Chad to establish commerciality for the Maku discovery by the end of 2013.

The map below depicts where the Kibea, North Sako, Tega and Maku Fields are located within the Doseo/Borogop Contractual Zone and the proposed route of the Doseo/Borogop Pipeline.



Evaluated Reserves and Resources

The GLJ Reports have assigned 18.8 MMbbl gross proved plus probable reserves to Kibea and 7.3 MMbbl gross proved plus probable reserves to Maku (9.4 MMbbl and 3.6 MMbbl, respectively, on a Net Participating Interest basis)[(5)]. During the third quarter of 2012, the Group completed a survey of the roads, field access and potential pipeline routes for the Kibea Field. The Group intends to order the necessary long-lead items for the Kibea Field in late 2013 and begin construction of the Doseo/Borogop Pipeline in 2014 and the drilling of development wells in late 2015 (subject to approval by the Government of Chad). The GLJ Reports estimate that the gross lease unrisked prospective resources located in the Doseo/Borogop Contractual Zone are 985.3 MMstb (mean) (calculated by the Group to be 656.9 MMstb on a Net Participating Interest basis). See paragraph 13—"Summary of key information from the GLJ Reports" in this Part VI and "Mineral reserve and mineral resource reporting" in Part III: "Presentation of Financial and Other Information".

Geology of the Doseo/Borogop Contractual Zone

Kibea Field

The Kibea Field is located in the north-east of the Doseo Basin, approximately 410 kilometres from Komé, a possible location of the tie-in to the Export Pipeline. Hydrocarbons are present in the Lower Cretaceous reservoirs in the Kibea structure. These strata consist of stacked fluvial, deltaic and lacustrine sediments with interbeds of shale dominated lacustrine and lake margin intervals that form top-seals. Oil-bearing Lower Cretaceous sandstone reservoirs include the C, D and E intervals. Reservoirs within the Lower Cretaceous E interval produced oil during testing.

Hydrocarbons are trapped at the Kibea Field within an anticline created by contractional inversion of a Cretaceous rift fault that is located to the north of the field. Although seismic coverage is limited to only six 2-D lines, the structure is a reasonably well-defined four-way closure. Depth maps were constructed for the Lower Cretaceous C, D and E flooding surface and these maps were used, in conjunction with data from well files, to constrain the areas used as input for probabilistic volume calculations. The structural relief is approximately 20 to 30 metres at the C and D levels and approximately 80 to 120 metres at the E level, with minor variations which are within the limits of seismic resolution.

(5) GLJ has assumed, for the purposes of estimating the Group's participating interest in any future EXAs which may be granted under each PSC, that the Government of Chad will elect to acquire a 25 per cent. participating interest in each EXA. Accordingly, the participating interest of each of the Group and Glencore has been assumed by GLJ to be 50 per cent. and 25 per cent. respectively, of the gross lease interest.

The primary target for the Kibea Field is the Lower Cretaceous E interval. The Lower Cretaceous E interval was tested and the GLJ Reports assigned 18.8 MMbbl gross proved plus probable reserves to it (9.4 MMbbl on a Net Participating Interest basis)[6]. The assigned reserves from the GLJ Reports are based on two reservoirs in the Lower Cretaceous E that tested oil at high rates. Additional reservoirs were tested and produced oil but the flow rates were considered too low by GLJ to assign reserves. Approximately 360 metres of the Lower Cretaceous E interval was penetrated by the Kibea-1 well, which was drilled in 1986 and tested oil with rates of up to 2,196 bbl/d with significant formation damage. Not all of the original test data obtained by the previous operator in respect of Kibea-1 was made available to the Group. The current seismic interpretation suggests that the Lower Cretaceous E interval could be significantly thicker than the penetrated section in Kibea-1, which could lead to further upside in the interval.

The Lower Cretaceous C and D intervals were penetrated by the Kibea-1 well but no testing took place in the intervals. The Kibea-1 well logs indicate hydrocarbon net pay is present in these intervals. The GLJ Reports did not evaluate the Lower Cretaceous C and D for reserves.

The Group intends to undertake an approximate 200 km^2 3-D seismic shoot covering the Kibea Field and adjacent exploration prospects early in the fourth quarter of 2013.

Maku Field

The Maku Field is located at the north edge of the Doseo Basin, approximately 240 kilometres from Komé, a possible location of the tie-in to the Export Pipeline. Hydrocarbons are present in the Lower Cretaceous reservoirs in the Maku structure. These strata consist of stacked fluvial, deltaic and lacustrine sediments, with interbeds of shale dominated lacustrine and lake margin intervals that form top-seals. Reservoirs within the Lower Cretaceous C interval produced oil during testing.

Hydrocarbons are trapped at the Maku Field within an anticline created by contractional inversion of a Cretaceous rift fault that is located to the north of the field. Although seismic coverage is limited to only eleven 2-D lines, the structure is a reasonably well-defined four-way closure. A depth map was constructed for the Lower Cretaceous flooding surface and this map was used, in conjunction with data from well files, to constrain the areas used as input for probabilistic volume calculations. The structural relief is approximately 100 to 200 metres at the C level.

The primary target for the Maku Field is the Lower Cretaceous C interval. The Lower Cretaceous C interval was tested and the GLJ Reports assigned 7.3 MMbbl gross proved plus probable reserves to it (3.6 MMbbl on a Net Participating Interest basis)[7]. The assigned reserves from the GLJ Reports are based on a sand package in the Lower Cretaceous C that produced oil and gas at high rates in the Maku-1 well. When drilled by the previous operators, the Maku-1 well produced oil and gas at 1,100 bbl/d with an oil/gas ratio of 2,800 scf/bbl. The Maku-2 well encountered more sands than the Maku-1 well but the Maku-2 well only tested one sand package and recovered water. It was stated in the well reports produced by EEPCI that the recovered water was formation water, but the water is now suspected by the Group to be drilling fluids. The Maku-2 well had multiple cores taken over the tested interval and the cores had good oil shows. Due to the uncertainty relating to the Maku-2 well, the GLJ Reports only assigned reserves to the tested sand around the Maku-1 well on the west side of the structure. Not all of the original test data obtained by the previous operator in respect of the Maku-1 and Maku-2 wells was made available to the Group.

The Lower Cretaceous D and E intervals were penetrated by the Maku-2 well but no testing took place in the intervals. The Maku-2 well logs show that the Lower Cretaceous D interval is predominantly shale at the Maku-2 well location and the Lower Cretaceous E interval contained sands interbedded with shale. The GLJ Reports did not evaluate the Lower Cretaceous C and D for reserves because no tests were conducted.

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(6) GLJ has assumed, for the purposes of estimating the Group's participating interest in any future EXAs which may be granted under each PSC, that the Government of Chad will elect to acquire a 25 per cent. participating interest in each EXA. Accordingly, the participating interest of each of the Group and Glencore has been assumed by GLJ to be 50 per cent. and 25 per cent. respectively, of the gross lease interest.

(7) GLJ has assumed, for the purposes of estimating the Group's participating interest in any future EXAs which may be granted under each PSC, that the Government of Chad will elect to acquire a 25 per cent. participating interest in each EXA. Accordingly, the participating interest of each of the Group and Glencore has been assumed by GLJ to be 50 per cent. and 25 per cent. respectively, of the gross lease interest.

Development of the Doseo/Borogop Contractual Zone

Multiple workstreams have been undertaken to support exploration and appraisal drilling in the Doseo/Borogop Contractual Zone. These workstreams include reconnaissance scouting activities in relation to roads, road assessments for civil work and scouting of lease sites. The scope of civil work related to these activities is sufficiently advanced to commence the tendering and award of contracts. Employees of the Group are located in Sarh (a major city in the region) in order to support scouting efforts and stakeholder relation initiatives. Upgrades of the existing road between Sarh and the Kibea Field have been budgeted and are expected to commence in the third quarter of 2013.

A concept study in relation to the Doseo/Borogop Pipeline (the "**Doseo/Borogop Pipeline Concept Study**") was completed in April 2013 by an independent engineering firm. The Doseo/Borogop Pipeline Concept Study will support a detailed front-end engineering and design study (the "**Doseo/Borogop Pipeline Engineering Study**"), which the Group expects to put to tender in the third quarter of 2013 and have completed in the fourth quarter of 2013. The Doseo/Borogop Pipeline Engineering Study will be used to determine the sizing of the Doseo/Borogop Pipeline, in addition to the requirements for related equipment and infrastructure (including pumping stations, if any, and roads).

Once completed, the Doseo/Borogop Pipeline Engineering Study will form the basis for the scope of work required for the tender package to select a qualified pipeline contactor to construct the Doseo/Borogop Pipeline. The Group's 2013 work programme, which has been approved by the Government of Chad, has allocated funding of approximately U.S.$30 million for the undertaking of the Doseo/Borogop Pipeline Engineering Study, in addition to the procurement of components and long-lead items. Components and long-lead items for the Doseo/Borogop Pipeline will be ordered in the third and fourth quarters of 2013, respectively. Construction of the Doseo/Borogop Pipeline is expected to commence in the third quarter of 2014, with completion scheduled during the second half of 2015.

An environmental impact assessment study was commenced in the first quarter of 2013 in respect of the Doseo/Borogop Contractual Zone at a cost to the Group of around U.S.$1 million. Such study is due to be submitted and approved during 2013. In addition, the Group expects to move one of the drilling rigs that is currently operating in the Mangara Field to the Doseo/Borogop Contractual Zone to allow for exploration and appraisal drilling to commence in the Doseo/Borogop Contractual Zone in the second half of 2013. The work programme also includes the drilling of an appraisal well in the Kibea Field during 2013.

In addition to the 3-D seismic shoot covering the Kibea Field and adjacent exploration prospects to be undertaken early in the fourth quarter of 2013, the Group has obtained high resolution satellite imagery over the Doseo/Borogop Contractual Zone and interpreted 2-D seismic.

North Sako and Tega Fields

Feasibility study plans for the North Sako Field and Tega Field were submitted to the Government of Chad in November 2011. Exploration drilling is planned in these fields in 2014, during which time additional seismic data may be acquired.

Expected 2013 work plan

The Group has scheduled the following key workstreams relating to the development of the Doseo/Borogop Contractual Zone to be undertaken during the 2013 calendar year:

- one appraisal well and one exploration well are planned to be drilled;
- an approximate 200 km^2 3-D seismic programme covering the Kibea Field and adjacent exploration prospects is scheduled for initiation early in the fourth quarter of 2013;
- procurement of components and long-lead items for the Doseo/Borogop Pipeline and undertaking of the Doseo/Borogop Pipeline Engineering Study; and
- road and infrastructure upgrades.

DOH Contractual Zone

DOH PSC

The DOH PSC provides the Group and Glencore with the exclusive right to explore and develop oil and gas reserves and resources in the DOH block, an area of approximately 824 km^2 (the "**DOH Contractual Zone**"), subject to the terms and conditions of the DOH PSC. The GLJ Reports estimate that the gross lease unrisked prospective resources located in the DOH Contractual Zone are 49.5 MMstb (mean) (calculated by the Group to be 33.0 MMstb on a Net Participating Interest basis).

The Group is the operator of the DOH Contractual Zone, with a 66.67 per cent. participating interest in the EEA. Pursuant to the Farm-in Agreement, Glencore has a 33.33 per cent. participating interest in the EEA. In order to secure the grant of the DOH PSC, the Group was obliged, pursuant to the DOH PSC, to pay a signing bonus of U.S.$13 million to the Government of Chad. As required by the DOH PSC, the Group also paid U.S.$1.04 million in relation to the Government of Chad's legal and other advisory fees and U.S.$3 million in consulting fees relating to the DOH PSC. The DOH PSC states that the payment of the signing bonus shall not constitute recoverable petroleum costs.

The DOH Contractual Zone contains several prospects and is subject to further exploration. The two wellbores drilled by previous operators within the DOH Contractual Zone have evidence of oil, but not in quantities of commercial interest that the Group would intend to develop. The Group intends to reprocess the seismic data collected by previous operators, which is expected to help verify prospectiveness and identify opportunities that might be drillable in 2014. To date, the focus of the Group's development activities has been the DOB/DOI and Doseo/Borogop Contractual Zones and there are no current plans to commence drilling operations in the DOH Contractual Zone prior to 2014.

The DOH PSC was approved by the DOH Ordinance issued by the President of Chad on 17 August 2011. In accordance with Article 125 of the Constitution of Chad, a presidential ordinance must be ratified by a law passed by the Chadian National Assembly. The Chadian National Assembly did not pass a ratification law in respect of the DOH Ordinance within the required timeframe, meaning that the DOH PSC is required to be approved by a law adopted by the Chadian National Assembly in order for it to be valid. The Group has requested that the Ministry of Petroleum table the relevant legislation before the Chadian National Assembly in order that approval thereof may be obtained as soon as possible, and the Group understands that steps are being taken by the Ministry of Petroleum to achieve this. According to the GLJ Reports, no reserves have been identified as of 31 December 2012 in the DOH Contractual Zone and the estimated gross lease unrisked prospective resources are 49.5 MMstb (mean), or approximately 3.9 per cent., of the Group's total gross lease unrisked prospective resources (mean). See "The Group is exposed to risks inherent in doing business in Chad" in Part II: "Risk Factors".

7 PSCs

History of the PSCs

In 2011, the Group acquired three PSCs in southern Chad. The Doseo/Borogop PSC and the DOB/DOI PSC were the first two PSCs signed by any person or company following revisions to the Government of Chad's petroleum law in 2010.

Each PSC provides the Group and Glencore with the exclusive right to explore and develop oil and gas reserves and resources within a specified Contractual Zone. See paragraph 6—"Description of business and operations" in this Part VI for a description of the Contractual Zones covered by the PSCs.

Overview

The PSCs are similar with respect to the processes and timelines in which exploration and exploitation are to be approved by the Government of Chad and conducted by the Group and Glencore (collectively, the "**Contractor**"). The PSCs also set forth similar mechanisms and formulae for the Government of Chad to elect to participate in the Contractor's exploration and exploitation activities, the royalties payable by the Contractor to the Government of Chad and the profit sharing formula between the Contractor and the Government of Chad. The only material differences amongst the three PSCs are the structure of the signing bonuses payable to the Government of Chad by the Contractor, the cost recoverability of certain expenses, the consulting fees paid relating to the DOH PSC and the minimum work commitments.

Exploration and Exploitation Process and Timelines

Below is a description of the process and timelines under the PSCs for development of the Contractual Zones governed by the PSCs.

Stage 1—Exploration Phase

Upon execution, the applicable Contractor under each PSC was granted an EEA for the relevant Contractual Zone.

Each EEA was granted for an initial term of five years (the "**Initial Exploration Term**"). The DOB/DOI PSC was signed on 18 March 2011, the Doseo/Borogop PSC was signed on 19 January 2011 and the DOH PSC was signed on 3 August 2011.

At the end of the Initial Exploration Term (subject to, amongst other things, performance of its minimum work programme (as described below) and compliance with all legal and regulatory requirements) the Contractor is eligible for an extension of the EEA for up to three years (the "**Renewal Exploration Term**"), provided that the Contractor applies at that time to retain no more than 50 per cent. of the Contractual Zone and submits the application for renewal a minimum of 120 days prior to the expiration of the Initial Exploration Term. Any areas of a Contractual Zone that have been included in an EXA are exempt from this relinquishment requirement. The EEA may be further extended for up to two years if required by the Contractor to complete a feasibility study in relation to a discovery made by the Contractor in the applicable Contractual Zone prior to the expiry of the Renewal Exploration Term.

The Contractor must carry out a minimum work programme during the Initial Exploration Term that contains work obligations totalling at least U.S.$50 million for each of the DOB/DOI PSC and Doseo/Borogop PSC and at least U.S.$15 million for the DOH PSC. The Contractor must submit annual work programmes and budgets to the Management Committee for approval prior to 30 September each year. As at 31 March 2013, work obligations of approximately U.S.$35.7 million, U.S.$44.7 million and U.S.$14.0 million remained outstanding under each of the DOB/DOI PSC, Doseo/Borogop PSC and DOH PSC, respectively.

If the Renewal Exploration Term is granted, the Contractor must carry out a minimum U.S.$5 million work programme for each of the DOB/DOI PSC and Doseo/Borogop PSC and a minimum of U.S.$1 million for the DOH PSC over the duration of the Renewal Exploration Term and must also continue to submit annual work programmes and budgets in the same level of detail as the work programmes and budgets submitted during the Initial Exploration Term. Any work expenditures made by the Contractor during the Initial Exploration Term in excess of the minimum work programme for the Initial Exploration Term may be applied towards the minimum work obligation for the Renewal Exploration Term.

If the Contractor fails to satisfy the minimum work programme obligation of either the Initial Exploration Term or the Renewal Exploration Term (or the EEA is revoked or forfeited for that period), it must pay to the Government of Chad an amount equal to 50 per cent. of the value of the work not completed within 30 days following the end of the period concerned, the effective date of the relevant total forfeiture or the date of the revocation of the EEA.

Stage 2—Feasibility/Commercial Deposit Phase

If the Contractor determines that one or more hydrocarbon discoveries within the applicable Contractual Zone is a Commercial Deposit (as defined below), the Contractor may apply for one or more EXAs from the Government of Chad.

Any application to the Government of Chad for an EXA must be accompanied by, amongst other things, a feasibility study, which must contain technical and economic data along with an evaluation and discussion and analysis of such data to support the commerciality of any Commercial Deposit.

A "**Commercial Deposit**" is a deposit whose economic profitability and technical feasibility have been substantiated by a feasibility study, which, in the Contractor's opinion, will lend itself to development and exploitation under economic conditions, in conformity with international oil industry practices.

Stage 3—Exploitation Phase

If the Contractor makes a hydrocarbon discovery within the Contractual Zone, it must notify the Government of Chad of this discovery as soon as possible and no later than two working days following such discovery.

If the Government of Chad is satisfied as to the commerciality of a Commercial Deposit it may issue one or more EXAs. The initial term of an EXA shall be 25 years (the "**Initial Exploitation Term**"). The Contractor must pay U.S.$2 million to the Government of Chad within five days of official journal publication of the decree granting authorisation related to the EXA. EXAs were granted by the Government of Chad in respect of the Badila and Mangara Fields in August 2012 and June 2012, respectively. The Contractor is also entitled to apply for a ten-year extension to the term of each EXA and such extension will be granted if the Contractor has met its contractual obligations under the EXA and has demonstrated that the relevant hydrocarbon deposits will remain commercially exploitable beyond the Initial Exploitation Term. This application for an extension must be submitted at least one year prior to the expiration of the Initial Exploitation Term.

Government of Chad Participation

Upon the approval of an EXA, the Government of Chad may elect to acquire up to a 25 per cent. participating interest in the relevant EXA (referred to as a "back-in" right), either directly or through a public body, including SHT, as was the case in respect of the Badila and Mangara EXAs and as the Group expects it to do in respect of future EXAs. If the Government of Chad elects to participate, it will be obliged to reimburse the Contractor for its proportionate share of all exploration costs attributed to the related Commercial Deposit and to finance its proportionate share of all development and production costs. All costs for which the Government of Chad is responsible to reimburse or finance will be recorded as an advance from the Contractor that accrues interest at LIBOR from the due date of the advance (except petroleum costs arising from petroleum operations prior to the issuance of the relevant EXA for which interest does not accrue) and shall be repayable out of the Government of Chad's proportionate share of Cost Oil (as defined below) for which it is entitled as a result of its participating interest. See "Risks relating to our business and operations" in Part II: "Risk Factors".

Economics of the PSCs

Royalties

Once commercial production has begun, the Contractor is required to pay the Government of Chad a royalty on net hydrocarbon production (a "**Production Royalty**") at a rate of 14.25 per cent. for crude oil and 5 per cent. for natural gas. The Production Royalty may, at the Government of Chad's election, be taken either in cash or in kind.

Cost Recovery

The PSCs provide that costs of exploration, appraisal, development and production operations attributed to an EXA may be recovered by the Contractor by receiving a quantity of hydrocarbon production from such EXA in each year ("**Cost Oil**"), the value of which shall not exceed 70 per cent. of the net production after deduction of the Production Royalty for such year. Unrecovered costs in each year are carried forward and may be recovered in subsequent years until all such costs are recovered. If the Cost Oil is less than 70 per cent. of the net production after deduction of the Production Royalty for any given year, the difference between the Cost Oil and 70 per cent. is contributed to Profit Oil.

Profit Sharing

The net production of hydrocarbons after deduction of the Production Royalty and the Cost Oil ("**Profit Oil**") from each EXA is allocated between the Government of Chad and the Contractor in accordance with an "R-Factor" determined each quarter for each EXA using the following formula:

$$\text{R-Factor} = \frac{CVH^{(1)} - CCPO^{(2)}}{CCDO^{(3)} + CCEO^{(4)}}$$

Notes:

(1) "CVH" means the cumulative value of hydrocarbons received by the Contractor, whether as Cost Oil or Profit Oil, since the issuance of the EXA up to the last day of the preceding quarter.

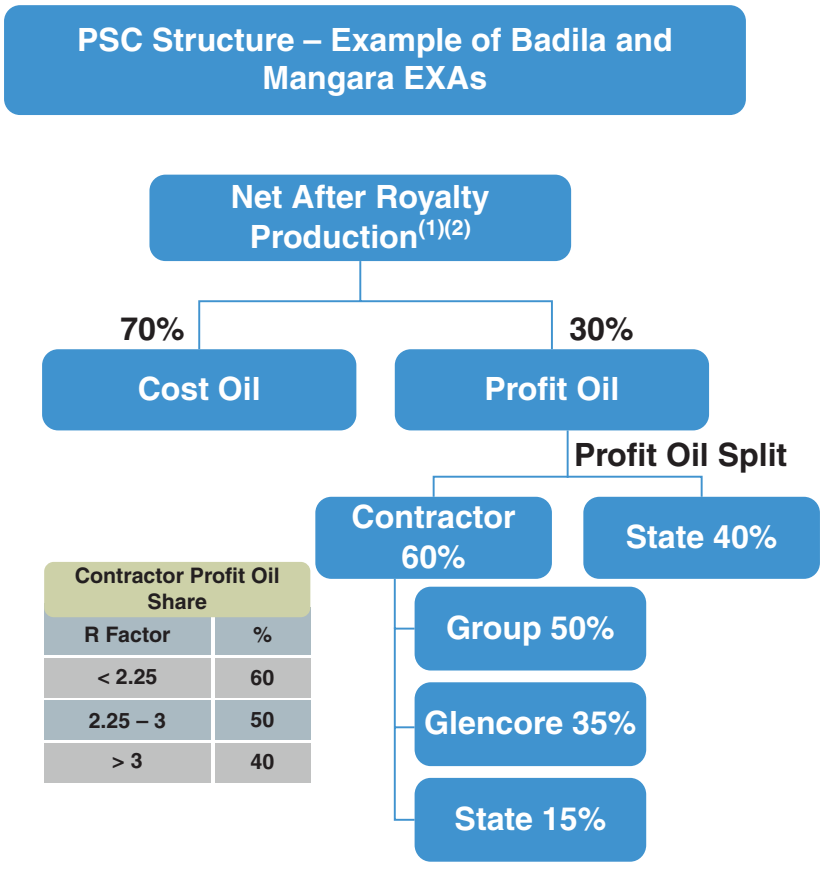
(2) "CCPO" means the cumulative costs of production operations since the issuance of the EXA up to the last day of the preceding quarter.

(3) "CCDO" means the cumulative costs of development operations since the issuance of the EXA up to the last day of the preceding quarter.

(4) "CCEO" means the cumulative costs of exploration costs assigned to the applicable EXA.

Profit Oil is shared between the Government of Chad and the Contractor based on the applicable R-Factor as follows:

R-Factor	Percentage of Profit Oil to the Contractor	Percentage of Profit Oil to the Government of Chad
Less than or equal to 2.25	60	40
Between 2.25 and 3	50	50
More than 3	40	60



(1) Royalty = 14.25% on oil, 5.0% on gas

(2) Net of transportation expense (not cost recoverable)

Infrastructure

The Contractor is entitled to construct and operate pipelines and facilities within the territory of Chad, both inside and outside of its Contractual Zones, in order to transport production of hydrocarbons from the Contractual Zones to the delivery points to purchasers or to the points of export, as applicable. Upon request, and provided the Contractor is in compliance with the terms of the relevant PSC, the Government of Chad shall issue to the Contractor an inland transport authorisation to construct and operate such pipelines and facilities (a "**Transportation Licence**") and will negotiate and enter into a transportation contract with the Contractor setting out the terms and conditions in respect thereof. The requirement to obtain a Transportation Licence does not apply to the construction of such pipelines and facilities within an EXA or between EXAs.

Mandatory Sales

If the Government of Chad cannot satisfy the domestic market consumption of crude oil out of its share of all crude oil produced within Chad, the Contractor may be required to sell such amount of its crude oil production to the Government of Chad as is required to satisfy such shortfall. The Government of Chad must notify the Contractor at least six months in advance of its desired purchase of the Contractor's crude oil and must indicate the amount needed to meet domestic demand. The obligation of a Contractor to supply the domestic market shall be proportionate to its share of hydrocarbon production relative to total hydrocarbon production within Chad. This calculation is to be carried out on a quarterly basis. Any crude oil required to be sold by the Contractor to the Government of Chad to supply the domestic market shall be sold at market rates as determined in accordance with the terms of the applicable PSC.

Abandonment

Once the Contractor estimates that, in the following year, the cumulative production from an EXA will amount to or exceed 50 per cent. of the proved reserves in that EXA, it is required to submit an abandonment work programme for such EXA. The Contractor is then required to contribute to an abandonment fund for the EXA using a formula detailed in the relevant PSC.

$$\text{Contribution to Abandonment Fund} = \frac{(\text{ECAW}^{(1)} - \text{PCAF}^{(2)}) \times \text{TP}^{(3)}}{\text{PR}^{(4)}}$$

Notes:

(1) "ECAW" means the estimated costs of the abandonment work.

(2) "PCAF" means the previous contributions to the abandonment fund for such EXA.

(3) "TP" means the total production from such EXA during the current year.

(4) "PR" means the proved reserves for such EXA developed and remaining to be produced as of the beginning of the then current year.

See paragraph 10.2—"PSCs" in Part XVI: "Additional Information" for further information in respect of the PSCs.

8 Glencore Farm-in

On 12 December 2012, PetroChad, Griffiths Chad and Griffiths DOH (together, the "**Farmors**") entered into the Farm-in Agreement with Glencore Exploration (DOB/DOI) Ltd. ("**Glencore DOB/DOI**"), Glencore Exploration (DOH) Ltd. ("**Glencore DOH**"), Glencore Exploration (Doseo/Borogop) Ltd. ("**Glencore Doseo/Borogop**" and, together with Glencore DOB/DOI and Glencore DOH, the "**Farmees**") and the Company as guarantor. President Déby signed a decree approving the Farm-in Agreement on 4 February 2013, and such decree was ratified by the Chadian National Assembly on 26 April 2013.

Upon the Farm-in Completion, the Farmees acquired from the Group, among other interests, a 33.33 per cent. participating interest in each of the PSCs, with the Group retaining 66.67 per cent. In addition, the Farmees acquired a 25 per cent. participating interest in the Badila and Mangara EXAs. As consideration, the Farmees agreed to pay U.S.$30,746,700 to the Farmors in respect of historic unrecoverable costs incurred in relation to the PSCs. The Farm-in Agreement also obliges the Farmees to carry a proportion of capital expenditure costs—up to U.S.$100 million a year between July 2012 and June 2014 and U.S.$100 million for the period from July 2014 to June 2016, subject to an aggregate limit of U.S.$300 million.

Pursuant to the Farm-in Advance Agreement, U.S.$100 million and U.S.$50 million was advanced by Glencore to the Group on 4 March 2013 and 30 May 2013, respectively, as advance consideration for its obligations under the Farm-in Agreement. Upon the Farm-in Completion, Glencore paid the Group U.S.$107,458,921 as consideration for its obligations under the Farm-in Agreement, net of the repayment of the Farm-in Advance. See paragraph 10—"Material contracts" in Part XVI: "Additional Information".

Pursuant to the Farm-in Agreement and the Farm-in Completion Letter, the Farm-in Completion took place on 13 June 2013 with the satisfaction of certain conditions precedent thereto being waived by Glencore, including: (i) the ratification by the Chadian National Assembly of certain technical amendments to the DOH PSC; and (ii) the issuance by the Ministry of Petroleum of an order approving the transfer of the DOH Transferred Interest (together, the "**Waived DOH Conditions**"). The Group has undertaken to Glencore to use its best endeavours to procure the satisfaction of the Waived DOH Conditions as soon as possible, and to treat the DOH Transferred Interest as having been transferred notwithstanding the Waived DOH Conditions.

In order to perfect the transfer of the Glencore Transferred Interests from the Group to Glencore as per the terms of the PSCs, the PSC Transfer Fee is payable to the Government of Chad. The PSC Transfer Fee was set at U.S.$3 million for each EXA and U.S.$1 million for each EEA, for an aggregate of U.S.$9 million, in the Transfer Fee Orders issued by the Minister for Petroleum on 17 May 2013. On 7 June 2013, the Group paid U.S$8 million to the Public Treasury of Chad for the transfer of the DOB/DOI Transferred Interest and Doseo/Borogop Transferred Interest. According to the Transfer Fee Orders, upon ratification of the DOH PSC by the Chadian National Assembly, the Group will be required to pay U.S.$1 million to perfect the transfer of the DOH Transferred Interest to Glencore.

In order for the amount of the PSC Transfer Fee to have legal effect, the Chadian National Assembly must enact the Confirmatory Law. Therefore, pursuant to the Farm-in Completion Letter, the Group has agreed to indemnify Glencore from any loss which Glencore incurs if legal title to the DOB/DOI Transferred Interest and the Doseo/Borogop Transferred Interest does not pass to Glencore as a result of the Confirmatory Law not being passed, or being passed but not on terms that are consistent with the Transfer Fee Orders. Notwithstanding the above, Glencore is required to pay its working interest share of costs and will be entitled to its working interest share of production and associated revenue. See "Risks relating to Chad" in Part II: "Risk Factors".

9 Paying Interest Committee Agreements

Pursuant to the Farm-in Agreement, PetroChad and Glencore DOB/DOI entered into an agreement on 12 December 2012 in respect of each of the Badila and Mangara EXAs to establish a paying interest committee to govern certain aspects of the relationship between them and determine certain decisions required pursuant to the DOB/DOI PSC and the Badila and Mangara JVAs. It is a requirement that a similar agreement be entered into for each future EXA in which Group and Glencore entities are participants. See paragraph 10—"Material contracts" in Part XVI: "Additional Information".

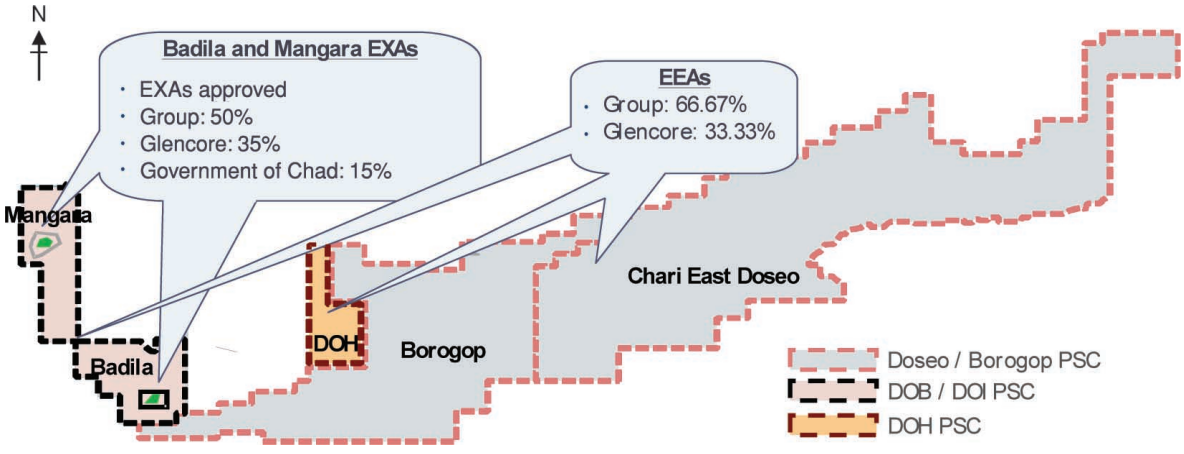
10 Joint Venture Agreements

Pursuant to the DOB/DOI PSC, on 24 October 2012 and 13 June 2012, respectively, PetroChad and SHT entered into joint venture agreements on substantially identical terms, the first in respect of the Badila EXA (the "**Badila JVA**") and the second in respect of the Mangara EXA (the "**Mangara JVA**"). On 25 February 2013, PetroChad, SHT and Glencore DOB/DOI entered into an assignment agreement and an amendment agreement to each of the Badila and Mangara JVAs to assign (i) one-third of PetroChad's and (ii) 40 per cent. of SHT's respective participating interests in each of the Badila and Mangara JVAs to Glencore DOB/DOI such that, upon completion of the assignments, PetroChad holds 50 per cent., SHT 15 per cent. and Glencore DOB/DOI 35 per cent., respectively, of the participating interest of each of the Badila and Mangara JVAs. The Badila and Mangara JVAs set out, *inter alia*, the rights and obligations of the relevant parties with respect to operations under the relevant PSC and relevant EXA. PetroChad is designated the operator under each of the Badila and Mangara JVAs. See paragraph 10—"Material contracts" in Part XVI: "Additional Information".

On 12 December 2012, pursuant to the terms of the Farm-in Agreement, (i) Griffiths Chad and Glencore Doseo/Borogop entered into a joint venture agreement in respect of the Doseo/Borogop PSC and Doseo-Borogop EEA (the "**Doseo/Borogop JVA**"), (ii) Griffiths Chad and Glencore DOH entered into a joint venture agreement in respect of the DOH PSC and DOH EEA (the "**DOH JVA**") and (iii) Griffiths Chad and Glencore DOB/DOI entered into a joint venture agreement in respect of the DOB/DOI PSC and

DOB/DOI EEA (the "**DOB/DOI JVA**" and, together with the Doseo/Borogop JVA and the DOH JVA, the "**EEA JVAs**"). The EEA JVAs set out, *inter alia*, the rights and obligations of the relevant parties with respect to operations under the relevant PSC and relevant EEA. Griffiths Chad is designated the operator under each EEA JVA. See paragraph 10—"Material contracts" in Part XVI: "Additional Information".

Furthermore, and pursuant to the terms of the Farm-in Agreement, on 25 February 2013 (i) the Government of Chad, Griffiths DOH, and Glencore DOH entered into an accession agreement to the DOH PSC, pursuant to which Glencore DOH acceded to the DOH PSC, (ii) the Government of Chad, PetroChad, and Glencore DOB/DOI entered into an accession agreement to the DOB/DOI PSC, pursuant to which Glencore DOB/DOI acceded to the DOB/DOI PSC and (iii) the Government of Chad, Griffiths Chad, and Glencore Doseo/Borogop entered into an accession agreement to the Doseo/Borogop PSC, pursuant to which Glencore Doseo/Borogop acceded to the Doseo/Borogop PSC.



11 Offtake arrangements with Glencore

On 12 December 2012, PetroChad, Griffiths Chad and Griffiths DOH (the "**Group Sellers**") and Glencore DOB/DOI, Glencore DOH and Glencore Doseo/Borogop (the "**Glencore Sellers**" and, together with the Group Sellers, the "**Offtake Sellers**") and Glencore Energy UK Ltd. (the "**Offtake Buyer**") entered into the Offtake Agreement. Under the terms of the Offtake Agreement, the Offtake Sellers agree to sell and deliver free on board to the Offtake Buyer, and the Offtake Buyer agrees to purchase, receive and pay for, all of the Offtake Sellers' Entitlement which is made available by the operator of the Kribi Terminal for delivery to the Offtake Buyer. The "**Offtake Sellers' Entitlement**" means all of each Offtake Seller's entitlement of crude oil produced under the PSCs, excluding any volumes of crude oil that are required to be delivered to the Government of Chad.

The Offtake Agreement expires upon (i) the expiry of all of the PSCs and (if applicable) any additional production sharing contracts in Chad to which the Offtake Agreement applies or (ii) Glencore Sellers no longer hold at least a 10 per cent. participating interest in a PSC or (if applicable) an additional production sharing contract in Chad to which the Offtake Agreement applies, in which case the Offtake Agreement shall terminate in respect of that PSC or additional production sharing contract only. See paragraph 10—"Material contracts" in Part XVI: "Additional Information".

12 Access to market

Export Pipeline

The Export Pipeline is essential to exporting the Group's future production to world markets from the Group's properties in southern Chad. Based on the nameplate throughput capacity of 250,000 bbl/d, and EEPCI production of 105,000 bbl/d, as reported by EEPCI, the Export Pipeline had utilisation of less than 50 per cent. as at 30 June 2012. The Group believes that, subject to the agreement of COTCO and TOTCO, the Export Pipeline's capacity can be increased with modifications including additional pump stations. Furthermore, as at 30 June 2012, the production of the operators of the Export Pipeline had declined by approximately 52 per cent. from a peak of 220,000 bbl/d in 2004. The Group believes that the production of the operators of the Export Pipeline is unlikely to increase.

The order of priority for use of the Export Pipeline gives priority to crude oil produced by the operators of the Export Pipeline. Second priority is given to production from the Permit H Zone, within which the

Group's Contractual Zones are located. As per the current drafts of the Transportation Agreements, within the Permit H Zone, priority of access in respect of a particular field is determined by the date of submission to the operators of the Export Pipeline of an official request for access (such request to be accompanied by the relevant field development plan approved by the Government of Chad). To the extent that a shipper does not utilise the capacity that it has been allocated, the shipper next in priority may use such excess capacity.

As per the current drafts of the Transportation Agreements, each year, every shipper will be required to submit a forecast of the volume of oil that it expects to transport through the Export Pipeline for each of the next five years. Based upon such forecast, each shipper will be allocated a fixed amount of capacity in the Export Pipeline to be utilised in the subsequent year. In the event that there is insufficient capacity within the Export Pipeline to meet the aggregate production of all shippers, capacity will be allocated between shippers on the basis of their respective priority. A shipper with priority over another may use all available capacity within the Export Pipeline if required, meaning that it is possible a shipper with lower priority may be denied access.

As the Group is targeting commencement of production from the Badila Field in July 2013, the Group expects to be in a position to take advantage of the anticipated excess capacity within the Export Pipeline. Based on current and anticipated medium-term production levels of the Badila and Mangara Fields and the Priority Fields (as provided by the operators of the Export Pipeline), and subject to the priority arrangements currently established, the Group believes that the Export Pipeline has sufficient capacity to service both the needs of the Priority Fields and those of the Badila and Mangara Fields.

The Group does not currently have access to the Export Pipeline. The Interconnection Agreement and the Facilities Modification Agreement have been executed. However, the Transportation Agreements, which are also required for the Group to access the Export Pipeline, have not yet been entered into. Until the Group gains access to the Export Pipeline (pursuant to the Transportation Agreements (or any interim agreements, if any, that may be agreed to provide temporary transportation rights pending finalisation of the Transportation Agreements)), it will be unable to commence production of oil and the Badila and Mangara D&E Plans would need to be halted, as trucking or transporting produced oil by rail is not feasible given the infrastructure currently in place in Chad. For more information, see "The Group will be dependent on the Export Pipeline to export its production" in Part II: "Risk Factors" and "Transportation Agreements" in this paragraph 12.

Interconnection Agreement

The Interconnection Agreement was entered into between PetroChad (as operator of the DOB/DOI PSC) and TOTCO on 25 October 2012 to enable the connection of the Group's transportation infrastructure to transport the Group's production from the Badila and Mangara Fields to the Export Pipeline. Under the terms of the Interconnection Agreement, PetroChad is responsible for the construction and installation of all facilities necessary for the transportation of crude oil from the DOB/DOI Contractual Zone to the designated interconnection point to the Export Pipeline and TOTCO is responsible for the construction and installation of all necessary modifications to the Export Pipeline in Chad. PetroChad intends to assign its rights and obligations under the Interconnection Agreement to PCT in due course. For more information, see paragraph 10.9—"Interconnection Agreement" in Part XVI: "Additional Information".

Facilities Modification Agreement

The Facilities Modification Agreement was entered into between PetroChad (as operator of the DOB/DOI PSC) and COTCO on 18 March 2013. The Facilities Modification Agreement provides for certain modifications to the Cameroonian portion of the Export Pipeline to accommodate the transportation of the Group's oil, including, among other things, the installation of metering equipment to measure new oil volumes being shipped in the Export Pipeline. For more information, see paragraph 10.10—"Facilities Modification Agreement" in Part XVI: "Additional Information".

Transportation Agreements

The Transportation Agreements have not yet been entered into but are in an advanced stage of negotiation. The Group expects that the Transportation Agreements will be entered into prior to targeted first production from the Badila Field in July 2013. The Transportation Agreements are expected to govern the terms of use of the Export Pipeline for the transport of oil produced in the Badila and Mangara Fields, including the order of priority for access and the applicable fees payable for use of the Export Pipeline. It is

anticipated that the Transportation Agreements will incorporate a set of general terms (the "**General Transportation Terms**") applicable to all shippers and a set of other terms specific to the Group. The General Transportation Terms are expected to include general terms of use of the Export Pipeline, including the order of priority for access. The fees reflected in the Transportation Agreements are expected to include payments in respect of a fixed and variable throughput charge, operating expenditure, capital expenditure and a utility rate of return for use of the Export Pipeline. Transit fees are also payable to the Government of Cameroon in respect of oil transported through the Cameroonian portion of the Export Pipeline.

Discussions concerning the finalisation of the Transportation Agreements are ongoing. The Company has attended a number of meetings concerning the Transportation Agreements; however the transit fee elements of the negotiations are being conducted principally between the Governments of Chad and Cameroon and TOTCO and COTCO, to which the Company has not been party. The Group expects to be notified of the final tariff in due course as part of the finalisation of the Transportation Agreements, prior to the targeted commencement of first production from the Badila Field in July 2013.

For more information, see "The Group will be dependent on the Export Pipeline to export its production" in Part II: "Risk Factors".

13 Summary of key information from the GLJ Reports

Introduction

The Group has commissioned an independent competent person's report on its oil assets by GLJ. The full report is set out in Part XIX: "GLJ Reports". Unless stated otherwise, the reserves and resources data and production estimates included in this Prospectus have been derived or extracted from the GLJ Reports.

The Group's evaluated undeveloped reserves are located in the DOB/DOI Contractual Zone and the Doseo/Borogop Contractual Zone and the Group's evaluated prospective resources are located in the DOB/DOI, Doseo/Borogop and DOH Contractual Zones.

There are numerous risks and uncertainties inherent in estimating quantities of oil and gas reserves and resources and the future cash flows attributed thereto. See "Mineral reserve and mineral resource reporting" and "Forward-looking statements" in Part III: "Presentation of Financial and Other Information", "Risks relating to our business and operations" in Part II: "Risk Factors" and "Additional Information relating to reserves and resources data" in this Part VI for a discussion of the risks and uncertainties associated with the estimates contained in the GLJ Reports.

Unless stated otherwise, the GLJ Reports give effect to the Farm-in Completion. In addition, all evaluations of future net revenue contained within the GLJ Reports are after the deduction of royalties, the Government of Chad's participating interest, development costs, production costs, as well as well abandonment costs and include the obligations of Glencore pursuant to the Farm-in Agreement. Indirect costs such as general, administrative and overhead costs have been included and are considered an expense eligible for recovery. Estimated future net revenues contained in the GLJ Reports do not necessarily represent the fair market value of the Group's reserves and resources. There is no assurance that the forecast price and cost assumptions contained in the GLJ Reports will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the GLJ Reports. The recovery and reserves and resources estimates of the Group's properties described in the GLJ Reports are estimates only. The actual reserves and resources on the Group's properties may be greater or less than those calculated.

The information in the summary tables below has been extracted without material adjustment from the GLJ Reports. The following information does not purport to be complete and is derived from, qualified in its entirety by, and should be read in conjunction with, the more detailed information appearing in Part XIX: "GLJ Reports".

Summary of crude oil reserves and resources as at 31 December 2012

	Summary of Undeveloped Reserves (in MMbbl)[1]								
	Gross (100%)[2][5]			Group's Net Participating Interest[3][5]			Group's net entitlement[4][5]		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Asset									
Mangara Field	11.3	32.7	84.2	5.6	16.3	42.1	5.4	13.4	29.2
Badila Field	17.6	30.6	51.0	8.8	15.3	25.5	5.9	8.6	13.0
Kibea Field	—	18.8	49.4	—	9.4	24.7	—	6.3	14.7
Maku Field	—	7.3	16.1	—	3.6	8.0	—	3.4	7.0
Total Reserves	**28.8**	**89.3**	**200.6**	**14.4**	**44.6**	**100.3**	**11.3**	**31.8**	**63.9**

Notes:

(1) All of the Group's proved, probable and possible reserves have been classified as light and medium crude oil. The Group has no heavy crude oil. Based on current market conditions in Chad, neither reserves or values have been attributed to gas or natural gas liquid volumes. However, the Group has rights to monetise gas volumes and is currently discussing and assessing this market potential for the future.

(2) Gross is the total marketable reserves assigned to the Group's concessions.

(3) The Government of Chad has elected to acquire a 25 per cent. participating interest in the Badila and Mangara EXAs and GLJ has assumed, for the purposes of estimating the Group's participating interest in any future EXAs which may be granted under each PSC, that the Government of Chad will continue to elect to acquire a 25 per cent. participating interest in each EXA. Accordingly, the Group's and Glencore's participating interests have been assumed to be 50 per cent. and 25 per cent. respectively, of the gross lease interest.

(4) Net reserves are the Group's share of Cost Oil and Profit Oil. Under this method, a portion of the reported reserves will increase as oil prices decrease (and *vice versa*) as the barrels necessary to achieve cost recovery change with prevailing oil prices.

(5) Columns may not add due to rounding.

	Summary of Prospective Resources (in MMstb), Gross (100%)							
	Gross Lease Unrisked (100%)[1][2]				Gross Lease Partially Risked (100%)[1][2][3]			
	P90 (Low)	P50 (Best)	P10 (High)	Mean	P90 (Low)	P50 (Best)	P10 (High)	Mean
Asset								
DOB/DOI Contractual Zone	67.6	184.8	476.7	239.6	18.7	56.9	149.5	74.2
Doseo/Borogop Contractual Zone	150.5	567.8	2,285.3	985.3	32.2	130.9	521.5	224.3
DOH Contractual Zone	16.5	35.3	101.3	49.5	2.0	6.1	19.4	8.9
Total Resources	**234.5**	**788.0**	**2,863.2**	**1,274.3**	**53.0**	**193.9**	**690.3**	**307.4**

Notes:

(1) Prospective resources include adjustment for a minimum economic field size of 1.5 MMstb.

(2) Columns may not add due to rounding.

(3) Partially risked prospective resources are risked for chance of geologic success and minimum economic field size. The chance of development and political risk has not been considered, which is why it is still defined as "partially risked" rather than "fully risked".

Additional information relating to reserves and resources data

Undeveloped Reserves

The Group has no developed reserves. Undeveloped reserves are attributed by GLJ in accordance with standards and guidelines contained in PRMS. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Proved and probable undeveloped reserves have been assigned in accordance with engineering and geological practices as defined under PRMS.

In general, the Group plans to start developing all of the proved undeveloped reserves contained within the DOI/DOB Contractual Zone identified by the GLJ Reports over the next 12 months. In some cases, it

will take longer than one year to develop these reserves. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to commodity pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion formation is no longer economic); (iv) a larger development programme may need to be spread out over several years to optimise capital allocation and facility utilisation; and (v) transportation issues, including but not limited to the Group's ability to gain and maintain access to the Export Pipeline. See paragraph 6—"Description of business and operations" in this Part VI and "Risks relating to Chad" in Part II: "Risk Factors".

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and natural gas prices and costs change. The reserve estimates contained in the GLJ Reports are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) well test results; (iii) ultimate recovery of reserves; (iv) success of future development activities; (v) marketability of production; (vi) effects of government regulations and (vii) other government levies imposed over the life of the reserves. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and a changing environment may impact these estimates.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in prices, costs reservoir performance and geologic conditions or production. These revisions can be either positive or negative. The Company has commissioned an updated independent competent person's report in respect of its reserves and resources for delivery in the third quarter of 2013.

Proved and Probable Undeveloped Reserves

All of the Group's proved undeveloped reserves and probable undeveloped reserves are located in the DOB/DOI and Doseo/Borogop Contractual Zones.

Contingent and/or Prospective Resources

The recovery of resources is subject to significant risk and uncertainty. There is no certainty that it will be commercially viable to produce any portion of the contingent resources reported in the GLJ Reports. In addition, there is no certainty that any portion of the UPIIP or prospective resources reported in the GLJ Reports will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the UPIIP or prospective resources. See "Mineral reserve and mineral resource reporting" in Part III: "Presentation of Financial and Other Information" and Part XVIII: "Glossary of Technical Terms" for a description of the risks and uncertainties associated with the resources estimates referenced below and the applicable resource category definitions, respectively.

Contingent Resources

The GLJ Reports estimate that the Kibea and Maku Fields have a net present value of less than zero at a 10 per cent. discount rate in the low estimate (1C) case. However, GLJ estimates that the net present value of these fields is positive at a 10 per cent. discount factor in the proved plus probable (2P) and proved plus probable plus possible (3P) cases. Given the fact that the Group has informed GLJ of its commitment to develop these fields, the recoverable hydrocarbons for the Kibea and Maku discoveries were classified by GLJ as contingent resources for the low estimate (1C) resource level, and as reserves in the 2P and 3P. As a result, no best estimate (2C) or high estimate (3C) contingent resources or 1P reserves were assigned.

Forward Contracts

The Group had no forward contracts associated with any of its properties as at the effective date of the GLJ Reports or as of the date hereof. The nature of the crude oil operations exposes the Group to risks associated with fluctuations in commodity prices and foreign currency exchange rates. Periodically, the Group may manage these risks through the use of derivative instruments.

14 Special Committee Investigation

Pursuant to a negotiated settlement, the Company pleaded guilty on 22 January 2013 to one count of bribing a foreign public official to induce the official to use his position to influence any acts or decisions of the foreign state for which the official performs duties or functions, contrary to Section 3(1)(b) of Canada's Corruption of Foreign Public Officials Act. Pursuant to the guilty plea, the Company paid a fine of C$10,350,000.

The plea was made in relation to conduct occurring between 30 August 2009 and 9 February 2011 (prior to the appointment of the existing management team and election of the Board of Directors) involving two consulting agreements entered into by the Company. The first consulting agreement was dated 30 August 2009 and entered into with a Maryland-incorporated entity called Ambassade du Tchad LLC, wholly owned by the Ambassador. The agreement provided for a U.S.$2,000,000 fee payable to the consultant if the Company was awarded PSCs in respect of the Doseo and Borogop blocks on or before 31 December 2009 or some other date mutually agreed by the parties. The services to be provided under the agreement by the consultant were generally described as providing advisory, logistics, operational and other assistance with respect to implementing the Company's oil and gas projects in Chad. The agreement was terminated and no payments were made by the Company pursuant to the agreement. The second consulting agreement was dated 15 September 2009 and entered into with a Nevada-incorporated entity called Chad Oil Consulting LLC ("**COCL**"), wholly owned by the spouse of the Ambassador. The agreement contained identical terms to those described above.

Also on 15 September 2009, (i) Nouracham Niam, the spouse of the Ambassador, was given, and took, the opportunity to purchase 1,600,000 Relevant Shares at U.S.$0.001 per Share and (ii) Ikram Saleh and Adoum Hassan (each nominated by Nouracham Niam) also purchased a total of 2,400,000 Relevant Shares at U.S.$0.001 per Share. The consulting agreement with COCL expired without payment, and, in mid-January, 2011, a new consulting agreement with minor changes to the description of services was entered into with the same entity. Pursuant to this agreement, COCL was paid U.S.$2,000,000 on 8 February 2011. Each of Nouracham Niam, Ikram Saleh and Adoum Hassan remain the registered holders of the Relevant Shares. The Relevant Shares were part of a larger issuance of Shares and were purchased by these individuals at the same price and time as the founders, former management and former directors of the Company.

A new management team and Board of Directors was appointed and elected, respectively, on and after 1 July 2011. They discovered the existence of the consulting arrangements in late October 2011. The Company established a Special Committee of the Board and engaged independent and specialised legal counsel to launch a full internal investigation and, shortly thereafter, the Company voluntarily self-disclosed its findings to the RCMP and U.S. DoJ, with whom the Company has cooperated throughout.

As acknowledged in the agreed statement of facts dated 14 January 2013 between the PPSC and the Company and approved by the court (the "**Agreed Statement of Facts**"), the Crown did not allege that any influence was actually obtained as a result of providing the benefits to the Ambassador.

On 14 November 2011, the Company received written assurance from the Minister for Petroleum that there was no external influence in the granting of the PSCs. In addition, on 9 March 2012, the Company received written confirmation from the General Secretary of the Ministry of Petroleum of the validity of the PSCs and of the Company's good standing in relation to the PSCs. In the Agreed Statement of Facts the Crown acknowledges that according to the Minister for Petroleum, the Ambassador neither has nor had any role or influence in the ultimate granting of a PSC.

As part of the plea arrangement with the Company (the "**Plea Agreement**"), the PPSC has undertaken to not take any further investigative or enforcement action against the Company or any "Associated Person" (defined as any current officer, director or employee of the Company) in relation to any of the events, transactions, materials or information that were disclosed to them. The PPSC has also confirmed in the

Plea Agreement that it is not aware of any other investigative or regulatory action that is underway or contemplated.

The guilty plea and fine were reviewed and considered adequate by the U.S. DoJ and a letter of declination confirming no further action would be taken by the U.S. DoJ was received by the Company on 13 February 2013.

The Company therefore does not anticipate, and believes there is no basis for, any further prosecutorial, investigatory or regulatory action against the Group in respect of these matters.

A provision of C$10,350,000 (U.S.$10,495,121) for the penalties and fines was made by the Company in its financial statements as at 31 December 2012.

Following the Company's guilty plea, the Crown made application for forfeiture of the Relevant Shares on the basis that they may be assets flowing from the commission of the offence of bribery. Between 19 February 2013 and 3 April 2013, all of the certificates representing the Relevant Shares were seized by the RCMP. The PPSC have confirmed that the Relevant Shares will be retained by the Canadian authorities until the conclusion of the proceedings relating to the application for their forfeiture. While retained by the Canadian authorities, the Relevant Shares can not be transferred or dealt with in any manner until the court proceedings in respect of their forfeiture is completed.

15 Anti-corruption policies and procedures and compliance

Since their appointment, the current management team has put in place policies and procedures to prevent occurrences of corruption. The Company works with its Compliance Officer and other advisers to ensure that these controls remain appropriate and implemented effectively. Among the measures taken by the Company, it has:

- appointed a Compliance Officer and a General Counsel;
- developed and implemented a comprehensive anti-corruption business integrity policy (the "**Business Integrity Policy**");
- conducted anti-corruption training throughout the Group, with a particular focus on local agents and interactions with foreign government officials (such training to be repeated annually);
- set up a confidential whistleblower line;
- improved procurement policy; and
- developed vendor risk assessment guidance and due diligence procedures.

By means of the Business Integrity Policy, the Company has:

- put in place a requirement for annual compliance certifications from employees and agents;
- created a due diligence checklist to be used when identifying and retaining agents, contractors and other third party service providers in foreign jurisdictions; and
- incorporated anti-corruption representations, warranties and controls within the standard form agency and consultancy agreements that the Group uses, along with a requirement to obtain a commitment of the agent or consultant to abide by all applicable laws and relevant Company policies in respect of improper payments.

Compliance Officer

Jim Evans was appointed as the Company's Compliance Officer on 12 March 2012. Mr Evans' duties include:

- chairing the monthly compliance meeting with the Chief Executive Officer, Chief Financial Officer and Vice President, Finance;
- overseeing and monitoring the compliance programme and ensuring all new employees receive and understand the Business Integrity Policy;
- developing, co-ordinating, and participating in a multifaceted educational and training programme that focuses on the compliance programme, and seeks to ensure that all appropriate employees and management are knowledgeable about, and comply with, the Business Integrity Policy;

- reporting on a regular basis to the Compliance Committee, Board of Directors and Chief Executive Officer on the Company's compliance processes and any potential violations;
- ensuring that independent contractors and agents are aware of the requirements of the compliance programme;
- co-ordinating internal compliance review and monitoring activities, including periodic reviews of departments;
- independently investigating and acting on matters related to compliance;
- developing policies and programmes that encourage managers and employees to report suspected fraud and other improprieties without fear of retaliation;
- implementing written policies, procedures, and standards of conduct;
- conducting periodic risk assessments;
- liaising with the General Counsel;
- conducting internal monitoring and auditing; and
- responding promptly to detected offences, developing corrective action, and reporting findings to the Board of Directors and Compliance Committee.

For more information on the Compliance Committee, see "Compliance Committee and Compliance Officer" in Part VIII: "Directors, Senior Managers and Corporate Governance".

Ethical Business Conduct

The Company has adopted a Code of Business Conduct and Ethics (the "**Code**"), which applies to all directors, officers, employees, contractors and partners of the Company. The Company expects that its directors, officers, employees, contractors and partners will adhere to the highest ethical standards in all of the Company's business activities. The Company's directors, officers, employees and consultants are expected to deal fairly with securityholders, customers, suppliers and competitors.

As all of the Company's oil and gas properties and operations are located in Chad, additional care and attention has been given in the Code to directors, officers, employees, contractors and partners' obligations to ensure they are in strict compliance at all times with Canadian anti-corruption legislation, the Corruption of Foreign Public Officials Act.

The Board and management of the Company monitor compliance with the Code. All directors, officers, employees, contractors and partners are encouraged to report violations of the Code in accordance with the procedures set forth in the Company's whistleblower policy (the "**Whistleblower Policy**"), which provides for the prompt reporting of any violations to an employee's supervisor, or alternatively, to any senior officer or director or to the Chairman. The Whistleblower Policy also promotes, among other things, the disclosure and reporting of any questionable accounting or auditing matters, fraudulent or misleading financial information.

Each director must disclose all actual or potential conflicts of interest and refrain from voting on matters in which such director has a conflict of interest. In addition, the director must excuse himself from any discussion or decision on any matter in which the director is precluded from voting as a result of a conflict of interest. Pursuant to the Company's Corporate Disclosure Policy (the "**Disclosure Policy**"), the directors and officers of the Company are required to publicly disclose their aggregate ownership interest in any entity with which the Company enters into a transaction. The Board has reviewed and approved the Disclosure Policy, in order to promote consistent disclosure practices aimed at informative, timely and broadly disseminated disclosure of material information to the market, in accordance with applicable securities legislation.

In addition, upon Admission, the Company will adopt an insider trading policy (the "**Insider Trading Policy**"). The Insider Trading Policy will set forth all of the Company's insiders' obligations regarding trading in the Company's securities.

16 Health, Safety and Environment

The Group endorsed a comprehensive health, safety and environment policy (the "**HSE Policy**") in 2011. The Group's HSE performance and compliance with the HSE Policy is reviewed on a quarterly basis by the

HSE Committee. The HSE Policy commits the Group to ensuring safe and healthy work environments and to compliance with (i) applicable environmental laws and regulations and (ii) good international oilfield practices. The HSE Policy also commits the Group to open communication and consultation with local communities as well as the payment of fair compensation for land or damages. Any such compensation payments are not intended primarily to offset environmental harm, but rather to compensate traditional land users for any loss of access (temporary or permanent) to their traditional lands.

In 2011, in anticipation of the development projects at the Badila and Mangara Fields, the Group used Chadian and international experts to prepare the DOB/DOI Environmental Impact Assessment. After public reviews, the DOB/DOI Environmental Impact Assessment was approved on 13 July 2012 by the Minister for Environment. In addition, the Group is in the process of implementing a comprehensive environmental and social management plan, waste management plan, oil spill response plan and compensation and resettlement plan (collectively, the "**Environmental Plans**"). The Environmental Plans are consistent with the International Finance Corporation ("**IFC**") 2006 Environmental and Social Performance Standards and currently guide the Group's field activities.

In addition to experienced site HSE supervisors from Canada and elsewhere, the Company employs four Chadian environmental monitors and advisers who work with the Group's project management team to ensure full and documented compliance with the applicable Environmental Plans.

In connection with the application for an inland transport authorisation in August 2012, the Group submitted an addendum to the previously approved DOB/DOI Environmental Impact Assessment. The DOB/DOI Environmental Impact Assessment addendum describes the environmental and social setting in the inland transport authorisation area, identifies the potential impacts of the projects at the Badila and Mangara Fields and confirms the mitigation measures set out in the applicable Environmental Plans in order to address any such impacts in a satisfactory way. The DOB/DOI Environmental Impact Assessment addendum has been approved by the Government of Chad.

The Group has applied to the Ministry of Petroleum for authorisation to flare surplus gas associated with oil production from the Badila Field on a non-emergency basis during the course of 2013. Flaring will be minimised to the extent possible and will be conducted in such a way as to ensure compliance with applicable IFC ground level ambient air standards. The Group is currently in discussions with SHT and EEPCI regarding potential economically and technically feasible alternatives to flaring the surplus gas from the Badila Field. Should the Group need to routinely flare gas beyond 2013, it is proposed that an injection well and associated facilities be constructed, which would obviate the need for non-emergency flaring in the future.

The Group believes that its operations are generally in compliance with applicable HSE regulations. To date, the Group has not had any serious accidents that have had significant environmental impact. The Company has not recorded any provision for environmental payments in its consolidated financial statements set out in Part XII: "Historical Financial Information", and the Group's HSE compliance and practices are not expected to have a material impact on the Company's financial or competitive position in 2013 or beyond. See "HSE Committee" in Part VIII: "Directors, Senior Managers and Corporate Governance".

17 Competition

The Group believes that its primary competitors are the approximately ten other independent exploration and production companies operating in Chad, as well as national oil companies with operations in Chad, including China National Petroleum Corporation ("**CNPC**") and CPC Corporation, Taiwan ("**CPC Taiwan**"). While the Group, together with Glencore, has exclusive access to the Contractual Zones for exploration and development under the terms of the PSCs, it faces competition for personnel, services and infrastructure from other companies operating in Chad.

18 Corporate social responsibility

The Directors believe that the Group has real responsibilities, both legal and ethical, to the communities in which it is active. The Group has a formal corporate social responsibility policy (the "**CSR Policy**") in place, which governs its day to day obligations to its local communities. A dedicated CSR adviser appointed by the Group travels to Chad on a regular basis to meet with local community leaders and local NGOs to identify opportunities for CSR initiatives.

The CSR Policy incorporates standard objectives, which include minimising environmental impact, providing fair compensation to impacted individuals and respecting local cultures. The CSR Policy also identifies areas of focus for the Group's CSR activities: (a) improving agricultural practices in Chad; (b) strengthening community infrastructure in Chad; and (c) helping Chadians grow and sustain businesses. In relation to the latter, the Group is working with Sarh University in Chad to establish an agribusiness incubator. This project will provide selected students with land, equipment, materials and mentoring to create and maintain viable, small-scale agribusinesses. The project is designed to help address Chad's food security and unemployment issues. In order to facilitate the implementation of the Group's CSR Policy, the Group intends to form a charitable foundation in Chad in the fourth quarter of 2013 which will administer future CSR projects. The initial cost of establishing such foundation is expected to be between U.S.$25,000 and U.S.$50,000.

19 Insurance

The Group's operations are subject to numerous operating risks normally associated with oil activities. The Group believes that its existing insurance coverage is reasonable to cover all general material risks associated with its operations, however, see "The Group's insurance and indemnities may not adequately cover all risks or expenses" in Part II: "Risk Factors".

20 Employees

As at 24 June 2013, the Company employed 87 full-time employees at its corporate headquarters located in Calgary, Alberta, Canada and 3 full-time employees in Houston, Texas, U.S.A. In addition, the Company, through its wholly owned subsidiaries, employs 144 full-time employees in Chad. The table below sets out the number of employees employed by the Group as of the dates indicated.

	31 December 2010	31 December 2011	31 December 2012	31 March 2013
Executive	0	7	10	10
Finance	0	7	11	29
Engineering, Drilling, SCM, Projects	0	10	51	98
Corporate Services	0	9	22	32
Exploration	0	6	6	8
HSE & Security	0	2	8	17
Corporate	0	2	5	6
Total	0	43	113	200

The Group intends to add additional professional, administrative and field staff as its business develops. Details relating to Employee share plans are set out in Part XVI: "Additional Information".

21 Properties, leases, plant and drilling equipment

The Group's material assets are its exploration and exploitation claims, licences and permits, further details of which are contained in Part XIX: "GLJ Reports".

22 Tax

Further details relating to taxation are set out in Part XIII: "Taxation".

23 Dividend policy

The Company has never declared or paid any dividends on the Shares. The Directors do not anticipate that the Company will pay dividends in the near future. The Directors will reconsider the Company's dividend policy as the Company advances the development of its operations. The Directors envisage that, at such time, the Company's dividend policy would be determined based on, and depend on, the results of the Company's operations, financial condition, cash requirements, future prospects, profits available for distribution and other factors deemed to be relevant at the time. The Company's current intention is that future dividends, if any, would be declared and paid in U.S. dollars, although the Company may choose to declare and/or pay dividends in another currency.

24 Reporting issuer status

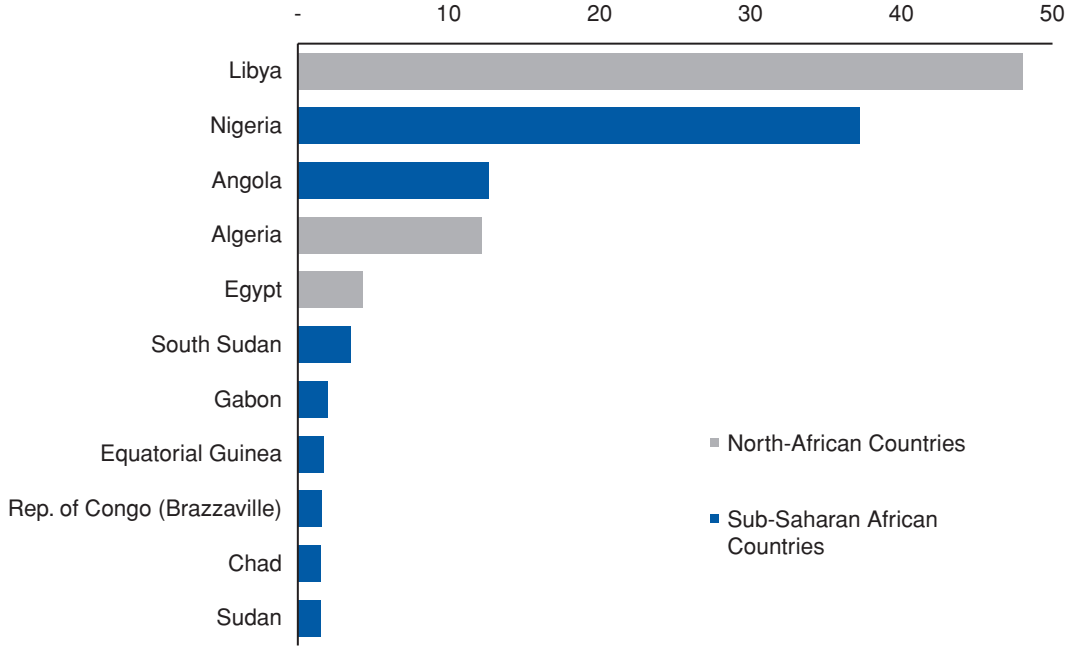
Prior to Admission, the Company will file the Canadian Prospectus with each of the Canadian Securities Regulators to enable the Company to become a "reporting issuer" in the Applicable Jurisdictions pursuant to the Applicable Canadian Securities Laws. Once a receipt has been received for the Canadian Prospectus from the Canadian Securities Regulators, the Company will become a reporting issuer in the Applicable Jurisdictions, which means that the Company will be subject to ongoing public disclosure requirements under the Applicable Canadian Securities Laws. Admission will not occur until the Company has become a reporting issuer in the Applicable Jurisdictions. See paragraph 6—"Memorandum and Articles of Association" in Part XVI: "Additional Information".

Overview of the Oil Industry in Chad

Introduction

According to BP plc, Chad had proved oil reserves of 1.5 billion barrels as at 31 December 2012, the seventh largest in Sub-Saharan Africa and the joint tenth (with Sudan) largest in Africa. At present, Chad does not have proved gas reserves[8].

Top Ten African Countries by Proved Oil Reserves as at 31 December 2012[9]
(billion barrels)



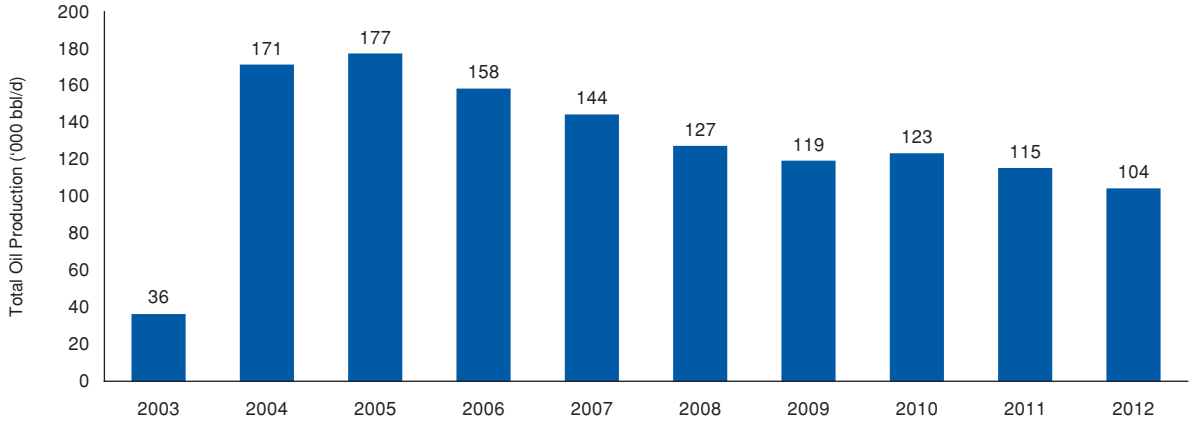
Oil production in Chad began in 2003. As the chart below shows, following initial ramp-up during 2004 and 2005, Chadian oil production experienced a rapid decline between 2006 and 2008. This was due to the challenges posed by the loose sand and fragmented nature of the oil-bearing formations of the Doba Basin. Since 2009, production has stabilised with the addition of production wells; of the 633 active wells at the end of 2011, 69 had been added during the year. As a result of several new fields coming onstream, the International Monetary Fund (the "**IMF**") expects Chadian oil production to increase significantly, from 104,000 bbl/d in 2012 to 189,000 bbl/d between 2013 and 2015[10].

(8) BP Statistical Review of World Energy 2013

(9) BP Statistical Review of World Energy 2013

(10) http://www.imf.org/external/pubs/ft/scr/2013/cr1387.pdf

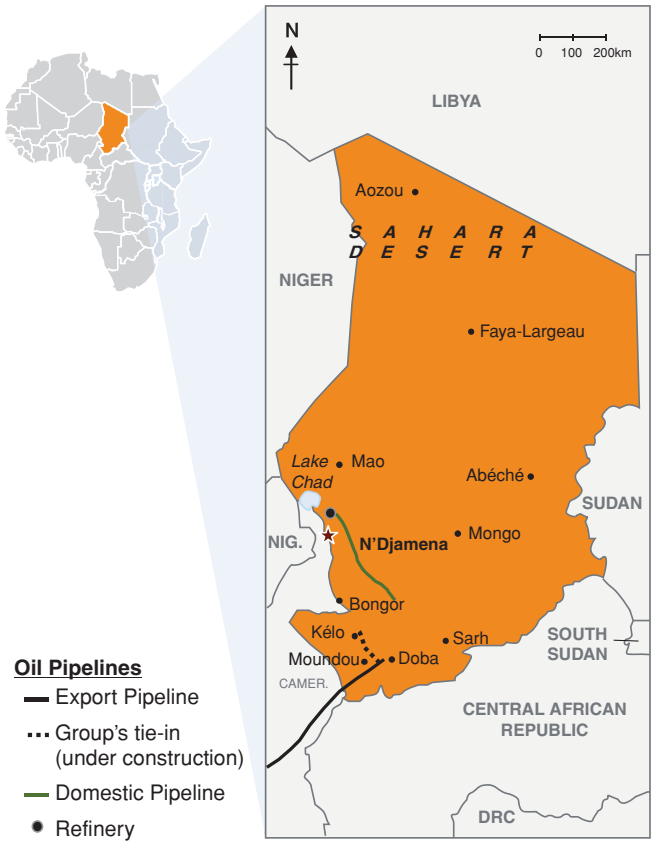
Oil Production in Chad[11]



The Government of Chad is highly dependent on oil revenues to finance its expenditure. According to African Economic Outlook, in 2011 the oil sector accounted for 27 per cent. of Chad's GDP and 63 per cent. of the Government of Chad's revenue. Longer-term, Chad intends to diversify its economy towards non-oil sectors, targeting a gradual decline in the non-oil primary deficit, from 25 per cent. in 2013 to 14-15 per cent. by 2017[12].

Geography of Chad

Chad is a developing country located in central Africa, which is bordered by Libya to the north, Sudan to the east, the Central African Republic to the south, Cameroon and Nigeria to the south-west, and Niger to the west. The capital city is N'Djamena, located in the south-western part of the country. The map below shows the location of Chad within Africa.



(11) http//www.eia.gov/countries/country-data.cfm?fips=CD#pet.

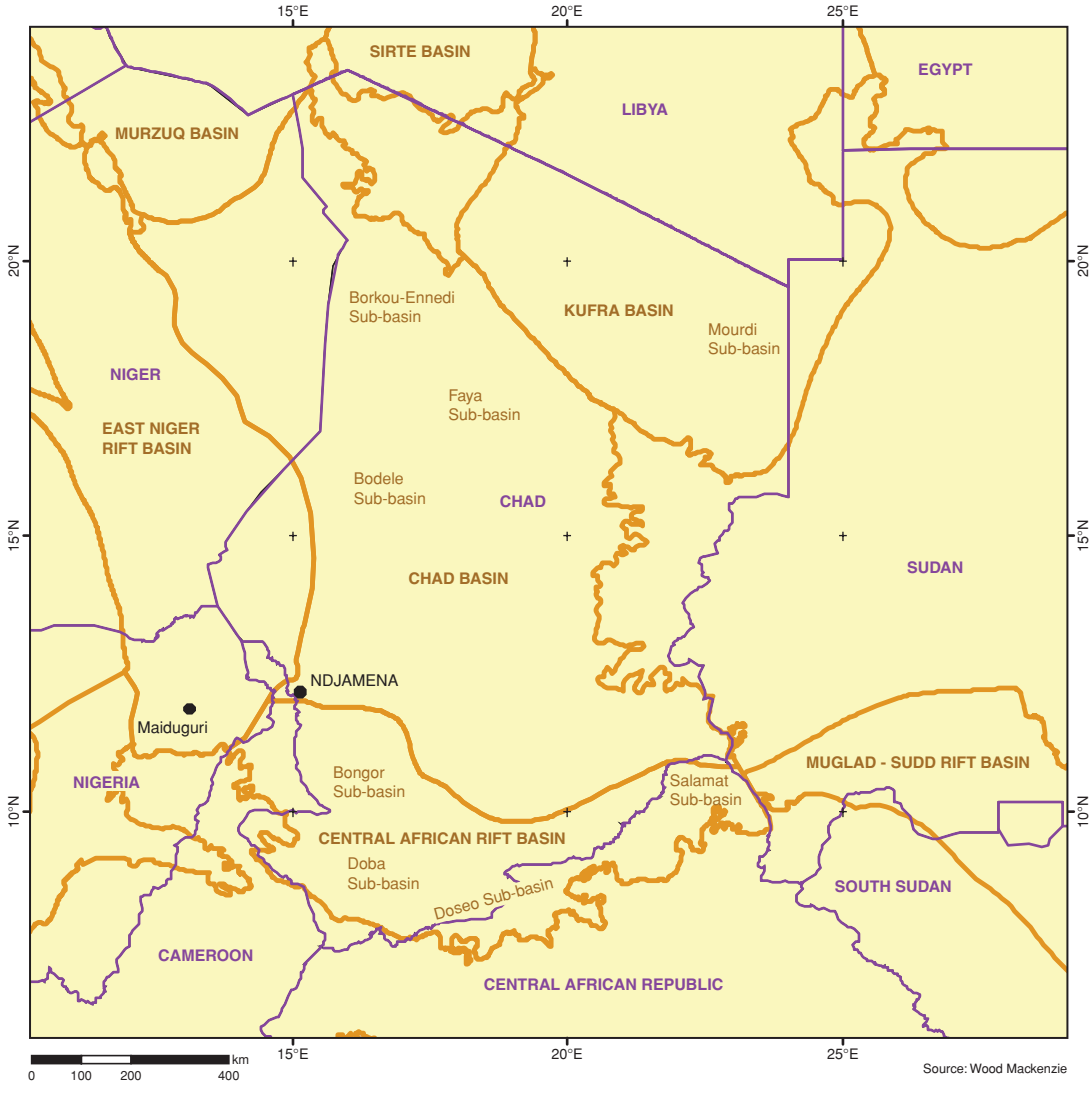
(12) African Economic Outlook Chad 2012 Report

Geology of Chad

Unless stated otherwise, all information contained within this subsection has been sourced from the Wood Mackenzie report entitled "Chad Country Overview" dated May 2013.

Chad consists of a Precambrian and Lower Paleozoic basement unconformably overlain by a series of Cretaceous to Cenozoic sedimentary basins. The younger basins are part of the Central Africa Fault Zone, a linked rift system extending from Nigeria through Niger, Chad and Sudan. All the basins are marked by extensive folding and faulting related to continental break-up and the formation of the Atlantic Ocean.

There are four main basins in Chad: the Central African Rift Basin; the East Niger Rift Basin; the Chad Basin; and the Kufra Basin in northern Chad, which extends into Libya. Hydrocarbon discoveries have been made in two basins, the Central African Rift Basin and the East Niger Rift Basin. All of the Group's Contractual Zones are located in the Central African Rift Basin in southern Chad.



Central Africa Rift Basin

In the south of Chad, the Central African Rift Basin consists of the Bongor Sub-basin, the Doba Sub-basin and Doseo Sub-basin. It is filled by up to 7,500 metres of mainly early Cretaceous continental clastics. Eleven oil and gas discoveries have been made in this basin.

Source Rocks

The source rocks are Lower Cretaceous (Aptian-Albian) grey to black lacustrine shales. The gross source interval can exceed 2,000 metres, but normally consists of a few hundred aggregate metres or less of thin-bedded organic-rich shales. Organic matter is mostly derived from plant materials.

Reservoir Rocks

The reservoir rocks are primarily Cretaceous fluvial sandstones and siliclastic sediments. Individual reservoir-intervals are normally less than five metres thick. Oil discovered in the Doba Basin to date is generally trapped at two levels. About 90 per cent. of reserves are relatively heavy crude (17-25° API) and are located in high-quality, Upper Cretaceous sandstones. The remaining 10 per cent. of reserves are lighter (30-50° API) and are contained in laterally discontinuous Lower Cretaceous sediments. In the Doseo Sub-basin, reservoirs are mainly Lower Cretaceous fluvial, fluvio-deltaic and turbiditic sandstones.

Seal

The hydrocarbons are sealed by interbedded lacustrine and flood plain shales. The structural styles range from simple tilted fault blocks to complex strike-slip flower structures. Structures of the Doba Sub-basin are represented by rotated fault blocks, transpressional anticlines and rollover structures. Traps in the Doseo Sub-basin are transtensional or transpressional flower structures and drag folds.

Development of the oil industry in Chad

Chad began efforts to develop its oil resources in 1969. Although exploration wells revealed the existence of oil between 1973 and 1975, a civil war in Chad that began in 1979 caused a halt in exploration in 1981. Following a cessation of conflict, exploration resumed and the legal foundation for the first major commercial project was put into effect in 1988. A "Convention Agreement" signed in 1988 (the "**1988 Convention**") granted a consortium of petroleum companies (the "**Consortium**") a concession of 30 years to develop the oilfields in the Doba Basin in southern Chad and to produce and transport oil to market. Under the 1988 Convention, the Consortium was granted an initial exploration permit to 2004.

By 1993 oil resources had been confirmed in the Doba Basin of southern Chad, within the original exploration territory designated in the 1988 Convention. In 1997 an amended Convention was enacted by the Chadian National Assembly, which set out the relationship between the Consortium and Chad, including protocols for environmental protection, land acquisition and compensation, as well as royalty and tax payments.

Part of the work undertaken by the Consortium included, as well as other oil transportation facilities, the construction of the Export Pipeline to carry crude oil produced from Chad across Cameroon to a marine shipping terminal approximately 11 kilometres offshore off the coast of Cameroon, near Kribi. See "Development of the Export Pipeline" in this Part VII.

From the original development efforts in the 1970s to the start of construction in 2000, several oil companies were at different times involved in the early funding and planning of the Export Pipeline. Currently, the Consortium consists of ExxonMobil (40 per cent., and the operator of the Export Pipeline), PETRONAS (35 per cent.), and Chevron (25 per cent.) (collectively, "**EEPCI**", the acronym for Esso Exploration and Production Chad, Inc.).

Oil transportation through the Export Pipeline commenced in late 2003 and peaked at almost 175,000 bbl/d in 2005, but volumes have since declined. For the first half of 2012, the average daily transit volume amounted to 105,000 bbl/d. Between its inception and 30 June 2012, the Export Pipeline transported a total of 436 MMbbl of crude in 482 tanker shipments to world markets[13].

Historical composition and participation of the Consortium

In 1969, ConocoPhillips acquired two concessions, the North Chari and South Chari blocks. One of the concessions was in the Chad Basin, while the other extended across the Doba, Doseo, Salamat and Bongor Basins. Following the outbreak of civil war in Chad in 1979, activities on the blocks were suspended and, in 1982, ConocoPhillips withdrew from Chad. Exxon (now ExxonMobil) acquired ConocoPhillips' interest in the Consortium and also assumed operatorship.

Chevron relinquished its interest in the North and South Chari blocks in 1993, with the equity split between ExxonMobil, Royal Dutch Shell plc ("**Shell**") and Total S.A. ("**Total**"). The partners were forced to relinquish much of this acreage in 1999, including all of the North Chari block. Shell and Total both left Chad in 2000. Chevron regained a 25 per cent. stake in the Doba and South Chari licences, and PETRONAS acquired a 35 per cent. equity share.

(13) http://www.essochad.com/Chad-English/PA/Files/32_ch02.pdf

In May 2004, the Consortium, as it was then constituted, signed a new convention with the Government of Chad (the "**2004 Convention**"). The 2004 Convention applies to exploration and development activities in fields outside those covered by the 1988 Convention (the "**Doba Oil Project**"). The 2004 Convention granted an exploration licence for five years from February 2004, with an option for a five-year renewal. However, in early 2009 the Consortium chose not to renew the Chari licences.

Crude oil transportation in Chad

Since the commissioning of the Doba Oil Project in 2003, all of its oil production has been shipped via the Export Pipeline to the Kribi export terminal off the coast of Cameroon. According to EEPCI, approximately 60 per cent. of the total U.S.$4 billion cost of the Doba Oil Project went to building the Export Pipeline, including the pipeline itself, pump stations and marine terminal[(14)]. A multi-layered set of interlocking contracts and agreements dictates the calculation of the oil transportation charges that TOTCO and COTCO collect from EEPCI's members, the shippers of the crude oil. The transportation costs associated with the Export Pipeline charges can be broken down into four categories:

- transit fee paid to Cameroon by COTCO;
- costs of operating and maintaining the Export Pipeline;
- repayment of commercial lender debt that helped finance the construction; and
- recovery of the investments made by the shareholders in the Export Pipeline, including the EEPCI and the Governments of Chad and Cameroon.

The safety record for the Doba Oil Project has been strong, with 0.13 recordable incidents per 200,000 work hours reported for the twelve months to 30 June 2012. This compares to 0.60 for the U.S. petroleum industry as a whole, as derived from reports to the American Petroleum Institute by participating companies[(15)]. To date, EEPCI has not reported any disruptions to the operations of the Export Pipeline due to terrorist attacks or other criminal activity.

Historical oil production in Chad

Unless stated otherwise, all information contained within this subsection has been sourced from the Wood Mackenzie report entitled "Chad Country Overview" dated May 2013.

Oil production in Chad started in July 2003 when the Miandoum field, part of the Doba Oil Project, was brought onstream. This was followed by Komé and Bolobo in March and August 2004, respectively. Production from the three fields has been restricted by a high water cut, low reservoir pressure, unconsolidated sands and complex reservoir geometry. A combination of well enhancements and the start-up of four satellite fields, Nya, Moundouli, Maikeri and Timbre, has helped to slow the rate of decline.

The Permit H fields became the second development project to produce when first oil was achieved in May 2011. Output will be initially limited by (i) capacity at a new-build refinery near N'Djamena, and (ii) demand for products. CNPC is expected to start exporting the surplus production via the Export Pipeline from 2017.

Historical oil-related capital expenditures

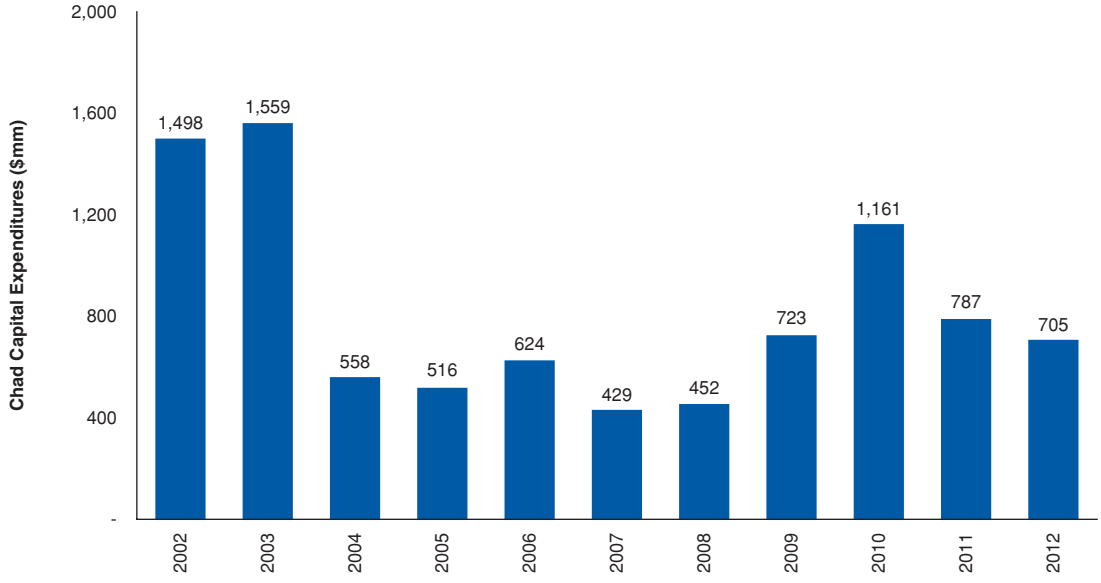
Unless stated otherwise, all information contained within this subsection has been sourced from the Wood Mackenzie report entitled "Chad Country Overview" dated May 2013.

Major oil-related capital expenditures in Chad occurred from the late-1990s to the early-2000s as work began on the Doba Oil Project and the Export Pipeline. Due to a variety of production issues in the Doba fields, the Consortium has invested heavily to mitigate production decline. The investments include the development of satellite fields, new production wells, water injection facilities and well enhancements. More recently there has been a further increase in capital expenditure arising from the development of the Permit H fields. This is expected to increase in 2016 when CNPC is forecasted to develop more reserves, which it is expect to export via the Export Pipeline. Future spend is also expected on the Company's Badila and Magara Fields and CPC Taiwan's Benoy project.

(14) http://www.essochad.com/Chad-English/PA/Files/17_ch13.pdf

(15) Chad/Cameroon Development Project Update No.32, http://www.essochad.com/Chad-English/PA/Files/32_allchapters_eng.pdf

Chad Capital Expenditures[16]
(U.S.$ million)

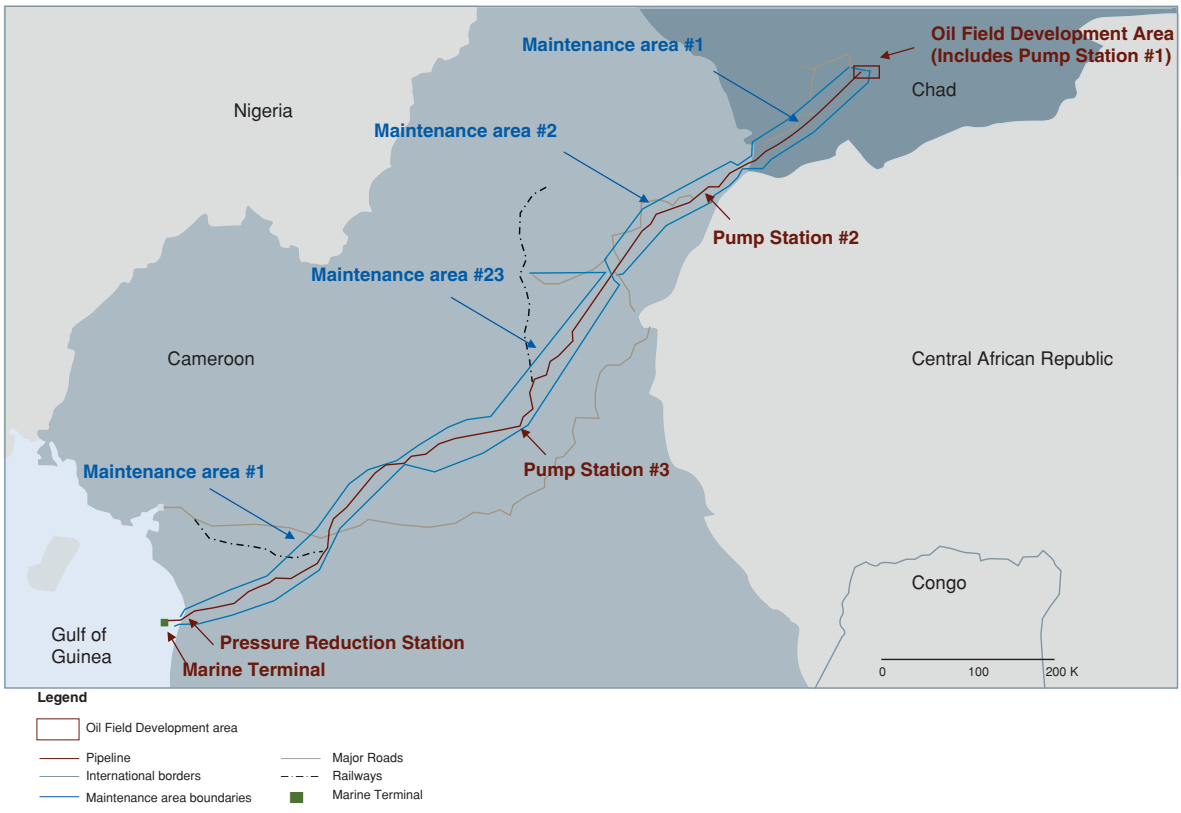


Development of the Export Pipeline

In 2000, the World Bank Group announced its approval to assist with a small portion of the necessary funding for the Export Pipeline. The World Bank Group provided approximately U.S.$93 million (U.S.$53 million for Cameroon and U.S.$40 million for Chad) to finance the governments of Chad and Cameroon's respective equity shares in the Export Pipeline and a U.S.$100 million loan from International Finance Company (a member of the World Bank Group) to each of Chad and Cameroon's joint-venture pipeline companies. The remaining funding (approximately 97 per cent. of the total cost to construct the Export Pipeline) was provided by EEPCI. The section of the Export Pipeline located in Chad is operated by TOTCO, a joint venture between Chad and EEPCI. The section of the Export Pipeline located in Cameroon is operated by COTCO, a joint venture between Cameroon and EEPCI. The map below depicts the location of the Export Pipeline. The Export Pipeline is a 1,070 kilometre, 30-inch pipeline running from the Doba Basin fields in southern Chad to the Kribi Terminal. The Export Pipeline has a nameplate capacity of 250,000 bbl/d, of which approximately 105,000 bbl/d is currently being utilised (based on the production from the Doba blocks)[17]. Furthermore, the Group believes that, subject to the agreement of COTCO and TOTCO, the Export Pipeline is expandable with additional pump stations. The Group does not currently have access to the Export Pipeline.

(16) Wood Mackenzie report entitled "Chad Country Overview" dated May 2013

(17) Esso Chad Project Update No. 32 (http://www.essochad.com/Chad-English/PA/Newsroom/TD_ProgressReports.aspx)



http://www.esso.com/Chad-English/PA/Files/26_allchapters.pdf

World Bank withdrawal from the Export Pipeline

The World Bank's participation in the Export Pipeline was made contingent upon Chad's approval of a Revenue Management Law (the "**RML**"). This measure was designed specifically to improve governance standards in the then emerging oil producer by preventing the Government of Chad from mis-using oil revenue. Chad's RML is codified in Chadian Law 001, which was passed by the Chadian National Assembly in 1998 and signed into law by President Déby in 1999. The law specifies that oil royalties are to be deposited into an offshore escrow account that saves 10 per cent. for future generations (the "**Future Generations Fund**"), and divides the remaining 90 per cent. among several sectors. Of the royalty revenue available for current spending, 80 per cent. is earmarked for key priority sectors (public health, social affairs, education, rural development, infrastructure, the environment and water resources), 15 per cent. is set aside for the state's recurring operating costs, and the remaining 5 per cent. is to be spent on development in the oil-producing Doba region. The RML was meant to ensure that oil revenue in Chad would promote development.

In 2005, in response to fiscal difficulties, the Chadian parliament proposed a law amending the RML in order to eliminate the Future Generations Fund. Despite being opposed by the World Bank, the law passed on 29 December 2005. Subsequently, in January 2006, the World Bank announced that it would withhold new loans and grants to Chad and suspend the disbursement of all International Development Association funds.

President Déby subsequently demanded that Exxon pay U.S.$50 million in oil royalties directly, bypassing the escrow account under the RML. This demand prompted negotiations and, in April 2006, the World Bank announced that it had reached an agreement with Chad and would resume lending activities, although reducing the 80 per cent. earmarked for priority sectors to 70 per cent.

In September 2008, however, the World Bank announced that it was withdrawing from the Export Pipeline project altogether after actual expenditures in 2007 failed to meet the allocations agreed in the 2006 agreement and incorporated in the budget, due primarily to sharp increases in military spending, and about 58 per cent. being spent on the priority sectors instead of the agreed 70 per cent. As part of its withdrawal terms, the Bank required that the Government of Chad repay its loans to the International Bank for Reconstruction and Development and the International Development Association. Chad promptly repaid such loans and the World Bank withdrew from the country. International Finance Corporation, a member

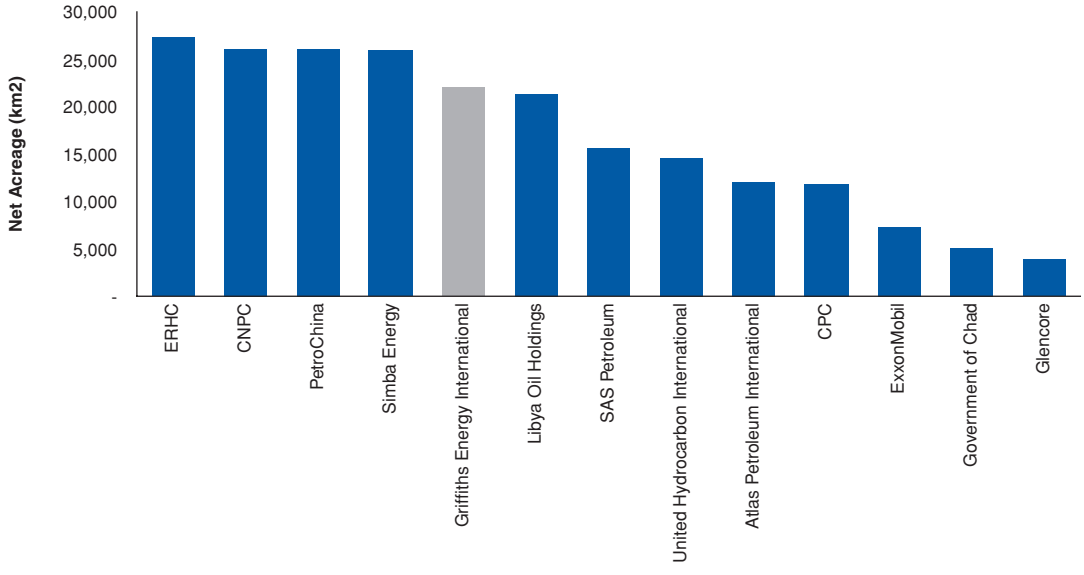
of the World Bank Group, remains involved in the project pursuant to its U.S.$100 million investment and continues to monitor the environmental and social performance of the Export Pipeline in Chad and Cameroon.

Current oil industry activity in Chad outside of EEPCI

In addition to EEPCI, CNPC and CPC Taiwan are other large entities with interests in Chad's oil industry. CNPC signed agreements in 1999 and 2004 with Chad, and has publicly announced certain discoveries for delivery to market by way of a pipeline and dedicated joint venture refinery outside N'Djamena. Production at Permit H came on stream in May 2011 and the refinery was brought online in June 2011 at 20,000 bbl/d capacity. CPC Taiwan signed agreements in 2006, and announced in February 2011 a discovery at the Benoy-1 well on the Chari-Ouest III block, which, in CPC Taiwan's opinion, is expected to produce 9,800 bbl/d of light crude oil[18]. The development plans of CPC Taiwan have not yet been announced. The Group estimates the Benoy-1 well to be approximately 50 kilometres from the Mangara-3 well on the Mangara Field.

The following chart sets forth the net acreage holdings of companies operating in Chad in 2011.

Net Acreage Holdings[19]



Legal Framework and Process in Chad

Overview

Chad is a civil law country. Upon obtaining independence from France in 1960, Chad continued to use the 1958 edition of the French Civil Code. The country is governed by the constitution of Chad, dated 31 March 1996, as amended in 2005 (the "**Constitution**"). The Constitution provides for the separation of powers between the executive, parliamentary, and judicial branches of power. These branches include an elected president, an appointed prime minister, and several levels of courts. Depending on the subject matter, laws can be passed by either the parliamentary or the executive branch. Acts of parliament are deliberated on and passed by the Chadian National Assembly and are subsequently signed into law by the president and published in the Official Gazette. Rules and regulations originate from the executive and are signed by the president and the prime minister.

Chad has been a member of the Organisation for the Harmonisation of Business Law in Africa ("**OHADA**") since 1993. OHADA has seventeen member states and a judicial institution for business law matters, the Common Court of Justice and Arbitration, seated in the Ivory Coast. OHADA's Uniform Acts (governing company law, general commercial law, security interests law, arbitration law, transportation law, insolvency law, accounting law and compulsory enforcement proceedings) have automatic effect in

(18) http://www.upstreamonline.com/hardcopy/news/article1205721.ece?newt_graphFrontpage_tab=companies

(19) Wood Mackenzie report entitled "Chad Country Overview" dated May 2013. Wood Mackenzie's calculation of the Group's net acreage does not account for Glencore's interest in a portion of the Doseo/Borogop PSC.

each member state without any further formalities, are mandatory and have the effect of revoking any prior contrary legislation.

Regulation of the oil industry in Chad and PSCs

The upstream oil and gas industry in Chad falls under the jurisdiction of the Ministry of Mines and Geology and the Ministry of Petroleum. However, major policies are controlled by the presidency. The Petroleum Code, which regulates the oil and gas industry in Chad, was adopted in 1962 and was abrogated in 2007 by the Hydrocarbons Law. In 2010, Chad reformed its petroleum regime, adopting the production sharing contract model as the sole form of oil and gas licensing.

Production sharing contracts are entered into between the Government of Chad, represented by the Minister in charge of hydrocarbons, and the relevant company. After it is executed, the production sharing contract, its schedules and amendments are approved by law. The approval law is then published in the Official Gazette. A decree adopted in the Council of Ministers grants the relevant EXA, which gives its beneficiary the exclusive right to undertake development and exploitation operations for a duration of 25 years.

In 2006, the Government of Chad established a national oil company known as *Société des Hydrocarbures du Tchad* ("**SHT**"). The primary purpose of SHT is to retain a carried interest in the exploration phase and a share of production in oil and gas development in Chad. SHT currently markets the Government of Chad's share of crude oil from the Doba Basin Project and, as of 1 July 2012, SHT has rights to sell such crude oil directly on the market. SHT also holds a 40 per cent. interest in the new 20,000 bbl/d refinery at Djarmaya. CNPC owns the remaining 60 per cent. stake in the refinery[(20)].

In advance of first production from the Doba Oil Project, in 1999 Chad adopted Law 001/PR/99, which incorporated a revenue management programme, as required by the World Bank as a condition for its support of the Doba Oil Project. Accordingly, the Petroleum Revenue Oversight and Control Committee was established (also known as the *Collège de Contrôle et de Surveillance des Ressources Pétrolieres* ("**CCSRP**")). Direct oil revenues, which include royalties and dividends on the shareholding in TOTCO, cannot be allocated or disbursed toward specific programmes without CCSRP's approval. CCSRP consists of nine members, including four representatives from civil society—one from each of a local non-governmental organisation, trade union and human rights organisation, and an alternating representative from one of the two major religious groups, Muslim and Christian. By contrast, indirect oil revenue, which includes tax on EEPCI, permits and other fees, is not subject to CCSRP's oversight. However, in 2005 Chadian parliament amended Law 001/PR/99, granting the government greater access to oil revenue for discretionary use, with security as a priority sector.

WTO, United Nations and EITI Membership

Chad became a World Trade Organisation Member in 1996, providing full autonomy in the conduct of its trade policies, and has been a United Nations member since 1960. Most recently, Chad became a candidate country of the Extractive Industries Transparency Initiative ("**EITI**"). EITI establishes a global standard for transparency in the oil, gas and mining sectors. EITI recognises the possibility of poverty, corruption and conflict associated with weak governance and aims to counter this with transparency and accountability. As a candidate country, Chad has met initial requirements and has committed to publishing all payments of taxes, royalties, and fees it has received from its extractive sector. Similarly, all extractive companies operating in Chad are required to publish the amounts they have paid to the Government of Chad. Chad became an EITI candidate in April 2010. Following a request by the Government of Chad in October 2012, the deadline for EITI validation was extended to 23 May 2013. The required validation report was issued by such deadline and, at present, Chad continues to be considered a candidate country. Upon successful completion of validation, it is expected that Chad would be recognised as EITI compliant.

Chad—General information and recent history

Geopolitical information

Chad gained its independence from France in 1960. President Déby became president in 1990 and has won four successive elections in 1996, 2001, 2006 and 2011. Chad is divided into 22 local regions, with each region further divided by department (of which there are 61), sub-prefectures (of which there are 200) and

(20) http://abarrelfull.wikidot.com/n-djamena-refinery-project

cantons (of which there are 446). A process for decentralisation began in 2003, but regions remain governed through presidentially appointed governors.

Chad has a population of approximately 11.5 million[21] people, approximately 28 per cent.[22] of whom live in urban areas. Chadian men have a life expectancy of 47 years and Chadian women have a life expectancy of 49 years[23]. French and Arabic are the official languages of Chad, although the language of Sara is also used in the south, and there are more than 120 different languages and dialects spoken throughout the country. Literacy (defined as being able to read and write French or Arabic) is estimated at 35 per cent.[24] A census conducted in 1993 estimated that the religious breakdown of the Chadian population to be approximately 53 per cent. Muslim, 20 per cent. Catholic, 14 per cent. Protestant, 7 per cent. animist and 6 per cent. other[25].

The World Bank estimates that around 55 per cent. of Chadians live below the poverty line and 36 per cent. live in extreme poverty[26]. According to the IMF, per capita income as of 2011 was estimated at approximately U.S.$1,900 (on a purchasing power parity basis)[27]. Prior to the commencement of oil production in 2003, Chad's primary economic activity was agricultural production and cotton exports. Accordingly, weather was a key determinant of annual economic growth. Initial oil production in 2003 resulted in a temporary spike in per capita GDP, although GDP growth has been moderate since 2005[28]. Based on the most recent United Nations Human Development Index (the "**HDI**") (which provides a composite measure of health, education and income), Chad's HDI was 0.336 in 2011[29], which gives the country a rank of 183 out of 187 countries with comparable data[30]. The HDI of Sub-Saharan Africa as a region increased from 0.366 in 1980 to 0.472 in 2011[31], placing Chad below the regional average.

According to the U.S. Department of State[32], there have been no reported incidents involving politically motivated damage to projects or installations in Chad, although kidnapping and banditry are persistent threats.

Travel guidelines published by the U.S. Department of State and the UK's Foreign and Commonwealth Office stipulate that Chad's capital N'Djamena is generally safe for travel whereas areas such as Eastern Chad, the Chad/Sudan border area, and the Chad/Central African Republic border area are considered high-risk and all but essential travel is advised against.

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(21) CIA World Factbook: https://www.cia.gov/library/publications/the-world-factbook/geos/cd.html

(22) CIA World Factbook: https://www.cia.gov/library/publications/the-world-factbook/geos/cd.html

(23) CIA World Factbook: https://www.cia.gov/library/publications/the-world-factbook/geos/cd.html

(24) CIA World Factbook, data for 2010: https://www.cia.gov/library/publications/the-world-factbook/fields/2103.html

(25) CIA World Factbook: https://www.cia.gov/library/publications/the-world-factbook/geos/cd.html

(26) http://web.worldbank.org/WBSITE/EXTERNAL/COUNTRIES/AFRICAEXT/CHADEXTN/0,,menuPK:349885~pagePK:141132~piPK:141107~theSitePK:349862,00.html

(27) http://www.imf.org/external/pubs/ft/weo/2012/02/weodata/weorept.aspx?sy=2010&ey=2017&scsm=1&ssd=1&sort=country&ds=.&br=1&pr1.x=62&pr1.y=16&c=628&s=PPPPC&grp=0&a=

(28) http://www.imf.org/external/pubs/ft/weo/2012/02/weodata/weorept.aspx?pr.x=43&pr.y=7&sy=2003&ey=2012&scsm=1&ssd=1&sort=country&ds=.&br=1&c=628&s=NGDPRPC&grp=0&a=

(29) http://hdrstats.undp.org/en/countries/profiles/TCD.html

(30) http://hdr.undp.org/en/statistics/

(31) http://hdrstats.undp.org/en/countries/profiles/TCD.html

(32) http://www.state.gov/e/eb/rls/othr/ics/2012/191126.htm

PART VIII

DIRECTORS, SENIOR MANAGERS AND CORPORATE GOVERNANCE

Directors and Senior Managers

Board of Directors

The board of directors of the Company whose names appear below (the "**Board of Directors**" or the "**Board**") is responsible for, and has the authority to determine, all matters relating to the strategic direction, policies, practices, goals for senior management and the operation of the Company.

The Directors of the Company are as follows:

Name of Director/ Principal residence	Position	Appointed[1]	Principal Occupation	Independent[2]
Gary Guidry Alberta, Canada	President, Chief Executive Officer and Executive Director	July 2011	President Chief Executive Officer and Executive Director, Caracal Energy Inc.	No[3]
Robert B. Hodgins Alberta, Canada	Independent Non-Executive Chairman	July 2011	Independent Business Person	Yes
Carol Bell London, United Kingdom	Independent Non-Executive Director	December 2012	Independent Business Person	Yes
John Bentley Fife, United Kingdom	Independent Non-Executive Director	August 2012	Independent Business Person	Yes
Peter Dey Ontario, Canada	Independent Non-Executive Director	March 2013	Chairman, Paradigm Capital Inc.[4]	Yes
Ronald W. Royal British Columbia, Canada	Independent Non-Executive Director	July 2011	Independent Business Person	Yes
Brooke Wade British Columbia, Canada	Independent Non-Executive Director	September 2011	President, Wade Capital Corporation[5]	Yes

Notes:

(1) The Directors are appointed at each annual general meeting of shareholders ("**AGM**") for a term expiring at the subsequent AGM (or until their successors are appointed pursuant to the Canada Business Corporations Act (the "**CBCA**")). The date provided is the date of first appointment.

(2) As such term is defined in Canadian National Instrument 58-101—Disclosure of Corporate Governance Practices ("**NI 58-101**"). Each of the independent Directors has no direct or indirect material relationship with the Company, including any business or other relationship, which could reasonably be expected to interfere with the Director's ability to act with a view to the best interests of the Company or which could reasonably be expected to interfere with the Director's exercise of independent judgment.

(3) Mr Guidry is not considered by the Board to be an independent director within the meaning of NI 58-101 in that he also serves as an Executive Director.

(4) The principal business of Paradigm Capital Inc. is an independent investment company.

(5) The principal business of Wade Capital Corporation is a private investment company.

Gary Guidry—President, Chief Executive Officer and Executive Director—aged 57

Mr Guidry is a professional engineer, holding a Bachelor of Science in Petroleum Engineering from Texas A & M University, and has over 30 years of experience in the international oil and gas industry. Mr Guidry was the President and Chief Executive Officer of Orion Oil & Gas Corporation from October 2009 until June 2011 and was the President and Chief Executive Officer of Tanganyika Oil Company Ltd. from April 2005 to June 2009. Previously, Mr Guidry has held various senior level positions, including President and Chief Executive Officer of Calpine Natural Gas Trust, President of Alberta Energy Company International (now Encana Corporation), a variety of senior management positions with Nexen Inc. and Occidental Petroleum Ltd. and Chairman of Pearl Exploration and Production Ltd. (now BlackPearl Resources Inc.).

He was also a director of Zodiac Exploration Corp. He is currently a director of several companies, including TransGlobe Energy Corporation, Africa Oil Corp. and ShaMaran Petroleum Corp.

Robert B. Hodgins—Independent Non-Executive Chairman—aged 61

Mr Hodgins is a chartered accountant, investor and director with over 30 years of oil and gas industry experience. Most recently Mr Hodgins was the Chief Financial Officer of Pengrowth Energy Trust from July 2002 until November 2004. Previously, Mr Hodgins held positions as Vice President and Treasurer of Canadian Pacific Ltd., Chief Financial Officer of TransCanada Pipelines Ltd. and as a director and Chairman of the Audit Committee for Skope Energy Inc. ("**Skope**"). He is currently a director of, and serves as Chairman of the Audit Committee for, several public companies, including Contact Exploration Inc., Lateral Capital Corp., Cub Energy Inc., Fairborne Energy Ltd., AltaGas Ltd., MEG Energy Corp., Enerplus Corporation and MGM Energy Corp.

Carol Bell—Independent Non-Executive Director—aged 54

Dr Bell has been an independent business person since 2003 and has over 30 years of experience in the oil and gas sector, most recently in an executive position as a managing director of Chase Manhattan's Global Oil & Gas Group. Prior to that, she was the head of European Equity Research at JP Morgan and head of its Global team in Oil and Gas Equity Research. Dr Bell has been a director of Petroleum Geo-Services ASA, a global offshore seismic services company, since October 2009 and of Salamander Energy plc, an exploration and production company, since January 2012. Dr Bell was also a director of Hardy Oil and Gas plc from December 2005 until May 2012, Revus Energy ASA from October 2007 until December 2008 and Det norske oljeselskap ASA from May 2011 until April 2013, all exploration and production companies. She is also a trustee of the Renewable Energy Foundation and a member of the Investment Advisory Committee of Gemini Oil & Gas Fund LP. Dr Bell holds a Master of Arts in Natural Sciences, a Bachelor of Arts in Earth Sciences and a PhD in Archaeology.

John Bentley—Independent Non-Executive Director—aged 65

Mr Bentley has 40 years of experience in the natural resources sector. He served in a number of senior management positions in the Gencor Group in South Africa, the United States, the United Kingdom and Brazil. In 1996 he was instrumental in floating Energy Africa Ltd on the Johannesburg Stock Exchange and became Chief Executive for the following five years. More recently he was Executive Chairman of FirstAfrica Oil plc until February 2007 and served on the boards of Rift Oil plc and Adastra Minerals Ltd. He currently serves on the board of a number of resource companies, including as Chairman of Faroe Petroleum plc since 2007, Deputy Chairman of Wentworth Resources Ltd since 2007 and Chairman of Scotgold Resources Ltd since 2009. Mr Bentley holds a degree in Metallurgy from Brunel University.

Peter Dey—Independent Non-Executive Director—aged 72

Mr Dey is a well known senior corporate executive and an experienced corporate director. He has been Chairman of Paradigm Capital Inc., an independent investment dealer, since November 2005. Mr Dey is a director of Goldcorp, Granite REIT and Enablence Technologies. He is also a director of the Massachusetts Museum of Contemporary Art. He is a former Chairman of the Ontario Securities Commission and former Chairman of Morgan Stanley Canada, and he was a Senior Partner of Osler, Hoskin & Harcourt LLP. In 1994, Mr Dey chaired the Toronto Stock Exchange Committee on Corporate Governance, and he has since been involved with developing global corporate governance standards as Chairman of the Private Sector Advisory Group of the Global Corporate Governance Forum. Mr Dey holds a Master of Laws from Harvard University, a Bachelor of Laws from Dalhousie University and a Bachelor of Science from Queen's University.

Ronald W. Royal—Independent Non-Executive Director—aged 64

Mr Royal is a professional engineer with over 35 years of experience with Imperial Oil Ltd. and ExxonMobil's international upstream affiliates. Mr Royal has served on the board of directors of Esso REP, EEPCI, TOTCO and COTCO. Prior to retiring in 2007, he was President and Production Manager of EEPCI and resided in N'Djamena, Chad from 2002 to 2007. In 2003, he was awarded the title "*Chevalier de l'Ordre National du Chad*" for his contribution to the economic development of Chad. Mr Royal has served as a director of Valeura Energy Inc. since March 2010 and sits on its Audit and Health, Safety and Environment and Reserves Committees.

Brooke Wade—Independent Non-Executive Director—aged 59

Mr Wade is a chartered accountant and holds a Bachelor of Commerce degree from the University of Calgary. Mr Wade has been the President of Wade Capital Corporation since July 2005, and prior thereto he was the co-founder, Chairman and Chief Executive Officer of Acetex Corporation. Prior to founding Acetex Corporation, Mr Wade was the founding President and Chief Executive Officer of Methanex Corporation.

Senior Managers

Day-to-day management of the Company's business is the responsibility of the persons below in addition to Gary Guidry.

Name of officer/ Principal residence	Position	Appointed	Principal Occupation
Trevor Peters Alberta, Canada	Chief Financial Officer	July 2011	Chief Financial Officer, Caracal Energy Inc.
J. Dean Tucker Alberta, Canada	Chief Operating Officer	July 2011	Chief Operating Officer, Caracal Energy Inc.
William (Joe) Taylor Alberta, Canada	Vice President, Engineering and Project Management	July 2011	Vice President, Engineering and Project Management, Caracal Energy Inc.
Ryan Ellson Alberta, Canada	Vice President, Finance	March 2012	Vice President, Finance, Caracal Energy Inc.
Lawrence W. West Alberta, Canada	Vice President, Exploration	July 2011	Vice President, Exploration, Caracal Energy Inc.
Nicholas J. Hands Alberta, Canada	Vice President, Asset Management	August 2011	Vice President, Asset Management, Caracal Energy Inc.
Jim Evans Alberta, Canada	Vice President, Corporate Services and Compliance	July 2011	Vice President, Corporate Services and Compliance, Caracal Energy Inc.
Hervé Manouan Alberta, Canada	Vice President and Country Manager, Chad	November 2012	Vice President and Country Manager, Chad, Caracal Energy Inc.
Tina Antony Alberta, Canada	Vice President, Legal and General Counsel	December 2012	Vice President, Legal and General Counsel, Caracal Energy Inc.

The senior management of the Company (each a "**Senior Manager**") is as follows:

Gary Guidry—President, Chief Executive Officer and Executive Director—aged 57

See the above disclosure under "Board of Directors" in this Part VIII.

Trevor Peters—Chief Financial Officer—aged 36

Mr Peters holds a Bachelor of Mathematics from the University of Waterloo. Mr Peters has over twelve years of experience in the finance and investment banking industry. Mr Peters was the Vice President, Corporate Planning and Business Development, of Orion Oil & Gas Corporation from October 2009 until June 2011. Previously, Mr Peters was President of Tritonia Holdings Ltd. and Manager, Corporate Planning, of North American Oil Sands Corporation from January 2006 until June 2007.

J. Dean Tucker—Chief Operating Officer—aged 51

Mr Tucker is a professional engineer holding a Bachelor of Engineering degree from Memorial University. Mr Tucker has over 25 years of oil and gas industry experience. Mr Tucker was the Chief Operating Officer of Orion Oil & Gas Corporation from April 2010 until June 2011. Prior thereto, Mr Tucker was Vice President, Production and Operations of Crew Energy Inc. from April 2009 until April 2010, Vice President of Pearl Exploration and Production Ltd. from August 2007 until January 2009 and Vice President, Operations of Real Resources Inc.

William (Joe) Taylor—Vice President, Engineering and Project Management—aged 46

Mr Taylor is a professional engineer and holds a Bachelor of Science degree in Geological Engineering from the University of Manitoba. Mr Taylor has over 20 years of oil and gas industry experience. Mr Taylor was the Vice President, Operations, for Orion Oil & Gas Corporation from March 2011 until May 2011. Prior thereto, Mr Taylor held positions with Penn West Petroleum Ltd., Pearl Exploration and Production Ltd., Husky Energy Inc., Marathon Oil Corporation and Chevron Canada.

Ryan Ellson—Vice President, Finance—aged 37

Mr Ellson is a chartered accountant and holds a Bachelor of Commerce degree and Masters of Professional Accounting from the University of Saskatchewan. Mr Ellson has more than ten years of oil and gas and public accounting experience. Mr Ellson was the Vice President, Finance, at Sea Dragon Energy Inc., an oil and gas company with operations in Egypt. Prior thereto, Mr Ellson held progressively senior roles with companies operating in India and Western Canada, namely being Chief Financial Officer and Vice President, Finance, of Canoro Resources Ltd. from January 2010 until July 2010 and the Corporate Controller and Director of Finance from January 2008 to January 2010. Prior thereto, Mr Ellson was the Corporate Controller and Manager of Finance at Delphi Energy Corp. from July 2005 until January 2008.

Lawrence W. West—Vice President, Exploration—aged 56

Mr West is a professional geologist and holds a Bachelor of Science degree in Geology from McMaster University and a Master of Business Administration from the University of Calgary. Mr West has over 32 years of oil and gas industry experience. Mr West was the Vice President, North America of Orion Oil & Gas Corporation from October 2009 until June 2011. Prior thereto, Mr West was the Vice President, Exploration and Principle, of Auriga Oil and Gas Ltd. from 2006 until October 2009 and Vice President, Exploration and Principle, of Chariot Energy Inc. from 2004 until 2006.

Nicholas J. Hands—Vice President, Asset Management—aged 44

Mr Hands is a professional engineer and holds a Masters degree in Engineering from Cambridge University. Mr Hands has over 20 years of oil and gas industry experience. Most recently Mr Hands was a Senior Engineering Advisor from May 2010 until June 2011, a Senior Development Manager from June 2009 until May 2010 and a Development Manager from June 2008 until May 2009 at Penn West Exploration (previously Penn West Energy Trust), an Engineering Manager with Highpine Oil and Gas Ltd. from September 2006 until April 2008 and an Asset Team Leader with Burlington Resources Canada Ltd. from November 2004 until August 2006. Mr Hands also held senior positions at Shell Canada Limited from January 1992 until October 2004.

Jim Evans—Vice President, Corporate Services and Compliance—aged 47

Mr Evans is a Certified General Accountant and holds a Bachelor of Commerce degree from the University of Calgary. Mr Evans has over seven years of oil and gas industry experience. Mr Evans was the Vice President, Human Resources and Corporate Controller, at Orion Oil & Gas Corporation from December 2009 until June 2011. Prior thereto, Mr Evans was the Corporate Controller and Manager, Finance, of Tanganyika Oil Company Ltd. from January 2006 until October 2009, and Assistant Controller of Western Co-operative Fertilizers Ltd. from September 1995 until January 2006. Mr Evans joined the Company in July 2011 as Vice President, Human Resources and Administration before becoming Vice President, Corporate Services and Compliance in March 2012.

Hervé Manouan—Vice President, General Manager, Chad—aged 51

Mr Manouan joined the Company in May 2012 as Finance Manager in Chad, and has been instrumental in setting up the finance and accounting groups in N'Djamena. In November 2012, Mr Manouan was promoted to Director General (Country Manager) in Chad, overseeing all of the Group's exploration and production activities. Mr Manouan has more than 20 years of international experience in multiple industries, but mostly in the oil and gas industry. Mr Manouan was Finance Manager of Kulczyk Oil Ventures Inc. from April 2011 until February 2012, Controller at Tera Environmental Consultants from February 2010 until March 2011 and Finance Manager at Encana Corp. from 2005 until December 2009.

Christine (Tina) Antony—Vice President Legal and General Counsel—aged 51

Ms Antony joined the Company as Vice President, Legal and General Counsel in December 2012. Most recently, Ms Antony was a Partner in the Securities, Corporate Finance and M&A department of Gowling Lafleur Henderson LLP. Ms Antony has 18 years' experience of corporate law. Ms Antony has worked with many domestic and international energy, industrial and real estate investment companies to raise capital and debt, undertake foreign operations, reorganise, list securities on domestic and foreign stock exchanges, establish and maintain corporate governance best practices and to merge with domestic and cross-border entities. Ms Antony received a Bachelor of Law degree in 1994.

Corporate Governance

The Board is committed to the highest standards of corporate governance. The Company has adopted mandates, charters, position descriptions and corporate governance principles and practices that address various matters, including: responsibilities and duties of the Board; composition of the Board, including criteria for remaining a director; compensation of the Board; composition and responsibilities of the Audit Committee and other Board committees; relationship of the Board to management of the Company; and director orientation and continuing education.

The Board believes that its commitment to a high standard of corporate governance practices is not only in the best interest of its shareholders, but that it also promotes effective decision-making at the Board level. The Board monitors and considers for implementation by the Company the corporate governance standards and guidelines which are proposed by applicable regulatory authorities or which are published by various non-regulatory organisations.

Terms of Reference of the Board

The Board has responsibility for the stewardship of the Company. The Board has adopted formal written terms of reference which are set out below. In carrying out these terms of reference, the Board meets regularly and a broad range of matters is discussed and reviewed for approval. These matters include overall corporate plans and strategies, budgets, internal controls and management information systems, risk management, as well as interim and annual financial and operating results. The Board is also responsible for the approval of all major transactions, including equity issuances, acquisitions and dispositions, as well as the Company's debt and borrowing policies. The Board strives to ensure that actions taken by management of the Company correspond closely with the objectives of the Board and shareholders.

Board Meetings

The following table identifies, as of 24 June 2013, the number of Board meetings that have been held during each Director's tenure as a Director and the number of such Board meetings attended by each Director.

Name[1]	Number of Board Meetings Held During Tenure[2]	Number of Board Meetings Attended During Tenure[2]
Gary Guidry	38	38
Robert B. Hodgins	37	37
Carol Bell	10	10
John Bentley	15	14
Peter Dey	7	7
Ronald W. Royal	37	37
Brooke Wade	33	33

Notes:

(1) Each of the Directors, except Gary Guidry, is independent, as such term is defined in NI 58-101. See "Directors and Senior Managers" in this Part VIII.

(2) Excludes meetings of the Special Committee or other Board committees.

The Board facilitates open and candid discussion among its independent Directors by holding in-camera sessions at the end of most regularly scheduled Board meetings, during which sessions the

non-independent Director(s) and management are not in attendance. Since 1 January 2012, there have been 14 Board meetings with such in-camera sessions.

UK Corporate Governance Code Compliance

Other than as disclosed within this subsection, the Company currently complies with the requirements of the UK Corporate Governance Code published by the Financial Reporting Council in September 2012 (the "**UK Corporate Governance Code**") and intends to continue to comply with the UK Corporate Governance Code following Admission.

The Company operates a formal risk management process and the Board approved a new risk register in January 2013. A controls framework was implemented following consultation with external consultants, who performed an independent review. However, while established as part of such process, controls relating to revenue and operating expenditure will only become applicable upon commencement of first production. A formal review of the effectiveness of internal controls will be undertaken prior to publication of the Company's 2013 annual report and accounts.

All of the members of the Board have been granted Options and/or Performance Warrants. The Group has implemented a formal policy that no further Options or Warrants will be granted to any Directors following Admission, except in exceptional circumstances. Notwithstanding the award of such Options and Performance Warrants, the Board considers all of the Non-Executive Directors to be independent within the meaning of "independent" as set out in the UK Corporate Governance Code and free from any business or other relationship which could materially interfere with the exercise of their independent judgement and considers Non-Executive Chairman, Robert B. Hodgins, to have been independent upon his appointment.

The UK Corporate Governance Code recommends that the Board should appoint one of its independent Non-Executive Directors as Senior Independent Director. The Company has not appointed a Senior Independent Director but may do so in due course.

In accordance with the UK Corporate Governance Code, the Board has established guidelines requiring specific matters to be subject to decision by the full Board, including material acquisitions and disposals, investment and capital projects. In addition, the Board has established audit, human resources and compensation, corporate governance, reserves, HSE and compliance committees with formally delegated duties and responsibilities within written terms of reference. If the need should arise, the Board may set up additional committees as appropriate.

Canadian Corporate Governance Guidelines Compliance

The Board is of the view that its approach to corporate governance is appropriate and aligns with the recommendations currently in effect and contained in Canada's National Policy 58-201—Corporate Governance Guidelines ("**NP 58-201**").

Audit Committee

The Board's Audit Committee (the "**Audit Committee**") has been structured to comply with the requirements of NI 52-110. Further, the UK Corporate Governance Code recommends that audit committees should comprise at least three members who should all be independent Non-Executive Directors, and that at least one member should have recent and relevant financial experience. The Audit Committee's terms of reference require that it comprise three or more Directors, each of whom is to be independent and to have appropriate financial literacy and experience. The Audit Committee is currently chaired by Carol Bell and its other current members are John Bentley, Ronald W. Royal and Brooke Wade, each of whom is an independent Non-Executive Director. The Directors consider all members of the Audit Committee to be independent and financially literate (as determined by NI 52-110) and to have recent and relevant financial experience. In considering criteria for the determination of financial literacy, the Board looked at the ability to read and understand a balance sheet, an income statement and a cash flow statement of a public company, as well as the director's past experience in reviewing or overseeing the preparation of financial statements. See "Directors and Senior Managers" in this Part VIII for biographies of the members of the Audit Committee, which sets forth the education and experience of each director relevant to the performance of his or her duties as a member of the Audit Committee. The Audit Committee meets formally at least four times per year, scheduled so as to permit timely review of the

interim and annual financial statements and reports, and senior management, including the Chief Financial Officer, may be invited to attend the meetings.

The purpose of the Audit Committee is to assist the Board in discharging its corporate governance responsibilities in relation to (i) the oversight, review and approval of the financial statements and the accounting and financial reporting processes of the Company, (ii) the assessment of the system of internal controls that management has established and (iii) the external audit process. It will also assist the Board, as requested, in reviewing the Company's financial policies and strategies, financial risk management practices and transactions or circumstances which could materially affect the financial profile of the Company. A copy of the Audit Committee terms of reference are set out in "Audit Committee Terms of Reference" in this Part VIII.

External Audit Service Fees

The following table summarises the fees paid by the Company and its subsidiaries to its auditors, for external audit and other services during the periods indicated. KPMG LLP, Chartered Accountants, became the Company's auditors on 5 August 2011. Prior thereto, there was no auditor appointed for the Company. All permissible categories of non-audit services require pre-approval by the Audit Committee, subject to certain statutory exemptions.

Year	Audit Fees[1]	Audit Related Fees[2]	Tax Fees[3]	All Other Fees[4]
	(C$'000)	(C$'000)	(C$'000)	(C$'000)
2012	574	—	76	402
2011	245	—	—	511

Notes:

(1) Represents the aggregate fees billed by the Company's external auditor in each of the last two fiscal years for audit fees, interim reviews and prospectus related services.

(2) Represents the aggregate fees billed in each of the last two fiscal years by the Company's external auditor for assurance and related services that are reasonably related to the performance of the audit or review of the Company's financial statements (and not reported under the heading "Audit Fees").

(3) Represents the aggregate fees billed in each of the last two fiscal years by the Company's external auditor for professional services for tax compliance, tax advice and tax planning. The services comprising the fees disclosed under this category consisted of general tax advice and routine tax planning matters.

(4) Represents the aggregate fees billed in each of the last two fiscal years by the Company's external auditor for products and services not included under the headings "Audit Fees", "Audit Related Fees" and "Tax Fees". The services comprising the fees disclosed under this category consisted of French translation of the Company's financial statements and management discussion and analysis and forensic audit service.

Human Resources and Compensation Committee

NP 58-201 recommends that compensation committees should be comprised of independent directors and the UK Corporate Governance Code recommends that remuneration committees should comprise at least three members who should all be independent Non-Executive Directors. The terms of reference of the Board's Human Resources and Compensation Committee (the "**Compensation Committee**") require that it comprise three or more Directors, each of whom is to be independent and to have appropriate experience. The Compensation Committee is currently chaired by Brooke Wade and its other current members are John Bentley, Peter Dey and Robert B. Hodgins, each of whom is an independent Non-Executive Director. The Directors consider all members of the Compensation Committee to have the appropriate experience. The Compensation Committee meets formally at least once each year, as the chairman of the Compensation Committee will determine, provided that a meeting shall be scheduled following preparation of the annual financial statements and reserves evaluation and for the purpose of determining bonuses in respect of the immediately preceding year.

The purpose of the Compensation Committee is to assist the Board in discharging its corporate governance responsibilities in relation to human resources policies and executive compensation matters. In addition the Compensation Committee reviews the compensation of Directors and the overall compensation policies of the Company. The Compensation Committee reviews and recommends, for approval by the Board, the compensation of the Board, the executive compensation philosophy and the remuneration policy for the Company. The Compensation Committee also reviews and recommends to the

Board the annual compensation package and performance objectives of the executive officers. The Compensation Committee shall also review the adequacy and form of the compensation of Directors periodically to determine if the compensation reflects realistically the responsibilities and risks involved in being an effective Director.

Governance and Nominations Committee

NP 58-201 recommends that nomination committees should be comprised of independent directors and the UK Corporate Governance Code recommends that nomination committees should comprise a majority of independent non-executive directors. The terms of reference of the Board's Governance and Nominations Committee (the "**Governance and Nominations Committee**") require that it comprise three or more Directors, each of whom is to be independent and to have appropriate experience. The Governance and Nominations Committee is currently chaired by Peter Dey and its other current members are Carol Bell and Robert B. Hodgins, each of whom is an independent Non-Executive Director. The Directors consider all members of the Governance and Nominations Committee to have the appropriate experience. The Governance and Nominations Committee will meet at least once each year, as the chairman of the Governance and Nominations Committee will determine.

The purpose of the Governance and Nominations Committee is to assist the Board in discharging its corporate governance responsibilities in relation to the corporate governance practices and policies with respect to the Company. The Governance and Nominations Committee is also responsible for recommending to the Board new candidates for election to the Board and recommending to the Board the new directorial nominees for each annual meeting of shareholders of the Company and nominees for election to fill vacancies on the Board and to address related matters.

Reserves Committee

The terms of reference of the Board's Reserves Committee (the "**Reserves Committee**") require that it comprise three or more Directors, each of whom is to be independent and have appropriate experience. The Reserves Committee is currently chaired by John Bentley and its other current members are Robert B. Hodgins and Ronald W. Royal, each of whom is an independent Non-Executive Director. The Directors consider all members of the Reserves Committee to have the appropriate experience. The Reserves Committee will meet at least twice per year, as the chairman of the Reserves Committee will determine, provided that at least one meeting shall be scheduled to permit timely review of the Company's statement of reserves data and other oil and gas information, the report of management and the Directors on oil and gas disclosure and the report of the independent qualified reserves evaluator or auditors on reserves data and public disclosure in respect thereof.

The purpose of the Reserves Committee is to assist the Board in discharging its corporate governance responsibilities generally and under Canadian National Instrument 51-101—Standards of Disclosure for Oil and Gas Activities with respect to the oil and natural gas reserves evaluation process of the Company and public disclosure of reserves data and related information in connection with the Company's oil and gas activities.

HSE Committee

The terms of reference of the Board's Health, Safety and Environment Committee (the "**HSE Committee**") require that it comprise three or more Directors, each of whom is to be independent and to have appropriate experience. The HSE Committee is currently chaired by Ronald W. Royal and its other current members are Peter Dey and Brooke Wade, each of whom is an independent Non-Executive Director. The Directors consider all members of the HSE Committee to have the appropriate experience. The HSE Committee will meet at least four times per year.

The purpose of the HSE Committee is to assist the Board in discharging its corporate governance responsibilities in relation to health, safety and environmental matters, including monitoring and overseeing the Company's policies and procedures for ensuring compliance by the Company with environmental regulatory requirements and ensuring that employees are provided with a safe environment in which to perform their duties.

Compliance Committee and Compliance Officer

The Board's Compliance Committee (the "**Compliance Committee**") consists of the Chief Executive Officer, Chief Financial Officer, Chief Operating Officer, Vice President, Corporate Services and Compliance, Vice President of Finance and Vice President, Legal and General Counsel.

The Compliance Committee's responsibilities include the establishment and maintenance of the practices and procedures necessary to implement the Group's Business Integrity Policy (see paragraph 15—"Anti-corruption policies and procedures and compliance" in Part VI: "Information on the Group" for further information) and monitor compliance with its provisions. The Compliance Committee will report directly to the Board at least once each year.

Jim Evans was appointed as the Company's Compliance Officer on 12 March 2012. Mr Evans is a professional accountant with over 20 years of experience. Previously, Mr Evans was the controller at Tanganyika, which had operations in both Egypt and Syria. During his time at Tanganyika, Mr Evans spent considerable time in Syria and Egypt and he is well versed in designing, implementing and testing effective internal controls. Mr Evans has experience and knowledge of working in an intermediate oil company with operations in emerging market jurisdictions. See paragraph 15—"Anti-corruption policies and procedures and compliance" in Part VI: "Information on the Group" for details of Mr Evans duties as Compliance Officer.

Operations in Chad

The Directors believe that it is critical to the success of the Company's business that operations in Chad and its corporate head office are co-ordinated, informed and responsive. The Board and Senior Managers have extensive experience in emerging markets similar to Chad. See "Directors and Senior Managers" in this Part VIII for biographies of the Directors and Senior Managers. Based on the experience of the Board and Senior Managers, the Company has implemented the following practices and protocols:

- the Company's Chief Executive Officer is in Chad as required and, historically, no less than one week out of every six weeks (for a total of eight weeks per year);
- the Company's Chief Financial Officer is in Chad as required and, historically, no less than one week out of every two months (for a total of six weeks per year);
- the Company's Vice President and Country Manager is fluent in English and French and lives in Chad;
- the Company's Chief Operating Officer, Corporate Controller, Vice President Engineering and Project Management and Vice President Corporate Services and Compliance are in Chad as required and, historically, no less than one to two weeks per month (for a total of 12 to 16 weeks per year);
- all other Senior Managers are in Chad as required and, historically, no less than twice per year for two to three weeks per year;
- Directors visit Chad at least once per year;
- daily reports from the field and other aspects of operations are circulated to all employees and management;
- weekly reports by operations personal are reviewed by management and circulated to Company employees;
- monthly reports are prepared by management for the Board, which include information from each of the operations, finance, reserves, resources, compliance/employee matters, legal and office services, health and safety departments of the Company;
- monthly training sessions are held by the Company for health, anti-corruption and security in Chad;
- emergency response programmes are updated regularly in which unannounced scenario training is held, including follow-up sessions to improve protocols;
- all employees of the Company have, as a minimum, a working knowledge of English, and all Company documents are provided in English and French; and
- interpreters are used, when required, for presentation by the Company to officials of the Government of Chad.

Orientation and Continuing Education

The Governance and Nominations Committee is mandated to oversee an orientation and education programme for new directors and to provide ongoing educational opportunities for all directors. The objectives of such programmes are to ensure that new directors fully understand: (i) the role of the Board and its committees; (ii) the contribution individual directors are expected to make (including, in particular, the commitment of time and resources that the Company expects from its directors); and (iii) the nature and operation of the Company's affairs.

Continuing education opportunities are directed at enabling individual directors to maintain or enhance their skills and abilities as directors, as well as ensuring that their knowledge and understanding of the Company's affairs remains current.

All new directors will be provided with a baseline of knowledge about the Company and its subsidiaries as deemed appropriate.

Nomination of Directors

The responsibility for identifying and recommending the nomination of new Board candidates has been set forth in the written mandate of the Governance and Nominations Committee. The Governance and Nominations Committee will work with the Board to determine the competencies and skills the Board considers necessary for the Board, as a whole, to possess, as well as the skills the Board considers each existing director to possess. The Governance and Nominations Committee will then identify potential Board members from diverse professional and personal backgrounds who combine a broad spectrum of experience and expertise with a reputation for integrity, which assessment will include a consideration of diversity, age, skills, competencies and experience in the context of the needs of the Board.

The Governance and Nominations Committee makes recommendations to the Board with respect to nominees for election at the next annual meeting of shareholders or to be appointed to fill vacancies between annual meetings of the shareholders and will approach nominees to ascertain their willingness to serve as a member of the Board.

Assessments

The Board is responsible for ensuring that there is a process in place for annually evaluating the effectiveness and contribution of the Board, the committees of the Board and the individual directors based on their applicable terms of reference or position description.

The objective of the assessments is to ensure the continued effectiveness of the Board in the execution of its responsibilities and to contribute to a process of continuing improvement. In addition to any other matters the Board deems relevant, the assessments will consider in the case of the Board or a committee, the applicable terms of reference, the applicable position descriptions, as well as the competencies and skills each individual director is expected to bring to the Board.

Position Descriptions

Chairman of the Board

The Board has developed a written position description for the Chairman. The Chairman's scope, duties and responsibilities include, but are not limited to, the following: being satisfied that the Board is alert to its obligations to the Company and to shareholders; determining the dates and locations of the meetings of the Board and the shareholders; requiring the Board to meet at least four times annually and as many additional times as necessary for the Board to carry out its duties and responsibilities effectively; approving agendas for Board meetings after being satisfied such agenda enables the Board to successfully carry out its duties; ensuring that all business that is required to be brought before a meeting of shareholders is brought before a meeting of shareholders; maintaining a liaison and communication with all members of the Board and the committee chairs to co-ordinate input from all members of the Board, and optimising the effectiveness of the Board and its committees; endeavouring to attend all meetings of the Board and the shareholders; being satisfied that the Board receives adequate and regular updates from the management of the Company on all issues important to the welfare and future of the Company; being satisfied that information requested by members of the Board or its committees of the Board is provided and meets their needs; reviewing conflict of interest issues with respect to members of the Board as they arise; providing leadership to enable the Board to act as a team in carrying out its duties and

responsibilities; chairing in camera meetings of the Board, without management of the Company present, at every Board meeting; and providing advice, counsel and mentorship to the fellow members of the Board.

Chief Executive Officer

The Board has developed a written position description for the Chief Executive Officer. The Chief Executive Officer's scope, duties and responsibilities include, but are not limited to, the following: maintaining a high level of integrity and assisting in creating a culture of integrity throughout the Company; working with the Board to determine the strategic direction of the Company; leading and assisting the Board in developing short-term and long-term plans and objectives to achieve the strategies of the Company; from time to time, determining with the Board, the budgets of the Company and the Board's expectations of the Chief Executive Officer; undertaking the day-to-day management and operation of the Company and providing leadership designed to achieve the objectives of the Company; stewarding the Company's expenditures within approved budgets; developing senior management succession and development plans and reporting to the Board at least annually on such plans, including recommending candidates for appointment as officers and senior management of the Company to the Board; ensuring appropriate policies and procedures of the Company are developed, maintained and disclosed; providing appropriate certifications regarding the Company and its activities, as may be required from time to time; ensuring that procedures are in place for appropriate communication to all stakeholders regarding the Company's activities and objectives; and complying with all stock exchange, regulatory and statutory requirements.

Committee Chairs

The Board has not developed separate written position descriptions for the chair of each Board committee. Instead, the Board has adopted written terms of reference for each of the Audit Committee, Reserves Committee, Governance and Nominations Committee, Human Resources and Compensation Committee and HSE Committee. Each of the written mandates provides that the chair will preside as chairman at each committee meeting and will lead the committee discussion on meeting agenda items.

Audit Committee Terms of Reference

The Audit Committee shall have the oversight responsibility, authority and specific duties as described below.

Composition

The Audit Committee will be comprised of three or more directors as determined by the Board, none of whom shall be an officer or employee of the Company or any subsidiary of the Company. In addition, each Audit Committee member shall satisfy the independence, financial literacy and experience requirements of applicable securities laws, rules or guidelines, any applicable stock exchange requirements or guidelines and any other applicable regulatory rules. Determinations as to whether a particular director satisfies the requirements for membership on the Audit Committee shall be made by the Board with the assistance of the Governance and Nominations Committee, if requested by the Board.

Members of the Audit Committee shall be appointed by the Board. The Governance and Nominations Committee of the Board shall recommend to the Board eligible directors to fill vacancies on the Audit Committee. Each member shall serve until his or her successor is appointed, unless such member shall resign or be removed by the Board or otherwise cease to be a director of the Company. The Board shall fill any vacancy if the membership of the Audit Committee is less than three directors.

The Chair of the Audit Committee may be designated by the Board or, if it does not do so, the members of the Audit Committee may elect a Chair by vote of a majority of the full Audit Committee membership.

Communication, Expenses and Authority to Engage Advisers

The Audit Committee shall have access to such officers and employees of the Company, the Company's external auditor and to such information respecting the Company, as it considers to be necessary or advisable in order to perform its duties and responsibilities.

The Audit Committee provides an avenue for communication, particularly for outside directors, with the external auditor, financial and senior management and the Board. The external auditor shall have a direct

line of communication to the Audit Committee through its Chair and shall report directly to the Audit Committee. The Audit Committee, through its Chair, may directly contact any employee in the Company as it deems necessary, and any employee may bring before the Audit Committee, on a confidential basis, any matter involving the Company's financial practices or transactions.

The Audit Committee has the authority to engage independent counsel and other advisers as it determines necessary to carry out its duties and to set the compensation for any such counsel and advisers. Any engagement of independent counsel or other advisers is to be at the Company's expense.

The Company shall be responsible for all expenses of the Audit Committee that are deemed necessary or appropriate by the Audit Committee in carrying out its duties.

Meetings and Record Keeping

Meetings of the Audit Committee shall be conducted as follows:

(1) the Audit Committee shall meet at least four times annually at such times and at such locations as the Chair of the Audit Committee shall determine, provided that meetings shall be scheduled so as to permit timely review of the quarterly and annual financial statements and reports. The external auditor or any two members of the Audit Committee may also request a meeting of the Audit Committee. The Chair of the Audit Committee shall hold in camera sessions of the Audit Committee, without management present, at every meeting;

(2) a resolution in writing, signed by all of the members of the Audit Committee is as valid as if it had been passed at a meeting of the Audit Committee;

(3) the Chair of the Audit Committee shall preside as chair at each Audit Committee meeting and lead Audit Committee discussion on meeting agenda items;

(4) the quorum for meetings shall be a majority of the members of the Audit Committee, present in person or by telephone or by other telecommunication device that permits all persons participating in the meeting to hear each other;

(5) if the Chair of the Audit Committee is not present at any meeting of the Audit Committee, one of the other members of the Audit Committee who is present at the meeting shall be chosen by the Audit Committee to preside at the meeting;

(6) the Chair shall, in consultation with management and the external auditor, establish the agenda for the meetings and instruct management to circulate properly prepared agenda materials to the Audit Committee with sufficient time for study prior to the meeting;

(7) every question at an Audit Committee meeting shall be decided by a majority of the votes cast; in the event of a tie vote on any matter, such matter shall be presented to the Board for its consideration and determination;

(8) the President and Chief Executive Officer, the Chief Financial Officer and the Controller shall be available to advise the Audit Committee, shall receive notice of meetings and may attend meetings of the Audit Committee at the invitation of the Chair of the Audit Committee. Other management representatives or employees may be invited to attend as necessary; and

(9) an Audit Committee member, or any other person selected by the Audit Committee, shall be appointed at each meeting to act as secretary for the purpose of recording the minutes of each meeting.

The Audit Committee shall provide the Board with a copy of the minutes of such meetings. Where minutes have not yet been prepared, the Chair shall provide the Board with oral reports on the activities of the Audit Committee. All material information reviewed and discussed by the Audit Committee at any meeting shall be referred to in the minutes and made available for examination by the Board upon request to the Chair.

Responsibilities

The Audit Committee is part of the Board. Its primary functions are to assist the Board in fulfilling its oversight responsibilities with respect to: (i) the oversight, review and approval of the financial statements and the accounting and financial reporting processes of the Company; (ii) the assessment of the system of internal controls that management has established; and (iii) the external audit process. In addition, the

Audit Committee shall assist the Board, as requested, in fulfilling its oversight responsibilities with respect to: (a) financial policies and strategies; (b) financial risk management practices; and (c) transactions or circumstances which could materially affect the financial profile of the Company.

The Audit Committee shall be directly responsible, in its capacity as a committee of the Board, for recommending to the Board the nomination of the external auditor and the compensation and retention of the external auditor and overseeing the work of the external auditor and the relationship of the external auditor with the Company (including the resolution of disagreements between management and the external auditor regarding financial reporting).

The Audit Committee should have a clear understanding with the external auditor that they must maintain an open and transparent relationship with the Audit Committee, and that the ultimate accountability of the external auditor is to the shareholders of the Company.

Specific Duties

A. *Relationship with External Auditor*

The Audit Committee shall:

(1) consider and make a recommendation to the Board as to the nomination or re-appointment of the external auditor for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services, ensuring that such auditor is a participant in good standing pursuant to applicable securities laws;

(2) consider and make a recommendation to the Board as to the compensation of the external auditor which is to be paid by the Company;

(3) oversee the work of the external auditor in performing their audit, review or attest services and oversee the resolution of any disagreements between management of the Company and the external auditor;

(4) review and discuss with the external auditor all significant relationships that the external auditor and its affiliates have with the Company and its affiliates in order to determine the external auditor's independence;

(5) as may be required by applicable securities laws, rules and guidelines, either:

   (a) pre-approve all non-audit services to be provided by the external auditor to the Company (and its subsidiaries, if any), or, in the case of de minimus non-audit services, approve such non-audit services prior to the completion of the audit; or

   (b) adopt specific policies and procedures for the engagement of the external auditor for the purposes of the provision of non-audit services; and

(6) review and approve the hiring policies of the Company regarding partners and employees and former partners and employees of the present and former external auditor of the Company.

B. *Financial Statements and Financial Reporting*

The Audit Committee shall:

(1) review with management and the external auditor, and recommend to the Board for approval, the annual and interim financial statements of the Company and related annual and interim financial reporting, including management's discussion and analysis and earnings press releases prior to the public disclosure of such information;

(2) upon completion of each audit, review with the external auditor the results of such audit. This process should include but not be limited to reviewing:

   (a) the scope and quality of the audit work performed;

   (b) the capability of the Company's financial personnel;

   (c) the co-operation received from the Company's financial personnel during the audit;

   (d) compliance with covenants under loan agreements;

   (e) the internal resources used;

(f) significant transactions outside of the normal business of the Company; and

(g) significant proposed adjustments and recommendations for improving internal accounting controls, accounting principles or management systems;

(3) review with management and recommend to the Board for approval, any financial statements of the Company which have not previously been approved by the Board and which are to be included in a prospectus or other public disclosure document of the Company;

(4) consider and be satisfied that adequate policies and procedures are in place for the review of the Company's public disclosure of financial information extracted or derived from the Company's financial statements, and periodically assess the adequacy of such procedures; and

(5) review accounting, tax, legal and financial aspects of the operations of the Company as the Audit Committee considers appropriate.

C. *Internal Controls*

The Audit Committee shall:

(1) review with management and the external auditor, the adequacy and effectiveness of the internal control and management information systems and procedures of the Company (with particular attention given to accounting, financial statements and financial reporting matters) and determine whether the Company is in compliance with applicable legal and regulatory requirements and with the Company's policies;

(2) read the external auditor's recommendations regarding any matters, including internal control and management information systems and procedures, and management's responses thereto, report to the Board on such recommendations and identify which recommendations should be adopted and provide reasons for rejecting those recommendations the Audit Committee feels should not be adopted; and

(3) establish procedures for the receipt, retention and treatment of complaints, submissions and concerns regarding accounting, internal controls or auditing matters and the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters;

D. *Financial Risk Management*

The Audit Committee shall:

(1) review the appropriateness and effectiveness of the Company's policies and business practices which impact on the financial integrity of the Company, including those relating to accounting and management reporting; and

(2) review the financial risks arising from the Company's exposure to such things as commodity prices, interest rates, foreign currency exchange rates and credit, the activities of the Company's marketing group, tax and government audits, tax filings and other matters affecting the Company's status or payment of income tax, and the Company's insurance program, including directors and officers' insurance, and report the results of such reviews to the Board for the purpose of assisting the Board in identifying the principal business risks associated with the business of the Company.

Review of Terms of Reference

The Governance and Nominations Committee shall review and reassess the adequacy of these terms of reference at least annually, and otherwise as it deems appropriate and recommend changes to the Board. Such review shall include the evaluation of the performance of the Audit Committee against criteria defined in the Audit Committee and Board terms of reference.

Terms of Reference of the Board of Directors

The Board of Directors shall have the oversight responsibility, authority and specific duties as described below.

Composition

Directors and Chairman

The Board shall appoint a chairman (the "**Chairman**") from amongst the directors which comprise the Board. The majority of the directors and the Chairman must be independent, as defined under applicable securities laws, rules or guidelines, any applicable stock exchange requirements or guidelines and any other applicable regulatory rules.

To ensure efficient, independent functioning of the Board, the Chairman shall be the effective leader of the Board. As such, the Chairman is responsible for ensuring that the Board's agenda enables the Board to successfully carry out its duties.

Committees

In addition to any other committees (including special committees) which the Board may in its discretion constitute from time to time, the Board shall have the following standing committees:

- Audit Committee;
- Reserves Committee;
- HSE Committee;
- Compensation Committee; and
- Governance and Nominations Committee.

Certain of the responsibilities of the Board may be delegated to these or other committees of the Board. The composition and responsibilities of these standing committees and any other standing committees of the Board will be as set forth in their terms of reference, as amended from time to time, and approved by the Board.

Committee members shall be appointed by the Board. The Governance and Nominations Committee shall provide the Board with its recommendation for filling any vacancies on any committees. The chair of each committee may be designated by the Board or, failing that, by the members of the particular committee. At each meeting of the Board, the chair of each committee (or such committee member as the chair may designate) shall report the results of meetings and any associated recommendations.

Board Membership Nomination and Evaluation

The Board has delegated the responsibility of recommending new director nominees to the Governance and Nominations Committee. The Governance and Nominations Committee shall, among other things, be responsible for recommending director candidates to the full Board. The Governance and Nominations Committee will also ensure an orientation programme for new directors has been established.

In addition, the Board has delegated the responsibility of annually evaluating the effectiveness and contribution of the Board, the committees of the Board and the individual directors to the Governance and Nominations Committee.

Communication

To ensure that the Company has in place policies and programmes that enable the Company to communicate effectively and in a timely manner with its shareholders, other stakeholders, analysts and the public generally the Board has adopted the Disclosure Policy.

Meetings and Record Keeping

(1) The Board shall meet regularly and at least quarterly at such times and at such locations as the Chairman shall determine.

(2) Notice of meetings shall be given to each director not less than 48 hours before the time of the meeting (unless such notice period is waived). Meetings of the Board may be held without formal notice if all of the directors are present and do not object to notice not having been given, or if those absent waive notice in any manner before or after the meeting. The notice of the meeting may be delivered personally, given by mail, facsimile or other electronic means of communication.

(3) Each member of the Board is expected to attend Board meetings and meetings of committees on which he or she is a member and to be familiar with deliberations and decisions as soon as possible after any missed meetings. Members of the Board are expected to prepare for meetings by reviewing the meeting materials distributed to members of the Board prior to such meetings.

(4) The independent directors of the Board shall regularly hold in camera sessions of the Board, with only independent directors present and at such times as the independent directors or Chairman determine advisable.

(5) A quorum for meetings shall be a majority of the members of the Board, present in person or by telephone or by other telecommunication device that permits all persons participating in the meeting to hear each other.

(6) If the Chairman is not present at any meeting, one of the other directors who is present at the meeting shall be chosen by the Board to preside at the meeting.

(7) The Chairman shall, in consultation with management, establish agendas for the meetings that enable the Board to successfully carry out its duties and instruct management to circulate appropriate agenda materials to the Board with sufficient time for study prior to the meeting.

(8) Every question at a Board meeting shall be decided by a majority of the votes cast.

(9) Management shall receive notice of meetings and may attend meetings of the Board at the invitation of the Chairman.

(10) The Corporate Secretary of the Company, or any other person selected by the Board, shall act as secretary for the purpose of recording the minutes of each meeting.

The minutes of the meeting of the Board shall be placed in the Company's minute book.

Duties and Responsibilities

In accordance with applicable laws, the Board is required to always act honestly and in good faith with a view to the best interests of the Company.

The Board is responsible for the stewardship of the Company and overseeing the management of the business of the Company. The responsibilities of the Board include:

(1) to the extent feasible, satisfying itself as to the integrity of the executive officers and that the executive officers create a culture of integrity throughout the Company;

(2) adopting a strategic planning process and approving, at least on an annual basis, a strategic plan for the Company which takes into account, among other things, the opportunities and risks of the business;

(3) identifying the principal risks of the Company's business, and ensuring appropriate systems are implemented to manage these risks;

(4) adopting and reviewing on an annual basis the Company's Disclosure Policy to ensure that disclosure made by the Company is accurate, informative, timely and broadly disseminated all in accordance with applicable laws and stock exchange rules and that the "Disclosure Committee" is effectively implementing the Disclosure Policy;

(5) ensuring that the Company has appropriate processes in place to effectively communicate with its employees, government authorities, other stakeholders and the public;

(6) ensuring the necessary internal controls and management systems are in place that effectively monitor the Company's operations and ensure compliance with applicable laws, regulations and policies, including reviewing on an annual basis the controls and procedures established for the certification of financial and other disclosure made by the Company;

(7) reviewing and approving the capital budget of the Company;

(8) developing clear position descriptions for the Chairman and the President and Chief Executive Officer;

(9) developing or approving the corporate goals and objectives that the President and Chief Executive Officer is responsible for meeting;

(10) ensuring succession planning programmes are in place; and

(11) establishing, with the assistance of the Governance and Nominations Committee, an appropriate system of corporate governance principles and guidelines applicable to the Company.

Stakeholder Communication

Any stakeholder may contact the Board by e-mail or in writing at:

Attention: Bob Hodgins, Chairman of the Board of Directors
Suite 2100, 555 - 4th Avenue S.W.
Calgary, Alberta, T2P 3E7
Canada

Telephone: +1 (403) 724 7200
Email: info@caracalenergy.com

Matters relating to the Company's accounting, internal accounting control or audit matters will be referred to the Audit Committee. Other matters will be referred to the Chairman.

Review of Terms of Reference

The Board or, at the request of the Board, the Governance and Nominations Committee, shall review and assess these Terms of Reference and any governance principles and guidelines established by the Board at least annually.

PART IX

SELECTED FINANCIAL INFORMATION

Selected financial and operating information relating to the Group set out below has been extracted, without material adjustment, from the financial statements contained in Part XII: "Historical Financial Information". The selected financial and operating information below should be read in conjunction with the whole of this Prospectus.

	Three months ended 31 March 2013 (unaudited)	Three months ended 31 March 2012 (unaudited)	Year ended 31 December 2012 (audited)	Year ended 31 December 2011 (audited)	Year ended 31 December 2010 (audited)
	(U.S.$'000)	(U.S.$'000)	(U.S.$'000)	(U.S.$'000)	(U.S.$'000)
Income statement:					
Revenues	—	—	—	—	—
Expenses	23,367	20,903	69,393	56,450	1,541
Deferred tax reduction	—	—	(5,381)	—	—
Net loss and comprehensive loss	23,367	20,903	64,012	56,450	1,541
Per Share data:					
Basic and diluted net loss and comprehensive loss per share	0.21	0.22	0.59	0.72	0.03
Basic and diluted weighted average number of shares outstanding	113,438	95,462	108,458	78,036	44,425
Cash flows:					
Operating activities	23,112	(9,663)	(55,186)	(24,443)	(1,941)
Investing activities	(61,799)	(6,246)	(161,299)	(106,728)	—
Financing activities	3,899	117,167	284,115	180,843	1,531

	As at 31 March 2013 (unaudited)	As at 31 March 2012 (unaudited)	As at 31 December 2012 (audited)	As at 31 December 2011 (audited)	As at December 2010 (audited)
	(U.S.$'000)	(U.S.$'000)	(U.S.$'000)	(U.S.$'000)	(U.S.$'000)
Statement of financial position:					
Current assets	97,424	154,664	132,121	52,909	822
Non-current assets	407,687	129,072	299,383	110,243	—
Total assets	505,111	283,736	431,504	163,152	822
Current liabilities	24,493	29,045	42,741	7,471	514
Non-current liabilities	246,076	2,015	137,590	1,995	—
Total liabilities	270,569	31,060	180,331	9,466	514
Total shareholders' equity	234,542	252,676	251,173	153,686	308
Total shares outstanding	115,624,419	112,448,719	112,761,219	88,008,719	44,612,500

PART X

OPERATING AND FINANCIAL REVIEW

The following discussion summarises the significant factors and events affecting the results of operations and financial condition of the Group for the three months ended 31 March 2013 and 2012 and the years ended 31 December 2012, 2011 and 2010, and should be read in conjunction with the consolidated financial statements of the Company reported in accordance with IFRS as adopted by the IASB set out under Part XII: "Historical Financial Information" and the other financial information contained elsewhere in this Prospectus, including under Part VI: "Information on the Group".

The following discussion of the Group's results of operations and financial condition contains forward-looking statements that reflect the current view of the Group's management. The Group's actual results could differ materially from those anticipated in any forward-looking statements as a result of the factors discussed below and elsewhere in this Prospectus, particularly under "Forward-looking statements" in Part III: "Presentation of Financial and Other Information" and Part II: "Risk Factors". Investors should carefully consider the following information, together with the other information contained in this Prospectus.

Overview

Founded in 2009, the Company is an independent oil and gas exploration, appraisal and development company which, together with Glencore, has exclusive rights to explore and develop oil and gas reserves and resources over an area of approximately 26,103 km^2 (6.4 million acres) in southern Chad. This area is comprised of three Contractual Zones, the rights to which were granted to the Group in 2011 pursuant to three production sharing contracts (each, a "**PSC**") that it entered into with the Government of Chad.

DOB/DOI Contractual Zone (DOB/DOI PSC)

- The DOB/DOI Contractual Zone covers an area of approximately 2,865 km^2. It contains two discoveries of commercial interest that the Group is currently developing: the Badila Field and the Mangara Field.
- The GLJ Reports estimate that the gross lease reserves attributed to the Badila and Mangara Fields are 28.8 MMbbl (proved), 63.2 MMbbl (proved plus probable) and 135.2 MMbbl (proved plus probable plus possible) (14.4 MMbbl, 31.6 MMbbl and 67.6 MMbbl, respectively, on a Net Participating Interest basis). "**Net Participating Interest**" means the Group's participating interest multiplied by the gross lease reserves, resources or production, as applicable.
- The GLJ Reports estimate that the gross lease unrisked prospective resources located in the DOB/DOI Contractual Zone are 239.6 MMstb (mean) (calculated by the Group to be 159.7 MMstb on a Net Participating Interest basis). When calculating Net Participating Interests in respect of prospective resources, the Group has assumed that it has a 66.67 per cent. participating interest. However, upon the approval of an EXA, the Government of Chad may elect to acquire up to a 25 per cent. participating interest in the relevant EXA and the Group's participating interest would be adjusted accordingly.
- Exclusive exploitation authorisations (each, an "**EXA**") to develop and produce from the Badila and Mangara Fields were granted to the Group by the Government of Chad in August 2012 and June 2012, respectively, and cover a combined area of 100 km^2.
- The Group is targeting commencement of first production from the Badila and Mangara Fields in July 2013 and the third quarter of 2013, respectively.
- The GLJ Reports forecast gross production, in the 2P case, of 23,000 bbl/d from the Badila and Mangara Fields by the end of 2013 and 36,000 bbl/d by the end of 2014 (11,500 bbl/d and 18,000 bbl/d, respectively, on a Net Participating Interest basis).

Doseo/Borogop Contractual Zone (Doseo/Borogop PSC)

- The Doseo/Borogop Contractual Zone covers an area of approximately 22,414 km^2 and contains four discoveries of commercial interest that the Group has identified as development priorities: the Kibea, Maku, Tega and North Sako Fields.
- The Group submitted a feasibility study and an EXA application for the Kibea Field in April 2013.

- The Group is currently undertaking feasibility studies on the Maku, Tega and North Sako Fields. The Group expects to submit an EXA application for the Maku Field during 2013.
- The GLJ Reports estimate that the gross lease reserves attributed to the Kibea and Maku Fields are zero (proved), 26.0 MMbbl (proved plus probable) and 65.4 MMbbl (proved plus probable plus possible) (zero, 13.0 MMbbl and 32.7 MMbbl, respectively, on a Net Participating Interest basis)[33]. The GLJ Reports estimate that the gross lease unrisked prospective resources located in the Doseo/ Borogop Contractual Zone are 985.3 MMstb (mean) (calculated by the Group to be 656.9 MMstb on a Net Participating Interest basis).

DOH Contractual Zone (DOH PSC)

- The DOH Contractual Zone covers an area of approximately 824 km^2.
- The DOH Contractual Zone is subject to further exploration. The two wellbores drilled by previous operators within the DOH Contractual Zone have evidence of oil, but not in quantities of commercial interest that the Group would intend to develop.
- The GLJ Reports estimate that the gross lease unrisked prospective resources located in the DOH Contractual Zone are 49.5 MMstb (mean) (calculated by the Group to be 33.0 MMstb on a Net Participating Interest basis).

Key Factors Affecting the Group's Results of Operations and Financial Condition

The results of the Group's operations and financial condition have been, and will continue to be, affected by many factors, some of which are beyond the Group's control. This section sets out certain key factors that the Board believes have affected the Group's results of operations and financial condition in the periods under review and, in particular, could affect its results of operations and financial condition in the future.

For a discussion of certain factors that may adversely affect the Group's results of operations and financial condition, also see Part II: "Risk Factors".

Oil Prices and Production Volumes

The Group's exploration and production strategies are and, when production commences, its results of operations will be, influenced significantly by crude oil prices. Crude oil prices have been volatile in the past and are likely to continue to be volatile in the future. Prices for oil are based on world supply and demand and a number of other factors, including government regulation and social and political conditions in oil producing regions. For the periods under review, the Group had no revenues and thus has not seen the impact of fluctuations of oil prices on its results. However, a decline in oil prices may reduce the amount of oil that the Group is able to produce economically or may reduce the viability of production levels of specific wells or of projects planned or in development to the extent that production costs exceed anticipated income from such production. The Group's production will be valued under the Offtake Agreement according to a price calculation formula which is based upon Dated Brent Crude. Consequently, any decline in that price would also result in a reduction in revenues and profitability, which could impair the Group's ability to make planned capital expenditure and its willingness to incur costs necessary for the development of the Group's assets.

As part of its longer term strategy, the Group intends to use cash flows generated by the sale of oil to further develop its properties and to carry out further exploration and appraisal activity in Chad. The long-term success of the Group will depend on its ability to find, acquire, develop and produce oil reserves commercially, and the Group's future profitability will be determined in large part by the difference between the income received for the oil the Group sells and its operating costs, as well as the costs incurred transporting and selling its oil. Currently, the Group does not intend to hedge against its exposure to oil prices.

Future oil exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other

(33) GLJ has assumed, for the purposes of estimating the Group's participating interest in any future EXAs which may be granted under each PSC, that the Government of Chad will elect to acquire a 25 per cent. participating interest in each EXA. Accordingly, the participating interest of each of the Group and Glencore has been assumed by GLJ to be 50 per cent. and 25 per cent. respectively, of the gross lease interest.

costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion, infrastructure and operating costs. While diligent well supervision and effective maintenance operations can contribute to maximising production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

The Group's ability to increase its gross production and control its costs will depend on many factors, some of which are beyond its control, including the Group being required to curtail, delay or suspend drilling operations due to unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, premature declines in reservoirs, blowouts, uncontrollable flows of crude oil or well fluids, pollution or other environmental risks, adverse weather conditions, compliance with governmental requirements, shortages or delays in the availability and delivery of equipment and changes to transport tariffs, royalty and other payments.

Access to market

The Contractual Zones are located in Chad. In order to monetise the Group's reserve base, the Group will have to transport its oil through the Export Pipeline from southern Chad to the Kribi Terminal, located off the coast of Cameroon. There is no other means for the Group to transport its production from its fields to its contracted purchaser, Glencore, or any other potential purchaser, as there is no rail infrastructure or adequate road access that would allow the Group to transport material quantities of oil to market by truck cost-effectively over the long term. The Group's physical links to the Export Pipeline that are required to commence first production comprise the Early Production Facilities, the Connection Pipe, the LACT Unit and the Hot Tap, each of which has already been constructed and commissioned.

Although the interests of all relevant stakeholders benefit from additional oil entering the Export Pipeline, there can be no assurance that the Group will be able to gain the necessary access and fully monetise its reserve base. In order to gain access to the Export Pipeline, the Group has signed the Interconnection Agreement with TOTCO and the Facilities Modification Agreement with COTCO. The Transportation Agreements, which are also required for the Group to access the Export Pipeline, have not yet been entered into. The Transportation Agreements are in an advanced stage of negotiation and the Group expects that they will be entered into prior to targeted first production from the Badila Field in July 2013.

The Interconnection Agreement, the Facilities Modification Agreement and the Transportation Agreements (once entered into) will not guarantee access to the Export Pipeline should producers with priority over the Group utilise its full capacity. Based on current and anticipated medium-term production levels of the Badila and Mangara Fields and the Priority Fields (as provided by the operators of the Export Pipeline), and subject to the priority arrangements currently established, the Group believes that the Export Pipeline has sufficient capacity to service both the needs of the Priority Fields and those of the Badila and Mangara Fields. Furthermore, were projected demand to exceed capacity, the Group expects that the Export Pipeline could, subject to the agreement of COTCO and TOTCO, be modified to accommodate increased production prior to its coming on line. It is anticipated that the costs of such modification would be paid by the shipper who, subject to the priority rules of access, required such modification in order to access the Export Pipeline.

Joint Venture Arrangements

The Group operates all of its assets but has two significant joint venture arrangements, one with the Government of Chad, through SHT, and the other with Glencore. Pursuant to the terms of the DOB/DOI PSC, the Government of Chad, through SHT, exercised its back-in rights in relation to the Badila and Mangara EXAs, which gave it, through SHT, a 25 per cent. participating interest in each (reduced to 15 per cent. following the sale of a 10 per cent. participating interest to Glencore in June 2013 pursuant to the Glencore/SHT Transaction). Consequently, this results in a reduction in the amount of revenue the Group is entitled to from the EXAs and, conversely, reduces the Group's share of costs within the EXAs. The Group expects that Government of Chad, through SHT, will exercise its back-in rights in respect of any future EXAs granted.

The Group's arrangements with Glencore comprise the Farm-in Agreement, the PIC Agreements, the Offtake Agreement, the EEA JVAs and the Badila and Mangara JVAs. Upon the Farm-in Completion, Glencore acquired from the Group (i) a 33.33 per cent. participating interest in each of the PSCs, with the Group retaining a 66.67 per cent. participating interest and (ii) a 25 per cent. participating interest in the Badila and Mangara EXAs, with the Group maintaining a 50 per cent. interest in each (after the SHT

back-in). As consideration, the Group received U.S.$30.75 million from Glencore in respect of historic unrecoverable costs incurred in relation to the PSCs. In addition, Glencore will carry a proportion of the Group's future capital expenditure costs, up to U.S.$100 million a year between July 2012 and June 2014 and U.S.$100 million for the period from July 2014 to June 2016, subject to an aggregate limit of U.S.$300 million.

In addition, the Group has contracted to sell all of its entitlement of crude oil production under the PSCs to Glencore pursuant to the Offtake Agreement. The Offtake Agreement provides that the price paid for the Group's oil will be determined according to a price calculation formula which is based upon Dated Brent Crude and includes incentives relating to the performance of Glencore thereunder. See paragraph 10—"Material contracts" in Part XVI: "Additional Information".

Changes in Reserves and Resources

Estimates of reserves and resources may be different from the quantity or quality of oil that is ultimately recovered from the Group's assets, and the revenue derived from its reserves and resources could therefore be different than planned for by the Group. Oil engineering is a subjective process of estimating underground accumulations of oil that cannot be measured in an exact manner. Estimates of the value and quantity of economically recoverable oil reserves and resources and rates of production necessarily depend on several variables and assumptions. Many of the factors for which assumptions are made in estimating reserves and resources are beyond the Group's control and, therefore, these assumptions may prove to be incorrect over time. In particular, assumptions about whether resources can be economically recovered may prove inaccurate, especially as to the recovery of resources from deeper wells. Any changes to these assumptions could have a material impact on the measurement of the recoverable amount and result in material impairment of the Group's asset reserves.

The Group's actual future net cash flows, as estimated by independent reserve engineers, will be affected by many factors which include, but are not limited to: actual production levels; supply and demand for oil; curtailments or increases in consumption by oil purchasers; changes in governmental regulation or taxation; tariffs, changes in the terms of the PSCs; and the impact of inflation on costs. Actual production and cash flows derived therefrom will vary from the estimates contained in the applicable engineering reports. The reserve reports are based in part on the assumed success of activities the Group intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the engineering reports will be reduced to the extent that such activities do not achieve the level of success assumed in the calculations.

Availability of Financing

To date the Group has funded itself through a series of financing rounds and through payments received pursuant to the Company's farm-in arrangements with Glencore. The financing rounds have included the sale of Shares and most recently the issuance of Convertible Bonds. See "Financing" in this Part X.

The Group anticipates developing its assets and undertaking its exploration programme in Chad using a combination of existing capital resources, anticipated future revenues and future funds raised from debt and equity, if available. Once first production commences, the Group expects to generate internal funds to expand its asset base and undertake its exploration plans. In order to maintain or adjust its capital structure, in future periods the Group may enter into joint venture agreements with third parties, incur long-term debt, issue new shares, sell assets, or execute a combination of the aforementioned items. The Group believes that its existing cash resources, together with the financial commitments of Glencore pursuant to the Farm-in Agreement and expected operating cash flow from production, will be sufficient to fund the Group's current capital expenditure plans for the next 12 months. If the revenues from the Group's reserves decrease as a result of lower oil prices and/or lower than projected production levels, its ability to expend the necessary capital to undertake its exploration and development programme, to replace its reserves and to maintain its production in the future will be adversely affected. Depending on the future exploration and development plans, the Group may require additional financing, which may not be available on favourable terms, or at all. Failure to obtain such financing on a timely basis could cause the Group to decelerate its exploration and development strategy and the Group may potentially be unable to drill all of its prospects prior to relinquishment. If the revenues from the Group's reserves decrease as a result of lower oil prices, additional taxes or royalty payments, this will impact its ability to expend the necessary capital to replace its reserves or to undertake its exploration and production programme. If cash flow from operations is not sufficient to satisfy capital expenditure requirements, there can be no assurance

that additional debt, equity or asset dispositions will be available to meet these requirements on acceptable terms, or at all.

Production, Exploration and Development Expenditure and Success Rates

The Group has incurred substantial expenses related to the acquisition of assets and early stage exploration activities, and in the future expects to incur further significant exploration and development expenditure as it moves closer to oil production. In particular, its level of expenditure will depend in substantial part on whether the Group is successful in discovering and appraising oil reserves and developing those reserves into oil producing assets.

In order to monetise fully future production, the Group is dependent on the successful completion of several key projects, in particular: (i) the Blending Export Terminal is scheduled for completion in the third quarter of 2013; (ii) the Early Production Facilities Expansion is scheduled for completion in the first quarter of 2014; (iii) the Mangara CPF is scheduled for completion in the third quarter of 2013; and (iv) the Mangara to Badila Pipeline is scheduled for completion in the third quarter of 2013. The failure to complete these and future projects on a timely basis could have a material adverse impact on the Group's ability to generate revenue.

Oil exploration involves a high degree of risk, and there can be no assurance that expenditure incurred in relation to future exploration activities undertaken by the Group will result in any new discoveries of oil in commercial quantities. The principal expenditure relating to the Group's exploration work programmes are those incurred in the course of the acquisition of seismic data and the drilling of exploration wells. Pursuant to the terms of the PSCs, the Group has obtained substantially all prior technical work and seismic data. However, to date, the Group has only explored a portion of its total acreage, and consequently will incur considerable exploration expense in the coming years.

Revenue

The Group has agreed, pursuant to the Offtake Agreement, to sell all of its entitlement of crude oil production under the PSCs to Glencore. It is expected that once revenue generation commences in the third quarter of 2013 (as expected), revenue from the sale of oil will be recorded on a lifting basis, as oil is produced from a contract area. Receipt of cash payments for oil will be subject to the shipment to, and receipt and purchase of the Group's oil by, Glencore. Any differences between volumes produced and volumes purchased will be recorded as an inventory adjustment.

The Group's revenue from operations will be calculated as the sum of its share of Cost Oil and Profit Oil, as stipulated by the respective PSCs. Cost Oil represents recovery of operating, exploration, capital and decommissioning costs by each of the Group, Glencore and SHT, as incurred in the normal course of business. In a given period, such costs can be recovered up to a maximum of 70 per cent. of net revenue, which represents gross revenue (crude oil volume sold multiplied by the price per barrel, net of the pipeline tariff) less the applicable royalty[34]. Cost Oil is therefore calculated as the smaller of (i) net revenue multiplied by the 70 per cent. maximum Cost Recovery; and (ii) the sum of the above mentioned operating, exploration, capital and decommissioning costs in a given period. Profit Oil is calculated as net revenue less Cost Oil; subsequently, each of the Group, Glencore and SHT are entitled to a share of Profit Oil ranging from 40 to 60 per cent., with the exact split determined by the R-Factor[35].

Pursuant to the inland transport authorisation, to the extent that a third party taps into the Connection Pipe, PCT would earn tariffs, tolls and fees, which would be recognised as revenue as they accrued in accordance with the terms of the related agreements.

Recent Developments

Share-based compensation

On 9 January 2013 the Board of Directors approved the 2013 Incentive Plan. The 2013 Incentive Plan was introduced to provide share awards to officers for achieving certain performance conditions. The 2013 Incentive Plan provides for a number of Awards based on a multiple of salary. However, these Awards only vest after a three-year period and provided the Company has performed in the top quartile when

(34) Royalty rates are 14.25 per cent. for oil and 5 per cent. for gas.

(35) R-Factor—(cumulative revenue—cumulative opex)/cumulative capex; all net to contractor.

compared against a selected peer group and certain internal targets are achieved. The 2013 Incentive Plan is described further in paragraph 9.2—"2013 Incentive Plan" in Part XVI: "Additional Information".

Special Investigation

On 15 January 2013 the Company was charged under section 3(1)(b) of Canada's Corruption of Foreign Public Officials Act in relation to conduct occurring between August 2009 and February 2011 involving two consulting agreements entered into by the Company. Pursuant to a negotiated settlement, the Company pleaded guilty on 22 January 2013 to one count of bribing a foreign public official to induce the official to use his position to influence any acts or decisions of the foreign state for which the official performs duties or functions, contrary to Section 3(1)(b) of Canada's Corruption of Foreign Public Officials Act. Pursuant to the guilty plea, the Company paid a fine of C$10,350,000 (U.S.$10,495,121), which has been accrued at 31 December 2012 and is included in general and administrative costs. For additional information see paragraph 14—"Special Committee Investigation" in Part VI: "Information on the Group".

Farm-in Consideration

In December 2012, the Company entered into the Farm-in Agreement with Glencore. Pursuant to the Farm-in Advance Agreement, U.S.$100 million and U.S.$50 million was advanced by Glencore to the Group on 4 March 2013 and 30 May 2013, respectively, as advance consideration for its obligations under the Farm-in Agreement. The Farm-in Completion occurred on 13 June 2013, pursuant to which Glencore paid the Group U.S.$107,458,921 as consideration for its obligations under the Farm-in Agreement, net of the repayment of the Farm-in Advance.

Operational Performance

The Group has one operating segment: oil exploration, development and production activities in Chad. For the periods under review, the Group has been focused on acquiring the PSCs in Chad and initial exploration and development activities on the acreages covered by the PSCs. During this time, the Group has generated operating losses and it is not anticipated to start generating revenues until the third quarter of 2013. Once the Company commences production and begins to earn revenues, the Group will be able to assess operational performance and profitability. There will be a period of ramp-up so that the initial year of production may not be indicative of future performance.

Selected Consolidated Financial Information

Below is a summary of financial data as of and for the three months ended 31 March 2013 and 2012 and the years ended 31 December 2012, 2011 and 2010.

	Three months ended 31 March 2013 (unaudited)	Three months ended 31 March 2012 (unaudited)	Year ended 31 December 2012 (audited)	Year ended 31 December 2011 (audited)	Year ended 31 December 2010 (audited)
			(U.S.$'000)		
Income statement:					
Revenues	—	—	—	—	—
Expenses	23,367	20,903	69,393	56,450	1,541
Deferred tax reduction	—	—	(5,381)	—	—
Net loss and comprehensive loss	23,367	20,903	64,012	56,450	1,541
Per Share data:					
Basic and diluted net loss and comprehensive loss per share	0.21	0.22	0.59	0.72	0.03
Basic and diluted weighted average number of shares outstanding	113,438	95,462	108,458	78,036	44,425
Cash flows:					
Operating activities	23,112	(9,663)	(55,186)	(24,443)	(1,941)
Investing activities	(61,799)	(6,246)	(161,299)	(106,728)	—
Financing activities	3,899	117,167	284,115	180,843	1,531

	As at 31 March 2013 (unaudited)	As at 31 March 2012 (unaudited)	As at 31 December 2012 (audited)	As at 31 December 2011 (audited)	As at 31 December 2010 (audited)
			(U.S.$'000)		
Statement of financial position:					
Current assets	97,424	154,664	132,121	52,909	822
Non-current assets	407,687	129,072	299,383	110,243	—
Total assets	505,111	283,736	431,504	163,152	822
Current liabilities	24,493	29,045	42,741	7,471	514
Non-current liabilities	246,076	2,015	137,590	1,995	—
Total liabilities	270,569	31,060	180,331	9,466	514
Total shareholders' equity	234,542	252,676	251,173	153,686	308
Total shares outstanding	115,624,419	112,448,719	112,761,219	88,008,719	44,612,500

The Company is exempt from any income taxes in Chad for activities covering each of the PSCs. In addition, all import taxes are waived during the five year initial terms of the respective PSCs.

Below is a summary of financial data as of and for the three months ended 31 December 2012, 30 September 2012, 30 June 2012, 31 March 2012, 31 December 2011, 30 September 2011, 30 June 2011 and 31 March 2011.

	Three months ended (unaudited)							
	31 December 2012	30 September 2012	30 June 2012	31 March 2012	31 December 2011	30 September 2011	30 June 2011	31 March 2011
	(U.S.$'000)							
Income statements:								
Revenues	—	—	—	—	—	—	—	—
Expenses	22,887	5,771	14,451	20,903	9,796	40,811	3,252	2,591
Net loss and comprehensive loss	22,887	5,771	14,451	20,903	9,796	40,811	3,252	2,591
Per common share data:								
Basic and diluted net loss per share	0.20	0.06	0.14	0.22	0.18	0.47	0.04	0.05
Weighted average number of shares outstanding—basic and diluted	112,761	112,761	112,754	95,462	88,009	86,240	80,886	56,652
Cash flows:								
Operating activities	(8,645)	(25,152)	(11,726)	(9,663)	(6,842)	(10,679)	(5,611)	(1,311)
Investing activities	(83,902)	(30,391)	(40,760)	(6,246)	(10,320)	51,810	(43,253)	(104,965)
Financing activities	(91)	167,083	(44)	117,167	995	5,182	14,565	160,101

	Three months ended (unaudited)							
	31 December 2012	30 September 2012	30 June 2012	31 March 2012	31 December 2011	30 September 2011	30 June 2011	31 March 2011
	(U.S.$'000)							
Statement of financial position:								
Current assets	132,121	216,860	102,765	154,664	52,909	65,728	84,202	115,316
Non-current assets	299,383	218,492	176,294	129,072	110,243	107,320	88,089	87,964
Total assets	431,504	435,352	279,059	283,736	163,152	173,048	172,291	203,280
Current liabilities	42,741	33,509	36,275	29,045	7,471	9,267	1,446	43,868
Non-current liabilities	137,590	130,182	2,037	2,015	1,995	1,974	1,564	1,564
Total liabilities	180,331	163,691	38,312	31,060	9,466	11,241	3,010	45,432
Total shareholders' equity	251,173	271,661	252,676	252,676	153,686	161,807	169,281	157,848

Results of Operations

Three months ended 31 March 2013 compared to three months ended 31 March 2012

Revenues

The Group did not generate any operating revenues during the three months ended 31 March 2013 or 2012.

Expenses

A summary of the expenses incurred by the Group during the three months ended 31 March 2013 and 2012 is presented in the table below:

	Three months ended 31 March (unaudited)	
	2013	2012
	(U.S.$'000)	
Salaries and benefits	5,825	2,704
Share-based compensation	2,121	2,608
Depreciation	394	195
General and administrative	4,920	14,389
Travel	1,988	1,274
Finance expense/(income)	7,765	(10)
Foreign exchange (gain)/loss	354	(257)
Net loss and comprehensive loss	23,367	20,903

Salaries and benefits

For the three months ended 31 March 2013, the Group had U.S.$5.8 million of expenses related to salaries and benefits, compared to U.S.$2.7 million for the three months ended 31 March 2012. This increase was due to the ongoing recruitment efforts to support the Group's development plans for its assets in Chad. The Group increased its headcount from approximately 58 employees at 31 March 2012 to 200 employees at 31 March 2013, as a result of which the Group has now recruited many key employees and has assembled the cornerstone of its management team. During the first quarter of 2013, the Company capitalized U.S.$1.1 million (2012—U.S.$0.6 million) of salaries and benefits.

Share-based compensation and Performance Warrants

Share-based compensation for the three months ended 31 March 2013 was U.S.$2.1 million, compared to U.S.$2.6 million for the three months ended 31 March 2012.

General and administrative

General and administrative expenses were U.S.$4.9 million in the three months ended 31 March 2013, compared to U.S.$14.4 million in the three months ended 31 March 2012. During the three months ended 31 March 2012, the Group accrued U.S.$9.5 million to provide for potential penalties and fines related to the Special Committee Investigation. Without this accrual, general and administrative costs for the three months ended 31 March 2013 are broadly flat on the previous period.

Travel

The Group incurred travel expenses of U.S.$2.0 million in the three months ended 31 March 2013, compared to U.S.$1.3 million for the three months ended 31 March 2012.

Finance expense/(income)

For the three months ended 31 March 2013, the Group incurred finance expense of U.S.$7.8 million, which was due almost entirely to interest payments due on the Convertible Bonds (as defined below).

Foreign exchange loss/(gain)

The Group incurred a foreign exchange loss of U.S.$0.4 million in the three months ended 31 March 2013 compared to a gain for U.S$0.3 million in the three months ended 31 March 2012.

Year ended 31 December 2012 compared to year ended 31 December 2011

Revenues

The Group did not generate any operating revenues during the years ended 31 December 2012 or 2011.

Expenses

A summary of the expenses incurred by the Group during the years ended 31 December 2012 and 2011 is presented in the table below:

	Year ended 31 December (audited)	
	2012	2011
	(U.S.$'000)	
Salaries and benefits	13,122	4,605
Share-based compensation	8,564	29,856
Depreciation	1,082	149
Consulting fees	2,560	8,266
Legal and professional fees	5,114	5,819
General and administrative	22,819	2,677
Travel	7,821	3,160
Change in fair value of Warrants	—	(69)
Finance expense/(income)	8,083	(463)
Foreign exchange (gain)/loss	228	2,450
Loss before tax	69,393	56,450
Deferred tax reduction	(5,381)	—
Net loss and comprehensive loss	64,012	56,450

Results in the year ended 31 December 2012 were impacted by increased expenses associated with the further development of the Group's assets in Chad. In the year ended 31 December 2011, a number of non-recurring costs in regard to the Special Committee Investigation, the acquisition of the PSCs and Share-based payments impacted results.

Salaries and benefits

For the year ended 31 December 2012, the Group had U.S.$13.1 million of expenses related to salaries and benefits, compared to U.S.$4.6 million for the year ended 31 December 2011. This increase was due to the ongoing recruitment efforts to support the Group's development plans for its assets in Chad. The Group's headcount increased from 43 employees at the end of 2011 to 113 employees at the end of 2012, as a result of which the Group has now recruited many key employees and has assembled the cornerstone of its management team. During 2012, the Group capitalised U.S.$3.4 million (2011—U.S.$0.9 million) of salaries and benefits.

Share-based compensation and Performance Warrants

Share-based compensation for the year ended 31 December 2012 was U.S.$8.6 million, compared to U.S.$29.9 million for the year ended 31 December 2011. In both 2012 and 2011, Options were issued to new employees as part of the recruitment and hiring process.

Consulting fees

Consulting fees for the year ended 31 December 2012 were U.S.$2.6 million, a substantial decrease from U.S.$8.3 million for the year ended 31 December 2011, as the Group replaced the majority of consultants with employees during the last six months of 2011 and the first quarter of 2012.

Legal and professional fees

Legal and professional fees were U.S.$5.1 million for the year ended 31 December 2012, compared with U.S.$5.8 million for the year ended 31 December 2011. While a significant portion of legal fees in 2011 pertained to the completion of the PSC signing and negotiation process, the majority of the legal fees in both 2011 and 2012 were a result of the Special Committee Investigation.

General and administrative

General and administrative expenses were U.S.$22.8 million in the year ended 31 December 2012, compared to U.S.$2.7 million in the year ended 31 December 2011. This increase was due, in large part, to the accrual of a U.S.$10.4 million fine provided for as a result of the Special Committee Investigation. The remainder of the increase in general and administrative costs was the result of increased activity and the need to support the Group's aggressive capital program. During 2012, the Group completed an early works programme, commenced construction of its facilities, pipelines and camps, and also commenced its drilling programme, resulting in increases to its in-country contract services, staff accommodation and office space costs, communications expenses, vehicle rental expenses, and prescribed PSC obligations such as local training, annual report fees and audit fees.

Travel

The Group incurred travel expenses of U.S.$7.8 million in the year ended 31 December 2012, compared with U.S.$3.2 million in the year ended 31 December 2011. The increase in travel was commensurate with the increased activity related to the execution of the Group's capital programme. In addition to the travel required for regular rotating staff in-country, frequent travel by the supporting technical employees from the Calgary office was required to ensure effective implementation of the business plan. Air travel to N'Djamena is expensive, but the Group has been actively changing its travel booking strategies in order to reduce overall flight costs, which has resulted in a significant decrease in the cost per ticket; however, this has been offset by increased activity.

Finance expense (income)

In the year ended 31 December 2012, the Group incurred finance expense of U.S.$8.1 million, which was due almost entirely to interest payments due on the Convertible Bonds (as defined below). For the year ended 31 December 2011, the Group maintained short-term investments of excess cash arising from private placement financing rounds, prior to these funds being used in the operating and investing activities of the Group. These investments generated net finance income of U.S.$0.5 million.

Foreign exchange loss

The Group incurred a foreign exchange loss of U.S.$0.2 million in the year ended 31 December 2012. The Group recorded a loss of U.S.$2.5 million in the year ended 31 December 2011, resulting from the higher level of activity in the latter half of that year, coupled with a deterioration of the U.S. dollar against the Canadian currency over the same period.

Year ended 31 December 2011 compared to year ended 31 December 2010

Revenues

The Group did not generate any operating revenues during the years ended 31 December 2011 or 2010.

Expenses

A summary of the expenses incurred by the Group during the years ended 31 December 2011 and 2010 is presented in the table below:

	Year ended 31 December (audited)	
	2011	2010
	(U.S.$'000)	
Salaries and benefits	4,605	—
Share-based compensation	29,856	—
Depreciation	149	—
Consulting fees	8,266	1,027
Legal and professional fees	5,819	279
General and administrative	2,677	143
Travel	3,160	175
Change in fair value of Warrants	(69)	10
Finance expense/(income)	(463)	10
Foreign exchange (gain)/loss	2,450	(103)
Net loss and comprehensive loss	56,450	1,541

Results in the year ended 31 December 2011 were impacted by the acquisition of the PSCs and Share-based payments. In the year ended 31 December 2010 the Group was in its start-up phase, primarily focused on evaluation of the acreage in Chad and negotiations with the Government to secure the PSCs.

Salaries and benefits

When the PSCs were secured in 2011, the Group initiated its recruitment drive to support the work programmes necessary to develop the acquired acreage, eventually incurring costs of U.S.$4.6 million. Over the prior year, the evaluation and negotiations were done through the use of consultants and the contributions of the Group's founders and, as a result, there were no employees in the year ended 31 December 2010.

Share-based compensation and Performance Warrants

With the recruitment drive in 2011, the Group offered Options as part of the total compensation package. Of the total expense of U.S.$29.9 million for the year ended 31 December 2011, over U.S.$14.0 million related to Options issued to the current management team, and U.S.$4.0 million related to Options that were granted to the Group's former Chief Executive Officer (which have since been exercised).

Consulting fees

Once the PSCs came into effect, a substantial amount of the initial work was accomplished by using experienced consultants. As a result, consulting fees for the year ended 31 December 2011 increased substantially to U.S.$8.3 million over U.S.$1.0 million for the year ended 31 December 2010.

Legal and professional fees

Legal and professional fees increased to U.S.$5.8 million in the year ended 31 December 2011 from U.S.$0.3 million in the year ended 31 December 2010. The majority of the legal fees in 2011 related to the Special Committee Investigation, though a significant portion also pertained to completing the PSC negotiation and signing process that commenced in 2010.

General and administrative

General and administrative fees increased to U.S.$2.7 million in the year ended 31 December 2011 from U.S.$0.1 million in the year ended 31 December 2010. This increase reflected increased charges for contract services, office space, communications costs, vehicle rental expenses, and prescribed PSC obligations such as local training, annual report fees and audit fees.

Travel

Travel expenses increased to U.S.$3.2 million in the year ended 31 December 2011 from U.S.$0.2 million in the year ended 31 December 2010. The increase in travel was commensurate with the increased activity upon the acquisition of the three PSCs. In addition to the rotating of employees in-country, frequent travel by the supporting technical staff from the Calgary-based head office was required to ensure effective implementation of the Group's strategy and business plan.

Foreign exchange loss

Foreign currency transactions were primarily the result of currency rate fluctuations between U.S. and Canadian dollars realised on the settlement of transactions and revaluations of current monetary assets and liabilities. The Group recorded a loss of U.S.$2.5 million in 2011 compared to a net gain of U.S.$0.1 million in the prior year. The loss in 2011 resulted from the higher level of activity in the latter half of the year, coupled with a deterioration of the U.S. dollar against the Canadian dollar over the same period.

Finance income

The Group maintained short-term investments of excess cash arising from private placement financing rounds, prior to these funds being used in the operating and investing activities of the Group. These investments generated net finance income for the year ended 31 December 2011 of U.S.$0.5 million. In 2010, the Group incurred a finance interest charge of U.S.$0.01 million on a loan from BDG Capital, an entity associated with the Group's founder. The loan, along with the interest charge, was repaid in 2010.

Liquidity and Capital Resources

The Group does not currently have any revenue from operations and has been historically reliant on its ability to raise funds through private equity and debt capital markets transactions. There can be no assurance that the Group will be successful in raising funds in future periods, although the Group expects to have sufficient working capital from its existing resources to fund itself for at least the next 12 months.

Capital Resources

Historically, the Group has financed its capital resource needs through the sale of Shares and Convertible Bonds with the objective of acquiring prospective oil assets and maximising long-term financial returns to its shareholders. The Group anticipates developing its assets in Chad utilising a combination of existing capital resources, anticipated future revenues and future funds raised from debt and equity, if available. The Group is targeting commencement of first production of oil from the Badila and Mangara Fields in July 2013 and the third quarter of 2013, respectively. In order to maintain or adjust its capital structure, in future periods the Group may pay dividends, return capital to shareholders, enter into joint venture agreements with third parties, incur long-term debt, issue new shares, sell assets, or execute a combination of the aforementioned items.

Cash flows

The following table sets forth the Group's cash flows during the three months ended 31 March 2013 and 2012 and the years ended 31 December 2012, 2011 and 2010.

	Three months ended 31 March (unaudited)		Years ended 31 December (audited)		
	2013	2012	2012	2011	2010
			(U.S.$'000s)		
Cash flows from Operating Activities	23,112	(9,663)	(55,186)	(24,443)	(1,941)
Cash flows from Investing Activities	(61,799)	(6,246)	(161,299)	(106,728)	—
Cash flows from Financing Activities	3,899	117,167	284,115	180,843	1,531
Cash and cash equivalents, end of the period	85,446	153,024	119,881	52,023	—

The Company's available cash resources as at 31 March 2013 and 2012 were U.S.$85.4 million and U.S.$153.0 million, respectively. In December 2012, the Company entered into the Farm-in Agreement with Glencore. Pursuant to the Farm-in Advance Agreement, U.S.$100 million and U.S.$50 million was

advanced by Glencore to the Group on 4 March 2013 and 30 May 2013, respectively, as advance consideration for its obligations under the Farm-in Agreement. The Farm-in Completion occurred on 13 June 2013, pursuant to which Glencore paid the Group U.S.$107,458,921 as consideration for its obligations under the Farm-in Agreement, net of the repayment of the Farm-in Advance.

For the year ended 31 December 2012, the Group generated a cash balance of U.S.$119.9 million. The principal components of this inflow were U.S.$291.0 million relating to the issue of Shares, Warrants and the Convertible Bonds. This was offset by an outflow of approximately U.S.$185.5 million relating to E&E additions in relation to the Badila and Mangara Field development projects and of U.S.$55.2 million relating to operating activities expenditure.

For the year ended 31 December 2011, the Group generated a cash balance of U.S.$52.0 million. The principal components of this inflow were U.S.$189.2 million raised from the issue of 37.5 million Shares in private placements and U.S.$2.0 million raised from the issue of 3.2 million Shares on the exercise of Options. This was offset by an outflow of U.S.$11.5 million relating to Share issue costs, an outflow of U.S.$106.3 million relating to E&E additions comprising signing bonuses of U.S.$100.4 million in relation to the acquisition of the Group's PSCs, an outflow of U.S.$3.0 million relating to the DOH consulting agreement and an outflow of U.S.$24.4 million relating to operating expenditures.

There were no material cash flows for the year ended 31 December 2010.

Financing

Since the Company's incorporation, it has primarily funded its operations through the sale of Shares and most recently the issuance of Convertible Bonds. The following is a summary of significant financings undertaken by the Group during the period under review.

U.S.$173.6 million Convertible Bonds

In September 2012, the Company issued U.S.$173.6 million pre-IPO convertible bonds (the "**Convertible Bonds**") with a maturity date of 30 September 2017 (the "**Maturity Date**"). The Convertible Bonds are convertible at any time up to 14 days prior to the Maturity Date (or 14 days prior to any earlier date fixed for redemption of the Convertible Bonds) at an initial conversion price of U.S.$6.07 per Share. The conversion price of the Convertible Bonds will be subject to adjustment on or following the occurrence of certain corporate events relating to the share capital of the Company.

Interest on the Convertible Bonds, initially at a rate of 12 per cent. per annum, will accrue quarterly and be compounded and capitalised semi-annually prior to a Qualifying Public Offering (a "**QPO**"). For the purpose of the Convertible Bonds, a QPO is defined as an offering of the Company's Shares which meets certain liquidity conditions and that results in a listing and admission to trading of the Shares on either (i) the regulated market of the London Stock Exchange (premium or standard listing on the Official List of the UK Listing Authority) or (ii) the Alternative Investment Market (AIM) operated by the London Stock Exchange. Following the QPO, the accrued but unpaid interest will become payable at the option of each bondholder either in cash or Shares. Effective 30 September 2013, interest will be accrued quarterly and compounded semi-annually at 12 per cent. plus a 50 basis point increase every six months until a QPO. However, if the QPO has not occurred prior to 30 September 2015, the Company will make payment on that date of all compounded and capitalised interest in cash. Following the earlier of a QPO and 30 September 2015, any further interest on the outstanding Convertible Bonds will be paid only in cash (without compounding) at the then prevailing rate.

The Convertible Bonds are redeemable by the Company from three months following a QPO at a redemption price equal to the principal amount plus accrued but unpaid interest, provided that the volume weighted average price of the Shares for 20 out of 30 consecutive dealing days ending not earlier than seven days prior to the date on which notice of redemption is provided is not less than 150 per cent. of the conversion price. If neither a QPO nor a change of control in relation to the Company has occurred prior to 30 September 2017, the Convertible Bonds which remain outstanding at the Maturity Date will be redeemed at 153.5 per cent. of their principal amount, together with accrued but unpaid interest.

The debt component of the Convertible Bonds is classified as a financial liability instrument and recorded in the financial statements of the Group at fair value net of issuance costs. The debt will be accreted using the effective interest rate method over the estimated life of the Convertible Bonds. The increase in the interest rate on the Convertible Bonds and the premium redemption feature are considered to be embedded derivatives and are not accounted. The conversion feature of the Convertible Bonds has been

classified as equity in the financial statements of the Group and is recorded as the residual value from the total proceeds less the fair value of the debt component, net of issuance costs.

Issued and outstanding Shares

The following table sets out certain information regarding Share issuances by the Group through 31 December 2012.

	Price Per Share	Shares Issued	Share Issue Costs	Amount
	(C$)	('000s)	(U.S.$'000)	
Balance at 31 December 2010		44,613		2,256
Private placements:				
11 January 2011[1]	2.50	900	136	2,125
25 February 2011 and 3 March 2011[2][3]	5.00	33,000	10,833	157,637
19 April 2011[2]	5.00	3,000	545	15,022
8 September 2011	5.00	577	—	2,927
Other:				
Management Units[4]	5.00	2,200	—	11,282
Management Options[5]	0.40	3,000	—	1,234
Shares issued to former CEO[6]	5.00	568	—	2,952
Exercise of employee share options	5.00	151	—	739
Value ascribed to Agent Advisory Options[3]	—	—	—	(3,258)
Value ascribed to 2011 Liquidity Warrants[2]	—	—	—	(2,775)
Transfer on exercise of Options[8]	—	—	—	14,476
Interest on shareholder loans[7]	—	—	—	49
Balance at 31 December 2011		88,009	11,514	204,666
Private placement:				
14 March 2012[8]	6.00	20,840	8,499	116,967
Other:				
Value ascribed to 2012 Liquidity Warrants[8]	—	—	—	(1,255)
Issued on exercise of 2011 Liquidity Warrants[2]	5.00	3,600	—	2,775
Other[9]	6.00	312	—	—
Interest on shareholder loans[7]	—	—	—	98
Deferred tax impact of share issue costs[8]	—	—	(4,979)	4,979
Balance, 31 December 2012		112,761	15,034	328,230
Conversion of 2012 Liquidity Warrants into Shares[10]	—	2,084	—	1,255
Agent Advisory Options converted into Shares[11]	—	779	—	5,153
Interest on shareholder loans	—	—	—	23
Balance, 31 March 2013	—	115,624	—	334,661

Notes:

(1) As a result of the completion of the private placement in January 2011, 0.6 million Purchase Warrants issued in a private placement completed in January 2010 were cancelled. The liability recorded at 31 December 2010 of U.S.$0.1 million was reversed upon cancellation of the Purchase Warrants.

(2) In connection with the private placements on 25 February 2011, 3 March 2011 and 19 April 2011, 3.6 million 2011 Liquidity Warrants were issued. The 2011 Liquidity Warrant terms called for them to be converted into Shares for no additional consideration on 1 January 2012 if a Liquidity Warrant Liquidity Event did not occur prior thereto. As no Liquidity Warrant Liquidity Event occurred, they were converted.

(3) In connection with the private placements on 25 February 2011 and 3 March 2011, the Company issued 2.0 million Agent Advisory Options to the placement agents which entitle the holder to acquire one Share at a price of C$5.00 per Share. The Agent Advisory Options vested on the date of grant and expire 24 months after the relevant date of issue. The fair value ascribed to Agent Advisory Options is U.S.$3.3 million, which has been reclassified to warrants in shareholders' equity.

(4) Shares were issued as part of the units (the "**2011 Units**") issued to the new management team. Each 2011 Unit was comprised of one Share and two Performance Warrants.

(5) The Company granted 3.0 million Seed Options to the new management team, directors, an insider, and the Corporate Secretary of the Group, exercisable at a price of C$0.40 per Share. These Seed Options were exercised immediately after grant, resulting in gross proceeds of U.S.$1.2 million to the Group and the issuance of an additional 3.0 million Shares. The fair value

of this benefit was estimated using a Black-Scholes valuation model with the following variables: risk free rate of 2.3 per cent., volatility of 62.5 per cent., an exercise price of C$0.40 and immediate vesting.

(6) Based on a prior agreement, on 2 September 2011, the Company issued 1.0 million Seed Options to the previous CEO of the Group exercisable at C$0.40 per Share, which were exercised on 30 September 2011. The Group paid the withholding tax on his behalf resulting in the Company issuing 0.6 million Shares at C$5.00 per Share.

(7) The 2011 Units purchased by the new management team of the Group on 1 July 2011 and 1 August 2011 were financed entirely through Share Purchase Loans made by the Group to the new management team in the amount of U.S.$11,281,800. This represents a benefit to management and, as a result, the fair value of this benefit was estimated to be U.S.$3.9 million using a Black-Scholes valuation model with the following variables: risk free rate of 2.3 per cent., volatility of 62.5 per cent., and exercise prices between C$5.01 and C$5.25 per Share. This benefit was expensed at the time of the transaction.

(8) In connection with the private placement on 14 March 2012, a total of 2.1 million 2012 Liquidity Warrants were issued, which will be converted to Shares at no additional consideration if a Liquidity Warrant Liquidity Event has not occurred prior to 14 March 2013. If a Liquidity Warrant Liquidity Event occurs prior to 14 March 2013, the 2012 Liquidity Warrants will expire, unexercised in accordance with their terms. For tax purposes, a Liquidity Warrant Liquidity Event is defined as:

- a public offering pursuant to which the Shares of the Company are admitted to trading on a recognised Canadian, United States or UK stock exchange;
- the completion of any transaction which results in all or substantially all of the outstanding Shares to be exchanged for the securities of another issuer which will be listed on a recognised Canadian, United States or UK stock exchange; or
- the acquisition of all or substantially all of the outstanding Shares for cash.

The fair value ascribed to 2012 Liquidity Warrants is U.S.$1.3 million, which has been reclassified to warrants in shareholders' equity as of 31 December 2011.

(9) The Company issued 0.3 million Shares in the first quarter of 2012 at no consideration to its lender as payment upon signing a term sheet for a credit facility. The Shares were issued at a price of C$6.00 per Share and include a put option of C$6.00. The put option is exercisable at any time by the holder; therefore, the carrying value of the instrument (U.S.$1,805,826) has been included in current liabilities as of 31 December 2012.

(10) The 2012 Liquidity Warrants described in Note 8 above were converted into Shares at no additional consideration as a Liquidity Warrant Liquidity Event did not occur prior to 14 March 2013. The fair value ascribed to the 2012 Liquidity Warrants of U.S.$1.3 million has been reclassified to share capital.

(11) Of the Agent Advisory Options described in Note 3 above, as at 31 March 2013, 0.8 million Agent Advisory Options had been exercised, and the remaining Agent Advisory Options have expired.

Warrants

The following table sets out the Group's outstanding Warrants at 31 December 2012.

	Number of Warrants	Liability Classified	Equity Classified
	('000s)	(U.S.$'000)	
Balance at 31 December 2010	613	69	—
Cancellation of Performance Warrants[1]	(613)	(69)	—
2011 Liquidity Warrants[2]	3,600	—	2,775
Agent Advisory Options	1,980	—	3,258
Management Performance Warrants[1]	4,400	—	5,660
Balance at 31 December 2011	9,980	—	11,693
2011 Liquidity Warrants exercised	(3,600)	—	(2,775)
2012 Liquidity Warrants issued	2,084	—	1,255
Employee Performance Warrants[2]	1,717	—	2,510
Balance at 31 December 2012	10,181	—	12,683
2012 Liquidity Warrants exercised	(2,084)	—	(1,255)
Agent Advisory Options converted into Shares	(779)	—	(1,282)
Agent Advisory Options expired	(1,201)	—	(1,976)
Employee Performance Warrants	—	—	139
Balance at 31 March 2013	6,117	—	8,309

Notes:

(1) Management Performance Warrants

In connection with the 2011 Units issued to management, 4.4 million Performance Warrants were issued. Each Performance

Warrant entitles the holder thereof to purchase one Share of the Company at a price of C$5.50 per Share for five years from the date of grant, subject to vesting. The Performance Warrants shall vest and become exercisable by the holder if the 10-day volume-weighted average trading price of the Company's Shares at any time, on any stock exchange upon which such Shares are listed, meets or exceeds C$15.00 or if a liquidity event (as defined in the certificates representing the Performance Warrants) occurs. The estimated fair value of the Performance Warrants of U.S.$5.7 million is included in the loss for the year ended 31 December 2011. The Group used the Black-Scholes pricing model to calculate the fair value of the Performance Warrants. Measurement inputs include the share price on measurement date (C$5.00), exercise price (C$5.50), expected volatility (62.5 per cent.), expected life (5 years) and the risk-free interest rate (2.3 per cent.).

(2) Employee Performance Warrants

In March 2012, the Company issued 1.7 million Performance Warrants to certain employees, officers and directors. Each Performance Warrant entitles the holder thereof to purchase one Share of the Company at a price of C$6.00 per Share for five years from the date of grant, subject to vesting. The Performance Warrants shall vest in ⅓ increments and become exercisable by the holder if the 10-day volume-weighted average trading price of the Company's Shares at any time, on any stock exchange upon which such Shares are traded, meets or exceeds C$7.50, C$9.00 and C$12.00, respectively, or if a change of control of the Company occurs. The estimated fair value of the Performance Warrants was U.S.$2.7 million. The Group used the Black-Scholes pricing model to calculate the fair value of the Performance Warrants. Measurement inputs include the share price on measurement date (C$6.00), exercise price (C$6.00), expected volatility (64.14 per cent.), expected life (5 years), forfeiture rate (10 per cent.) and the risk-free interest rate (1.61 per cent.).

Capital Expenditures

Historical

The nature of the Group's business is capital intensive, both in terms of the initial costs associated with establishing the necessary facilities and infrastructure to support commercial production of oil and the ongoing costs associated with exploration, drilling and production. For the year ended 31 December 2012, the Group had a total capital expenditure of U.S.$189.1 million, investing in oil exploration, appraisal and development in its properties.

The following table sets out the Group's capital expenditures for the three months ended 31 March 2013 and 2012 and the years ended 31 December 2012, 2011 and 2010.

	Three months ended 31 March (unaudited)		Year ended 31 December (audited)		
	2013	2012	2012	2011	2010
			(U.S.$'000)		
Signing bonus	—	—	4,000	93,000	—
Legal fees relating to PSCs	—	—	—	7,440	—
Consulting fees relating to PSCs	—	—	—	3,000	—
Studies and seismic	8,559	1,667	7,039	52	—
Drilling and workovers	29,538	231	24,740	—	—
Facilities	52,950	14,164	107,045	—	—
Infrastructure, camps and land acquisitions	12,765	569	21,032	—	—
Inventory	—	—	18,301	—	—
Corporate assets	3,766	2,101	6,263	4,591	—
Total Cash Capital Expenditures	107,578	18,732	188,420	108,083	—
Decommissioning liability	370	(19)	(75)	1,918	—
Depreciation	(373)	(176)	(1,007)	(111)	—
Capitalised Share-based compensation	729	292	1,802	354	—
Total Non-Cash Capital Expenditure	726	97	720	2,161	—
Total	108,304	18,829	189,140	110,244	—

Signing bonuses, legal and consulting fees

Signing bonuses of U.S.$4.0 million paid in 2012 related to payments associated with the approval of the Badila and Mangara EXAs (U.S.$2.0 million for each). All signing bonuses are paid to the Government of Chad as agreed and outlined in the terms of the PSCs.

Signing bonuses paid in 2011 related to the Group's three PSCs (U.S.$40.0 million for the DOB/DOI PSC, U.S.$40.0 million for the Doseo/Borogop PSC, and U.S.$13.0 million for the DOH PSC). The Group also paid legal and consulting fees related to the PSCs of U.S.$7.4 million and U.S.$3.0 million, respectively.

Studies and seismic

A 3-D seismic programme commenced in March 2013 over the Badila Field and Bitanda exploration prospect with an estimated budget of U.S.$17.1 million. Costs as of 31 March 2013 were U.S.$8.2 million and the acquisition phase was completed in May 2013. A 3-D seismic programme was completed over the Mangara EXA lands in the first quarter of 2012 for a total cost of U.S.$6.5 million. Other studies and seismic work were undertaken in 2012 as the Group prepared to complete another 3-D programme in early 2013, as well as some additional 2-D seismic studies.

Drilling and workovers

During the three months ended 31 March 2013, the Group (i) completed the drilling and testing of the Badila-2 well, (ii) completed the drilling of the Badila-3 well and (iii) commenced the drilling of the Mangara-4 well. In anticipation of production commencing from Badila-1 and Badila-2 during July 2013, a workover of the Badila-1 wellbore was begun in March, for a cumulative cost as at 31 March 2013 of U.S.$1.8 million. The Group spent U.S.$24.7 million on drilling activities in 2012, including two drilling re-entries, Mangara-2 and Badila-1, at a cost of approximately U.S.$9.5 million. Drilling and workovers also include costs associated with the preparation of future well leases, construction of well pads, mobilisation of drilling rigs, and the purchasing of long-lead items.

Facilities

Major components of the Group's facilities expenditure of U.S.$107.0 million in 2012 included engineering of the central processing facilities, general sales terminal and pipeline. The early works programme in 2012 consisted of crossing the Logone River with four 12-inch oil pipelines, and initial construction on the Connection Pipe which will connect the Blending Export Terminal to the Export Pipeline, and the LACT Unit, which is the final oil measurement point prior to the Group's production from the Badila and Mangara Fields entering the Export Pipeline.

- Early Production Facilities

  Construction of the Early Production Facilities was commenced in November 2012. The Early Production Facilities will treat and process initial production from Badila and were commissioned in April 2013. Each facility has a processing capacity of 7,000 bbl/d. Construction of the Early Production Facilities Expansion, providing for a further 10,000 bbl/d of processing capacity, is expected to commence in late 2013 with commissioning expected to take place in the first quarter of 2014.

- ITA Facilities

  The ITA Facilities comprise the Blending Export Terminal, the Connection Pipe, the LACT Unit and the Hot Tap. The Blending Export Terminal, located close to the Badila Field, is scheduled for completion and commissioning in the third quarter of 2013. The Connection Pipe, which will transport the Group's oil from the Badila and Mangara Fields to the Export Pipeline, was completed and commissioned in May 2013. The LACT Unit, which will act as the final oil measurement point prior to the Group's production from the Badila and Mangara Fields entering the Export Pipeline, was completed and commissioned in May 2013. The Hot Tap, which allows oil to flow into the Export Pipeline from the Connection Pipe, was completed and commissioned in June 2013.

Infrastructure, camps and land acquisition

Throughout 2012, as part of the early works program, the Group conducted an extensive land acquisition initiative whereby all lands needed for the Badila and Mangara development project were successfully acquired. This included the lands for all facilities, pipelines, roads, future wells and camps. All major road infrastructure required for the development project was built or upgraded, and camps were purchased and are currently being set up at the adjacent to the central processing facilities and general sales terminal sites. Total capital expenditure related to infrastructure, camps and land acquisition in 2012 was U.S.$21.0 million.

Budgeted

The principal cash requirements of the Group in 2013 will be to fund the Group's capital expenditure plan which relates to completion of certain infrastructure projects and the continued exploration and development of its properties. The plan is budgeted at approximately U.S.$626.4 million (gross), subject to

financing and requisite approvals from the Government of Chad and the Group's joint venture partners. This 2013 capital expenditure programme is expected to include the following projects:

Badila Capital Expenditure

U.S.$104.7 million (gross) is budgeted by the Group to be spent in 2013. Major projects include drilling and testing three development wells, at a cost of approximately U.S.$11.2 million per well (gross). Other key components of the 2013 Badila programme are facilities construction projected to cost U.S.$23.4 million (gross), Export Pipeline upgrades at a cost of approximately U.S.$6.6 million (gross) and associated freight and other support costs of approximately U.S.$11.1 million (gross).

Mangara Capital Expenditure

U.S.$287.0 million (gross) is budgeted by the Group to be spent in 2013 (gross of Glencore's contribution pursuant to the Farm-in Agreement). Major projects include drilling and testing of four wells at a total cost of approximately U.S.$50.3 million (gross) and facilities construction at a cost of approximately U.S.$124.3 million (gross), including the Mangara CPF, which will treat and process initial production from Mangara. The facility will have an initial capacity of 10,000 bbl/d which will be expandable on a modular basis to between 25,000 and 40,000 bbl/d. Other key components of the 2013 Mangara programme are Export Pipeline upgrades and pipeline costs of approximately U.S.$31.8 million (gross), including the Mangara to Badila Pipeline which will carry production from the Mangara CPF to the Blending Export Terminal, located close to the Badila Field. The Blending Export Terminal is expected to be installed and commissioned in the third quarter of 2013. Associated freight and other support costs are expected to amount to approximately U.S.$41.6 million (gross).

ITA Capital Expenditure

U.S.$43.0 million (gross) is budgeted by the Group to be spent in 2013 for capital expenditure relating to the ITA Facilities, including approximately U.S.$12.4 million (gross) for the Badila Processing Facility to LACT pipeline, approximately U.S.$7.9 million (gross) for the Hot Tap, approximately U.S.$10.6 million (gross) related to blending equipment and approximately U.S.$10 million (gross) for Blending & Exporting Terminal upgrades.

Exploration Capital Expenditure

U.S.$191.7 million (gross) is budgeted by the Group to be spent in 2013 for capital expenditure relating to exploration, including approximately U.S.$64.4 million (gross) for the DOI/DOB Contractual Zone, approximately U.S.$126.5 million (gross) for the Doseo/Borogop Contractual Zone and approximately U.S.$0.8 million (gross) for the DOH Contractual Zone.

Quantitative and Qualitative Disclosures on Market Risk

The Group's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production and financial activities such as credit risk, liquidity risk and market risk.

The following table provides fair value measurement information for financial assets and financial liabilities as at 31 March 2013 and 2012 and 31 December 2012, 2011 and 2010. The carrying values of the Group's financial assets and liabilities approximate their fair values due to the short-term nature of the instruments:

	31 March (unaudited)		31 December (audited)		
	2013	2012	2012	2011	2010
			(U.S.$'000)		
Financial assets:					
Cash	85,446	153,024	119,881	52,023	—
Accounts receivable	11,978	1,640	12,240	886	822
	97,424	154,664	132,121	52,909	822
Accounts payable and accrued liabilities	24,493	29,045	42,741	7,471	514
Total	24,493	29,045	42,741	7,471	514

Credit risk

Credit risk is the risk of financial loss to the Group if a customer or counterparty to a financial instrument fails to meet its contractual obligations. On entering into any business contract, the extent to which the arrangement exposes the Group to credit risk is considered.

The Group's policy to mitigate credit risk associated with these balances is to establish relationships with reputable counterparties. As at 31 December 2012, the Group had Share Purchase Loans outstanding to officers of the Group in the amount of U.S.$9.9 million. The Group considers the Share Purchase Loans to have negligible credit risk given the security on the loans and the holders of the loans.

As at 31 December 2012, the Group's maximum exposure to credit risk in respect of accounts receivable was U.S.$12.2 million. An aging analysis of accounts receivable is noted in the table below:

	As at 31 December 2012
	(U.S.$'000)
Less than 30 days	9,970
31 to 90 days	1,695
Greater than 90 days (deposits)	575
Total	12,240

Liquidity risk

Liquidity risk is the risk that the Group will not be able to meet its financial obligations as they fall due. The Group's approach to managing liquidity is to ensure it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Group's reputation.

Typically, the Group will ensure that it has sufficient cash on demand to meet expected operational expenses for a period of 60 days, including the servicing of financial obligations. To achieve this objective, the Group prepares a cash flow forecast, which is regularly monitored and updated as warranted.

The contractual maturities of all accounts payable and accrued liabilities are less than one year.

Market risk

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates will affect the Group's income or the value of the financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimising the return.

The Group may use both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors.

Commodity price risk

Price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil are impacted not only by the relationship between the U.S. dollar and other currencies, but also world economic events that impact the perceived levels of supply and demand.

Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. During the year ended 31 December 2012 the Group incurred interest expense on the Convertible Bonds at the rates prescribed in the underlying agreement.

Future Commitments and Contingencies

Pursuant to its concession agreements in Chad, the Company is required to perform certain minimum exploration activities by the expiry of the Initial Exploration Terms associated with each of the PSCs, all of which are within the next five years:

Concession Name	Expiry Date	Original Minimum Work Requirement	Remaining Minimum Work Required as at 31 March 2013
		(U.S.$'000)	
Doseo/Borogop PSC	January 26, 2016	50,000	44,678
DOB/DOI PSC	April 24, 2016	50,000	35,741
DOH PSC	August 2, 2016	15,000	13,990
Total		115,000	94,409

Pursuant to its concession agreements in Chad, the Company is required to pay certain prescribed amounts relating to the training of Chadian nationals and employees of the Ministry of Petroleum, audits of the Government of Chad, and the presentation of annual reports to the Government of Chad. These prescribed amounts under the terms of the concession agreements are approximately $3.0 million per annum.

The Company has office lease commitments in N'Djamena, Chad, and Calgary, Alberta, Canada. Non-cancellable future operating lease rentals of approximately $1.4 million per annum are required from 2013 to 2015.

The following is a summary of the Company's contractual obligations as at 31 December 2012:

Contractual Obligations	Under 1 year	1-3 years	4-5 years	+5 years	Total
			(U.S.$'000)		
Convertible Bonds[1]	—	—	303,500	—	303,500
Interest on Convertible Bonds[2]	5,956	81,374	46,675	—	134,005
Accounts payable	42,741	—	—	—	42,741
Annual PSC payments	2,850	8,550	—	—	11,400
Operating lease payments	1,400	3,700	—	—	5,100
Total	52,947	93,624	350,175	—	496,746

(1) Assumes the Convertible Bonds are not converted prior to maturity.

(2) Interest on the Convertible Bonds is capitalised to the principal amount until 30 September 2015.

Transactions with Related Parties

See paragraph 13—"Related Party Transactions" in Part XVI: "Additional Information" for a discussion of all transactions involving related parties.

Use of Estimates and Critical Accounting Policies

The preparation of the consolidated financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates and affect the results reported in these consolidated financial statements.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognised in the period in which the estimates are revised and in any future periods affected. Information about significant areas of estimation, uncertainty and critical judgments in applying accounting policies that have the most significant effect on the amounts recognised in the consolidated financial statements are as follows:

- The calculation of deferred income tax assets and liabilities is based on management's interpretation of applicable laws, regulations and relevant court decisions, and in the case of deferred income tax assets, projections of future earnings to be applied against loss carry forward positions.

- The recoverability of intangible exploration and evaluation assets is based on numerous assumptions including estimated reserves, forward commodity price forecasts, development plans, political and social uncertainties, discount rates and various other factors. The recoverability of the intangible exploration and evaluation assets is also impacted by the policy election permitted under IFRS as to the level at which exploration and evaluation assets are tested for impairment (see "Notes to Consolidated Financial Statements—2(f)" in Part XII: "Historical Financial Information".
- The fair value of Share-based compensation is based on estimates relating to option life, volatility, share price and the outcome of performance conditions.

Property, plant and equipment and intangible exploration and evaluation assets

Recognition and measurement

(a) Development and production costs ("**D&P**")

Property, plant and equipment is stated at cost, less accumulated depletion and depreciation and accumulated impairment losses.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of any decommissioning obligation, if any, and, for qualifying assets, borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognised as oil interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognised in profit or loss as incurred. Such capitalised oil interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognised. The costs of the day-to-day servicing of property, plant and equipment are recognised in profit or loss as incurred. Where an asset or part of an asset that was separately depreciated is replaced and it is probable that future economic benefits associated with the item will flow to the Group, the expenditure is capitalised and the carrying amount of the replaced asset is derecognised. Inspection costs associated with major maintenance programmes are capitalised and amortised over the period to the next inspection. All other maintenance expenditures are expensed as incurred.

(b) Intangible exploration and evaluation ("**E&E**") expenditures

Pre-license costs are recognised in profit or loss as incurred.

Exploration and evaluation expenditures, including the costs of acquiring licenses, directly attributable general and administrative costs, geological and geophysical costs, other direct costs of exploration (drilling, trenching, sampling and evaluating the technical feasibility and commercial viability of extraction) and evaluation are accumulated and capitalised as intangible exploration and evaluation assets. Interest is not capitalised on E&E assets.

On a quarterly basis, a review of any areas classified and accounted for as E&E assets is performed to determine whether enough information exists to make a determination of the technical feasibility and commercial viability of the area. Where appropriate, review may indicate that an area should be further sub-divided due to a significant portion having been explored whilst a significant undeveloped portion with different traits (i.e. different zone, technical approach, play type, etc.) remains that requires additional E&E activities to arrive at the point where it can be assessed for technical feasibility and commercial viability.

The assessment of technical feasibility and commercial viability is performed on an area level basis unless further sub-division is merited. Depending on the extent and complexity of the prospective play, many wells may need to be drilled and potentially significant E&E costs accumulated prior to obtaining enough information to make the determination of technical feasibility and commercial viability possible.

E&E costs are not amortised prior to the conclusion of appraisal activities. At the completion of appraisal activities, if technical feasibility is demonstrated and commercial reserves are discovered, then, the carrying value of the relevant E&E asset will be reclassified as a D&P asset into the cash generating unit ("**CGU**")

to which it relates, but only after the carrying value of the relevant E&E asset has been assessed for impairment, and where appropriate, its carrying value adjusted. If the Group determines the area is not technically feasible and commercially viable, accumulated E&E costs are expensed.

(c) Depletion and depreciation

The net carrying value of development and production assets will be depleted using the unit of production method by reference to the ratio of production in the period to the related proved and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. These estimates are reviewed by independent reserve engineers at least annually. Producing assets are generally grouped with other assets that are dedicated to serving the same reserves for depreciation purposes.

Proved and probable reserves are estimated at least annually by independent qualified reserve evaluators and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. For interim financial statements internal estimates of changes in reserves and future development costs are used for determining depletion for the period.

For property, plant and equipment other than development and production assets, the Group provides for depreciation based on the estimated useful lives of the assets.

Depreciation methods, useful lives and residual values are reviewed at each reporting date, and adjusted if appropriate, to ensure that these are consistent with the expected pattern of consumption of the future economic benefit embodied in the asset.

Impairment

(a) Financial assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortised cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognised in profit or loss.

An impairment loss is reversed when there is a significant change in the underlying estimates or other objective evidence. For financial assets measured at amortised cost the reversal is recognised in profit or loss.

(b) Non-financial assets

Intangible exploration and evaluation costs are tested for impairment when reclassified to oil properties or whenever facts and circumstances indicate potential impairment. Exploration and evaluation assets are tested separately for impairment or grouped with the relevant CGU or groups of CGUs. An impairment loss is recognised for the amount by which the exploration and evaluation expenditure's carrying amount exceeds its recoverable amount. The recoverable amount is the higher of the exploration and evaluation expenditure's fair value less costs to sell and their value in use.

Values of oil properties and other property, plant and equipment are reviewed for impairment when indicators of such impairment exist. If any indication of impairment exists an estimate of the asset's recoverable amount is calculated. Assets are grouped for impairment assessment purposes at the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets (the CGU). The recoverable amount of an asset or CGU is the greater of its fair value less costs to sell and its value in use. Where the carrying amount of an asset group exceeds its recoverable amount, the asset group is considered impaired and is written down to its recoverable amount. An impairment loss is charged to the profit or loss. In assessing value in use, the estimated future cash flows

are adjusted for the risks specific to the asset group and are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money.

For assets excluding goodwill, an assessment is made at each reporting date as to whether there is any indication that previously recognised impairment losses may no longer exist or may have decreased. If such indication exists, the Group makes an estimate of the recoverable amount. A previously recognised impairment loss is reversed only if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognised. If that is the case the carrying amount of the asset is increased to its recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognised for the asset in prior years.

Share-based compensation

The Group uses the fair value method for valuing Share-based compensation. Under this method, the compensation cost attributed to Options and other Share-based compensation granted is measured at the fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of Options that vest. Upon the settlement of the Options the previously recognised value in contributed surplus is recorded as an increase to shareholders' capital.

Provisions

A provision is recognised if, as a result of a past event, the Group has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognised for future operating losses.

Decommissioning obligations

The Group's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalised in the relevant asset category.

Decommissioning obligations are measured at the present value of management's best estimate of the expenditures required to settle the present obligation at the balance sheet date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognised as finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalised. Actual costs incurred upon settlement of asset retirement obligations are charged against the provision to the extent the provision was established.

Revenue

Revenue from the sale of oil is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer which is usually when legal title passes to the external party. This is generally at the time the product enters the pipeline or is delivered to the refinery. Revenue is measured net of discounts, customs duties and royalties.

Tariffs, tolls and fees, if any, charged to other entities for use of pipelines and/or facilities owned by the Group are recognised as revenue as they accrue in accordance with the terms of the related agreements. Where the Group acts as agent on behalf of a third party to transport or process oil, any associated fee income is recognised on a net basis.

Income tax

Income tax expense comprises current and deferred tax. Income tax expense is recognised in profit or loss except to the extent that it relates to a business combination or items recognised directly in equity or other comprehensive income.

Current tax is the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date and any adjustment in respect of previous years.

Deferred tax is recognised using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognised on the initial recognition of assets or liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable profit or loss. In addition, deferred tax is not recognised for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realised simultaneously. The Company does not incur tax in Chad on oil and gas sales under the terms of the PSCs.

A deferred tax asset is recognised to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilised. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realised.

PART XI

CAPITALISATION AND INDEBTEDNESS STATEMENT

The following table sets out the Group's consolidated capitalisation and indebtedness as at 31 March 2013.

	31 March 2013 (U.S.$'000)
Total current debt	
Guaranteed	—
Secured	—
Unguaranteed/unsecured	—
Total non-current debt (excluding current portion of long-term debt)	
Guaranteed	—
Secured	—
Unguaranteed/unsecured[(1)]	243,289

(1) Unguaranteed/unsecured debt refers to Convertible Bonds of U.S.$143.3 million and an advance from Glencore of U.S.$100 million.

	31 March 2013 (U.S.$'000)
Shareholders' equity	
Share capital	334,661
Share premium	—
Other reserves[(1)]	45,688

(1) Other reserves do not include accumulated deficit of U.S.$145.8 million as at 31 March 2013.

The capitalisation information has been extracted without adjustment from the unaudited interim consolidated financial statements of the Company as of and for the three months ended 31 March 2013. Except as described in Note 10 "Subsequent events" to the unaudited interim consolidated financial statements of the Company as of and for the three months ended 31 March 2013, there has been no material change in the Group's capitalisation since 31 March 2013.

The following table sets out the Group's net indebtedness as at 31 March 2013.

	31 March 2013 (U.S.$'000)
Cash	85,446
Cash equivalent	—
Trading securities	—
Liquidity	—
Current financial receivable	—
Current bank debt	—
Current portion of non-current debt	—
Other current financial debt	—
Current financial debt	—
Net current financial indebtedness	(85,446)
Non-current bank loans	—
Bonds issued	143,289
Other non-current loans[(1)]	100,000
Non-current financial indebtedness	243,289
Net financial indebtedness	157,843

(1) On 30 May 2013, an additional advance of U.S.$50 million was received from Glencore as discussed in Note 10 "Subsequent events" to the unaudited interim consolidated financial statements of the Company as of and for the three months ended 31 March 2013.

The Group has no indirect or contingent liabilities.

As at 31 May 2013 (being the latest practicable date prior to the publication of this Prospectus) the total borrowings of the Company were U.S.$298.2 million.

PART XII

HISTORICAL FINANCIAL INFORMATION

Interim Consolidated Statements of Financial Position (unaudited)

		As at 31 March 2013	As at 31 December 2012
		(U.S.$'000)	
Assets			
Current:			
Cash and cash equivalents		85,446	119,881
Accounts receivable		11,978	12,240
		97,424	132,121
Intangible exploration and evaluation assets	Note 4	403,774	295,747
Property, plant and equipment		3,913	3,636
Total Assets		505,111	431,504

		As at 31 March 2013	As at 31 December 2012
		(U.S.$'000)	
Liabilities and Shareholders' Equity			
Current:			
Accounts payable and accrued liabilities		24,493	42,741
Long term liabilities:			
Advance	Note 8	100,000	—
Convertible bonds	Note 7	143,289	135,511
Decommissioning obligations		2,945	2,079
Share-based compensation liability	Note 6	292	—
Total Liabilities		270,569	180,331
Share capital	Note 5	334,661	328,230
Contributed surplus	Note 6	17,627	13,233
Warrants and agent options	Note 5	8,309	12,683
Equity component of convertible bonds		29,395	29,395
Share purchase loans		(9,643)	(9,928)
Deficit		(145,807)	(122,440)
Total Shareholders' Equity		234,542	251,173
Commitments	Note 9	—	—
Subsequent events	Note 10	—	—
Total Liabilities and Shareholders' Equity		505,111	431,504

The notes are an integral part of these interim consolidated financial statements

Interim Consolidated Statements of Operations (unaudited)

		Three months ended 31 March	
		2013	2012
		(U.S.$'000)	
Expenses			
Salaries and benefits		5,825	2,704
Share-based compensation	Note 6	2,121	2,608
Depreciation		394	195
General and administrative		4,920	14,389
Travel		1,988	1,274
Finance expense (income)		7,765	(10)
Foreign exchange loss (gain)		354	(257)
Net loss and comprehensive income		23,367	20,903
Loss per share:			
Basic and diluted		0.21	0.22

Interim Consolidated Statements of Changes in Shareholders' Equity (unaudited)

	Three months ended 31 March	
	2013	2012
	(U.S.$'000)	
Share Capital (Note 5)		
Balance, beginning of the period	328,230	204,666
Share issuance, net of costs	—	117,133
Conversion of liquidity warrants into shares	1,255	2,774
Interest on share purchase loans	23	24
Agency options converted to shares	5,183	—
Value ascribed to liquidity warrants	—	(1,255)
Balance, end of the period	334,661	323,342
Contributed Surplus (Note 6)		
Balance, beginning of the period	13,233	5,376
Share-based compensation	1,689	2,450
Share-based compensation—capitalised	729	292
Agency options expired	1,976	—
Balance, end of the period	17,627	8,118
Warrants and Agent Options (Note 5)		
Balance, beginning of the period	12,683	11,693
Conversion of liquidity warrants into shares	(1,255)	(2,774)
Value ascribed to liquidity warrants	—	1,255
Agency options converted to shares	(1,282)	—
Agency options expired	(1,976)	—
Share-based compensation for performance warrants	139	158
Balance, end of the period	8,309	10,332
Equity Component of Convertible Bonds		
Balance, beginning of the period	29,395	—
Balance, end of the period	29,395	—
Share Purchase Loans		
Balance, beginning of the period	(9,928)	(9,621)
Interest on loans	(23)	(24)
Interest received on loans	28	34
Foreign exchange	280	(174)
Balance, end of the period	(9,643)	(9,785)
Deficit		
Balance, beginning of the period	(122,440)	(58,428)
Net loss of the period	(23,367)	(20,903)
Balance, end of the period	(145,807)	(79,331)
Total Shareholders' Equity	234,542	252,676

The notes are an integral part of these interim consolidated financial statements

Interim Consolidated Cash Flows

		Three months ended 31 March	
		2013	2012
		(U.S.$'000)	
Operating Activities			
Net loss		(23,367)	(20,903)
Adjustments for:			
Depreciation		394	195
Accretion		24	21
Share-based compensation		2,121	2,608
Interest on convertible bonds		7,779	—
Foreign exchange (gain)		(74)	83
Changes in non-cash working capital		36,235	8,333
		23,112	(9,663)
Investing Activities			
Intangible exploration and evaluation additions		(106,928)	(17,258)
Property, plant and equipment additions		(650)	(1,474)
Changes in non-cash working capital		(54,221)	12,486
Advance	Note 8	100,000	—
		(61,799)	(6,246)
Financing Activities			
Net proceeds from issuance of shares and warrants		3,871	117,133
Interest received on share purchase loans		28	34
		3,899	117,167
Effects of exchange rate changes on cash and cash equivalents		353	(257)
Increase in cash and cash equivalents		(34,435)	101,001
Cash and cash equivalents, beginning of period		119,881	52,023
Cash and cash equivalents, end of period		85,446	153,024

The notes are an integral part of these interim consolidated financial statements.

1 Reporting entity

Griffiths Energy International Inc. ("**Griffiths**" or the "**Company**") was incorporated pursuant to the Canada Business Corporations Act on 20 April, 2009. The Company is engaged in oil and gas exploration, development and production activities in the Republic of Chad, which is located in central Africa.

2 Basis of preparation

The interim consolidated financial statements of the Company have been prepared using accounting policies in accordance with International Accounting Standard ("**IAS**") 34: Interim Financial Reporting, International Financial Reporting Standards and interpretations (collectively referred to as "**IFRS**") as issued by the International Accounting Standards Board ("**IASB**").

These interim consolidated financial statements are approved by the Board of Directors on 26 April, 2013.

The interim consolidated financial statements should be read in conjunction with the Company's annual financial statements for the years ended 31 December, 2012 and 31 December, 2011.

On 1 January, 2013, the Company adopted new standards with respect to consolidations (IFRS 10), joint arrangements (IFRS 11), disclosure of interests in other entities (IFRS 12), fair value measurements (IFRS 13) and amendments to financial instrument disclosures (IFRS 7). The adoption of these standards had no impact on the amounts recorded in the consolidated financial statements as at 1 January, 2013 or on the comparative periods.

All amounts are expressed in US$ thousands unless otherwise stated.

3 Determination of fair values

A number of the Company's accounting policies and disclosures require the determination of fair value, both for financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

The different levels of financial instrument valuation methods have been defined as follows:

Level 1 Fair value measurements are based on unadjusted quoted market prices. Level 2 Fair value measurements are based on valuation models and techniques where the significant inputs are derived from quoted indices. Level 3 Fair Value Measurements are based on unobservable information.

The carrying value of cash and cash equivalents, accounts receivables, and accounts payable and accrued liabilities included in the consolidated statements of financial position approximate fair value due to the short term nature of those instruments. The fair value of the advance approximates its carrying value at the balance sheet date. The fair value of the liability component of the convertible bonds approximate their fair carrying value as interest rates and the credit spread has not altered significantly since the issue date.

4 Intangible exploration and evaluation assets

	Three months ended	
	31 March 2013	31 December 2012
	(U.S.$'000)	
Balance, beginning of period	295,747	108,556
Additions	108,048	187,265
Changes in decommissioning obligations	(21)	(75)
Balance, end of period	403,774	295,747

5 Share capital

(a) Issued and outstanding common shares:

	Note	Cash proceeds per share	Shares issued	Share issue costs	Amount
				(U.S.$'000)	
Balance, beginning of period			112,761	15,034	328,230
Conversion of liquidity warrants into shares	(i)	—	2,084	—	1,255
Agency options converted into shares	(ii)	$5.00	779	—	5,153
Interest on shareholder loans			—	—	23
Balance, end of period			115,624	15,034	334,661

(i) In connection with the private placement on 14 March, 2012, a total of 2.1 million liquidity warrants were issued, which were converted to common shares at no additional consideration as a liquidity event did not occur prior to 14 March, 2013. The fair value ascribed to the liquidity warrants of U.S.$1.3 million has been reclassified to share capital.

(ii) In connection with the private placement dated 25 February, 2011 and 3 March, 2011, the Company issued 2.0 million options to the agents which entitled the holder to acquire one common share at a price of $5.00 per common share. The agent options vested on the date of grant and expired 24 months after such date. The fair value ascribed to agent options is U.S.$3.3 million. As at 31 March, 2013, U.S.$0.8 million agent options have been exercised, and the remaining agent options have expired.

(b) Warrants:

	Note	Number of Warrants	Amount
		(000's)	(U.S.$'000)
Balance, beginning of period		10,181	12,683
Liquidity warrants exercised	5a(i)	(2,084)	(1,255)
Agency options converted into shares	5a(ii)	(779)	(1,282)
Agency options expired	5a(ii)	(1,201)	(1,976)
Employee performance warrants		—	139
Balance, end of period		6,117	8,309

6 Share-based compensation and contributed surplus

(a) A continuity of contributed surplus for the period is as follows:

	Amount
Balance, beginning of the period	13,233
Agency options expired	1,976
Employee options	1,689
Employee options—capitalised	729
Balance, end of period	17,627

(b) Performance units

On January 9, 2013 the Board of Directors approved a new Long Term Incentive Plan (the "**Plan**") for officers and other key executives of the Company. A total of 1.1 million performance units was granted under the new plan in the first quarter. The Plan was introduced to retain, attract and motivate key executives who are critical to executing the long term business strategy. A participant in the plan is awarded a notional number of units based on a multiple of salary. Upon vesting, a participant can, at their option, receive common shares or a cash payment of equivalent value. The performance units vest after a three-year period based on specific performance targets. The performance targets are as follows: 37.5% of the award will be subject to targets relating to the Total Shareholder Return ("**TSR**") of the Company against a group of peer companies and 37.5% of the award will be subject to targets relating to net asset value of the company per share based on proven and probable reserves discounted at 10%. The remaining 25% are not subject to performance conditions.

The Company is required to account for the performance unit plan as a liability based award whereby the estimated fair value of grants made under the plan is recorded as a liability each period based on the outstanding vested performance units. The change in the fair value of the liability each period is recorded as stock based compensation in the statement of operations.

The fair value of a performance unit is based on the following:

(i) 25% with no performance conditions—fair value is based on the underlying value of the Company's common stock.

(ii) 75% with performance conditions—fair value is based on the underlying value of the Company's common stock adjusted for the probability of meeting the market and non-market performance conditions.

At March 31, 2013, the Company recorded a liability of U.S.$0.3 million with an offsetting charge to the statement of operations. A nil forfeiture rate was used when recording the estimated compensation cost.

(c) Details of the options outstanding are as follows:

	Number of Options (000's)	Weighted Average Remaining Life (Years)	Weighted Average Exercise Price ($)
Outstanding, beginning of the period	5,982	4.24	5.67
Granted	761	4.84	6.17
Expired or forfeited	(60)	4.56	6.00
Outstanding, end of period	6,683	4.09	5.72
Number exercisable, end of period	1,181	3.65	5.44

7 Convertible bonds

	Debt Component	Equity Component
Balance, beginning of period	135,511	29,395
Interest accrued during the year	5,676	—
Non-cash accretion expense	2,102	—
	143,289	29,395

On September 13, 2012, the Company completed a financing through the issuance of U.S.$173.6 million unsecured pre-IPO convertible bonds (the "**Bonds**") with a maturity date of September 30, 2017. A summary of certain key terms of the Bonds is set out below.

- The Bonds are convertible at any time up to 14 days prior to the maturity date (or 14 days prior to any earlier date fixed for redemption of the Bonds) at an initial conversion price of U.S.$6.07 per common share. The conversion price of the Bonds will be subject to adjustment on or following the occurrence of certain corporate events relating to the share capital of the Company.
- Interest on the Bonds, initially at a rate of 12 percent per annum, is accrued quarterly and compounded and capitalized semi-annually prior to a Qualifying Public Offering (a "**QPO**"). Following the QPO such accrued but unpaid interest will become payable at the option of each bondholder either in cash or common shares. For the purpose of the Bonds, a QPO is defined as an offering of the Company's common shares which meets certain liquidity conditions and that results in a listing and admission to trading of the common shares on either (i) the regulated market of the London Stock Exchange (premium or standard listing on the Official List of the UK Listing Authority) or (ii) the Alternative Investment Market (AIM) operated by the London Stock Exchange. Effective September 30, 2013, interest will be accrued quarterly and compounded semi-annually at 12 percent plus a 50 basis point increase every six months until a QPO. However, if the QPO has not occurred prior to September 30, 2015, the Company shall make payment on that date of all compounded and capitalized interest in cash. Following the earlier of a QPO and September 30 2015, any further interest on the outstanding Bonds will be paid only in cash (without compounding) at the then prevailing rate.
- The Bonds are redeemable by the Company from three months following a QPO at a redemption price equal to the principal amount plus accrued but unpaid interest, provided that the volume weighted average price of the common shares for 20 out of 30 consecutive dealing days ending not earlier than seven days prior to the date on which notice of redemption is provided is not less than 150 percent of the conversion price. If neither a QPO nor a change of control in relation to the Company has occurred prior to September 30, 2016, the Bonds which remain outstanding at the maturity date will be redeemed at 153.5 percent of their principal amount, together with accrued but unpaid interest.

8 Advance

On December 12, 2012 the Company entered into a definitive Farm-in Agreement (the "**Agreement**") in which it would assign a one third working interest, subject to certain closing conditions, in each of its three PSCs and related agreements (the "**Transaction**"). On February 4, 2013, a Presidential Decree was signed to give effect to the Transaction; however, pursuant to the Agreement the Transaction does not close until

it is ratified by the Chadian National Assembly of Chad (the "**Closing**"). The Company is expecting the Transaction to close in the second quarter of 2013. On March 1, 2013, the Company entered into an Advance Agreement (the "**Advance**") whereby the Company received U.S.$100 million, a portion of the amount due to the Company pursuant to the Farm-in Agreement on Closing. The Advance does not bear interest up until and including the Closing date, after which point the Advance would bear interest at LIBOR plus five percent if not repaid immediately. In the event the Transaction does not close by December 17, 2013, the Company will begin repayment of the Advance in April 2014 with full repayment by December 31, 2014. Furthermore, if the Transaction does not close by 17 December. 2013, interest is due from the date of the advance agreement until full repayment has occurred.

9 Commitments

Pursuant to concession agreements in the Republic of Chad, the Company is required to perform certain minimum exploration activities by the expiry of the Initial Exploration Terms associated with each of the Company's PSCs, all of which are within the next five years:

	Expiry Date	Original Minimum Work Requirement	Remaining Minimum Work Requirement as at 31 March 2013
Doseo/Borogop PSC	26 January 2016	50,000	44,678
Mangara/Badila PSC	24 April 2016	50,000	35,741
DOH PSC	2 August 2016	15,000	13,990
Total		115,000	94,409

Pursuant to concession agreements in the Republic of Chad, the Company is required to pay certain prescribed amounts relating to the training of Chadian Nationals and employees of the Energy Ministry, audits of the State, and the presentation of annual reports to the State. These prescribed amounts under the terms of the concession agreements are approximately U.S.$3.0 million per annum.

The Company has office lease commitments in N'Djamena, Chad, and Calgary, Alberta. Non-cancellable future operating lease rentals of approximately U.S.$1.4 million per annum are required from 2013 to 2015.

10 Subsequent events

On May 29, 2013, the Company amended the Advance Agreement to increase the amount of the Advance from U.S.$100 million to U.S.$150 million. All other terms remained unamended. Pursuant to the Advance Agreement as amended, the Company received an additional U.S.$50 million on May 30, 2013, being a portion of the amount due to the Company, on Closing, pursuant to the Farm-in Agreement.

On June 13, 2013 the Company closed the Farm-in Agreement in which it transferred a one third working interest in each of its PSCs and related agreements. Upon closing, the Company received a cash payment of approximately U.S.$107 million, net of the repayment of the U.S.$150 million Advance, recorded a receivable of approximately U.S.$200 million and reduced intangible exploration and evaluation assets by U.S.$457.5 million.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of Directors of Griffiths Energy International Inc.

Report on the Consolidated Financial Statements

We have audited the accompanying consolidated financial statements of Griffiths Energy International Inc., which comprise the consolidated statements of financial position as at 31 December 2012, 2011 and 2010, the consolidated statements of operations, changes in shareholders' equity and cash flows for each of the years in the three year period ended 31 December 2012, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian Generally Accepted Auditing Standards and International Standards on Auditing. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Griffiths Energy International Inc. as at 31 December 2012, 2011 and 2010, and its consolidated financial performance and its consolidated cash flows for each of the years in the three year period ended 31 December 2012 in accordance with International Financial Reporting Standards.

Report on Other Legal and Regulatory Requirements

For the purposes of Prospectus Rule 5.5.3R (2)(f) we are responsible for this report as part of the Prospectus and declare that we have taken all reasonable care to ensure that the information contained in this report is, to the best of our knowledge, in accordance with the facts and contains no omission likely to affect its import. This declaration is included in the Prospectus in compliance with item 1.2 of Annex I and item 1.2 of Annex III of the Prospectus Directive Regulation.

signed "KPMG LLP"

Chartered Accountants
Calgary, Canada
27 June 2013

Consolidated Statements of Financial Position

	Note	As at 31 December 2012	2011	2010
			(U.S.$'000)	
Assets				
Current:				
Cash and cash equivalents		119,881	52,023	—
Accounts receivable	4	12,240	886	822
		132,121	52,909	822
Intangible exploration and evaluation assets	6	295,747	108,557	—
Property, plant and equipment		3,636	1,686	—
Total Assets		431,504	163,152	822

Liabilities and Shareholders' Equity

	Note	As at 31 December 2012	2011	2010
			(U.S.$'000)	
Current:				
Accounts payable and accrued liabilities	5	42,741	7,471	514
Long term liabilities:				
Convertible bonds	9	135,511	—	—
Decommissioning obligations	10	2,079	1,995	—
Total Liabilities		180,331	9,466	514
Share capital	7(a)	328,230	204,666	2,256
Contributed surplus	8	13,233	5,376	30
Warrants and agent options	7(b)	12,683	11,693	—
Equity component of convertible bonds	9	29,395	—	—
Share purchase loans		(9,928)	(9,621)	—
Deficit		(122,440)	(58,428)	(1,978)
Total Shareholders' Equity		251,173	153,686	308
Commitments	17			
Subsequent events	20			
Total Liabilities and Shareholders' Equity		431,504	163,152	822

The notes are an integral part of these consolidated financial statements

Consolidated Statement of Operations

	Note	As at 31 December 2012	2011	2010
			(U.S.$'000)	
Expenses:				
Salaries and benefits		13,122	4,605	—
Share-based compensation	7(b) and 8	8,564	29,856	—
Depreciation		1,082	149	—
Consulting fees		2,560	8,266	1,027
Legal and professional fees		5,114	5,819	279
General and administrative		22,819	2,677	143
Travel		7,821	3,160	175
Change in fair value of liquidity warrants		—	(69)	10
Finance expense (income)	12	8,083	(463)	10
Foreign exchange loss (gain)		228	2,450	(103)
Net loss before tax		69,393	56,450	1,541
Deferred tax reduction	11	(5,381)	—	
Net loss and comprehensive income		64,012	56,450	1,541
Loss per share:				
Basic and diluted	13	0.59	0.72	0.03

The notes are an integral part of these consolidated financial statements

Consolidated Statements of Changes in Shareholders' Equity

	Note	As at 31 December 2012	2011	2010
			(U.S.$'000)	
Share Capital	7(a)			
Balance, beginning of the year		204,666	2,256	642
Share issuance, net of costs		121,946	178,945	1,673
Transfer from contributed surplus on exercise of options		—	17,428	—
Shares issued to new management team		—	11,282	—
Conversion of liquidity warrants into shares		2,775	—	—
Interest on share purchase loans		98	49	—
Exercise of options		—	739	—
Value ascribed to liquidity warrants		(1,255)	(2,775)	(59)
Value ascribed to agent options		—	(3,258)	—
Balance, end of the year		328,230	204,666	2,256
Contributed Surplus	8			
Balance, beginning of the year		5,376	30	—
Share-based compensation		6,055	24,196	30
Share-based compensation—capitalised		1,802	354	—
Transfer to share capital on exercise of options		—	(17,428)	—
Withholding tax		—	(1,776)	—
Balance, end of the year		13,233	5,376	30
Warrants and Agent Options	7(b)			
Balance, beginning of the year		11,693	—	—
Conversion of liquidity warrants into shares		(2,775)	—	—
Value ascribed to liquidity warrants		1,255	2,775	—
Value ascribed to agent options		—	3,258	—
Share-based compensation for performance warrants		2,510	5,660	—
Balance, end of the year		12,683	11,693	—
Equity Component of Convertible Bonds	9			
Balance, beginning of the year		—	—	—
Issue of convertible bonds		41,313	—	—
Deferred tax impact		(10,360)	—	—
Convertible bond issue costs allocated to equity		(1,558)	—	—
Balance, end of the year		29,395	—	—
Share Purchase Loans				
Balance, beginning of the year		(9,621)	—	—
Share purchase loans		—	(11,282)	—
Repayment of share purchase loans		—	1,259	—
Interest on loans		(98)	(49)	—
Interest received on loans		95	16	—
Foreign exchange		(304)	435	—
Balance, end of the year		(9,928)	(9,621)	—
Deficit				
Balance, beginning of the year		(58,428)	(1,978)	(437)
Net loss for the year		(64,012)	(56,450)	(1,541)
Balance, end of the year		(122,440)	(58,428)	(1,978)
Total Shareholders' Equity		251,173	153,666	308

The notes are an integral part of these consolidated financial statements

Consolidated Cash Flows

	Note	As at 31 December 2012	2011	2010
			(U.S.$'000)	
Operating Activities				
Net loss		(64,012)	(56,450)	(1,541)
Adjustments for:				
Depreciation		1,082	149	—
Accretion		85	40	—
Share-based compensation		8,564	28,080	—
Interest on convertible bonds		8,213	—	—
Shares issued for consulting fees		—	—	177
Foreign exchange (gain)		(532)	(1,917)	(3)
Change in fair value of warrants		—	(69)	10
Deferred tax reduction		(5,381)	—	—
Changes in non-cash working capital	15	(3,205)	5,724	(584)
		(55,186)	(24,443)	(1,941)
Investing Activities				
Intangible exploration and evaluation additions		(185,463)	(106,285)	—
Property, plant and equipment additions		(2,957)	(1,798)	—
Changes in non-cash working capital	15	27,121	1,355	—
		(161,299)	(106,728)	—
Financing Activities				
Net proceeds from issuance of shares and warrants		116,967	178,946	1,507
Shareholder loan		—	—	404
Repayment of shareholder loan		—	—	(404)
Repayment of share purchase loans		—	1,259	—
Interest received on share purchase loans		95	16	—
Issue of convertible bonds		173,600	—	—
Convertible bond issue costs		(6,547)	—	—
Proceeds from exercise of options		—	739	—
Changes in non-cash working capital	15	—	(117)	24
		284,115	180,843	1,531
Effect of exchange rate changes on cash and cash equivalents		228	2,351	3
Increase in cash and cash equivalents		67,858	52,023	(407)
Cash and cash equivalents, beginning of year		52,023	—	407
Cash and cash equivalents, end of year		119,881	52,023	—

The notes are an integral part of these consolidated financial statements

Notes to Consolidated Financial Statements

Years ended 31 December 2012, 2011 and 2010 (Expressed in US$ thousands, unless otherwise stated)

1. Reporting entity:

Griffiths Energy International Inc. ("**Griffiths**" or the "**Company**") was incorporated pursuant to the Canada Business Corporations Act on 20 April 2009. The Company is engaged in oil and gas exploration, development and production activities in the Republic of Chad, which is located in central Africa.

(a) Statement of compliance:

These consolidated financial statements of the Company have been prepared in accordance with International Financial Reporting Standards and interpretations (collectively referred to as "**IFRS**") as issued by the International Accounting Standards Board ("**IASB**").

These financial statements are approved by the Board of Directors on 10 April, 2013.

(b) Basis of preparation:

These consolidated financial statements have been prepared on the historical cost basis. The Company's accounting policies have been applied consistently to all periods presented in these consolidated financial statements.

(c) Functional and presentation currency:

These consolidated financial statements are expressed in United States dollars ("**$**" or "**US$**"), which is the functional and presentational currency of the Company and its subsidiaries.

(d) Use of judgments and estimates:

The preparation of the consolidated financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates and affect the results reported in these consolidated financial statements.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognised in the period in which the estimates are revised and in any future periods affected. Information about significant areas of estimation uncertainty and critical judgments in applying accounting policies that have the most significant effect on the amounts recognized in the consolidated financial statements are as follows:

The calculation of deferred income tax assets and liabilities is based on management's interpretation of applicable laws, regulations and relevant court decisions, and in the case of deferred income tax assets, projections of future earnings to be applied against loss carry forward positions.

The recoverability of intangible exploration and evaluation assets is based on numerous assumptions including estimated reserves, forward commodity price forecasts, development plans, political and social uncertainties, discount rates and various other factors. The recoverability of the intangible exploration and evaluation assets is also impacted by the policy election permitted under IFRS as to the level exploration and evaluation assets are tested for impairment (see Note 2(f) in this Part XII).

The fair value of share-based compensation is based on estimates relating to option life, volatility, share price and the outcome of performance conditions.

2. Significant accounting policies:

A summary of the Company's significant accounting policies is set out below.

(a) Basis of consolidation:

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, potential voting rights that currently are exercisable are taken into account. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control

commences until the date that control ceases. Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements.

(b) Business combinations:

The acquisition method is used to account for business combinations. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of the exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date, irrespective of the extent of any non-controlling interest. The Company elects on a transaction-by-transaction basis whether to measure non-controlling interest at its fair value, or at its proportionate share of the recognized amount of the identifiable net assets, at the acquisition date. The excess of the cost of acquisition over the fair value of the Company's share of the net fair value of the identifiable assets, liabilities and contingent liabilities is recorded as goodwill. If the cost of an acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognized immediately in profit or loss.

Transaction costs that are incurred in connection with a business combination, other than those associated with the issue of debt or equity securities, are recognized in profit or loss.

(c) Foreign currency:

Transactions in foreign currencies are translated to United States dollars at exchange rates at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to United States dollars at the period end exchange rate. Non-monetary assets and liabilities denominated in foreign currencies that are carried at fair value are translated to U.S. dollars at the exchange rate at the date that the fair value was determined. Non-monetary assets held at historical cost are not retranslated subsequent to initial recognition. Foreign currency differences arising on translation are recognized in profit or loss.

(d) Financial instruments:

Non-derivative financial instruments comprise cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities. Non-derivative financial instruments are recognized initially at fair value. Subsequent to initial recognition non-derivative financial instruments are measured as described below.

Financial assets and liabilities are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets are derecognized when the rights to receive cash flows from the assets have expired or have been transferred and the Company has transferred substantially all risks and rewards of ownership.

Financial assets and liabilities are offset and the net amount is reported in the balance sheet when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

Cash and cash equivalents are comprised of cash on hand, term deposits held with banks, and other short-term highly liquid investments with original maturities of three months or less.

Financial assets at fair value through profit or loss:

An instrument is classified at fair value through profit or loss if it is held for trading or is designated as such upon initial recognition. Financial instruments are designated at fair value through profit or loss if the Company manages such investments and makes purchase and sale decisions based on their fair value in accordance with the Company's risk management or investment strategy. Upon initial recognition, attributable transaction costs are recognized in profit or loss when incurred. Financial instruments are measured at fair value, and changes therein are recognized in profit or loss.

Other:

Other non-derivative financial instruments, such as accounts receivable, accounts payable and accrued liabilities are measured at amortized cost using the effective interest method, less any impairment losses.

Accounts receivable, which are non-derivative financial assets that have fixed or determinable payments that are not quoted in an active market, are classified as loans and receivables. They are included in current assets, except for maturities greater than 12 months after the reporting date, which are classified as non-current assets.

The convertible debentures are considered a compound instrument as they can be converted to a fixed number of common shares at the option of the holder. The liability component of a compound financial instrument is recognized initially at the fair value of a similar liability that does not have an equity conversion option. The equity component is recognized initially at the difference between the fair value of the compound financial instrument as a whole and the fair value of the liability component. Any directly attributable transaction costs are allocated to the liability and equity components in proportion to their initial carrying amounts. Subsequent to initial recognition, the liability component of a compound financial instrument is measured at amortized cost using the effective interest method.

Equity instruments:

Equity instruments are classified as equity. Incremental costs directly attributable to the issue of common shares and share options are recognized as a deduction from equity, net of any tax effects, if any.

(e) Property, plant and equipment and intangible exploration and evaluation assets:

Recognition and measurement

(i) Development and production costs ("**D&P**"):

Property, plant and equipment is stated at cost, less accumulated depletion and depreciation and accumulated impairment losses.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of any decommissioning obligation, if any, and, for qualifying assets, borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in profit or loss as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in profit or loss as incurred. Where an asset or part of an asset that was separately depreciated is replaced and it is probable that future economic benefits associated with the item will flow to the Company, the expenditure is capitalized and the carrying amount of the replaced asset is derecognized. Inspection costs associated with major maintenance programs are capitalized and amortized over the period to the next inspection. All other maintenance expenditures are expensed as incurred.

(ii) Intangible exploration and evaluation ("**E&E**") expenditures:

Pre-license costs are recognized in profit or loss as incurred.

Exploration and evaluation expenditures, including the costs of acquiring licenses, directly attributable general and administrative costs, geological and geophysical costs, other direct costs of exploration (drilling, trenching, sampling and evaluating the technical feasibility and commercial viability of extraction) and evaluation are accumulated and capitalized as intangible exploration and evaluation assets. Interest is not capitalized on E&E assets.

On a quarterly basis, a review of any areas classified and accounted for as E&E assets is performed to determine whether enough information exists to make a determination of the technical feasibility and commercial viability of the area. Where appropriate, review may indicate that an area should be further sub-divided due to a significant portion having been explored whilst a significant undeveloped portion with different traits (i.e. different zone, technical approach, play type, etc.) remains that requires additional E&E activities to arrive at the point where it can be assessed for technical feasibility and commercial viability.

The assessment of technical feasibility and commercial viability is performed on an area level basis unless further sub-division is merited. Depending on the extent and complexity of the

prospective play, many wells may need to be drilled and potentially significant E&E costs accumulated prior to obtaining enough information to make the determination of technical feasibility and commercial viability possible.

E&E costs are not amortized prior to the conclusion of appraisal activities. At the completion of appraisal activities, if technical feasibility is demonstrated and commercial reserves are discovered, then, the carrying value of the relevant E&E asset will be reclassified as a development and production asset ("**D&P**") into the cash generating unit ("**CGU**") to which it relates, but only after the carrying value of the relevant E&E asset has been assessed for impairment, and where appropriate, its carrying value adjusted. If the Company determines the area is not technically feasible and commercially viable, accumulated E&E costs are expensed.

(iii) Depletion and depreciation:

The net carrying value of development and production assets will be depleted using the unit of production method by reference to the ratio of production in the period to the related proved and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. These estimates are reviewed by independent reserve engineers at least annually. Producing assets are generally grouped with other assets that are dedicated to serving the same reserves for depreciation purposes.

Proved and probable reserves are estimated at least annually by independent qualified reserve evaluators and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. For interim financial statements internal estimates of changes in reserves and future development costs are used for determining depletion for the period.

For property, plant and equipment other than development and production assets, the Company provides for depreciation based on the estimated useful lives of the assets.

Depreciation methods, useful lives and residual values are reviewed at each reporting date, and adjusted if appropriate, to ensure that these are consistent with the expected pattern of consumption of the future economic benefit embodied in the asset.

(f) Impairment:

(i) Financial assets:

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in profit or loss.

An impairment loss is reversed when there is a significant change in the underlying estimates or other objective evidence. For financial assets measured at amortized cost the reversal is recognized in profit or loss.

(ii) Non-financial assets:

Intangible exploration and evaluation costs are tested for impairment when reclassified to oil and gas properties or whenever facts and circumstances indicate potential impairment. Exploration and evaluation assets are tested separately for impairment or grouped with the relevant CGU or groups of CGUs. An impairment loss is recognized for the amount by which the exploration and evaluation expenditure's carrying amount exceeds its recoverable amount. The recoverable

amount is the higher of the exploration and evaluation expenditure's fair value less costs to sell and their value in use.

Values of oil and gas properties and other property, plant and equipment are reviewed for impairment when indicators of such impairment exist. If any indication of impairment exists an estimate of the asset's recoverable amount is calculated. Assets are grouped for impairment assessment purposes at the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets (the cash generating unit or "**CGU**"). The recoverable amount of an asset or CGU is the greater of its fair value less costs to sell and its value in use. Where the carrying amount of an asset group exceeds its recoverable amount, the asset group is considered impaired and is written down to its recoverable amount. An impairment loss is charged to the profit or loss. In assessing value in use, the estimated future cash flows are adjusted for the risks specific to the asset group and are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money.

For assets excluding goodwill, an assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the Company makes an estimate of the recoverable amount. A previously recognized impairment loss is reversed only if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognized. If that is the case the carrying amount of the asset is increased to its recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years.

(g) Share-based compensation:

The Company uses the fair value method for valuing share-based compensation. Under this method, the compensation cost attributed to stock options and other share-based compensation granted is measured at the fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest. Upon the settlement of the stock options the previously recognized value in contributed surplus is recorded as an increase to shareholders' capital.

(h) Provisions:

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

(i) Decommissioning obligations:

The Company's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's best estimate of the expenditures required to settle the present obligation at the balance sheet date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of asset retirement obligations are charged against the provision to the extent the provision was established.

(j) Revenue:

Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer which is usually when legal title passes to the external

party. This is generally at the time the product enters the pipeline or is delivered to the export terminal. Revenue is measured net of discounts, customs duties and royalties.

Tariffs, tolls and fees, if any, charged to other entities for use of pipelines and/or facilities owned by the Company are recognised as revenue as they accrue in accordance with the terms of the related agreements. Where the Company acts as agent on behalf of a third party to transport or process oil and natural gas, any associated fee income is recognised on a net basis.

(k) Lease payments:

Payments made under operating leases are recognised in profit or loss on a straight-line basis over the term of the lease. Lease incentives received are recognised as an integral part of the total lease expense over the term of the lease.

(l) Finance income and expenses:

Finance income comprises interest income and is recognized as it accrues in profit or loss, using the effective interest method.

Finance expense comprises interest expense on borrowings, accretion of the discount on provisions and impairment losses recognized on financial assets.

(m) Income tax:

Income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to a business combination or items recognized directly in equity or other comprehensive income.

Current tax is the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date and any adjustment in respect of previous years.

Deferred tax is recognised using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable profit or loss. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realised simultaneously. Deferred taxes related to the production service contracts are not recorded in the Republic of Chad.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realised.

(n) Earnings per share ("**EPS**"):

Basic earnings per share is calculated by dividing the profit or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. The dilutive effect of options and warrants is calculated using the treasury stock method whereby "in the money" options and warrants are added to the weighted average number of shares outstanding during the period. The dilutive effect of convertible debentures is determined by adjusting the profit or loss attributable to common shareholders to exclude the interest and carrying charges associated with the convertible debentures. The weighted average number of common shares for the period is increased by the number of common shares that would be issued if the convertible debentures were outstanding for the entire period. The impact of the convertible debentures on diluted EPS is excluded if it is anti-dilutive.

(o) Segment reporting:

A segment is a distinguishable component of the Company that is engaged either in providing related products or services (business segment), or in providing products or services within a particular economic environment (geographical segment), which is subject to risks and returns that are different from those of other segments. The Company has one reportable segment, which comprises oil and gas exploration, development and production activities within the Republic of Chad.

(p) Accounting policies adopted 1 January 2013:

The Company adopted IFRS 10 Consolidated Financial Statements, IFRS 11 Joint Arrangements, IFRS 12 Disclosures of Interests in Other Entities, as well as the consequential amendments to IAS 28 Investments in Associates and Joint Ventures (2011) and IFRS 13 Fair Value Measurement, with a date of initial application of 1 January 2013.

The adoption of these standards on 1 January 2013 had no impact on the amounts recorded in the Company's financial statements.

(i) IFRS 10 Consolidated Financial Statements

IFRS 10 introduces a new control model that is applicable to all investees; among other things, it requires the consolidation of an investee if the Company controls the investee on the basis of de facto circumstances.

Subsidiaries are entities controlled by the Company. The Company controls an entity when it is exposed to, or has rights to, variable returns from its involvement with the entity and has the ability to affect those returns through its power over the entity. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

(ii) IFRS 11 Joint Arrangements

Joint arrangements are arrangements of which the Company has joint control, established by contracts requiring unanimous consent for decisions about the activities that significantly affect the arrangements' returns. Under IFRS 11, joint arrangements are classified as either joint operations or joint ventures depending on the Company's rights to the assets and obligations for the liabilities of the arrangements. When making this assessment, the Company considers the structure of the arrangements, the legal form of any separate vehicles, the contractual terms of the arrangement and other facts and circumstances. Previously, the structure of the arrangement was the sole focus of classification.

As at 31 December 2012, the Company has no joint arrangements under IFRS 11. A significant portion of the Company's oil and gas activities are conducted with others, however, these are considered jointly controlled assets and are outside the scope of IFRS 11. These financial statements reflect only the Company's proportionate share of the related assets, obligations, revenue and expenses of jointly controlled assets.

(iii) IFRS 12 Disclosures of Interests in Other Entities

IFRS 12 sets out certain disclosures that are required relating to interests in subsidiaries, associates, joint arrangements and unconsolidated structured entities. The Company does not have any investments that are not consolidated nor has it entered into any joint arrangements or structured entities.

The Company's subsidiaries, as detailed in note 18, are all wholly owned at 31 December 2012. The determination of whether to consolidate these entities did not involve any significant judgments or assumptions. There are no significant restrictions on the ability of the Company to access or use the assets, and settle the liabilities of the Company and its subsidiaries except for customary limitations in the convertible note agreement.

(iv) IFRS 13 Fair Value Measurement

IFRS 13 defines fair value, sets out a single standard framework for measuring fair value and the required disclosures about fair value measurements. Fair value is defined as the price that would

be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

IFRS 13 is applied prospectively to fair value measurements occurring on or after 1 January 2013. The additional disclosure requirements of IFRS 13 are also applied prospectively and will be presented, as relevant, in the 2013 interim and annual financial statements.

(q) Accounting standards issued but not yet applied:

The IASB has issued the following standard which has not yet been adopted by the Company. The below standard is effective on 1 January 2015. The Company has not yet begun the process of assessing the impact that the new standard will have on its financial statements.

IFRS 9—Financial Instruments were issued in November 2009 and contained requirements for financial assets. This standard addresses classification and measurement of financial assets and replaces the multiple category and measurement models in IAS 39 for debt instruments with a new mixed measurement model having only two categories: amortized cost and fair value through profit or loss. IFRS 9 also replaces the models for measuring equity instruments, and such instruments are either recognized at fair value through profit or loss or at fair value through other comprehensive income. Where such equity instruments are measured at fair value through other comprehensive income, dividends are recognized in profit or loss to the extent not clearly representing a return of investment; however, other gains and losses (including impairments) associated with such instruments remain in accumulated comprehensive income indefinitely. Requirements for financial liabilities were added in October 2010 and they largely carried forward existing requirements in IAS 39, Financial Instruments—Recognition and Measurement, except that fair value changes due to credit risk for liabilities designated at fair value through profit and loss would generally be recorded in other comprehensive income.

3. Determination of fair values:

A number of the Company's accounting policies and disclosures require the determination of fair value, both for financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

The different levels of financial instrument valuation methods have been defined as follows:

Level 1 Fair value measurements are based on unadjusted quoted market prices. Level 2 Fair value measurements are based on valuation models and techniques where the significant inputs are derived from quoted indices. Level 3 Fair Value Measurements are based on unobservable information.

The carrying value of cash and cash equivalents, accounts receivables, and accounts payable and accrued liabilities included in the consolidated statements of financial position approximate fair value due to the short term nature of those instruments.

The fair value of stock options and warrants is measured using a Black-Scholes option pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility based on peer comparisons, weighted average expected life of the instruments based on historical experience and general option holder behavior, expected dividends, and the risk-free interest rate.

The fair value of the debt feature of the convertible bond is measured using the discounted principal and interest payments, incorporating the period that interest is capitalized. The discount rate used in calculating the fair value is based on a discount rate for a similar debt instrument with the same terms absent a conversion feature. The fair value of the debt feature at 31 December 2012 approximates its carrying value due to the proximity of the balance sheet date to the date when the debentures were issued.

4. Accounts receivable:

	Year ended 31 December		
	2012	2011	2010
	(U.S.$'000s)		
Prepaids and advances	11,592	98	—
Deposits	257	293	800
Other receivables	391	495	22
Total	12,240	886	822

Prepaids and advances relate predominately to cash calls for various projects which are customary in the industry. Accounts receivable are unsecured and non-interest bearing. Normal payment terms are 60 to 120 days. There was no provision for doubtful accounts or significant write-offs recorded in 2012, 2011 or 2010.

5. Accounts payable and accrued liabilities:

	Year ended 31 December		
	2012	2011	2010
	(U.S.$'000s)		
Trade payables	18,886	—	174
Other payables	2,793	5,454	—
Accrued liabilities	21,062	2,017	271
Warrants	—	—	69
Total	42,741	7,471	514

Trade and other payables are non-interest bearing and are normally settled on 30 to 60 day terms

6. Intangible exploration and evaluation assets:

	Year ended 31 December		
	2012	2011	2010
	(U.S.$'000s)		
Balance, beginning of year	108,557	—	—
Additions	187,265	106,639	—
Changes in decommissioning obligations	(75)	1,918	—
Balance, end of year	295,747	108,557	—

7. Share capital:

(a) Issued and outstanding common shares:

	Note	Price per share	Shares issued (000's)	Share issue costs	Amount
		CS$		(U.S.$'000s)	
Balance, 1 January 2010		—	42,129	—	642
Private placements:					
January 2010	(i), (ii)	—	2,484	—	1,673
Other:					
Value ascribed to warrants	(ii)	—	—	—	(59)
Balance, 31 December 2010			44,613	—	2,256
Private placements:					
11 January 2011	(iii)	C$2.50	900	136	2,125
25 February 2011 and 3 March 2011	(iv), (v)	C$5.00	33,000	10,833	157,637
19 April 2011	(iv)	C$5.00	3,000	545	15,022
8 September 2011		C$5.00	577	—	2,927
Other:					
Management Units	(vi)	C$5.00	2,200	—	11,282
Management Options	(vii)	C$0.40	3,000	—	1,234
Shares issued to former CEO	(viii)	C$5.00	568	—	2,952
Exercise of employee stock options		C$5.00	151	—	739
Value ascribed to agent options	(v)	—	—	—	(3,258)
Value ascribed to liquidity warrants	(iv)	—	—	—	(2,775)
Transfer on exercise of options	note 8	—	—	—	14,476
Interest on shareholder loans	(ix)	—	—	—	49
Balance 31 December 2011			88,009	11,514	204,666
Private placement:					
14 March 2012	(x)	C$6.00	20,840	8,499	116,967
Other:					
Value ascribed to liquidity warrants	(x)	—	—	—	(1,255)
Issued on exercise of liquidity warrants	(iv)	C$5.00	3,600	—	2,775
Other	(xi)	C$6.00	312	—	—
Interest on shareholder loans	(ix)	—	—	—	98
Deferred tax impact of share issue costs	note 11	—	—	(4,979)	4,979
Balance, 31 December 2012			112,761	15,034	328,230

Transactions in 2010

(i) As a result of the completion of the private placement in January 2010, 1.9 million common shares were issued at a price of C$0.30 per common share for net proceeds of $0.5 million.

(ii) In connection with the private placement completed in January 2010, the Company issued 0.6 million units at a price of C$2.00 per unit for proceeds of $1.2 million. Each unit consisted of one common share and one common share purchase warrant.

Transactions in 2011

(i) As a result of the completion of the private placement in January 2011, 0.6 million warrants issued to a private placement completed in January 2010 were cancelled. The liability recorded at 31 December 2010 of $0.1 million was reversed upon cancellation of the warrants.

(ii) In connection with the private placements on 25 February 2011, 3 March 2011, and 19 April 2011, 3.6 million liquidity warrants were issued. The terms called for them to be converted to common shares at no additional consideration on 1 January 2012 if a liquidity event did not occur prior thereto.

(iii) In connection with the private placement, the Company issued 2.0 million options to the agents which entitle the holder to acquire one common share at a price of C$5.00 per common share. The

agent options vested on the date of grant and will expire 24 months after such date. The fair value ascribed to agent options is $3.3 million which has been reclassified to warrants in shareholders' equity.

(iv) Shares were issued as part of the units (the "**Units**") issued to the new management team. Each Unit was comprised of one common share and two Warrants (the "**Performance Warrants**") (note 7(b)(i)).

(v) The Company granted 3.0 million stock options to the new management team, directors, an insider, and the Corporate Secretary of the Company, exercisable at a price of C$0.40 per share. These options were exercised immediately after grant, resulting in gross proceeds of $1.2 million to the Company and the issuance of an additional 3.0 million common shares. The fair value of this benefit was estimated using a Black-Scholes valuation model with the following variables: risk-free rate of 2.3%, volatility of 62.5%, an exercise price of $C0.40 and immediate vesting.

(vi) Based on a prior agreement, on 2 September 2011, the Company issued 1.0 million stock options to the previous Chief Executive Officer of the Company (the "**Executive**"), exercisable at C$0.40 per share, which were exercised on 30 September 2011. The Company paid the withholding tax on behalf of the Executive resulting in the Company issuing 0.6 million shares at C$5.00 to the Executive.

(vii) The Units purchased by the new management team of the Company on 1 July 2011 and 1 August 2011 were financed entirely through share purchase loans made by the Company to the new management team. This represents a benefit to management and as a result, the fair value of this benefit was estimated to be $3.9 million using a Black-Scholes valuation model with the following variables: risk-free rate of 2.3%, volatility of 62.5%, and exercise prices between C$5.01 and C$5.25. This benefit was expensed at the time of the transaction.

Transactions in 2012

(i) In connection with the private placement on 14 March 2012, a total of 2.1 million liquidity warrants were issued, which will be converted to common shares at no additional consideration if a liquidity event has not occurred prior to 14 March 2013. If a liquidity event occurs prior to 14 March 2013, the warrants will expire, unexercised in accordance with their terms. A liquidity event is defined as:

- a public offering pursuant to which the common shares of the Company are listed on a recognized Canadian, United States or UK stock exchange ("**Recognized Exchange**");
- the completion of any transaction which results in all or substantially all of the outstanding common shares of the Company to be exchanged for the securities of another issuer which will be listed on a Recognized Exchange; or
- the acquisition of all or substantially all of the outstanding common shares of the Company for cash.

The fair value ascribed to liquidity warrants is $1.3 million which has been reclassified to warrants in shareholders' equity.

(ii) The Company issued 0.3 million shares in Q1 at no consideration to an arm's length party as payment upon signing a term sheet for a credit facility. The shares were issued at a price of C$6.00 per share and include a put option of C$6.00. The put option is exercisable at any time by the holder; therefore, the carrying value of the instrument has been included in current liabilities.

(b) Warrants:

	Note 7	Number of Warrants	Liability Classified	Equity Classified
		(000's)	U.S.$	U.S.$
Balance, 1 January 2010		—	—	—
Share purchase warrants		613	69	—
Balance, 31 December 2010		613	69	—
Cancellation of warrants	(a)(iii)	(613)	(69)	—
Liquidity warrants	(a)(iv)	3,600	—	2,775
Agent options	(a)(v)	1,980	—	3,258
Management Performance warrants	(b)(i)	4,400	—	5,660
Balance, 31 December 2011		9,980	—	11,693
Liquidity warrants exercised	(a)(iv)	(3,600)	—	(2,775)
Liquidity warrants issued	(a)(x)	2,084	—	1,255
Employee Performance Warrants	(b)(ii)	1,717	—	2,510
Balance, 31 December 2012		10,181	—	12,683

At 31 December 2012, the following warrants were outstanding:

	Number of Warrants	Exercise Price	Expiration
	(000's)		
Agent options	1,980	C$5.00	Q1 2013
Management performance warrants	4,400	C$5.50	Q3 2016
Liquidity warrants	2,084	—	14 March 2013[1]
Employee performance warrants	1,717	C$6.00	Q1 2017

Note:

(1) Convert to common shares on 14 March 2013 if a liquidity event does not occur. Expire if a liquidity event occurs prior to 14 March 2013.

(i) Management Performance Warrants

In connection with the units issued to management (Note 7(a)(vi)), 4.4 million Performance Warrants were issued. Each Performance Warrant entitles the holder thereof to purchase one common share of the Company at a price of C$5.50 per share with a five year expiry, subject to vesting. The Performance Warrants shall vest and become exercisable by the holder if the 10 day volume-weighted average trading price of the Company's common shares at any time, on any stock exchange upon which such common shares are listed, meets or exceeds C$15.00 or if a liquidity event (as defined in the certificates representing the Performance Warrants) occurs. The estimated fair value of the performance warrants of $5.7 million is included in the loss for the year ended 31 December 2011. The Company used the Black-Scholes pricing model to calculate the fair value of the Performance Warrants. Measurement inputs include the share price on measurement date (C$5.00), exercise price (C$5.50), expected volatility (62.5%), expected life (five years) and the risk-free interest rate (2.3%).

(ii) Employee Performance Warrants

In March 2012, the Company issued 1.7 million Performance Warrants to certain employees, officers and directors. Each Performance Warrant entitles the holder thereof to purchase one common share of the Company at a price of C$6.00 per share with a five year expiry, subject to vesting. The Performance Warrants shall vest in one-third increments and become exercisable by the holder if the 10 day volume-weighted average trading price of the Company's common shares at any time, on any stock exchange upon which such common shares are listed, meets or exceeds C$7.50, C$9.00 and C$12.00, or if a change of control occurs. The estimated fair value of the Performance Warrants was $2.7 million. The Company used the Black-Scholes pricing model to calculate the fair value of the Performance Warrants. Measurement inputs include the share price on measurement date (C$6.00), exercise price (C$6.00), expected volatility (64.14%), expected life (five years), forfeiture rate (10%) and the risk-free interest rate (1.61%).

8. Contributed surplus:

	Note	Amount (U.S.$'000s)
Balance, 1 January 2010		—
Share-based compensation		30
Balance, 31 December 2010		30
Share purchase loans	7(a)(ix)	3,875
New management options	7(a)(vii)	14,357
New employee options	(ii)	1,235
New employee options—capitalized		354
Former management options		4,729
Transfer to share capital on exercise of options		(14,476)
Shares issued to former CEO		(2,952)
Withholding tax		(1,776)
Balance, 31 December 2011		5,376
Extension of share purchase loans	(i)	1,736
Employee options	(ii)	4,319
Employee options—capitalized	(ii)	1,802
Balance, 31 December 2012		13,233

(i) Extension of share purchase loans

The share purchase loans previously granted by the Company to the Chief Executive Officer and the Chief Financial Officer were extended to 1 July 2016. The Company estimated the compensation cost associated with the loan extensions using a Black-Scholes option pricing model and recognized the estimated cost of $1.7 million. The Company used the Black-Scholes pricing model to calculate the fair value of the loan extensions. Measurement inputs include the share price on measurement date (C$6.00), exercise price (C$6.00), expected volatility (64.14%), expected life (five years), forfeiture rate (10%) and the risk-free interest rate (1.61%).

(ii) Employee options

The Company has an employee stock option plan under which it may grant, at the Company's discretion, options to purchase common shares to employees, directors and consultants of the Company. Options are granted at the market price of the shares on the date of grant, have a five-year term and vest in one-third tranches starting on the first anniversary of the grant. The Company uses the Black-Scholes pricing model to calculate the fair value for grants of options to new employees. Measurement inputs include the share price on measurement date (C$5.00—C$6.00), exercise price (C$5.00—C$6.00), expected volatility (67%), expected life (five years), initial forfeiture rate (10%) and the risk-free interest rate (1.59%—1.68%). The estimated forfeiture rate will be adjusted to reflect the actual number of options that vest.

	Number of Options (000's)	Weighted Average Remaining Life (Years)	Weighted Average Exercise Price (C$)
Outstanding 1 January 2010 and 31 December 2010	—	—	—
New employee options granted	2,803	4.17	5.00
Exercised during the period	(151)	3.75	5.00
Expired or forfeited during the period	(174)	3.75	5.00
Outstanding 31 December 2011	2,478	4.17	5.00
Granted during the period	4,134	4.64	6.00
Expired or forfeited during the period	(630)	4.21	5.19
Options outstanding, 31 December 2012	5,982	4.24	5.67
Options exercisable, 31 December 2012	656	3.66	5.00

9. Convertible bonds:

	Debt Component	Equity Component
	(U.S.$'000s)	
Issued on 13 September 2012	132,287	41,313
Less issue costs	(4,989)	(1,558)
Deferred tax impact	—	(10,360)
Interest accrued during the year	5,957	—
Non-cash accretion expense	2,256	—
	135,511	29,395

On 13 September 2012, the Company completed a financing through the issuance of $173.6 million unsecured pre-IPO convertible bonds (the "**Bonds**") with a maturity date of 30 September 2017. A summary of certain key terms of the Bonds and the manner in which they are accounted for in the financial statements of the Company is set out below.

- The Bonds are convertible at any time up to 14 days prior to the maturity date (or 14 days prior to any earlier date fixed for redemption of the Bonds) at an initial conversion price of $6.07 per common share. The conversion price of the Bonds will be subject to adjustment on or following the occurrence of certain corporate events relating to the share capital of the Company.
- Interest on the Bonds, initially at a rate of 12 per cent. per annum, is accrued quarterly and compounded and capitalized semi-annually prior to a Qualifying Public Offering (a "**QPO**"). Following the QPO such accrued but unpaid interest will become payable at the option of each bondholder either in cash or common shares. For the purpose of the Bonds, a QPO is defined as an offering of the Company's common shares which meets certain liquidity conditions and that results in a listing and admission to trading of the common shares on either (i) the regulated market of the London Stock Exchange (premium or standard listing on the Official List of the UK Listing Authority) or (ii) the Alternative Investment Market (AIM) operated by the London Stock Exchange. Effective 30 September 2013, interest will be accrued quarterly and compounded semi-annually at 12 per cent. plus a 50 basis point increase every six months until a QPO. However, if the QPO has not occurred prior to 30 September 2015, the Company shall make payment on that date of all compounded and capitalized interest in cash. Following the earlier of a QPO and 30 September 2015, any further interest on the outstanding Bonds will be paid only in cash (without compounding) at the then prevailing rate.
- The Bonds are redeemable by the Company from three months following a QPO at a redemption price equal to the principal amount plus accrued but unpaid interest, provided that the volume weighted average price of the common shares for 20 out of 30 consecutive dealing days ending not earlier than seven days prior to the date on which notice of redemption is provided is not less than 150 per cent. of the conversion price. If neither a QPO nor a change of control in relation to the Company has occurred prior to 30 September 2017, the Bonds which remain outstanding at the maturity date will be redeemed at 153.5 per cent. of their principal amount, together with accrued but unpaid interest.
- The debt component of the Bonds is classified as a financial liability and recorded in the financial statements of the Company at fair value, net of issuance costs with the residual value allocated to shareholders' equity. The debt will be accreted using the effective interest rate method over the estimated life of the Bonds.

10. Decommissioning obligations:

The decommissioning obligations relate to wells drilled on the lands within the Doseo/Borogop, Mangara/Badila and DOH production sharing contracts and roads and pipeline construction. The decommissioning obligation calculated by management is based on estimated costs to abandon and reclaim the properties and the estimated timing of the costs to be incurred in future periods. As at 31 December 2012, the estimated total undiscounted decommissioning obligations were $5.4 million. These obligations will be settled based on the useful lives of the underlying assets, the majority of which are expected to be settled within the next 25 years, primarily between 2027 and 2036. The discounted future decommissioning liabilities were calculated using a risk-free discount rate of 4% and an expected inflation rate of 2%.

11. Income taxes:

(a) Provision for deferred income taxes:

	2012	2011	2010
		(U.S.$'000s)	
Loss before income taxes	(69,393)	(56,450)	(1,541)
Canadian statutory income tax rate	25%	26.5%	28%
Expected tax recovery	(17,348)	(14,959)	(431)
Adjustments:			
Share-based compensation	2,141	7,912	—
Change in unrecognized deferred taxes	2,311	2,879	377
Foreign exchange	57	1,942	—
Expenses incurred with no recognized tax benefit	4,906	2,451	—
Change in income tax rates and other	2,552	(225)	54
Deferred tax reduction	(5,381)	—	—

Recording the equity component of the convertible debenture resulted in the recognition of a $10.4 million deferred income tax liability. This deferred tax liability was recorded as part of the equity component of the convertible bonds. The Company recorded previously unrecognized deferred tax assets to offset this deferred tax liability. Share capital was reduced by $5.0 million and a deferred income tax reduction of $5.4 million was recorded relating to the previously unrecognized tax benefits of share issue costs and non-capital losses, respectively.

The Company did not generate any domestic income during the years ended 31 December 2012, 31 December 2011 and 31 December 2010 and has no reasonable expectation to do so in future periods. Income in future periods, if any, is expected to be generated in the Republic of Chad. Accordingly, the benefit of non-capital losses and other tax assets has not been recognized except to the extent to offset existing taxable temporary differences.

(b) Deferred tax balances:

The Company has Canadian non-capital losses of $54.8 million that will begin to expire in 2029. The Company does not incur tax in Chad on oil and gas sales under the terms of the PSCs.

12. Finance expense (income):

	2012	2011	2010
		(U.S.$'000s)	
Accretion of decommissioning obligations	85	40	—
Interest accrued on convertible bonds	5,957	—	—
Non-cash accretion on convertible bonds	2,256	—	—
Other interest expense (income)	(215)	(503)	10
Finance expense (income)	8,083	(463)	10

13. Loss per share:

	2012	2011	2010
		(U.S.$'000s)	
Net loss and comprehensive loss	64,012	56,450	1,541
Weighted average number of shares	108,458	78,036	44,425
Loss per share—basic and diluted	0.59	0.72	0.03

All outstanding dilutive instruments are anti-dilutive to the loss per share.

14. Financial instruments:

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production and financial activities such as:

- Credit risk;

- Liquidity risk;
- Market risk;

(a) Credit risk:

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations. On entering into any business contract, the extent to which the arrangement exposes the Company to credit risk is considered.

The Company's policy to mitigate credit risk associated with these balances is to establish relationships with reputable counterparties including highly rated financial institutions.

The majority of the Company's cash is held in operating accounts with a publicly traded, international bank therefore the Company considers these assets to have negligible credit risk. The Company does not hold significant cash in Chad.

As at 31 December 2012, the Company had share purchase loans outstanding to officers of the Company in the amount of $9.9 million. The Company considers the share purchase loans to have negligible credit risk given the security on the loans and the holders of the loans.

The Company's maximum exposure to credit risk in respect of accounts receivable is $12.2 million. An aging analysis of accounts receivable is noted in the table below:

	U.S.$'000s
Less than 30 days	9,970
31 to 90 days	1,695
Greater than 90 days (Deposits)	575
Total	12,240

(b) Liquidity risk:

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity is to ensure it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Company's reputation.

Typically the Company will ensure that it has sufficient cash on demand to meet expected operational expenses for a period of 60 days, including the servicing of financial obligations. To achieve this objective, the Company prepares a cash flow forecast, which is regularly monitored and updated as warranted.

The contractual maturities of all accounts payable and accrued liabilities are less than one year.

(c) Market risk:

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates will affect the Company's income or the value of the financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return.

The Company may use both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions will be conducted within risk management tolerances that are reviewed by the Board of Directors.

(i) Commodity price risk:

Price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by not only the relationship between the United States dollar and other currencies but also world economic events that impact the perceived levels of supply and demand. The Company currently does not have any production and therefore is not exposed to commodity price risk.

(ii) Foreign currency risk:

Currency risk is the risk that the fair value of future cash flows will fluctuate as a result of changes

in foreign exchange rates. The reporting and functional currency of the Company is United States dollars (US$). Substantially all of the Company's capital expenditures and major service contracts related to the exploration and development in Chad are denominated in US$, and as such the Company holds substantially all of its cash in US$ in order to mitigate against foreign currency risk.

The Company's operations are in foreign jurisdictions, therefore the Company is exposed to foreign currency exchange rate risk on some of its activities. General and administrative expenses, are denominated in currencies other than US$ including the Canadian dollar (C$), the Great British Pound (GBP), and the Central African Franc (CFA). The Company also settles certain capital expenditures in Euro (EUR), C$ and CFA. To match the foreign currency on the trade payables related to these activities the Company may hold cash in the currency of the transaction.

The following table contains an analysis of US$ equivalent cash balances and trade payables denominated in each currency:

	Cash	Trade Payables
US$	117,710	14,762
C$	436	3,195
GBP	1,031	—
CFA	704	929
Total	119,881	18,886

(iii) Interest rate risk:

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The convertible bonds bear interest at the prescribed rate in the debenture agreements. The effect of interest rate fluctuations would not have had a significant effect on the Company's reported net loss for the years ended 31 December 2012, 2011 or 2010.

15. Supplemental cash flow information:

	2012	2011	2010
		(U.S.$'000s)	
Changes in non-cash working capital is comprised of:			
Accounts receivable	(11,354)	(64)	(807)
Accounts payable and accrued liabilities	35,270	7,026	247
Change in non-cash working capital:	23,916	6,962	(560)
Operating activities	(3,205)	5,724	(584)
Investing activities	27,121	1,355	—
Financing activities	—	(117)	24
	23,916	6,962	(560)

16. Capital management:

The Company's policy is to maintain a strong capital base so as to maintain stakeholder (including shareholders, Government of the Republic of Chad, and creditors) confidence and to sustain future development of the business. The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of its oil assets. The Company considers its capital structure to include shareholders' equity and working capital. In order to maintain or adjust the capital structure, the Company may issue shares, raise debt and/or adjust its capital spending to manage its projected debt levels.

17. Commitments:

Pursuant to concession agreements in the Republic of Chad, the Company is required to perform certain minimum exploration activities by the expiry of the Initial Exploration Terms associated with each of the Company's PSCs, all of which are within the next five years:

Concession Name	Expiry Date	Original Minimum Work Requirement	Remaining Minimum Work Requirement as at 31 December 2012
Doseo/Borogop PSC	26 January 2016	50,000	45,934
Mangara/Badila PSC	24 April 2016	50,000	41,071
DOH PSC	2 August 2016	15,000	14,409
Total		115,000	101,414

Pursuant to concession agreements in the Republic of Chad, the Company is required to pay certain prescribed amounts relating to the training of Chadian Nationals and employees of the Energy Ministry, audits of the State, and the presentation of annual reports to the State. These prescribed amounts under the terms of the concession agreements are approximately $3.0 million per annum.

The Company has office lease commitments in N'Djamena, Chad, and Calgary, Alberta. Non-cancellable future operating lease rentals of approximately $1.4 million per annum are required from 2013 to 2015.

18. Subsidiaries and Jurisdictions:

The Company has established the following subsidiaries for the purpose of carrying out its oil and gas operations, all of which were wholly owned at 31 December 2012:

(i) Griffiths Energy Holdings Limited registered in Bermuda;

(ii) PetroChad Holdings Limited registered in Bermuda;

(iii) PetroChad (Mangara) Limited registered in Bermuda. This entity holds the Mangara/Badila PSC;

(iv) Griffiths Energy (Chad) Ltd registered in Bermuda. This entity holds the Doseo/Borogop PSC;

(v) Griffiths Energy (DOH) Limited registered in Bermuda. This entity holds the DOH PSC;

(vi) Griffiths Energy (U.S.) Inc. registered in the State of Delaware, USA; and

(vii) PetroChad Transportation Company Limited registered in Bermuda. This entity holds certain transportation assets in Chad.

19. Related Party Transactions:

(i) Director's remuneration:

	2012	2011	2010
Fees to non-executive directors	301	122	—
Share-based compensation	1,087	202	—
	1,388	324	—

(ii) Compensation of key management personnel:

	2012	2011	2010
Salaries and other benefits	2,043	913	—
Bonuses	270	—	—
Share-based compensation	4,688	23,893	—
	7,001	24,806	—

Compensation for key management personnel includes all amounts earned and awarded to the Company's officers.

20. Subsequent events:

(i) Farm-in agreement

On December 12, 2012 the Company entered into a definitive Farm-in Agreement (the "**Agreement**") in which it would assign a one third working interest, subject to certain closing conditions, in each of its three PSCs and related agreements (the "**Transaction**"). On February 4, 2013, a Presidential Decree was signed to give effect to the Transaction. On March 1, 2013, the Company entered into an Advance Agreement (the "**Advance**") whereby the Company received U.S.$100 million, a portion of the amount due to the Company pursuant to the Agreement on closing. In the event the Transaction did not close by December 2013, the Company would have started repayment of the Advance in April 2014 with full repayment by December 31, 2014.

On May 29, 2013, the Company amended the Advance Agreement to increase the amount of the Advance from U.S.$100 million to U.S.$150 million. All other terms remained unamended. Pursuant to the Advance Agreement as amended, the Company received an additional U.S.$50 million on May 30, 2013, being a portion of the amount due to the Company, on Closing, pursuant to the Farm-in Agreement.

On June 13, 2013 the Company closed the Farm-in Agreement in which it transferred a one third working interest in each of its PSCs and related agreements. Upon closing, the Company received a cash payment of approximately U.S.$107 million, net of the repayment of the U.S.$150 million Advance, recorded a receivable of approximately U.S.$200 million and reduced intangible exploration and evaluation assets by U.S.$457.5 million.

(ii) Share-based compensation

On 9 January 2013 the Board of Directors approved a new Long Term Incentive Plan (the "**Plan**") for officers and other key executives of the Company. The Plan was introduced to retain, attract and motivate key executives who are critical to executing the long term business strategy. The Plan awards a number of shares based on a multiple of salary. The Plan awards shares in the form of nominal cost options. However, these shares only vest after a three-year period and the full award is made only if the Company has performed in the top quartile when compared against a selected peer group and certain internal targets are achieved. The Company granted 1.0 million nominal cost options under the Plan.

(iii) Special investigation

On 15 January 2013 the Company was charged under section 3(1)(b) of Canada's Corruption of Foreign Public Officials Act relating to contracts (the "**Contracts**") entered into by the prior management and Board of Directors. On 22 January 2013, the Company reached a settlement and resolution agreement with respect to the Contracts and agreed to pay a fine of U.S.$10.5 million ($10.35 CAD) which has been accrued at 31 December 2012 and is included in general and administrative costs.

PART XIII
TAXATION

1 United Kingdom Taxation

Overview

The comments set out below are based on current UK tax law as applied in England and Wales and HM Revenue & Customs practice (which may not be binding on HM Revenue & Customs) as at the date of this Prospectus, both of which are subject to change, possibly with retrospective effect. They are intended as a general guide and apply only to shareholders of the Company resident and, in the case of an individual, domiciled, for tax purposes in the UK and to whom "split year" treatment does not apply (except insofar as express reference is made to the treatment of non-UK residents), who hold Shares as an investment and who are the absolute beneficial owners thereof. The comments further assume that the holders of the Depositary Interests are the beneficial owners of the underlying Shares. The discussion does not address all possible tax consequences relating to an investment in the Shares. Certain categories of shareholders, such as traders, brokers, dealers, banks, financial institutions, insurance companies, investment companies, collective investment schemes, tax-exempt organisations, persons connected with the Company or Group, persons holding the Shares as part of hedging or conversion transactions, shareholders who are not domiciled or not ordinarily resident in the UK, shareholders who have (or are deemed to have) acquired their Shares by virtue of an office or employment and shareholders who are, are to become or have been officers or employees of the Company or a company forming part of the Group, may be subject to special rules and this summary does not apply to such shareholders. This summary also does not apply to any individual shareholder who owns 10 per cent. or more of the issued ordinary share capital of the Company.

Shareholders and prospective shareholders who are in any doubt about their tax position, or who are resident or otherwise subject to taxation in a jurisdiction outside the UK, should consult their own professional advisers immediately.

The UK taxation summary below is written on the basis that the Company is and remains resident for tax purposes only in Canada and will therefore be subject to the Canadian tax regime and not (save as in respect of any UK source income) the UK tax regime. Dividends paid by the Company will, on this basis, be regarded as Canadian dividends rather than UK dividends.

Taxation of the Company

The Directors intend to conduct the affairs of the Company in such a manner as to minimise, so far as they consider reasonably practicable, taxation suffered by the Company. This will include conducting the affairs of the Company so that the Company does not become resident in the UK for taxation purposes. Accordingly, and provided that the Company does not carry on a trade in the UK (whether or not through a permanent establishment situated therein), the Company will not be subject to UK income tax or corporation tax other than on UK source income from which UK tax is deducted at source.

Taxation of Dividends

The following paragraphs apply equally to shareholders and holders of Depositary Interests.

The Company will not be required to withhold amounts on account of UK tax at source when paying a dividend.

UK resident individuals and institutional shareholders

A UK resident individual shareholder who receives a dividend from the Company will be entitled to a tax credit which may be set off against the shareholder's total income tax liability. The tax credit will be equal to 10 per cent. of the aggregate of the dividend (before deduction of any Canadian withholding tax) and the tax credit (the "**Gross Dividend**"). Such an individual shareholder who is liable to income tax at the basic rate will be subject to tax on the dividend at the rate of 10 per cent. of the Gross Dividend, so that the tax credit will satisfy in full such shareholder's liability to income tax on the dividend. In the case of such an individual shareholder who is liable to income tax at the higher rate, the tax credit will be set against but not fully match the shareholder's tax liability on the Gross Dividend and such shareholder will have to account for further income tax equal to 22.5 per cent. of the Gross Dividend (which is also equal to 25 per cent. of the cash dividend (before deduction of any Canadian withholding tax)) to the extent that the Gross Dividend when treated as the top slice of the shareholder's income falls above the threshold for higher rate income tax. In the case of such an individual shareholder who is subject to income tax at the

additional rate, the tax credit will also be set against but not fully match the shareholder's liability on the Gross Dividend and such shareholder will have to account for further income tax equal to 27.5 per cent. of the Gross Dividend (which is also equal to approximately 30.6 per cent. of the cash dividend received) to the extent that the Gross Dividend when treated as the top slice of the shareholder's income falls above the threshold for additional rate income tax.

Canadian withholding tax withheld from the payment of a dividend will generally be available as a credit against the income tax payable by an individual shareholder in respect of the dividend.

A UK resident individual shareholder who is not liable to income tax in respect of the Gross Dividend and other UK resident taxpayers who are not liable to UK tax on dividends, including pension funds and charities, will not be entitled to claim repayment of the tax credit attaching to dividends paid by the Company.

UK resident corporate shareholders

Shareholders who are within the charge to corporation tax in respect of Shares will be subject to corporation tax on the gross amount of any dividends paid by the Company, subject to any applicable credit for Canadian withholding tax, unless (subject to special rules for such shareholders that are small companies) the dividends fall within an exempt class and certain other conditions are met. Each shareholder's position will depend on its own individual circumstances, although it would normally be expected that the dividends paid by the Company would fall within an exempt class.

Non-UK resident shareholders

Non-UK resident shareholders will not be liable to income or corporation tax in the UK on dividends paid on the Shares unless the shareholder carries on a trade (or profession or vocation) in the UK and the dividends are either a receipt of that trade or, in the case of corporation tax, the Shares are held by or for a UK permanent establishment through which the trade is carried on. Non-UK resident shareholders will not generally be able to claim repayment from HM Revenue & Customs of any part of the tax credit attaching to dividends paid by the Company. A shareholder resident outside the UK may also be subject to foreign tax on dividend income under local law. Shareholders who are not resident for tax purposes in the UK should obtain their own tax advice concerning tax liabilities on dividends received from the Company.

Stamp Duty and Stamp Duty Reserve Tax ("SDRT")

No *ad valorem* UK stamp duty or SDRT is payable on the issue of Depositary Interests by the Depositary. Provided that the Shares are not registered in any register kept in the UK by or on behalf of the Company, any agreement to transfer the Shares will not be subject to UK SDRT. No UK stamp duty will be payable on the transfer of the Shares, provided that any instrument of transfer is not executed in the UK and does not relate to any property situate, or to any matter or thing done or to be done, in the UK. Assuming that transfers of Depositary Interests operate without any written instrument of transfer or written agreement to transfer, no UK stamp duty will be payable on the transfer of such Depositary Interests. The position regarding UK SDRT in respect of an agreement to transfer Depositary Interests and the settlement of transactions electronically through CREST will be notified to the market by way of an operational bulletin to be issued by Euroclear UK & Ireland prior to Admission.

2 Canadian Taxation

CERTAIN CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

The following is a general summary, as of the date hereof, of the principal Canadian federal income tax considerations under the Income Tax Act (Canada) (the "**Tax Act**") generally applicable to a holder of Shares who, at all relevant times, (a) is not, and is not deemed to be, resident in Canada for purposes of the Tax Act and any applicable income tax treaty or convention, (b) holds the Shares as capital property, and (c) deals at arm's length with, and is not affiliated with, the Company for purposes of the Tax Act (a "**Holder**"). The Shares will generally be considered to be capital property to a Holder unless the Holder holds such Shares in the course of carrying on a business of buying and selling securities or has acquired them in one or more transactions considered to be an adventure or concern in the nature of trade. This summary assumes that the Holder does not, and will not be deemed to, use or hold the Shares in the course of carrying on a business in Canada.

This summary is based upon: (a) the current provisions of the Tax Act and the regulations thereunder in force as of the date hereof; (b) all specific proposals (the "**Tax Proposals**") to amend the Tax Act or the regulations thereunder that have been publicly announced by, or on behalf of, the Minister of Finance

(Canada) prior to the date hereof; (c) certain factual matters pertaining to the Company set out in this Prospectus; and (d) the current published administrative policies and assessing practices of the Canada Revenue Agency. This summary assumes that all such Tax Proposals will be enacted in the form currently proposed but no assurance can be given in that regard. This summary does not otherwise take into account or anticipate any changes in law, administrative policy or assessing practice, whether by legislative, regulatory, administrative, governmental or judicial decision or action, nor does it take into account the tax laws of any province or territory of Canada or of any jurisdiction outside of Canada.

Generally, for purposes of the Tax Act, all amounts relating to the acquisition, holding or disposition of the Shares must be determined in Canadian dollars. Any such amount that is expressed or denominated in a currency other than Canadian dollars must be converted into Canadian dollars using the relevant exchange rate quoted by the Bank of Canada at noon on the relevant day or such other rate of exchange acceptable to the Minister of National Revenue (Canada).

This summary is of a general nature only and is not intended to be, nor should it be construed to be, legal or tax advice to any particular Holder, and no representations with respect to the income tax considerations applicable to any particular Holder are made. This summary does not address the income tax considerations relevant to all types of Holders or all circumstances. Accordingly, prospective Holders are urged to consult their own tax advisers about the specific tax consequences to them of acquiring, holding and disposing of Shares in their particular circumstances.

Dividends

A dividend paid or credited (or deemed under the Tax Act to be paid or credited) on the Shares to a Holder will generally be subject to Canadian withholding tax under the Tax Act at a rate of 25 per cent., subject to any reduction in the rate of such withholding under the provisions of an applicable income tax treaty or convention. For example, in the case of a Holder who is a resident of the United Kingdom or the United States for purposes of the *Canada United Kingdom Income Tax Convention* or the *Canada United States Tax Convention*, respectively, and who qualifies for the benefits of such tax convention, the rate of such withholding will generally be reduced to 15 per cent. or such other applicable rate pursuant to such income tax treaty.

Disposition of Shares

A Holder will not be subject to tax under the Tax Act in respect of any capital gain realised on a disposition or deemed disposition of Shares unless the Shares constitute "taxable Canadian property" (as defined in the Tax Act) to the Holder at the time of the disposition and the Holder is not entitled to relief under an applicable income tax treaty or convention.

Provided that the Shares are listed on a "designated stock exchange", which currently includes the London Stock Exchange, the Shares generally will not constitute taxable Canadian property of a Holder, unless, at any time during the 60-month period immediately preceding the disposition, (i) the Holder, persons with whom the Holder does not deal at arm's length, or the Holder together with all such persons, owned 25 per cent. or more of the issued shares of any class or series of shares in the capital stock of the Company, and (ii) the Shares derived (directly or indirectly) more than 50 per cent. of their fair market value from real or immovable property situated in Canada, Canadian resource properties, timber resource properties or options or interests in respect of any such property, all as defined for the purposes of the Tax Act. Based upon the operations and principal assets of the Company as described herein, the Shares are not anticipated to be taxable Canadian property as of the date hereof. However, the determination whether the Shares constitute taxable Canadian property must be made at the relevant time in respect of any disposition of Shares.

If the Shares are considered taxable Canadian property to a Holder, an applicable income tax treaty or convention may exempt that Holder from tax under the Tax Act in respect of their disposition. Otherwise, in the event that the Shares constitute taxable Canadian property of a Holder and any capital gain that would be realised on a disposition thereof is not exempt from tax under the Tax Act pursuant to an applicable income tax treaty or convention, a disposition or deemed disposition of such Shares (other than to the Company, unless purchased by the Company in the open market in the manner in which shares are normally purchased by any member of the public in the open market) will generally give rise to a capital gain (or a capital loss) equal to the amount by which the proceeds of disposition of such Shares, net of any reasonable costs of disposition, exceed (or are less than) the adjusted cost base of such Shares to the Holder. Generally, one half of any such capital gain must be included in the Holder's income for that year and one half of any such capital loss is generally deducted against taxable capital gains realised in that year from dispositions of taxable Canadian property. Certain excess allowable capital losses from the dispositions of taxable Canadian property may be claimed in any of the three preceding taxation years or any subsequent taxation year subject to the rules contained in the Tax Act.

PART XIV

ARRANGEMENTS RELATING TO ADMISSION

1 Dealing arrangements

THIS PROSPECTUS DOES NOT CONSTITUTE AN OFFER TO SELL OR AN INVITATION TO SUBSCRIBE FOR, OR THE SOLICITATION OF AN OFFER TO PURCHASE OR TO SUBSCRIBE FOR, ANY SHARES TO ANY PERSON IN ANY JURISDICTION.

Application has been made to (i) the FCA for the Shares to be admitted to listing on the premium listing segment of the Official List and (ii) to the London Stock Exchange for such Shares to be admitted to trading on the London Stock Exchange's main market for listed securities.

It is expected that Admission will take place and unconditional dealings in the Shares will commence on the London Stock Exchange at 8.00 a.m. (London time) on or around 5 July 2013. Settlement of dealings from that date will be on a three-day rolling basis. These dates and times may be changed without further notice.

The Company has established arrangements to enable investors to settle the Shares under the CREST system. CREST is a paperless settlement procedure enabling securities to be evidenced otherwise than by a certificate and transferred otherwise than by a written instrument. Securities issued by non-UK companies, such as the Company, cannot be held or transferred electronically in the CREST system. To enable investors to settle the Shares through CREST, the Company has entered into a depositary interest arrangement. See Part XV: "CREST and Depositary Interests".

The Sponsor and any of its affiliates acting as an investor for its or his or her own account may hold Shares, any other securities of the Company or other related investments. Such persons do not intend to disclose the extent of any such investment otherwise than in accordance with any legal or regulatory obligation to do so.

2 Sponsor arrangements

Details of the terms of the Sponsor's Agreement are set out in paragraph 10.1—"Sponsor's Agreement" in Part XVI: "Additional Information".

3 Lock-up arrangements

Pursuant to the Sponsor's Agreement, the Company has agreed that, subject to certain exceptions (including in respect of the conversion of the Convertible Bonds into Shares in accordance with their terms (and potentially any accrued but unpaid interest in relation thereto)), for a period of 120 days from the date of Admission, it will not, without the prior written consent of the Sponsor, directly or indirectly offer, sell or contract to sell, or otherwise dispose of any Shares or interests in Shares or enter into any transaction with the same economic effect as any of the foregoing.

Upon the occurrence of a qualifying public offer (a "**QPO**") under the terms of the Convertible Bonds, the Company will:

(i) procure that no Director or Senior Manager will sell Shares, or any warrants or options relating to Shares, for a period of not less than 365 days following the effective date of the QPO; and

(ii) seek undertakings from holders of more than 5 per cent. of the outstanding Shares not to sell such Shares for a period of not more than 120 days following the effective date of the QPO.

It is anticipated that, together, The Bradley Griffiths BDG Trust, BDG Capital Ltd. and Griffiths Energy and Resources Inc. may dispose of up to two million Shares or interests in up to two million Shares, upon terms to be determined, in the near- to medium-term following Admission.

For more information, see "Dilution and further sales" in Part II: "Risk Factors". For further details of the Sponsor Agreement, see paragraph 10—"Material contracts" in Part XVI: "Additional Information".

4 Notice to overseas persons

The distribution of this Prospectus in certain jurisdictions may be restricted by law. No action has been or will be taken by the Company or the Sponsor to permit the possession, issue or distribution of this Prospectus in any jurisdiction where action for that purpose may be required. Accordingly, neither this

Prospectus nor any advertisement nor any other material related to this Prospectus may be distributed or published in any jurisdiction except under circumstances that will result in compliance with any applicable laws and regulations. Persons into whose possession this Prospectus comes should inform themselves about and observe any such restrictions. Any failure to comply with these restrictions may constitute a violation of the securities laws of any such jurisdiction.

The Shares have not been, and will not be, registered under the U.S. Securities Act of 1933 or under the applicable securities laws of any state of the United States.

This Prospectus has not been, and will not be, filed with the Canadian Securities Regulators as a prospectus under the Applicable Canadian Securities Laws. This Prospectus does not purport to include the information required of a prospectus under the Applicable Canadian Securities Laws. This Prospectus may not be issued or distributed in Canada or to a resident of Canada.

PART XV

CREST AND DEPOSITARY INTERESTS

CREST and Depositary Interests

The Company has established arrangements to enable investors to settle interests in the Shares through the CREST system. CREST is a paperless settlement system allowing securities to be transferred from one person's CREST account to another without the need to use share certificates or written instruments of transfer. Securities issued by non-UK companies, such as the Company, cannot be held or transferred electronically in the CREST system. However, depositary interests allow such securities to be dematerialised and settled electronically through CREST. Where investors choose to settle interests in the Shares through the CREST system, and pursuant to depositary arrangements established by the Company, Computershare Investor Services plc (the "**Depositary**") will hold the Shares and issue dematerialised depositary interests (the "**Depositary Interests**") representing the underlying Shares, which will be held on trust for the holders of the Depositary Interests. The Depositary Interests will be independent securities constituted under English law which may be held and transferred through the CREST system. Investors should note that it is the Depositary Interests which will be admitted to and settled through CREST and not the Shares.

The Articles are consistent with CREST membership in respect of Depositary Interests and the holding and transfer of Depositary Interests in uncertified form. Under the CBCA, companies are not prohibited from issuing shares in book-entry form but shareholders have the right to require the companies to issue physical certificates. The Board has passed a resolution authorising the issuance of shares in book-entry form.

The Company and the Depositary entered into a depositary agreement (the "**Depositary Agreement**") on 27 June 2013, the principal terms of which are summarised below.

The Depositary Interests will be created pursuant to and issued on the terms of a deed poll executed on 21 June 2013 by the Depositary in favour of the holders of the Depositary Interests from time to time (the "**Deed Poll**"). Prospective holders of Depositary Interests should note that they will have no rights against Euroclear UK and Ireland (the operators of CREST) or its subsidiaries in respect of the underlying Shares or the Depositary Interests representing them.

If a holder of Shares so requests, its Shares will be transferred to an account of the Depositary or its nominated custodian (the "**Custodian**") and the Depositary will issue Depositary Interests to participating CREST members. Each Depositary Interest will be treated as one Share for the purposes of determining, for example, eligibility for any dividends. The Depositary will pass on to holders of Depositary Interests any stock or cash benefits received by it as holder of Shares on trust for such Depositary Interest holder. Depositary Interest holders, through the Depositary, will also be able to receive notices of meetings of holders of Shares and other notices issued by the Company to its shareholders.

The Depositary Interests will have the same security code (ISIN) as the underlying Shares and will not require a separate admission to the London Stock Exchange's main market for listed securities. The Depositary Interests can then be traded and settlement will be within the CREST system in the same way as any other CREST securities. Application will be made for the Depositary Interests to be admitted to CREST with effect from Admission.

A holder of the Shares on the principal share register of the Company maintained in Canada (the "**Share Register**") (a "**Principal Register Holder**") will be able to do the following to obtain a Depositary Interest for its Shares: (a) if held directly, send in its Share certificates to the Registrar; or (b) if held in a nominee account, provide instructions to its broker who will then obtain a withdrawal of the Shares from the system of CDS Clearing and Depositary Services Inc. ("**CDS**"). In addition, the Principal Register Holder, either directly or through its broker, must complete a Depositary Interest issuance request form that may be obtained from the Registrar. The Registrar will then either cancel the Share certificate or the CDS position, as applicable. After these steps, a Depositary Interest can be created and is then issued to the CREST participant that the holder, or the holder's broker, requested on the Depositary Interest issuance request form.

If a Principal Register Holder wishes to cancel its Depositary Interest, it will either directly or through its broker instruct the applicable CREST participant to initiate a CREST withdrawal (where such withdrawal is sent to the Depositary) for the name that appears on the Share Register. The Depositary Interest will then be cancelled by the Depositary and the related Share will be credited to the account on the Share

Register by the Registrar. The Registrar will either send the Principal Register Holder a new Share certificate if held directly, or if held in nominee form, by electronically updating the CDS position associated with the holder's broker.

The information included within this Part XV relating to the obtaining and cancellation of Depositary Interests by a Principal Register Holder is intended to be a summary only and is not to be construed as legal, business or tax advice. Each investor should consult his or her own lawyer, financial adviser, broker or tax adviser for legal, financial or tax advice in relation to Depositary Interests.

Deed Poll

The Deed Poll was executed on 21 June 2013 by the Depositary and contains the following provisions:

- The Depositary will hold (itself or through the Custodian), as bare trustee, the underlying Shares and all and any rights and other securities, property and cash attributable to the underlying Shares pertaining to the Depositary Interests for the benefit of the holders of the relevant Depositary Interests as tenants in common. The Depositary will re-allocate securities or Depositary Interests distributions allocated to the Depositary or Custodian *pro rata* to the Shares held for the respective accounts of the holders of Depositary Interests but will not be required to account for fractional entitlements arising from such re-allocation.
- Holders of Depositary Interests agree to give such warranties and certifications to the Depositary as the Depositary may reasonably require. In particular, holders of Depositary Interests warrant, *inter alia*, that the securities in the Company transferred or issued to the Depositary or Custodian on behalf of the Depositary for the account of the Depositary Interest holder are free and clear of all liens, charges, encumbrances or third party interests and that such transfers or issues are not in contravention of the Company's constitutional documents or any contractual obligation, or applicable law or regulation binding or affecting such holder, and holders of Depositary Interests agree to indemnify the Depositary against any liability incurred as a result of any breach of such warranty.
- The Depositary and any Custodian shall pass on to the Depositary Interest holders and, so far as they are reasonably able, exercise on behalf of the Depositary Interest holders all rights and entitlements received or to which they are entitled in respect of the underlying Shares which are capable of being passed on or exercised. Rights and entitlements to cash distributions, to information, to make choices and elections and to call for, attend and vote at meetings shall, subject to the Deed Poll, be passed on in the form in which they are received together with amendments and additional documentation necessary to effect such passing-on, or, as the case may be, exercised in accordance with the Deed Poll. If arrangements are made which allow a holder to take up rights in the Company's securities requiring further payment, the holder must put the Depositary in cleared funds before the relevant payment date or other date notified by the Depositary if it wishes the Depositary to exercise such rights.
- The Depositary will be entitled to cancel Depositary Interests and treat the holders thereof as having requested a withdrawal of the underlying securities in certain circumstances, including where a Depositary Interest holder fails to furnish to the Depositary such certificates or representations as to material matters of fact, including his identity, as the Depositary deems appropriate.
- The Depositary warrants that it is an authorised person under the FSMA and is duly authorised to carry out custodian and other activities under the Deed Poll. It also undertakes to maintain that status and authorisation.
- The Deed Poll contains provisions excluding and limiting the Depositary's liability. For example, the Depositary shall not be liable to any Depositary Interest holder or any other person for liabilities in connection with the performance or non-performance of obligations under the Deed Poll or otherwise except as may result from its negligence or wilful default or fraud or that of any person for whom it is vicariously liable, provided that the Depositary shall not be liable for the negligence, wilful default or fraud of any Custodian or agent which is not a member of its group unless it has failed to exercise reasonable care in the appointment and continued use and supervision of such Custodian or agent.

Except in the case of personal injury or death, any liability incurred by the Depositary to a holder under the Deed Poll is limited to the lesser of:

(a) the value of the Shares that would have been properly attributable to the Depositary Interests to which the liability relates; and

(b) that proportion of £5 million which corresponds to the portion which the amount the Depositary would otherwise be liable to pay to the holder bears to the aggregate of the amounts the Depositary would otherwise be liable to pay to all such holders in respect of the same act, omission, or event which gave rise to such liability or, if there are no such amounts, £5 million.

- The Depositary is entitled to charge holders of Depositary Interests fees and expenses for the provision of its services under the Deed Poll.
- Each holder of Depositary Interests is liable to indemnify the Depositary and any Custodian (and their agents, officers and employees), and hold each of them harmless from and against all liabilities arising from or incurred in connection with, or arising from any act related to, the Deed Poll so far as they relate to the property held for the account of that holder, other than those caused by or resulting from the wilful default, negligence or fraud of (i) the Depositary or (ii) the Custodian or any agent if such Custodian or agent is a member of the Depositary's group or if, not being a member of the same group, the Depositary shall have failed to exercise reasonable care in the appointment and continued use of such Custodian or agent.
- The Depositary is entitled to make deductions from the deposited property or any income or capital arising there from, or to sell such deposited property and make deductions from the sale proceeds thereof, in order to discharge the indemnification obligations of Depositary Interest holders.
- The Depositary may terminate the Deed Poll by giving not less than 90 days' notice. During such notice period, Depositary Interest holders may cancel their Depositary Interests and withdraw their deposited property and, if any Depositary Interests remain outstanding after termination, the Depositary shall, as soon as reasonably practicable, and amongst other things, (i) deliver the deposited property in respect of the Depositary Interests to the relevant Depositary Interest holder or, at the Depositary's discretion, (ii) sell all or part of such deposited property. It shall, as soon as reasonably practicable, deliver the net proceeds of any such sale, after deducting any sums due to the Depositary, together with any other cash held by it under the Deed Poll *pro rata* to the Depositary Interest holders in respect of their Depositary Interests.
- The Depositary or the Company may require from any holder (i) information as to the capacity in which Depositary Interests are owned or held by such holders and the identity of any other person with any interest of any kind in such Depositary Interests or the underlying Shares and the nature and amounts of such interests, (ii) evidence or declaration of nationality or residence of the legal or beneficial owner(s) of Depositary Interests and such information as is required to transfer the relevant Depositary Interests or Shares to the holder and (iii) such information as is necessary or desirable for the purposes of the Deed Poll or CREST system, and holders are bound to provide such information requested. The holders of Depositary Interests consent to the disclosure of such information by the Depositary, Custodian or Company to the extent necessary or desirable to comply with their respective legal or regulatory obligations.
- Furthermore, to the extent that the Company's constitutional documents, applicable laws or regulations, the Ground Rules for the Management of the FTSE UK Index Series (if applicable), or any court or legal or regulatory authority may require or the Company deems it necessary or desirable in connection therewith (including in response to requests for information), the disclosure to the Company of, or limitations in relation to, beneficial or other ownership of, or interests of any kind whatsoever in the Company's securities, the Depositary Interest holders are to comply with such provisions and with the Company's instructions with respect thereto, and consent to the disclosure of such information for such purposes.

It should also be noted that holders of Depositary Interests may not have the opportunity to exercise all of the rights and entitlements available to holders of Shares, including, for example, the ability to vote on a show of hands. In relation to voting, it will be important for holders of Depositary Interests to give prompt instructions to the Registrar or its nominated Custodian, in accordance with any voting arrangements made available to them, to vote the underlying Shares on their behalf or, to the extent possible, to take advantage

of any arrangements enabling holders of Depositary Interests to vote such Shares as a proxy of the Registrar or its nominated Custodian.

Depositary Agreement

The Depositary Agreement was entered into between the Company and the Depositary on 27 June 2013 and contains the following provisions:

- Under the Depositary Agreement, the Company appoints the Depositary to constitute and issue from time to time, upon the terms of the Deed Poll, a series of Depositary Interests representing Shares and to provide certain other services (including depositary services, custody services and dividend services) in connection with such Depositary Interests.
- The Depositary agrees that it will comply with the terms of the Deed Poll and that it will perform its obligations with reasonable skill and care. The Depositary assumes certain specific obligations, including, for example, to arrange for the Depositary Interests to be admitted to CREST as participating securities and provide copies of, and access to, the register of Depositary Interests.
- The Company acknowledges that it shall be its responsibility and undertakes to advise the Depositary promptly of any securities laws or other applicable laws, rules or regulations in the Province of Alberta and Canada which the Depositary must comply with in providing the services.
- The Company agrees to provide such assistance, information and documentation to the Depositary as is reasonably required by the Depositary for the purposes of performing its duties, responsibilities and obligations under the Depositary Agreement.
- The Depositary is to indemnify the Company and its officers and employees from and against any loss (excluding indirect, consequential or special loss) which any of them may incur in any way as a result of or in connection with the fraud, negligence or wilful default of the Depositary (or its officers, employees, agents or sub-contractors).
- Subject to earlier termination, the appointment of the Depositary shall continue for a fixed period of one year and thereafter until terminated in accordance with the terms of the Depositary Agreement. Should the Depositary Agreement be terminated for any reason, other than arising from the Depositary's fraud, negligence, wilful default or material breach of a term of the Depositary Agreement, the Company shall within 30 days of termination pay to the Depositary, the Depositary's reasonable costs and expenses of transferring the Depositary Interest register to its new registrar. Either party may terminate the Depositary Agreement by giving not less than 90 days' notice in writing. Either party may terminate the Depositary Agreement with immediate effect by notice in writing if the other party (i) shall be in persistent or material breach of any material term (of the Depositary Agreement) and such breach is not remedied within 30 days of a request for such remedy, (ii) goes into insolvency or liquidation or administration or a receiver is appointed over any part of its undertaking or assets, subject to certain provisos or (iii) shall cease to have the appropriate authorisations which permit it lawfully to perform its obligations under the Depositary Agreement.
- The Depositary will be entitled to employ agents for the purposes of carrying out certain of its obligations under the Depositary Agreement which the Depositary reasonably considers to be of a specialist nature.
- The Company is to pay to the Depositary an annual fee for the services. The Company shall pay a fixed fee for the deposit, cancellation and transfer of the Depositary Interests and the compilation of the initial Depositary Interests register. The Company shall in addition reimburse the Depositary within 30 days of the Depositary's invoice for all network charges, CREST charges, money transmission and banking charges and other out-of-pocket expenses incurred by it in connection with the provision of the services under the Depositary Agreement.
- The Company will indemnify the Depositary from and against all loss suffered by the Depositary as a result of or in connection with the performance of its obligations under the Depositary Agreement.
- The aggregate liability of the Depositary to the Company over any 12-month period under the Depositary Agreement will not exceed twice the amount of the Fees (as defined in the Depositary Agreement) payable in any 12-month period in respect of a single claim or in the aggregate.

PART XVI

ADDITIONAL INFORMATION

1 Responsibility

The Company and the Directors, whose names and principal functions are set out in Part VIII: "Directors, Senior Managers and Corporate Governance", accept responsibility for the information contained in this Prospectus. To the best of the knowledge of the Company and the Directors (each of whom has taken all reasonable care to ensure that such is the case), the information contained in this Prospectus is in accordance with the facts and does not omit anything likely to affect the import of such information.

GLJ accepts responsibility for the information contained in the GLJ Reports, as set out in Part XIX: "GLJ Reports". To the best of the knowledge of GLJ (which has taken all reasonable care to ensure that such is the case), the information contained in the GLJ Reports is in accordance with the facts and does not omit anything likely to affect the import of such information.

2 Incorporation

2.1 The Company was incorporated and registered in Canada on 20 April 2009, under the CBCA, with the name "First Dune Oil and Gas Inc." and with the registered number 716005-4. Pursuant to an amendment to the Company's articles of association (the "**Articles**") filed on 10 August 2009, the Company changed its name to Griffiths Energy International Inc. Pursuant to an amendment to the Articles filed on 23 May 2013, the Company changed its name to Caracal Energy Inc.

2.2 The legislation under which the Company operates is the CBCA.

2.3 The Company's registered and head office is located at Suite 2100, 555 - 4th Avenue S.W., Calgary, Alberta, Canada, T2P 3E7, telephone +1 (403) 724 7200.

2.4 By resolution of the shareholders dated 22 May 2013, KPMG LLP, whose address is 2700, 205 - 5th Avenue S.W., Calgary, Alberta, Canada, T2P 4B9, was reappointed as the auditor of the Company. KPMG LLP is registered to carry out audit work by the Institute of Chartered Accountants of Alberta.

3 The Group and principal activities

The Company is the principal operating and holding company of the Group. The principal subsidiaries and subsidiary undertakings of the Company are as follows:

Name	Place and date of incorporation	Principal activity	Percentage ownership
Griffiths Energy Holdings Ltd . . .	Bermuda, 19 January 2011	Holding Company	100%
PetroChad (Mangara) Limited . . .	Bermuda, 1 March 2011	Oil and gas exploration and development	100%
Griffiths Energy (Chad) Ltd	Bermuda, 19 January 2011	Oil and gas exploration and development	100%
Griffiths Energy (DOH) Ltd.	Bermuda, 8 August 2011	Oil and gas exploration and development	100%
Griffiths Energy (U.S.) Inc.	Delaware, United States, 21 March 2011	Oil and gas exploration and development	100%
PetroChad Transportation Limited	Bermuda, 15 May 2012	Administration of transportation under any inland transport authorisation	100%[37]

4 Share capital

4.1 The authorised common share capital of the Company consists of an unlimited number of Shares without nominal or par value. As of the date of this Prospectus, 115,657,752 Shares were issued and outstanding.

4.2 The Company was incorporated on 20 April 2009 with one Share issued to the subscriber for C$1.00.

(37) Glencore is expected to acquire a 33.33% ownership interest in PCT from the Group in July 2013.

4.3 Since its incorporation, there have been the following changes in the authorised and issued share capital of the Company:

- During October 2009, the Company issued, in aggregate, 40,000,000 Shares at a price of C$0.001 per Share pursuant to a private placement.
- During December 2009 and January 2010, the Company issued, in aggregate, 4,000,000 Shares at a price of C$0.30 per Share pursuant to various private subscriptions.
- During January 2010, the Company issued, in aggregate, 612,500 units (the "**2010 Units**") at a price of C$2.00 per 2010 Unit pursuant to various private subscriptions. Each 2010 Unit was comprised of one Share and one Warrant (each, a "**Purchase Warrant**"). The terms of the Purchase Warrants were such that in the event that the Company completed the next private subscription at a subscription price equal to or greater than C$2.50 per Share, each Purchase Warrant would be automatically cancelled. In the event that the next private subscription was made at a subscription price equal to or less than C$2.50 per Share, each Purchase Warrant would convert automatically to Shares for no additional consideration.
- On 11 January 2011, the Company issued 900,000 Shares at a price of C$2.50 per Share pursuant to a private subscription. Pursuant to the completion of this private subscription, the 612,500 Purchase Warrants issued in January 2010 were automatically cancelled. See the paragraph above for further information.
- During February, March and April 2011, the Company issued, in aggregate, 36,000,000 Shares at C$5.00 per Share pursuant to a brokered private subscription. As part of this private subscription, one-tenth (1/10) of a liquidity warrant (each, a "**2011 Liquidity Warrant**") was issued for each Share, for an aggregate of 3,600,000 2011 Liquidity Warrants issued. Each 2011 Liquidity Warrant automatically converted into one Share, for no additional consideration thereof, on 1 January 2012.
- In connection with the February and March 2011 private subscriptions, the Company issued, in aggregate, 1,980,000 options to the syndicate of agents (the "**Agent Advisory Options**"), each of which entitles the holder thereof to acquire one Share at a price of C$5.00 per Share and expires 24 months after its issuance date. As at 31 March 2013, 779,200 Agent Advisory Options have been exercised, and the remaining 1,200,800 Agent Advisory Options have automatically expired.
- On 1 July 2011, the Company issued, in aggregate, 2,000,000 units (the "**2011 Units**") at a price of C$5.00 per 2011 Unit to the then current management team of the Company (contemporaneously with their appointment as officers of the Company). Each 2011 Unit was comprised of one Share and two Warrants (each, a "**Performance Warrant**"). The Performance Warrants expire five years from the date of issue. Each Performance Warrant, once vested, is exercisable for one Share at an exercise price of C$5.50 per Share.
- During the third quarter of 2011, the Company issued, in aggregate, 3,000,000 Share options to new management and directors, which were fully vested and immediately exercisable upon their issue, with an exercise price of C$0.40 per Share (the "**Seed Options**").
- On 1 July 2011, the Company issued, in aggregate, 1,975,000 Shares at a price of C$0.40 per Share to the management team of the Company upon the exercise of Seed Options.
- On 25 July 2011, the Company issued, in aggregate, 165,000 Seed Options to certain members of the Board. Also, on 25 July 2011 the Company issued 405,000 Shares at a price of C$0.40 per Share to the Board members upon the exercise of Seed Options.
- On 1 August 2011, the Company issued a further 200,000 2011 Units at a price of C$5.00 per Unit to a new management appointee. Each Unit was comprised of one Share and two Performance Warrants.
- On 1 August 2011, the Company issued, in aggregate, 125,000 Shares at a price of C$0.40 per Share to the management team of the Company upon the exercise of Seed Options.
- On 2 September 2011, the Company granted, in aggregate, 165,000 Seed Options to certain members of the Board. Also on 2 September 2011, the Company issued, in aggregate, 495,000 Shares at a price of C$0.40 per Share to the members of the Board upon the exercise of Seed Options.

- On 8 September 2011, the Company issued, in aggregate, 577,200 Shares at a price of C$5.00 per Share pursuant to private subscriptions. Participants in this private subscription included, among others, the new directors of the Company elected on 2 September 2011.
- During September 2011, the Company issued 568,353 Shares at a price of C$0.40 per Share to the former Chief Executive Officer of the Company upon the exercise of Seed Options. The Seed Options were granted to the prior Chief Executive Officer on 2 September 2011 pursuant to a prior agreement.
- During the fourth quarter of 2011, the Company issued, in aggregate, 150,666 Shares to employees of the Company in connection with the Company's employee Option Plan, further details of which are set out in paragraph 9—"Employee share plans" in this Part XVI.
- In January 2012, the Company issued 3,600,000 Shares as a result of the conversion of 3,600,000 2011 Liquidity Warrants issued in connection with the private placements on 25 February 2011, 3 March 2011, and 19 April 2011. The 2011 Liquidity Warrants were converted to Shares at no additional consideration as a Liquidity Warrant Liquidity Event did not occur prior to 1 January 2012.
- On 14 March 2012, the Company issued 20,840,000 Shares at a price of C$6.00 per Share pursuant to a brokered private subscription. As part of this private subscription, one-tenth (1/10) of a liquidity warrant (each, a "**2012 Liquidity Warrant**") was issued for each Share, for an aggregate of approximately 2,084,000 2012 Liquidity Warrants issued. Each whole 2012 Liquidity Warrant automatically converted into one Share, for no additional consideration thereof, because a Liquidity Warrant Liquidity Event did not occur prior to 14 March 2013.
- In March 2012, the Company issued 1.7 million Performance Warrants to certain employees, Senior Managers and Directors. Each Performance Warrant entitles the holder thereof to purchase one Share at a price of C$6.00 per Share with a five year expiry, subject to vesting in 1/3 increments.
- During the first quarter of 2012, the Company issued, in aggregate, 312,500 Shares at a price of C$6.00 per Share to an arm's length party as payment upon signing a term sheet for a credit facility. These Shares are subject to a put option which is exercisable at any time at a price of C$6.00.
- On 13 September 2012, the Company issued U.S.$173.6 million Convertible Bonds. The Convertible Bonds are convertible at any time up to 14 days prior to the Maturity Date (or 14 days prior to any earlier date fixed for redemption of the Convertible Bonds) at an initial conversion price of U.S.$6.07 per Share. The conversion price of the Convertible Bonds will be subject to adjustment on or following the occurrence of certain corporate events relating to the share capital of the Group.
- In February and March 2013 the Company issued 779,200 Shares as a result of the exercise of Agent Advisory Options in connection with the private placement dated 25 February 2011 and 3 March 2011.
- In March 2013 the Company issued 2,084,000 Shares as a result of the conversion of 2012 Liquidity Warrants issued in connection with the private placement on 14 March 2012. The 2012 Liquidity Warrants were converted to Shares at no additional consideration as a Liquidity Warrant Liquidity Event did not occur prior to 14 March 2013.
- In April 2013 the Company issued 33,333 Shares to certain members of the Board in connection with the Option Plan.
- During the first quarter of 2013, 115,445 restricted share units ("**RSUs**") and 20,735 deferred share units ("**DSUs**") were granted to Directors for Directors' fees and 1,093,602 performance share units ("**PSUs**") were granted to the Senior Managers, effective 1 January 2013 under the 2013 Incentive Plan.
- Peter Dey was appointed to the Board of Directors in March 2013 and in connection therewith was granted 130,000 Options with an exercise price of C$6.25 and an expiration date of 13 March 2018.

4.4 The following table sets forth the existing common share capital of the Company as of the date of this Prospectus and the common share capital of the Company as it is expected to be immediately after Admission.

	Outstanding as at date hereof	Outstanding immediately following Admission
Number	115,657,752	115,657,752
Amount	N/A(1)	N/A(1)

Note:

(1) The value of the Shares as at the date hereof is not reasonably ascertainable given that the Shares are not, and have never been, publicly listed or traded. The Shares do not have a nominal or par value.

4.5 As at 24 June 2013 (being the latest practicable date prior to the publication of this Prospectus), 7,708,000 Shares are issuable upon exercise of outstanding Options, 5,975,000 Shares are issuable upon exercise of outstanding Performance Warrants and an additional 1,229,782 Shares are issuable upon vesting of outstanding Awards. See paragraph 9.1—"Option Plan" and paragraph 9.2—"2013 Incentive Plan" in this Part XVI and Part X: "Operating and Financial Review", respectively, for a description of the terms of the Options, Awards and the Performance Warrants. The Convertible Bonds are convertible at an initial conversion price of U.S.$6.07 per Share. 28,599,670 Shares would be issuable in the event that conversion of all the Convertible Bonds took place at this conversion price. See Part X: "Operating and Financial Review" for a description of the Convertible Bonds.

4.6 Set forth below are details regarding the Shares and all securities that are convertible into Shares issued by the Company during the 12-month period prior to the date of this Prospectus.

Type of security	Date of issuance/grant	Number	Issue price/ exercise price per security	Expiration date
Shares	25 February 2013	614,851	C$5.00	N/A
	3 March 2013	164,349	C$5.00	N/A
	14 March 2013	2,084,000	N/A	N/A
	26 April 2013	33,333	C$5.00	N/A
Options	26 June 2012- 24 June 2013	4,013,000	C$6.00	24 June 2017- 17 June 2018
Convertible Bonds	13 September 2012	28,599,670	U.S.$6.07	30 September 2017
RSUs	1 January 2013	115,445	C$6.41	N/A
PSUs	1 January 2013	1,093,602	C$6.41	N/A
DSUs	14 March 2013	20,735	C$6.25	N/A

4.7 When admitted to trading, the Shares will be registered with ISIN number CA1407561077 and SEDOL number BB97882.

4.8 Following Admission, the price of the Shares will be quoted on the London Stock Exchange in pounds sterling.

4.9 The aggregate market value of the Shares immediately following Admission will be at least £700,000.

5 Memorandum and Articles of Association

5.1 Summary of the memorandum of association of the Company

The Company's objects are not limited by anything contained in its memorandum of association or Articles and so there are no restrictions on the type of business that the Company may carry on.

5.2 Summary of the Articles

The Articles have been adopted conditional upon Admission and contain the provisions summarised below.

5.3 **Rights, preferences and restrictions attaching to the Shares**

Pursuant to the Articles, the Company is authorised to issue an unlimited number of Shares without nominal or par value of a class designated as common shares.

The holders of the Shares are entitled to:

(a) vote at any meeting of shareholders of the Company other than meetings of the holders of another class of shares;

(b) receive the remaining property of the Company upon dissolution; and

(c) to receive any dividend declared by the Directors on the Shares.

The Articles do not contain any restrictions on Share transfers.

Pursuant to the CBCA, the Articles may, by a resolution passed by a majority of not less than two-thirds of the votes cast by the shareholders voting, change the designation of all or any of the Company's shares, and add, change or remove any rights, privileges, restrictions and conditions, including rights to accrued dividends, in respect of all or any of the Company's shares, whether issued or unissued.

5.4 **Allotment of securities and pre-emption rights**

The Articles include pre-emption provisions requiring that equity securities issued for cash by the Company must first be offered to existing holders of Shares in proportion to their existing holdings of Shares (excluding treasury shares). Exceptions to this rule include the allotment of:

(a) bonus shares;

(b) equity securities to be paid up (either wholly or partly) otherwise than in cash; and

(c) equity securities allotted for cash which are to be held under an employee share scheme.

The Company may from time to time pass a resolution, subject to such resolution receiving the approval of 75 per cent. of shareholders, empowering the Board to exercise all the powers of the Company to allot equity securities wholly for cash:

(i) in connection with a rights issue;

(ii) in connection with a pre-emptive offer, up to an aggregate nominal amount specified in the resolution as being the "Authorised Allotment Amount"; and

(iii) otherwise than in connection with a rights issue or a pre-emptive offer, up to an aggregate nominal amount specified in the resolution as being the "Non-Pre-Emptive Amount".

Any authority shall expire on the day specified in the resolution, not being more than five years after the date on which the resolution is passed.

5.5 **Meetings of shareholders**

Calling of meetings

A meeting of shareholders may be called at any time by resolution of the Board or by the Chairperson of the Board or the President and the Secretary shall cause notice of a meeting of shareholders to be given when directed so to do by resolution of the Board or by the Chairperson of the Board or the President.

Giving of notice

A printed, written or typewritten notice of each meeting of shareholders shall be given to the Chairperson of the Board, the President, the Secretary, each director and the auditor of the Company and to each shareholder entitled to vote at such meeting not less than 21 days (exclusive of the day on which the notice is given and of the day of such meeting) nor more than 60 days (inclusive of the day on which the notice is given and of the day of such meeting) before the meeting.

Omission of notice

Accidental omission to give notice of any meeting to any person entitled thereto or the non-receipt of any notice by any such person shall not invalidate any resolution passed or any proceedings taken at any meeting.

Persons entitled to be present

The only persons entitled to attend a meeting of shareholders shall be those entitled to vote thereat and the Chairperson of the Board, the President, the Secretary, the directors, the scrutineer or scrutineers and the auditor of the Company and others who, although not entitled to vote, are entitled or required under any provisions of the CBCA or the by-laws to be present at the meeting. Any other person may be admitted only on the invitation of the chairperson of the meeting or with the consent of the meeting.

Votes to govern

At all meetings of shareholders every question shall, unless otherwise required by law, the Articles, the by-laws, or a unanimous shareholder agreement, be determined by the majority of the votes duly cast on the question. In case of an equality of votes, the chairman presiding at the meeting shall not have a second or casting vote in addition to the vote or votes to which he may be entitled as a shareholder.

Quorum

At any meeting of shareholders, the shareholder or shareholders present in person or represented by proxy and entitled to attend and vote at such meeting shall be a quorum for the choice of a chairperson (if required) and for the adjournment of the meeting. Subject to the paragraph below, for all other purposes a quorum for any meeting of shareholders (unless a greater number of shareholders and/or a greater number of shares are required by the CBCA or by the Articles or by-laws) shall be two individuals present in person, each of whom is either a shareholder entitled to attend and vote at such meeting or a proxyholder appointed by such a shareholder, holding or representing by proxy not less than 5 per cent. of the total number of the issued Shares for the time being enjoying voting rights at such meeting. No business shall be transacted at any meeting while the requisite quorum is not present.

If the Company has only one shareholder or only one shareholder of any class or series of Shares, the shareholder present in person or represented by proxy constitutes a meeting.

5.6 **Directors**

Borrowing Powers

The Board may from time to time

(a) borrow money on the credit of the Company;

(b) issue, reissue, sell or pledge debt obligations of the Company;

(c) subject to the CBCA, give a guarantee on behalf of the Company to secure performance of an obligation of any person; and

(d) mortgage, hypothecate, pledge or otherwise create a security interest in all or any property of the Company, owned or subsequently acquired, to secure any debt obligation of the Company.

The Board may by resolution delegate all or any of the powers conferred on them by paragraphs (a) and (c) above, to any one or more of the directors, the Managing Director, any committee of the Board, the Chairperson of the Board (if any), the President, any Vice President, the Secretary, the Treasurer, any Assistant Secretary, any Assistant Treasurer or the General Manager.

Committees

The Board may appoint from among their number one or more committees and may by resolution delegate to any such committee any powers of the Board, subject to such restrictions as may be imposed from time to time by resolution of the Board and subject to the limits on authority contained in the CBCA.

5.7 **Meetings of the Board**

Place of meetings

Meetings of the Board and of any committee of the Board may be held at any place within or outside Canada.

Calling of meetings

A meeting of the Board may be called at any time by the Chairperson of the Board, the President, a Vice President (if he or she is a director) or any two of the directors and the Secretary shall cause notice of a meeting of the Board to be given when so directed by such person or persons.

Notice of meetings

Notice of any meeting of the Board shall be given to each director not less than two days (exclusive of Saturdays, Sundays, holidays and the day on which the notice is given but inclusive of the day of the meeting) before the meeting is to take place.

The notice of a meeting of the Board shall specify the time and place at which such meeting will be held and any of the following matters that are to be dealt with at the meeting:

(a) the submission to the shareholders of any question or matter requiring the approval of the shareholders;

(b) the filling of a vacancy among the Board or in the office of auditor of the Company or appointing additional directors;

(c) the issue of securities of the Company;

(d) the declaration of a dividend or dividends on shares of the Company;

(e) the purchase, redemption or other acquisition of shares of the Company;

(f) the payment of a commission for purchase of shares of the Company;

(g) the approval of a management proxy circular;

(h) the approval of a take-over bid circular or circular of the Board;

(i) the approval of the annual financial statements of the Company; or

(j) the adoption, amendment or repeal of any by-law or by-laws.

Regular meetings

The Board may by resolution fix a day or days in any month or months for the holding of regular meetings at a time and place specified in such resolution. A copy of any resolution of the Board specifying the time and place for the holding of regular meetings of the Board shall be sent to each director at least two days (exclusive of Saturdays, Sundays, holidays and the day on which the copy of the resolution is sent but inclusive of the day of the first of such regular meetings) before the first of such regular meetings and no notice shall be required for any of such regular meetings.

Participation

Where all the directors have consented thereto, any director may participate in a meeting of the Board or any committee of the Board by means of telephonic, electronic or other communication facility that permits all persons participating in the meeting to communicate adequately with each other and a director participating in such a meeting by such means shall be deemed to be present at that meeting for purposes of the CBCA and this by-law.

Quorum

Subject to the Articles and the qualification that at least 25 per cent. or, if the Company has fewer than four directors at least one, of the directors present be resident Canadians, a majority of the number of directors or minimum number of directors required by the Articles constitutes a quorum at any meeting of directors.

Voting

All questions arising at any meeting of the Board shall be decided by a majority of votes, but in case of an equality of votes, the chairperson of the meeting (if he or she is a director) shall not have, in addition to his or her original vote, a second or casting vote.

5.8 **Officers**

Officers

The Board may, annually or as often as may be required, by resolution appoint a President or a Chairperson of the Board, and a Secretary. In addition, the Board may from time to time by resolution appoint such other officers as the Board determines to be necessary or advisable in the interests of the Company, which officers shall have such authority and shall perform such duties as are hereinafter specified or as may from time to time be prescribed by resolution of the Board. None of the said officers need be a member of the Board. Any two of the aforesaid offices may be held by the same person except those of President and Vice President.

Appointment of President or Chairperson of the Board or Secretary

At the first meeting of the Board after each annual meeting of shareholders, the Board may appoint a President or a Chairperson of the Board, and a Secretary. In default of any such appointment the then incumbent shall hold office until his or her successor is appointed.

Removal of officers

All officers shall be subject to removal by resolution of the Board at any time.

Delegation of duties of officers

In case of the absence or inability to act of the Chairperson of the Board, the President, a Vice President or any other officer of the Company, or for any other reason that the Board may deem sufficient, the Board may delegate the powers of such officer to any other person for the time being.

Chairperson of the Board

If the provisions of a resolution of the Board so specify, the Chairperson of the Board shall, if present, preside at all meetings of the Board and shareholders. He or she shall sign all instruments which require his or her signature and shall perform all duties incident to his or her office, and shall have such other powers and duties as may from time to time be assigned to him or her by the Board.

President

Subject to the provisions of any resolution of the Board specifying the duties of the Chairperson of the Board, the President shall, if present, preside at all meetings of directors and shareholders. He or she shall sign all instruments which require his or her signature and shall perform all duties incident to his or her office, and shall have such other powers and duties as may from time to time be assigned to him or her by the Board.

Managing Director

The directors may appoint from their number a Managing Director who is a resident Canadian and may delegate to such Managing Director any of the powers of the Board (except power to do anything referred to in items (a) through (j) of the "Notice of meetings" summary in paragraph 5.7—"Meetings of the Board" in this Part XVI.

General Manager

The General Manager shall have such powers to manage the business of the Company (except power to do anything referred to in items (a) through (j) of the "Notice of meetings" summary in paragraph 5.7—"Meetings of the Board" in this Part XVI as may from time to time be prescribed by resolution of the Board.

Vice President

During the President's absence or inability or refusal to act, the President's duties may be performed and his or her powers may be exercised by the Vice President, or if there are more than one, by the Vice Presidents in order of seniority or designation (as determined by the Board), except that no Vice President shall preside at a meeting of the Board unless he or she is a director. A Vice President shall also perform such duties and exercise such powers as may from time to time be prescribed by resolution of the Board.

Secretary

The Secretary shall give, or cause to be given, all notices required to be given to shareholders, directors, auditors and members of committees. He or she shall enter or cause to be entered in the books kept for that purpose minutes of all proceedings at the meetings of directors and of shareholders. He or she shall be the custodian of the corporate seal (if any) of the Company and of all books, papers, records, documents and other instruments belonging to the Company. He or she shall perform such other duties as may from time to time be prescribed by resolution of the Board.

Treasurer

The Treasurer shall have the care and custody of all the funds and securities of the Company and shall deposit the same in the name of the Company in such bank or banks or with such depositary or depositaries as the Board may by resolution direct. He or she shall at all reasonable times exhibit his or her books and accounts to any director upon application at the office of the Company during business hours. He or she shall sign or countersign such instruments as require his or her signature and shall perform all duties incident to his or her office or that are properly required of him or her by resolution of the Board. He or she may be required to give such bond for the faithful performance of his or her duties as the Board in its discretion may require but no director shall be liable for failure to require any bond or for the insufficiency of any bond or for any loss by reason of the failure of the Company to receive any indemnity thereby provided.

Assistant Secretary and Assistant Treasurer

During the Secretary's absence or inability or refusal to act, the Assistant Secretary (if any) shall perform all the duties of the Secretary. The Assistant Secretary shall also have such other powers and duties as may from time to time be assigned to him or her by resolution of the Board.

During the Treasurer's absence or inability or refusal to act, the Assistant Treasurer (if any) shall perform all the duties of the Treasurer. The Assistant Treasurer shall also have such other powers and duties as may from time to time be assigned to him or her by resolution of the Board.

Delegation of Board Powers

The Board may from time to time by resolution delegate to any officer or officers power to manage the business of the Company except power to do anything referred to in items (a) through (j) of the "Notice of Meetings" summary in paragraph 5.7—"Meetings of the Board" in this Part XVI.

Vacancies

If any office of the Company shall for any reason be or become vacant, the directors by resolution may appoint a person to fill such vacancy.

Variation of duties

Notwithstanding the foregoing, from time to time the Board may by resolution vary, add to or limit the powers and duties of an office or of an officer occupying any office.

Chief Executive Officer

The Board may by resolution designate any one of the officers as the Chief Executive Officer of the Company and may from time to time by resolution rescind any such designation and designate another officer as the Chief Executive Officer of the Company. If the Board shall fail to designate one of the officers as the Chief Executive Officer of the Company or if at any time or from time to time the Board shall rescind any such designation without designating another officer as the Chief Executive Officer of the Company, the President shall be deemed to have been designated the Chief Executive Officer of the Company until the Board designates another officer as the Chief Executive Officer of the Company.

The officer designated or deemed to have been designated as the Chief Executive Officer of the Company as above shall exercise general supervision over the affairs of the Company.

5.9 **For the protection of Directors and Officers**

Liability for acts of others

Subject to the provisions of the CBCA, no director or officer shall be liable for the acts, receipts, neglects or defaults of any other director or officer or employee or for joining in any receipts or acts for conformity or for any loss, damage, or expense happening to the Company through the insufficiency or deficiency of title to any property acquired by order of the Board for or on behalf of the Company or for the insufficiency or deficiency of any security in or upon which any of the moneys of or belonging to the Company shall be placed out or invested or for any loss or damage arising from the bankruptcy, insolvency, or tortious act of any person with whom any moneys, securities or effects of the Company shall be lodged or deposited or for any loss occasioned by any error of judgment or oversight on his or her part, or for any other loss, damage or misfortune whatsoever which may happen in the execution of the duties of his or her respective office or trust or in relation thereto.

Indemnity of Directors and Officers

Subject to the provisions of the CBCA, the Company shall indemnify a director or officer of the Company, a former director or officer of the Company, or another individual who acts or acted at the Company's request as a director or officer, or an individual acting in a similar capacity, of another entity, against all costs, charges and expenses, including an amount paid to settle an action or satisfy a judgment, reasonably incurred by the individual in respect of any civil, criminal or administrative, investigative or other proceeding in which the individual is involved because of that association with the Company or other entity if:

(a) the individual acted honestly and in good faith with a view to the best interests of the Company or, as the case may be, to the best interests of the other entity for which the individual acted as director or officer or in a similar capacity at the Company's request; and

(b) in the case of a criminal or administrative action or proceeding that is enforced by a monetary penalty, the individual had reasonable grounds for believing that his or her conduct was lawful.

Advance of costs

The Company may advance moneys to a director, officer or other individual for the costs, charges and expenses of a proceeding referred to in the "Indemnity of Directors and Officers" summary above in this Part XVI. The individual shall repay the moneys if the individual does not fulfil the conditions of the "Indemnity of Directors and Officers" summary above in this Part XVI.

Directors' expenses

The directors shall be reimbursed for their out-of-pocket expenses incurred in attending Board, committee or shareholders' meetings or otherwise in respect of the performance by them of their duties and no confirmation by the shareholders of any such reimbursement shall be required.

Responsibility for contracts

The directors for the time being shall not be under any duty or responsibility in respect of any contract, act or transaction whether or not made, done or entered into in the name or on behalf of the Company, except such as shall have been submitted to and authorised or approved by the Board. If any director or officer shall be employed by or shall perform services for the Company otherwise than as a director or officer or shall be a member, shareholder, director or officer of a person which is employed by or performs services for the Company, the fact of his or her being a director or officer of the Company shall not disentitle such director or officer or such person from receiving proper remuneration for such services.

Submission of contracts or transactions to shareholders for approval

The Board in its discretion may submit any contract, act or transaction for approval or ratification at any annual or general meeting of the shareholders called for the purpose, *inter alia*, of considering such contract, act or transaction and any contract, act or transaction so submitted that is approved by a resolution passed by a majority of the votes cast at any such meeting (unless any different or additional requirement is imposed by the CBCA, by the Articles or by any other by-law) shall be as valid and as

binding upon the Company and upon all the shareholders as though it had been approved or ratified by every shareholder.

5.10 **Dividends**

Each Share has an equal right to receive any dividend declared by the Company. The declaration of a dividend (including, without limitation, the rate, frequency, form (cash or equity securities) and the cumulative or non-cumulative nature of payments) is a matter within the discretion of the Board and cannot be delegated by the Board, nor can the Board be compelled to declare and pay dividends. Under the CBCA, dividends cannot be paid if there are reasonable grounds for believing that the Company cannot meet either of the following tests: (i) the Company is, or would after the payment be, unable to pay its liabilities as they become due; or (ii) the realisable value of the Company's assets would, after the payment, be less than the aggregate of its liabilities and stated capital. Any dividends that might be declared and paid are paid to the shareholders of record on the record date that is determined by the Board.

5.11 **Winding-up**

Subject to any particular rights or limitations for the time being attached to any Shares, if the Company is wound up, the assets available for distribution among the shareholders shall be distributed to them *pro rata* to the number of Shares held by each shareholder at the time of the commencement of the winding-up.

5.12 **Disclosures pursuant to Canadian securities laws**

In Canada, securities laws are generally a matter of provincial/territorial jurisdiction. Once a receipt has been received for the Canadian Prospectus from the Canadian Securities Regulators, the Company will become a "reporting issuer" (as defined under the provincial securities law) in all provinces of Canada, except for Quebec. The Province of Alberta will be the principal jurisdiction in Canada in which the Company is a reporting issuer. Under the Canadian securities laws applicable to the Company, once it is a reporting issuer, when any person ("**an offeror**"), except pursuant to a formal bid, acquires beneficial ownership of, or the power to exercise control or discretion over, or securities convertible into, voting or equity securities or any class of a reporting issuer that, together with such offeror's securities would constitute 10 per cent. or more of the outstanding securities of that class, the offeror must immediately issue and file a press release announcing the acquisition, and file a report of such acquisition with the applicable securities regulatory authorities within two business days thereafter. Certain institutional investors may elect an alternate reporting system. Once an offeror has filed such report, the offeror is required to issue further press releases and file further reports each time the offeror, or any person acting jointly or in concert with the offeror, acquires beneficial ownership of, or the power to exercise control or direction over, or securities convertible into, an additional 2 per cent. or more of the outstanding securities of the applicable class.

5.13 **Disclosures pursuant to the Disclosure and Transparency Rules**

The provisions of Chapter 5 of the Disclosure and Transparency Rules ("**DTR5**") apply to the Company and its shareholders. For the purposes of DTR5, the Company is a "non-UK issuer" as such term is defined in DTR5.

DTR5 requires a shareholder to notify the Company if the voting rights held by any such shareholder (including by way of certain financial instruments) reach, exceed or fall below 5 per cent., 10 per cent., 15 per cent., 20 per cent., 25 percent., 30 per cent., 50 per cent. and 75 per cent. of the Company's outstanding share capital. Under DTR5, certain voting rights in the Company may be disregarded.

5.14 **Takeover regulation and mandatory bids**

Takeover bids for Canadian companies are governed by the CBCA and by securities legislation in each province or territory of Canada in which there are shareholders of the Company. A "takeover bid" is generally defined as an offer to acquire outstanding voting or equity securities of a class made to any holder in the local jurisdiction of the securities subject to the offer if the securities subject to the offer, together with the securities held by the offeror and any person acting in concert with the offeror, constitute, in aggregate, 20 per cent. or more of the outstanding securities of that class of securities at the date of the offer. Subject to limited exemptions, a takeover bid must be made to all holders of securities of

the class that is subject to the bid who are in the local jurisdiction and must allow such security holders 35 days to deposit securities pursuant to the bid.

The offeror must deliver to the security holders a takeover bid circular which describes the terms of the takeover bid and the directors of the reporting issuer must deliver a directors' circular within 15 days of the date of the bid, making a recommendation to security holders to accept or reject the bid and the reasons for the recommendation or a statement that the directors are unable to make or are not making a recommendation and the reasons why.

Generally, an offeror may not enter into a collateral agreement, understanding or commitment that has the effect of providing a security holder with consideration of greater value than that offered to other security holders of the same class. While provincial or territorial securities laws in Canada only regulate offers to shareholders in the particular province or territory, the Canadian Securities Administrators have adopted a policy whereby they may issue a cease trade order against a company if a takeover bid is not made to all Canadian security holders.

Shareholders not resident in Canada are advised that the provincial securities laws in Canada may not apply in foreign jurisdictions. Accordingly, the availability of a takeover bid to shareholders residing outside of Canada will be dependent on whether such takeover bid may be made to such non-Canadian shareholders pursuant to applicable legislation of the jurisdiction in which the non-Canadian shareholder resides and the actions of the offeror.

5.15 **Squeeze out**

Under the applicable Canadian corporate legislation, where an offeror has successfully acquired 90 per cent. of the shares of a company (exclusive of those previously held by the offeror), the offeror may, within four months after making the offer to acquire shares, send written notice to any shareholder who did not accept the offer, compelling them to sell their shares on the same terms as contained in the original offer, subject to the right of such shareholder to make application to court, in which case the court may set the price and terms of payment and make such other consequential orders and give such directions as it deems appropriate. There is no reciprocal mechanism in Canada whereby any shareholder who did not accept the original offer from the offeror might require such offeror to compulsorily acquire their shares on the terms of the original offer.

6 Directors' and other interests

6.1 The Directors and their functions within the Company and brief biographies are set out in Part VIII: "Directors, Senior Managers and Corporate Governance".

6.2 The business address of each of the Directors and each Senior Manager is Suite 2100, 555 - 4th Avenue S.W., Calgary, Alberta, Canada T2P 3E7.

6.3 The table below sets out the interest of the Directors and Senior Managers in the share capital of the Company (excluding any Options, Performance Warrants and Awards which are described in

paragraphs 6.4 and 6.5 in this Part XVI) as at 24 June 2013 (being the latest practicable date prior to the publication of this Prospectus) and immediately following Admission:

	Number of Shares as at 24 June 2013	Percentage of existing issued share capital as at 24 June 2013	Percentage of voting rights as at 24 June 2013	Number of Shares immediately following Admission	Percentage of issued share capital immediately following Admission	Percentage of voting rights immediately following Admission
Name of Director						
Robert B. Hodgins	165,000	0.14%	0.14%	165,000	0.14%	0.14%
Carol Bell	—	—	—	—	—	—
John Bentley	—	—	—	—	—	—
Peter Dey	—	—	—	—	—	—
Ronald W. Royal	185,000	0.16%	0.16%	185,000	0.16%	0.16%
Brooke Wade	265,000	0.23%	0.23%	265,000	0.23%	0.23%
Name of Senior Manager						
Gary Guidry	1,500,000	1.30%	1.30%	1,500,000	1.30%	1.30%
Trevor Peters	750,000	0.65%	0.65%	750,000	0.65%	0.65%
J. Dean Tucker	750,000	0.65%	0.65%	750,000	0.65%	0.65%
William (Joe) Taylor	325,000	0.28%	0.28%	325,000	0.28%	0.28%
Ryan Ellson	90,000	0.08%	0.08%	90,000	0.08%	0.08%
Lawrence W. West	325,000	0.28%	0.28%	325,000	0.28%	0.28%
Nicholas J. Hands	319,000	0.28%	0.28%	319,000	0.28%	0.28%
Jim Evans	325,000	0.28%	0.28%	325,000	0.28%	0.28%
Hervé Manouan	0	—	—	0	—	—
Tina Antony	6,000	0.01%	0.01%	6,000	0.01%	0.01%
TOTAL	5,005,000	4.33%	4.33%	5,005,000	4.33%	4.33%

6.4 The following table sets forth, for each Director and Senior Manager, all Option-based and Share-based awards outstanding as at 31 December 2012 under the Option Plan (described in paragraph 9—"Employee share plans" in this Part XVI).

	Option-based Awards				Share-based Awards		
	Number of Shares underlying unexercised Options	Option exercise price	Option expiration date	Value of unexercised in-the-money Options[1]	Number of Shares that have not vested[2]	Market or payout value of Share-based awards that have not vested	Market or payout value of vested Share-based awards not paid out or distributed
		(C$)		(C$)		(C$)	(C$)
Name of Director							
Robert B. Hodgins	100,000	5.00	1 September 2016	—	—	—	—
Carol Bell	130,000	6.00	11 December 2017	—	—	—	—
John Bentley	130,000	6.00	29 August 2017	—	—	—	—
Ronald W. Royal	100,000	5.00	1 September 2016	—	—	—	—
Brooke Wade	100,000	5.00	1 September 2016	—	—	—	—
Name of Senior Manager							
Gary Guidry	300,000	6.00	12 March 2017	—	—	—	—
Trevor Peters	150,000	6.00	12 March 2017	—	—	—	—
J. Dean Tucker	150,000	6.00	12 March 2017	—	—	—	—
William (Joe) Taylor	125,000	6.00	12 March 2017	—	—	—	—
Ryan Ellson	60,000	5.00	1 September 2016	—	—	—	—
	95,000	6.00	12 March 2017	—	—	—	—
	30,000	6.00	9 November 2017	—	—	—	—
Lawrence W. West	125,000	6.00	12 March 2017	—	—	—	—
Nicholas J. Hands	125,000	6.00	12 March 2017	—	—	—	—
Jim Evans	125,000	6.00	12 March 2017	—	—	—	—
Hervé Manouan	50,000	6.00	16 May 2017	—	—	—	—
	100,000	6.00	20 November 2017	—	—	—	—
Tina Antony	150,000	6.00	10 December 2017	—	—	—	—

Notes:

(1) The value of unexercised in-the-money Options is not reasonably ascertainable given that the Shares are not, and have never been, publicly listed or traded.

(2) No Share-based awards were outstanding as at 31 December 2012. Pursuant to the 2013 Incentive Plan 115,445 RSUs and 20,735 DSUs in aggregate were granted to the Directors (excluding Mr Guidry) and 1,093,602 PSUs in aggregate were granted to the Senior Managers effective 1 January 2013, pursuant to the 2013 Incentive Plan.

6.5 As at 24 June 2013, the following Performance Warrants had been granted to Directors and Senior Managers, such Performance Warrants being exercisable at the price shown below.

	Number of Shares underlying unexercised Performance Warrants as at 24 June 2013	Warrant exercise price	Performance Warrant expiration date	Value of unexercised in-the-money Performance Warrants[1]
		(C$)		(C$)
Name of Director				
Robert B. Hodgins	100,000	6.00	12 March 2017	—
Carol Bell	—	—	—	—
John Bentley	—	—	—	—
Peter Dey	—	—	—	
Ronald W. Royal	70,000	6.00	12 March 2017	—
Brooke Wade	70,000	6.00	12 March 2017	—
Name of Senior Manager				
Gary Guidry	1,400,000	5.50	1 July 2016	—
	150,000	6.00	12 March 2017	—
Trevor Peters	700,000	5.50	1 July 2016	—
	75,000	6.00	12 March 2017	—
J. Dean Tucker	700,000	5.50	1 July 2016	—
	75,000	6.00	12 March 2017	—
William (Joe) Taylor	400,000	5.50	1 July 2016	—
	62,500	6.00	12 March 2017	—
Ryan Ellson	80,000	6.00	12 March 2017	—
Lawrence W. West	400,000	5.50	1 July 2016	—
	62,600	6.00	12 March 2017	—
Nicholas J. Hands	400,000	5.50	1 August 2016	—
	62,500	6.00	12 March 2017	—
Jim Evans	400,000	5.50	1 July 2016	—
	62,500	6.00	12 March 2017	—
Hervé Manouan	—	—	—	—
Tina Antony	—	—	—	—

Note:

(1) The number of Performance Warrants that may have vested cannot be quantified because the market value of the Shares is not reasonably ascertainable given that the Shares are not, and have never been, publicly listed or traded.

6.6 As at 24 June 2013 (being the latest practicable date prior to the date of this Prospectus), there were outstanding loans equal to U.S.$9,750,000 granted by the Company to certain members of the management team of the Company in July and August 2011 in order for them to purchase, in aggregate, 2,200,000 2011 Units (as described in paragraph 4—"Share capital" in this Part XVI) (the "**Share Purchase Loans**"). The Share Purchase Loans bear interest at the rate equal to that prescribed for the purposes of Subsection 80.4(1) of the Income Tax Act (Canada) and are secured by the Shares and Performance Warrants of each person, respectively. The Share Purchase Loans made to Gary Guidry, Trevor Peters, J. Dean Tucker, William (Joe) Taylor, Lawrence W. West and Jim Evans who purchased 2011 Units on 1 July 2011 are due and payable in full on or before 1 July 2016. The Share Purchase Loan made to Nicholas J. Hands who purchased 2011 Units on 1 August 2011 is due and payable on 1 August 2016.

6.7 Indebtedness of Directors and Senior Managers

Name and Principal Position	Largest amount outstanding during 2012 (C$)	Amount outstanding as at 24 June 2013 (C$)	Financially assisted securities purchased during 2012 (Shares)	Security for current indebtedness (Shares)	Amount forgiven during 2012 (C$)
Gary Guidry President and Chief Executive Officer	3,500,000	2,500,000	—	500,000	—
Trevor Peters Chief Financial Officer	1,750,000	1,500,000	—	300,000	—
J. Dean Tucker Chief Operating Officer	1,750,000	1,750,000	—	350,000	—
Jim Evans Vice President, Corporate Services and Compliance	1,000,000	1,000,000	—	200,000	—
Nicholas J. Hands Vice President, Asset Management	1,000,000	1,000,000	—	200,000	—
William (Joe) Taylor Vice President, Engineering and Project Management	1,000,000	1,000,000	—	200,000	—
Lawrence W. West Vice President, Exploration	1,000,000	1,000,000	—	200,000	—
Hervé Manouan Vice President and Country Manager, Chad	—	—	—	—	—
Tina Antony Vice President, Legal and General Counsel	—	—	—	—	—

6.8 Save as set out in paragraph 6.7 in this Part XVI, as at 24 June 2013 (being the latest practicable date prior to the date of this Prospectus), there were no outstanding loans granted by any member of the Group to any Director or Senior Manager, nor by any Director or Senior Manager to any member of the Group, nor was any guarantee which had been provided by any member of the Group for the benefit of any Director or Senior Manager, or by any Director or Senior Manager for the benefit of any member of the Group, outstanding.

6.9 So far as the Company is aware, as at 24 June 2013 (being the latest practicable date prior to the publication of this Prospectus), the following person (other than Directors and Senior Managers) had an interest in five per cent. or more of the issued share capital of the Company:

Shareholder	Number of Shares prior to Admission(1)	Percentage of existing issued share capital prior to Admission(1)	Percentage of voting rights prior to Admission	Number of Shares immediately following Admission(1)	Percentage of issued share capital immediately following Admission(1)	Percentage of voting rights immediately following Admission
The Bradley Griffiths BDG Trust	12,651,000	10.9%	10.9%	12,651,000	10.9%	10.9%

Note:

(1) As at 24 June 2013 and immediately following Admission, the outstanding fully diluted share capital of the Company was, and will be, 159,170,204 and the percentage of the outstanding fully diluted share capital of the Company held by The Bradley Griffiths BDG Trust was, and will be, 7.95%.

6.10 Save as set out in paragraph 6.9 in this Part XVI, the Company is not aware of any person who has, or will immediately following Admission have, an interest of 5 per cent. or more of the issued share capital of the Company.

6.11 Save as disclosed above, the Company is not aware of any person who directly or indirectly, jointly or severally, exercises or could exercise control over the Company.

6.12 The Company and the Directors are not aware of any arrangements, the operation of which may at a subsequent date result in a change in control of the Company.

6.13 The person referred to in paragraph 6.9 in this Part XVI does not have voting rights in respect of the share capital of the Company (issued or to be issued) which differ from any other shareholder of the Company.

7 Directors' service, terms of appointment and compensation

7.1 The terms of the Directors' service are summarised in the table below:

Name	Title	Date of appointment[1]	Notice period[2]	Annual fee
				(C$)
Gary Guidry	President and Chief Executive Officer	July 2011	24 months	Nil[3]
Robert B. Hodgins .	Non-Executive Chairman	July 2011	N/A	230,000
Carol Bell	Non-Executive Director	December 2012	N/A	170,000
John Bentley	Non-Executive Director	August 2012	N/A	170,000
Peter Dey	Non-Executive Director	March 2013	N/A	129,595[4]
Ronald W. Royal . .	Non-Executive Director	July 2011	N/A	170,000
Brooke Wade	Non-Executive Director	September 2011	N/A	170,000

Notes:

(1) The Directors are appointed at each AGM for a term expiring at the subsequent AGM (or until their successors are appointed pursuant to the CBCA). The date provided is the date of first appointment.

(2) Not applicable for non-management Directors due to annual appointment of all Directors at the AGM. Unless Directors are re-elected, resign, or otherwise cease to hold office in accordance with the CBCA, Directors retire from office at the end of the next AGM.

(3) Gary Guidry received a salary of C$275,000 during the year ended December 31, 2012 for his services as President and Chief Executive Officer and did not receive any additional compensation for his services as a director. He will receive a salary of C$450,000 from 1 January 2013 to 31 December 2013 for his services as President and Chief Executive Officer and will not receive any additional compensation for his services as a director.

(4) For the period from 13 March 2013 to 31 December 2013.

7.2 The following sets out a description of the service contracts and letters of appointment (where applicable) entered into with each Director:

Executive Directors

Gary Guidry is the only Director who is also a member of the executive management team. Mr Guidry has an employment contract in relation to his position as the President and Chief Executive Officer and does not receive any additional compensation in his capacity as a Director.

Non-executive Directors

Historically, the Board's compensation policies provided that Non-Executive Directors would be paid: (i) an annual retainer of C$40,000; (ii) an annual retainer of C$6,000 for each Board committee that they chair (other than the chair of the Audit Committee, who receives an annual retainer of C$12,000); and (iii) an annual retainer of C$3,000 for each Board committee of which they are a member (other than the chair of such committees). In addition, the Chairman of the Board was paid an annual retainer of C$15,000. All of the retainers were paid *pro rata* for any year where a role was not held for a complete calendar year. The Company also reimbursed Directors for all reasonable expenses incurred in order to attend meetings. Board members, including Executive Directors, were also eligible to participate in the Option Plan prior to its replacement by the 2013 Incentive Plan, effective 1 January 2013 (see paragraph 9.1—"Option Plan" and paragraph 9.2—"2013 Incentive Plan" in this Part XVI) and any other long-term compensation plans adopted by the Company from time to time.

Effective 1 January 2013, the compensation plan established for Non-Executive Directors provides that Non-Executive Directors will be paid: (i) an annual retainer of C$110,000; (ii) an annual retainer of C$30,000 for each Board committee that they chair (other than the chair of the Audit Committee, who receives an annual retainer of C$45,000); and (iii) an annual retainer of C$15,000 for each Board committee of which they are a member (other than the chair of such committees). In addition, the Chairman of the Board will be paid an annual retainer of C$75,000. All of the retainers are paid *pro rata* for any year where a role was not held for a complete calendar year. The Company also reimburses Directors for all reasonable expenses incurred in order to attend meetings. Non-Executive Directors are also permitted to nominate a minimum of 50 per cent. of their fees to be paid in RSUs or DSUs pursuant to the 2013 Incentive Plan (see paragraph 9.2—"2013 Incentive Plan" in this Part XVI).

Termination and Change of Control Benefits

Each of the President and Chief Executive Officer, the Chief Financial Officer and each of the three most highly compensated executive officers other than the Chief Executive Officer and the Chief Financial Officer (the "**Named Executive Officers**" or "**NEOs**") is a party to an executive employment agreement with the Company, pursuant to which the Company will make a payment to each NEO equal to the sum of: (i) 12 months base salary of the NEO for each of Messrs. Taylor and Ellson and 24 months base salary of the NEO for each of Messrs. Guidry, Peters and Tucker, and all outstanding and accrued regular and special vacation pay; and (ii) for a period of six months following the date of termination, all benefits the NEO was entitled to immediately prior to the date of termination (collectively, the "**Termination Payment**") in the event of a "change of control" or in the event of "constructive dismissal" of the NEO.

Payment with respect to "change of control" is triggered upon occurrence of any of the following: (i) if any person, any associate or affiliate of such person or any persons acting jointly or collectively as a group, becomes the beneficial owner, directly or indirectly, of securities of the Company that result in such person being in a position to exercise effective control of the Company, provided that any person or group of persons carrying more than 50 per cent. of the votes entitled to vote generally on the election of Directors shall be deemed to be in a position to exercise effective control of the Company; or (ii) where less than a majority of the nominees of the Company are elected to the Company's Board of Directors at any shareholders' meeting at which an election of directors takes place; or (iii) upon the sale, lease or transfer of all or substantially all of the Company's assets to a person or group of persons; or (iv) upon the entering into of any written agreement which contemplates a merger, amalgamation, arrangement, business combination or similar transaction with a person or group of persons.

If the executive employment agreements had been terminated at the end of 2012, the following amounts would have been paid to the NEOs: Mr Guidry—C$550,000; Mr Peters—C$500,000; Mr Tucker—C$500,000; Mr Taylor—C$225,000; Mr Ellson—C$210,000.

7.3 The aggregate remuneration paid, including any contingent or deferred compensation, and benefits in kind granted to the Directors by the Company and its subsidiaries (excluding Options, Performance Warrants and Awards) during the financial year ended 31 December 2012 for services in all capacities was C$235,000. Such remuneration was paid as follows:

Name of Director and principal position[7]	Year	Fees earned[1]	Share-based awards[2]	Option based awards[3]	Non-equity incentive plan compensation	Pension value	All other compensation	Total compensation
		(C$)	(C$)	(C$)	(C$)	(C$)	(C$)	(C$)
Robert B. Hodgins	2012	84,000	—	327,000[6]	—	—	—	418,000
Carol Bell	2012	2,200	—	461,000[4]	—	—	—	463,000
John Bentley	2012	14,000	—	438,000[3]	—	—	—	452,000
Ronald W. Royal	2012	66,000	—	229,000[5]	—	—	—	296,000
Brooke Wade	2012	69,000	—	229,000[5]	—	—	—	229,000

Notes:

(1) Represents all fees paid.

(2) No Share-based awards were granted during the financial year ended 31 December 2012. Pursuant to the 2013 Incentive Plan, 115,445 RSUs in aggregate were granted to the Directors (excluding Mr Guidry) effective 1 January 2013, pursuant to the 2013 Incentive Plan. The aggregate Canadian dollar amount of such RSUs based on their fair value on the grant date is C$740,000.

(3) Does not represent cash paid or expected to be paid to the Director during 2012. Amount is based on the grant date fair value of Options granted to the Director on 29 August 2012 calculated using the Black-Scholes Model. Mr Bentley was granted 130,000 Options on 29 August 2012. The grant date fair value was determined in accordance with IFRS 2—Share Based Payments, to be consistent with the accounting fair value used by the Company in its financial statements. Black-Scholes is a commonly used methodology for valuing options which provides an objective and reasonable estimate of fair value. The key assumptions of this valuation were as follows: fair value of C$3.37 per Share, risk free interest rate of 1.38%; expected life in years of 5; expected volatility of 66.9% and dividend per Share of C$nil. See paragraphs 6.4 and 6.5 in this Part XVI.

(4) Does not represent cash paid or expected to be paid to the Director during 2012. Amount is based on the grant date fair value of Options granted to the Director on 11 December 2012 calculated using the Black-Scholes Model. Ms Bell was granted 130,000 Options on 11 December 2012. The grant date fair value was determined in accordance with

IFRS 2—Share Based Payments, to be consistent with the accounting fair value used by the Company in its financial statements. Black-Scholes is a commonly used methodology for valuing options which provides an objective and reasonable estimate of fair value. The key assumptions of this valuation were as follows: fair value of C$3.54 per Share, risk free interest rate of 1.30%; expected life in years of 5; expected volatility of 71.7% and dividend per Share of C$nil. See paragraphs 6.4 and 6.5 in this Part XVI.

(5) Does not represent cash paid or expected to be paid to the Director during 2012. Amount is based on the grant date fair value of Performance Warrants granted to the Director on 12 March 2012 calculated using the Black-Scholes Model. Each of Messrs. Royal and Wade were granted 70,000 Performance Warrants on 12 March 2012. The grant date fair value was determined in accordance with IFRS 2—Share Based Payments, to be consistent with the accounting fair value used by the Company in its financial statements. Black-Scholes is a commonly used methodology for valuing options which provides an objective and reasonable estimate of fair value. The key assumptions of this valuation were as follows: fair value of C$3.27 per Share, risk free interest rate of 1.61%; expected life in years of 5; expected volatility of 64.1% and dividend per Share of C$nil. See paragraphs 6.4 and 6.5 in this Part XVI.

(6) Does not represent cash paid or expected to be paid to the Director during 2012. Amount is based on the grant date fair value of Performance Warrants granted to the Director on 12 March 2012 calculated using the Black-Scholes Model. Mr Hodgins was granted 100,000 Performance Warrants on 12 March 2012. The grant date fair value was determined in accordance with IFRS 2—Share Based Payments, to be consistent with the accounting fair value used by the Company in its financial statements. Black-Scholes is a commonly used methodology for valuing options which provides an objective and reasonable estimate of fair value. The key assumptions of this valuation were as follows: fair value of C$3.27 per Share, risk free interest rate of 1.61%; expected life in years of 5; expected volatility of 64.1% and dividend per Share of C$nil. See paragraphs 6.4 and 6.5 in this Part XVI.

(7) Peter Dey was appointed to the Board of Directors in March 2013.

7.4 The aggregate remuneration paid, including any contingent or deferred compensation, and benefits in kind granted to the Senior Managers by the Company and its subsidiaries (excluding Options, Performance Warrants and Awards) during the financial year ended 31 December 2012 for services in all capacities was C$1,980,500. Such remuneration for each of the financial years ended 31 December 2010, 31 December 2011 and 31 December 2012 was paid as follows:

Name of Senior Manager and principal position	Year	Salary[1]	Share-based awards[2]	Option-based awards[3]	Non-equity incentive plan compensation	Pension value	All other compensation[21]	Total compensation
		(C$)	(C$)	(C$)	(C$)	(C$)	(C$)	(C$)
Gary Guidry[20]	2012	275,000	—	1,013,000[3]	—	—	68,000	1,847,800
				491,000[11]				
	2011	137,500	—	3,680,000[15]	—	—	—	3,817,500
	2010	—	—	—	—	—	—	—
Trevor Peters	2012	250,000	—	507,000[6]	—	—	40,600	1,042,600
			—	245,000[12]				
	2011	125,000	—	1,840,000[15]	—	—	—	1,965,000
	2010	—		—	—	—	—	—
J. Dean Tucker	2012	250,000	—	507,000[6]	—	—	40,600	1,042,600
				245,000[12]				
	2011	125,000	—	1,840,00[15]	—	—	—	1,965,000
	2010	—	—	—	—	—	—	—
William (Joe) Taylor	2012	225,000	—	422,000[5]	—	—	25,300	877,300
				205,000[14]				
	2011	112,500	—	575,000[15]	—	—	—	687,500
	2010	—	—	—	—	—	—	—
Ryan Ellson	2012	200,000	—	321,000[4]	—	—	19,800	1,084,800
				105,000[8]				
				262,000[13]				
	2011	71,000	—	167,000[17]	—	—	—	468,000
		—	—	230,000[16]	—	—	—	—
	2010	—	—	—	—	—	—	—
Lawrence W. West	2012	225,000	—	422,000[5]	—	—	25,300	877,300
				205,000[14]				
	2011	112,500	—	575,000[15]	—	—	—	687,500
	2010	—	—	—	—	—	—	—
Nicholas J. Hands	2012	225,000	—	422,000[5]	—	—	25,300	877,300
				205,000[14]				
	2011	112,500		575,000[16]	—	—	—	687,500
	2010	—	—	—	—	—	—	—
Jim Evans	2012	215,000	—	422,000[5]	—	—	24,200	866,200
			—	205,000[14]				
	2011	107,500		575,000[15]	—	—	—	682,500
	2010	—	—	—	—	—	—	—
Hervé Manouan	2012	99,400[18]	—	165,000[7]	—	—	—	618,400
		—		354,000[9]				—
	2011	—	—	—	—	—	—	
	2010	—	—	—	—	—	—	—
Tina Antony	2012	16,100[19]	—	528,000[10]	—	—	—	544,100
	2011	—	—	—	—	—	—	—
	2010	—	—	—	—	—	—	—

Notes:

(1) Represents all cash and non-cash base salary earned.

(2) No Share-based awards were granted during the financial year ended 31 December 2012. Pursuant to the 2013 Incentive Plan, 1,093,602 PSUs in aggregate were granted to the Senior Managers effective 1 January 2013, pursuant to the 2013 Incentive Plan. The aggregate Canadian dollar amount of such PSUs based on their fair value on the grant date is C$7,010,000.

(3) Does not represent cash paid or expected to be paid to the executive during 2012. Amount is based on the grant date fair value of Options granted to the executive on 12 March 2012 calculated using the Black-Scholes Model. Mr Guidry was granted 300,000 Options on 12 March 2012. The grant date fair value was determined in accordance with IFRS 2—Share Based Payments, to be consistent with the accounting fair value used by the Company in its financial statements. Black-Scholes is a commonly used methodology for valuing options which provides an objective and reasonable estimate of fair value. The key assumptions of this valuation were as follows: fair value of C$3.38 per Share, risk free interest rate of 1.48%; expected life in years of 5; expected volatility of 67.0% and dividend per Share of C$nil. See paragraphs 6.4 and 6.5 in this Part XVI.

(4) Does not represent cash paid or expected to be paid to the executive during 2012. Amount is based on the grant date fair value of Options granted to the executive on 12 March 2012 calculated using the Black-Scholes Model. Mr Ellson was

granted 95,000 Options on 12 March 2012. The grant date fair value was determined in accordance with IFRS 2—Share Based Payments, to be consistent with the accounting fair value used by the Company in its financial statements. Black-Scholes is a commonly used methodology for valuing options which provides an objective and reasonable estimate of fair value. The key assumptions of this valuation were as follows: fair value of C$3.38 per Share, risk free interest rate of 1.48%; expected life in years of 5; expected volatility of 67.0% and dividend per Share of C$nil. See paragraphs 6.4 and 6.5 in this Part XVI.

(5) Does not represent cash paid or expected to be paid to the executive during 2012. Amount is based on the grant date fair value of Options granted to the executive on 12 March 2012 calculated using the Black-Scholes Model. Each of Messrs. Evans, Hands, Taylor and West were granted 125,000 Options on 12 March 2012. The grant date fair value was determined in accordance with IFRS 2—Share Based Payments, to be consistent with the accounting fair value used by the Company in its financial statements. Black-Scholes is a commonly used methodology for valuing options which provides an objective and reasonable estimate of fair value. The key assumptions of this valuation were as follows: fair value of C$3.38 per Share, risk free interest rate of 1.48%; expected life in years of 5; expected volatility of 67.0% and dividend per Share of C$nil. See paragraphs 6.4 and 6.5 in this Part XVI.

(6) Does not represent cash paid or expected to be paid to the executive during 2012. Amount is based on the grant date fair value of Options granted to the executive on 12 March 2012 calculated using the Black-Scholes Model. Each of Messrs. Tucker and Peters were granted 150,000 Options on 12 March 2012. The grant date fair value was determined in accordance with IFRS 2—Share Based Payments, to be consistent with the accounting fair value used by the Company in its financial statements. Black-Scholes is a commonly used methodology for valuing options which provides an objective and reasonable estimate of fair value. The key assumptions of this valuation were as follows: fair value of C$3.38 per Share, risk free interest rate of 1.48%; expected life in years of 5; expected volatility of 67.0% and dividend per Share of C$nil. See paragraphs 6.4 and 6.5 in this Part XVI.

(7) Does not represent cash paid or expected to be paid to the executive during 2012. Amount is based on the grant date fair value of Options granted to the executive on 16 May 2012 calculated using the Black-Scholes Model. Mr Manouan was granted 50,000 Options on 16 May 2012. The grant date fair value was determined in accordance with IFRS 2—Share Based Payments, to be consistent with the accounting fair value used by the Company in its financial statements. Black-Scholes is a commonly used methodology for valuing options which provides an objective and reasonable estimate of fair value. The key assumptions of this valuation were as follows: fair value of C$3.29 per Share, risk free interest rate of 1.45%; expected life in years of 5; expected volatility of 64.9% and dividend per Share of C$nil. See paragraphs 6.4 and 6.5 in this Part XVI.

(8) Does not represent cash paid or expected to be paid to the executive during 2012. Amount is based on the grant date fair value of Options granted to the executive on 9 November 2012 calculated using the Black-Scholes Model. Mr Ellson was granted 30,000 Options on 9 November 2012. The grant date fair value was determined in accordance with IFRS 2—Share Based Payments, to be consistent with the accounting fair value used by the Company in its financial statements. Black-Scholes is a commonly used methodology for valuing options which provides an objective and reasonable estimate of fair value. The key assumptions of this valuation were as follows: fair value of C$3.49 per Share, risk free interest rate of 1.30%; expected life in years of 5; expected volatility of 7% and dividend per Share of C$nil. See paragraphs 6.4 and 6.5 in this Part XVI.

(9) Does not represent cash paid or expected to be paid to the executive during 2012. Amount is based on the grant date fair value of Options granted to the executive on 20 November 2012 calculated using the Black-Scholes Model. Mr Manouan was granted 100,000 Options on 20 November 2012. The grant date fair value was determined in accordance with IFRS 2—Share Based Payments, to be consistent with the accounting fair value used by the Company in its financial statements. Black-Scholes is a commonly used methodology for valuing options which provides an objective and reasonable estimate of fair value. The key assumptions of this valuation were as follows: fair value of C$3.54 per Share, risk free interest rate of 1.35%; expected life in years of 5; expected volatility of 71.6% and dividend per Share of C$nil. See paragraphs 6.4 and 6.5 in this Part XVI.

(10) Does not represent cash paid or expected to be paid to the executive during 2012. Amount is based on the grant date fair value of Options granted to the executive on 10 December 2012 calculated using the Black-Scholes Model. Ms Antony was granted 150,000 Options on 10 December 2012. The grant date fair value was determined in accordance with IFRS 2—Share Based Payments, to be consistent with the accounting fair value used by the Company in its financial statements. Black-Scholes is a commonly used methodology for valuing options which provides an objective and reasonable estimate of fair value. The key assumptions of this valuation were as follows: fair value of C$3.52 per Share, risk free interest rate of 1.28%; expected life in years of 5; expected volatility of 71.1% and dividend per Share of C$nil. See paragraphs 6.4 and 6.5 in this Part XVI.

(11) Does not represent cash paid or expected to be paid to the executive during 2012. Amount is based on the grant date fair value of Performance Warrants granted to the executive on 12 March 2012 calculated using the Black-Scholes Model. Mr Guidry was granted 150,000 Performance Warrants on 12 March 2012. The grant date fair value was determined in accordance with IFRS 2—Share Based Payments, to be consistent with the accounting fair value used by the Company in its financial statements. Black-Scholes is a commonly used methodology for valuing options which provides an objective and reasonable estimate of fair value. The key assumptions of this valuation were as follows: fair value of C$3.27 per Share, risk free interest rate of 1.61%; expected life in years of 5; expected volatility of 64.1% and dividend per Share of C$nil. See paragraphs 6.4 and 6.5 in this Part XVI.

(12) Does not represent cash paid or expected to be paid to the executive during 2012. Amount is based on the grant date fair value of Performance Warrants granted to the executive on 12 March 2012 calculated using the Black-Scholes Model. Each of Messrs. Tucker and Peters were granted 75,000 Performance Warrants on 12 March 2012. The grant date fair value was determined in accordance with IFRS 2—Share Based Payments, to be consistent with the accounting fair value

used by the Company in its financial statements. Black-Scholes is a commonly used methodology for valuing options which provides an objective and reasonable estimate of fair value. The key assumptions of this valuation were as follows: fair value of C$3.27 per Share, risk free interest rate of 1.61%; expected life in years of 5; expected volatility of 64.1% and dividend per Share of C$nil. See paragraphs 6.4 and 6.5 in this Part XVI.

(13) Does not represent cash paid or expected to be paid to the executive during 2012. Amount is based on the grant date fair value of Performance Warrants granted to the executive on 12 March 2012 calculated using the Black-Scholes Model. Mr Ellson was granted 80,000 Performance Warrants on 12 March 2012. The grant date fair value was determined in accordance with IFRS 2—Share Based Payments, to be consistent with the accounting fair value used by the Company in its financial statements. Black-Scholes is a commonly used methodology for valuing options which provides an objective and reasonable estimate of fair value. The key assumptions of this valuation were as follows: fair value of C$3.27 per Share, risk free interest rate of 1.61%; expected life in years of 5; expected volatility of 64.1% and dividend per Share of C$nil. See paragraphs 6.4 and 6.5 in this Part XVI.

(14) Does not represent cash paid or expected to be paid to the executive during 2012. Amount is based on the grant date fair value of Performance Warrants granted to the executive on 12 March 2012 calculated using the Black-Scholes Model. Each of Messrs. Evans, Hands, Taylor and West were granted 62,500 Performance Warrants on 12 March 2012. The grant date fair value was determined in accordance with IFRS 2—Share Based Payments, to be consistent with the accounting fair value used by the Company in its financial statements. Black-Scholes is a commonly used methodology for valuing options which provides an objective and reasonable estimate of fair value. The key assumptions of this valuation were as follows: fair value of C$3.27 per Share, risk free interest rate of 1.61%; expected life in years of 5; expected volatility of 64.1% and dividend per Share of C$nil. See paragraphs 6.4 and 6.5 in this Part XVI.

(15) Does not represent cash paid or expected to be paid to the executive during 2011. Amount is based on the grant date fair value of immediately exercisable Seed Options granted to the NEO on 1 July 2011 calculated using the Black-Scholes Model. The Seed Options granted to each NEO on 1 July 2011 were as follows: 800,000 Seed Options were granted to Mr Guidry, 400,000 Seed Options were granted to each of Messrs Peters and Tucker, and 125,000 Seed Options were granted to each of Messrs. Taylor, West and Evans. The grant date fair value was determined in accordance with IFRS 2—Share Based Payments, to be consistent with the accounting fair value used by the Company in its financial statements. Black-Scholes is a commonly used methodology for valuing options which provides an objective and reasonable estimate of fair value. The key assumptions of this valuation were as follows: fair value of C$4.60 per Share, risk free interest rate of 2.3%; expected life in years of nil; expected volatility of 62.5% and dividend per Share of C$nil. These Seed Options vested immediately upon grant and were immediately exercised on 1 July 2011 at a price of C$0.40 per Share. See paragraphs 6.4 and 6.5 in this Part XVI.

(16) Does not represent cash paid or expected to be paid to the NEO during 2011. Amount is based on the grant date fair value of immediately exercisable Seed Options granted to the NEO on 1 July 2011 calculated using the Black-Scholes Model. The Seed Options granted to each NEO on 1 August 2011 were as follows: 125,000 Seed Options were granted to Mr Hands, 50,000 Seed Options were granted to Mr Ellson. The grant date fair value was determined in accordance with IFRS 2—Share Based Payments, to be consistent with the accounting fair value used by the Company in its financial statements. Black-Scholes is a commonly used methodology for valuing options which provides an objective and reasonable estimate of fair value. The key assumptions of this valuation were as follows: fair value of C$4.60 per Share, risk free interest rate of 2.3%; expected life in years of nil; expected volatility of 62.5% and dividend per Share of C$nil. These Seed Options vested immediately upon grant and were immediately exercised on 1 July 2011 at a price of C$0.40 per Share. See paragraphs 6.4 and 6.5 in this Part XVI.

(17) Does not represent cash paid or expected to be paid to the executive during 2011. Amount is based on the grant date fair value of Options on 1 September 2011 calculated using the Black-Scholes Model. Mr Ellison was granted 60,000 Options on 1 September 2011. The grant date fair value was determined in accordance with IFRS 2—Share Based Payments, to be consistent with the accounting fair value used by the Company in its financial statements. Black-Scholes is a commonly used methodology for valuing options which provides an objective and reasonable estimate of fair value. The key assumptions of this valuation were as follows: fair value of C$2.79 per Share, risk free interest rate of 1.47%; expected life in years of 5; expected volatility of 66.2% and dividend per Share of C$nil. See paragraphs 6.4 and 6.5 in this Part XVI.

(18) Mr Manouan was appointed Vice President, Country Manager, Chad on 20 November 2012.

(19) Ms Antony was appointed Vice President, Legal and General Counsel on 10 December 2012.

(20) Mr Guidry does not receive any additional compensation in his capacity as a Director of the Company.

(21) Represents all cash bonuses earned during 2011 and paid in 2012.

7.5 The total amount set aside or accrued by the Company or its subsidiaries to provide pension, retirement or similar benefits for the Directors and Senior Managers for the financial year ended 31 December 2012 was nil.

7.6 The Directors and Senior Managers:

- are or have been directors or partners of the following companies and partnerships at any time in the previous five years:

Name of Director	Company/partnership	Position currently held (Y/N)	Stock Exchange
Gary Guidry	Orion Oil and Gas Corporation	N	TSX
	TransGlobe Energy Corporation	Y	TSX, NASDAQ
	Zodiac Exploration Corporation	N	TSXV
	Africa Oil Corporation	Y	TSXV
	ShaMaran Petroleum Corp.	Y	TSXV
	Tanganyika Oil Company Ltd.	N	TSX, OMX
	Pearl Exploration and Production Ltd.	N	TSX, OMX
Robert B. Hodgins	Altagas General Partner Inc.	N	TSX
	Enerplus Resources Fund	N	TSX, NYSE
	Enerflex	N	TSX
	MEG Energy Corp.	Y	TSX
	Santonia Energy Inc.	Y	TSX
	Orion Oil & Gas Corporation	N	TSX
	Skope Energy Inc.	N	TSX
	Altagas Ltd.	Y	TSX
	Enerplus Corporation	Y	TSX, NYSE
	Cub Energy Inc.	Y	TSXV
	MGM Energy Corp.	Y	TSX
	Lateral Capital Corp.	Y	TSXV
	Contact Exploration Inc.	Y	TSXV
Carol Bell	Hardy Oil and Gas plc.	N	LSE
	Revus Energy ASA	N	OSE
	Barcud Derwen Ltd	N	N/A
	Petroleum Geo-Services ASA	Y	OSE
	Det norske oljeselskap ASA	N	OSE
	Salamander Energy plc	Y	LSE
	S4C	Y	N/A
	GeoVS Ltd.	Y	N/A
John Bentley	Faroe Petroleum plc	Y	AIM
	Wentworth Resources Ltd.	Y	AIM, OSE
	Resaca Exploitation Inc.	Y	AIM
	Scotgold Resources Ltd.	Y	AIM, ASX
	Kea Petroleum plc	Y	AIM
	SacOil Holdings Ltd.	N	AIM, JSE
	Thombo Petroleum Ltd.	Y	N/A
	Balmuir Estates Nominees Ltd.	Y	N/A
	Balmuir Estates Farming	Y	N/A
	Ptarmigan Natural Resources Ltd.	Y	N/A
	Sylvan Energy LLC	Y	N/A
	Rift Oil plc	N	N/A
	CDS Oil & Gas Group plc	N	N/A
	LGH (UK) Ltd.	N	N/A
Peter Dey	Paradigm Capital Inc.	Y	TSX
	GoldCorp Inc.	Y	TSX
	Granite REIT	Y	NYSE, TSX
	Enablence Technologies	Y	TSX
	Addax Petroleum Corp.	N	LSE, TSX
	MI Developments Inc.	Y	TSX
	Coventree Inc.	N	TSX
Ronald W. Royal	Valeura Energy Inc.	Y	TSX
Brooke Wade	Wade Capital Corporation	Y	N/A
	Network Capital Management, Inc.	Y	N/A
	Novinium, Inc.	Y	N/A
	Henry Company	N	N/A

Name of Director	Company/partnership	Position currently held (Y/N)	Stock Exchange
	Plaze Inc.	N	N/A
	Acetex Corporation	N	TSX
Name of Senior Manager			
Trevor Peters	Orion Oil & Gas Corporation	N	TSX
	Tritonia Holdings Ltd.	N	N/A
	North American Oil Sands Corporation	N	N/A
J. Dean Tucker	Orion Oil & Gas Corporation	N	TSX
	Crew Energy Ltd.	N	TSX
	Pearl Exploration and Production Ltd.	N	TSX, OMX
William (Joe) Taylor	Orion Oil & Gas Corporation	N	TSX
Ryan Ellson	Canoro Resources Ltd.	N	N/A
Lawrence W. West	Orion Oil & Gas Corporation	N	TSX
	Auriga Oil & Gas Ltd.	N	N/A
Nicholas J. Hands	N/A	N/A	N/A
Jim Evans	N/A	N/A	N/A
Hervé Manouan	N/A	N/A	N/A
Tina Antony	Sonics Exploration Ltd.	Y	N/A

- have no convictions relating to fraudulent offences within the last five years;
- except as disclosed below, have not within the previous five years been directors or officers of any company at the time of any bankruptcy, receivership or liquidation; and
- have not within the previous five years received any official public incrimination and/or sanction by any statutory or regulatory authorities (including designated professional bodies) and have not been disqualified by a court from acting as a director of a company or from acting in the management or conduct of the affairs of a company.

7.7 Cease trade orders, bankruptcies, penalties or sanctions and conflict of interests

Cease Trade Orders

To the knowledge of the Company, other than as described below, no Director, executive officer or Senior Manager of the Company (nor any personal holding company of any of such persons) is, as of the date of this Prospectus, or was within ten years before the date of this Prospectus, a director, chief executive officer or chief financial officer of any company (including the Company), that: (a) was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**"), that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Bankruptcies

To the knowledge of the Company, other than as described below, no Director, executive officer or Senior Manager of the Company, or shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company (nor any personal holding company of any of such persons): (a) is, as of the date of this Prospectus, or has been within the ten years before the date of this Prospectus, a director or executive officer of any company (including the Company) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the ten years before the date of this Prospectus, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to

or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

Mr Hodgins was a director of Skope Energy Inc., which, on 27 November 2012, applied for and received protection from its creditors by order of the Court of Queen's Bench of Alberta pursuant to the Companies Creditors' Arrangements Act (Canada). Skope was delisted from the TSX as a result of its financial condition on 10 October 2012. Mr Hodgins resigned as a director of Skope on 19 February 2013.

Mr Dey ceased to be a director of the Chicago Sun Times in 2008, prior to its filing for Chapter 11 Bankruptcy in the United States on 31 March 2009.

Dr. Bell was Chairman of Barcud Derwen Ltd., a private television facilities company based in Wales, which was put into administration by its directors in 2010.

Penalties or Sanctions

To the knowledge of the Company, no Director, executive officer or Senior Manager of the Company, or shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company (nor any personal holding company of any of such persons), has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision. See paragraph 14—"Special Committee Investigation" in Part VI: "Information on the Group" for information regarding settlement matters involving the Company and the PPSC and the U.S. DoJ.

Conflicts of Interest

None of the Directors or Senior Managers (and none of the directors or officers of any subsidiary of the Company) has any potential conflicts of interests between their duties to the Company (or any subsidiary of the Company) and their private interests or other duties. See paragraph 7.6 in this Part XVI.

8 Compensation discussion and analysis

8.1 The following CD&A describes the significant elements of the Company's executive compensation program, with particular emphasis on the process for determining compensation payable to the Named Executive Officers.

8.2 Based on compensation levels paid or issued as at the end of 2012, the NEOs for the purposes of this CD&A are as follows:

(a) Gary Guidry, President and Chief Executive Officer;

(b) Trevor Peters, Chief Financial Officer;

(c) J. Dean Tucker, Chief Operating Officer;

(d) W.J. (Joe) Taylor, Vice President Engineering and Project Management; and

(e) Ryan Ellson, Vice President Finance.

8.3 **CD&A overview**

The Company's executive compensation programme is administered by the Compensation Committee. As part of its mandate, the Compensation Committee reviews and recommends to the Board the remuneration of the NEOs. The Compensation Committee is also responsible for reviewing the Company's compensation policies, compensation matrix and guidelines generally. For a description of the Compensation Committee and its current members, see Part VIII: "Directors, Senior Managers and Corporate Governance".

The Compensation Committee has considered the risks associated with the Company's executive compensation programme and believes that the balance of short and long term variable compensation is appropriate to discourage NEOs and other Senior Managers from taking risks that may be detrimental to the ongoing business of the Company. On a quarterly basis, the Board monitors expenditures and performance metrics against approved annual programs and budgets to further deter risk taking behaviour.

The Company does not have a policy preventing an NEO, other Senior Manager or Director from purchasing financial instruments that are designed to hedge or offset a decrease in market value of equity securities granted as compensation or held, directly or indirectly, by the NEO, Senior Manager or Director.

8.4 **Competitive positioning**

The Compensation Committee reviews the compensation for the NEOs, other Senior Managers and Directors against a group of competitor companies. To ensure that compensation is competitive, on 15 October 2012, the Compensation Committee engaged an external compensation consultant, Hugessen Consulting Inc. ("**Hugessen**"), to review and assess the comparability of the executive programme to those of oil and gas companies of a similar size and complexity.

2013 Executive Compensation Comparator Group

The following table lists the peer comparator group for 2013 compensation benchmarking purposes:

UK Companies		Canadian Companies	
Afren Plc	Ophir Energy plc	Africa Oil Corp.	Niko Resources Ltd.
Cairn Energy PLC	Premier Oil plc	Bankers Petroleum Ltd.	PetroBakken Energy Ltd.
EnQuest PLC	RusPetro plc	Celtic Exploration Ltd.	Petrominerales Ltd.
Genel Energy plc	Salamander Energy plc	Grant Tierra Energy, Inc.	TransGlobe Energy Corp.
Heritage Oil plc	SOCO International plc		

Fees Paid to External Compensation Consultant

The total fees paid to Hugessen are as outlined below:

Year	Executive Compensation Related Fees	All Other Fees[(1)]
2012[(1)]	C$0.1 million	—

Note:

(1) Prior to retaining Hugessen on 15 October 2012, the Company and the Compensation Committee had not retained an external compensation consultant and paid no fees in relation thereto.

8.5 **Compensation philosophy and objectives of the compensation programme**

The Compensation Committee seeks to encourage growth in reserves, production, cash flow and earnings while focusing on achieving attractive returns on capital in order to enhance shareholder value. To achieve these objectives, the Company believes it is critical to create and maintain a compensation programme that attracts and retains committed, highly qualified personnel and that aligns the interests of the Senior Managers with the interests of the shareholders by providing appropriate rewards and incentives.

The Company's executive compensation programme is designed to attract, recruit and retain individuals of high calibre to serve as executive officers of the Company, to motivate their performance in order to achieve the Company's strategic objectives and to align the interests of executive officers with the long-term interests of the Company's shareholders and enhancement in share value.

8.6 **Components of compensation**

The Company compensates its NEOs through the following: (i) base salary; (ii) short-term incentive compensation comprised of discretionary cash bonuses based on performance; and (iii) long-term incentive compensation (historically comprised of grants of Options and, effective as of 1 January 2013, comprised of grants of Awards) at levels which the Compensation Committee believes are reasonable in the light of the performance of the Company. In addition, the Seed Options issued to the executive team appointed on 1 July 2011 and 1 August 2011, and the purchase of Shares related thereto, enabled such persons to make a meaningful equity investment in the Company so as to better align their interests with the interests of the Company's shareholders. For a description of the issuances of such Seed Options, see paragraph 4—"Share capital" in this Part XVI. The Company has established a compensation matrix which sets forth the range of compensation applicable to each level of employee of the Company.

For 2013 and beyond, the Compensation Committee and the Company, along with Hugessen, reviewed and developed a comprehensive compensation plan designed to take into account the compensation "best practice" in the United Kingdom (pursuant to which the use of options is not considered to be in the best interest of Company stakeholders) and still be able to retain and recruit high calibre employees. The new plan has addressed salaries, short term incentive compensation, along with long term incentive compensation.

8.7 **Base salary**

Base salaries are intended to compensate each NEO's core competencies, skills, experience and contribution to the Company and are paid in order to retain committed, highly qualified personnel. The Compensation Committee believes that base salaries should be competitive but total compensation should be weighted toward variable, long term performance-based components.

Base salaries are compared to the Company's industry peer group through publicly available information and available compensation surveys prepared by compensation consultants, including Hugessen. Consideration has been and will be given to the Company's growth plans, area of operations and its objective of attracting and retaining highly talented individuals from within the industry.

8.8 **Cash bonus**

Discretionary cash bonuses are intended to motivate and reward the accomplishment of specific business and operating objectives within a defined period. Given the early stage of development of the Company, a small prorated bonus was awarded in 2012 for 2011 performance and in 2013 for 2012 performance.

Cash bonuses are paid at the discretion of the Board on the recommendation of the Compensation Committee, based upon the achievement of certain corporate objectives. Cash bonuses recommended by the Compensation Committee are intended to be generally competitive with the market. The Compensation Committee considers the Company's performance during the year with respect to the qualitative goals in the context of market and economic trends and forces, extraordinary internal and market-driven events, unanticipated developments and other extenuating circumstance in making bonus recommendations.

The Compensation Committee met with management of the Company in the first quarter of 2013 to review the proposed 2013 base bonus award target (determined by reference to a target percentage of base salary) and on 9 January 2013 the Board approved the 2013 base bonus award target, on recommendation from the Compensation Committee. A scorecard approach to measure performance against set criteria determined yearly by the Compensation Committee, with the participation of the Chief Executive Officer, will be used to determine bonus awards. Performance criteria currently include operational, financial, market and strategic measures.

Proposed cash bonuses for NEOs, excluding the Chief Executive Officer, will be recommended by the Chief Executive Officer, reviewed by the Compensation Committee, and, if deemed appropriate, recommended to the Board for approval. Any cash bonus to be paid to the Chief Executive Officer will be determined by the Board based on recommendations received from the Compensation Committee.

8.9 **Option Awards, RSUs, PSUs and DSUs**

The Compensation Committee believes that the grant of RSUs, PSUs and/or DSUs (as applicable) to Directors and Senior Managers (including NEOs) pursuant to the 2013 Incentive Plan serves to motivate achievement of the Company's long-term strategic objectives while aligning the interests of management with shareholders of the Company.

Initially, the Company planned to use Options as its main long term incentive plan, however the Company decided on 9 January 2013 to use a combination of RSUs, PSUs and DSUs for Directors and Senior Managers and Options for non-executive employees in order to deliver long term incentives to its Directors, Senior Managers and employees, as applicable, and to better align with the compensation regimes of peer group companies traded on the London Stock Exchange.

The Compensation Committee assesses individual and corporate performance, as measured by the price of the Shares, and the anticipated future hiring requirements of the Company when reviewing the proposed number of Awards and Options (as applicable) to be granted. The Compensation Committee also considers the overall number of Awards and Options outstanding relative to the number of outstanding

Shares and the overall number of Awards and/or Options held by each individual grantee relative to the number of Awards and Options available for grant under the 2013 Incentive Plan and the Option Plan, respectively, in determining whether to make (and the size of) new grants of Awards and Options (as applicable). The Company also utilises the grant of Options and Awards in recruiting new employees.

8.10 **Options—Value Vested or Earned During 2012**

The value of Options granted to the NEOs that vested during 2012 cannot be quantified as at the respective vesting dates. The market value of the Shares on the date the Options vested and were exercised is not ascertainable given that the Shares are not, and have never been, publicly listed or traded. Therefore, the value of the vested and exercised Options is not currently known.

9 Employee share plans

9.1 Option Plan

The Option Plan was initially adopted by the Board on 30 June 2011 and approved by shareholders of the Company on 2 September 2011. Effective 1 January 2013, except in exceptional circumstances, no further Options will be granted to Senior Managers or Directors under the Option Plan but non-executive employees will continue to be eligible to receive Options in the future. All outstanding Options granted to Senior Managers or Directors as at 1 January 2013 will continue to be administered in accordance with the Option Plan.

The Option Plan is intended to provide an incentive, in the form of a proprietary interest in the Company, to Eligible Optionees who are in a position to contribute materially to the successful operation of the business of the Company, to increase their interest in the Company and to provide a means through which the Company can attract and retain persons of experience and ability.

Options are awarded by the Board following the recommendation of the Compensation Committee and the Chief Executive Officer regarding the level of responsibility and contribution of the recipients toward the Company's goals and objectives in line with the Company's compensation matrix. Under the Option Plan, unless otherwise determined by the Board, Options will vest in one third increments over a three-year period, starting on the first anniversary of the date of grant. Each Option has an exercise price equal to the prevailing market price of the Shares at the time of the grant. Pursuant to the Option Plan, the market price is determined at the most recent closing price of the Shares on the last trading day of the stock exchange on which the Shares are listed, prior to the date on which the Option is granted.

Options may be granted in such numbers as the Board may determine, except that: (i) the aggregate number of Shares that may be reserved for issuance under the Option Plan or any other security based compensation arrangements (whether or not executive) must not exceed 10 per cent. of the issued and outstanding Shares (on a non-diluted basis); (ii) the number of Shares, when combined with any other Share-based compensation arrangements, issuable (or reserved for issuance) to "insiders" (as such term is defined in the Option Plan) of the Company and their associates and affiliates may not exceed 10 per cent. of the issued and outstanding Shares (on a non-diluted basis); (iii) there may not be issued to "insiders", within a one-year period, a number of Shares, that, when combined with any other security based compensation arrangement, will exceed 10 per cent. of the issued and outstanding Shares (on a non-diluted basis); and (iv) the issuance of Shares to any one Eligible Optionee of the Company, when combined with any other security based compensation arrangements, within a one-year period may not exceed 5 per cent. of the issued and outstanding Shares (on a non-diluted basis).

9.2 2013 Incentive Plan

The 2013 Incentive Plan was initially adopted by the Board on 9 January 2013, effective 1 January 2013.

The purpose of the 2013 Incentive Plan is to develop the interests of the Eligible Grantee in the growth and development of the Company, to sustain their commitment to long-term profitability and to maximize shareholder value. With this strategy in mind, a combination of RSUs, PSUs and/or DSUs may be granted from time to time to Eligible Grantees pursuant to the 2013 Incentive Plan in order to sustain a commitment to long-term profitability and maximize shareholder value.

Under the 2013 Incentive Plan, all RSUs, PSUs and DSUs are granted by resolution of the Directors, and upon execution by the Compensation Committee of an award agreement setting out the details and terms of the Award, without any monetary consideration being payable to the Company. The vesting periods and

expiry dates on the Awards will vary depending on a number of factors, including whether the Eligible Grantee is a Director, Senior Manager or employee and the determinations made by the Compensation Committee based on the circumstances at the time of the grant. Any Shares issuable under a PSU grant will be based on performance of the Company compared to a group of similar companies, the performance of the Company *vis-à-vis* targets set for value growth, and a portion will be issuable based on continuous employment with the Company, where any such performance targets or other conditions are set by the Compensation Committee and approved by the Board. If an event occurs which causes the Compensation Committee to consider that any performance targets or other condition is no longer appropriate, the Compensation Committee may substitute, vary or waive any performance target or condition in such manner as (i) is reasonable in the circumstances; and (ii) except in the case of waiver produces a fairer measure of performance and is not materially less difficult to satisfy. To the extent that the performance measures are attained by the Company, PSUs are converted into the appropriate number of Shares which are issued from treasury or purchased in the open market without any further consideration payable to the Company in respect thereof. DSUs and RSUs will not be subject to any performance conditions but Shares will be issuable under DSUs and RSUs based on vesting conditions, which will primarily include the passage of time. Notwithstanding the foregoing, the Company shall have the option of paying out the value of any Awards in the form of cash and the Award holder can elect to receive the value of the Award in cash.

Awards may be granted in such numbers as the Board may determine, except that Awards may not be made if: (i) if the aggregate number of Shares issued or reserved for issuance under the 2013 Incentive Plan or any other security based compensation arrangements (whether or not executive), within the preceding 10-year period, would exceed 10 per cent. of the issued and outstanding Shares (on a non-diluted basis); (ii) if the aggregate number of Shares issued or reserved for issuance, to any Eligible Grantee under the 2013 Incentive Plan or any other executive Share-based compensation arrangements, within the preceding 10-year period, would exceed 5 per cent. of the issued and outstanding Shares (on a non-diluted basis); or (iii) if, in respect of any Eligible Grantee, the market value of the Shares subject to that the proposed Award(s) to the Eligible Grantee, when aggregated with the market value of the Shares subject to all incentive awards granted to such Eligible Grantee pursuant to the 2013 Incentive Plan or any other executive security based compensation arrangements in the same financial year would exceed 475 per cent. of such Eligible Grantee's annual remuneration. Pursuant to the 2013 Incentive Plan, the market value is: (i) if the Shares are traded on the London Stock Exchange, the middle market quotation (as derived from the daily official list of the London Stock Exchange) on the preceding business day; or (ii) if the Shares are not traded on the London Stock Exchange, as determined by the Compensation Committee, acting in good faith.

9.3 **Dilution limits**

The Company will operate its employee share plan arrangements in line with UK corporate governance best practice and any relevant Canadian requirements.

As noted in paragraphs 9.1 "Option Plan" and paragraph 9.2 "2013 Incentive Plan" in this Part XVI, Shares issued and reserved for issuance under all security based compensation arrangements (whether or not executive), within the preceding 10-year period, may not exceed 10 per cent. of the issued and outstanding Shares (on a non-diluted basis). Further, Shares issued and reserved for issuance under all executive Share-based compensation arrangements, within the preceding 10-year period, may not exceed 5 per cent. of the issued and outstanding Shares (on a non-diluted basis).

For the avoidance of doubt, any Option or Share-based awards that have been granted by the Company prior to Admission will be excluded from the above limits. This additional flexibility will ensure the Board has the ability to recruit and retain key talent, particularly in Canada where remuneration market practice is for relatively low base salary, in comparison to the UK, coupled with a greater emphasis on variable pay through the grant of market-priced share options.

As such, 14,456,782 Shares to be issued pursuant to the Company's pre-Admission Share-based arrangements will be excluded from the 5 per cent. and 10 per cent. in 10-year dilution calculations set out above. This equates to approximately 12 per cent. of the ordinary share capital on Admission.

The Board will closely monitor the annual flow of Share-based awards such that the Company remains within the above limits.

10 Material contracts

The following contracts (not being contracts entered into in the ordinary course of business) have been entered into by the Company or another member of the Group within the two years immediately preceding the date of this Prospectus, and are or may be material.

10.1 **Sponsor's Agreement**

The Company, each of the Directors, a Senior Manager and the Sponsor have entered into a sponsor's agreement dated 27 June 2013 (the "**Sponsor's Agreement**"). Pursuant to the Sponsor's Agreement, the Sponsor has agreed to act as sponsor to the Company in connection with Admission. The obligations of the Sponsor are subject to certain conditions which are typical for an agreement of this nature, including the continued accuracy of certain warranties. The Sponsor has the right to terminate the Sponsor's Agreement before Admission in certain specified circumstances. Under the terms of the Sponsor's Agreement, each of the Company, the Directors and the Senior Manager have given certain representations, undertakings and warranties to the Sponsor. The Company has also agreed to provide the Sponsor with certain indemnities, which are provided to indemnify the Sponsor and its affiliates against, inter alia, claims made against them or losses incurred by them that may arise out of or in connection with Admission.

Pursuant to the Sponsor's Agreement, the Company has agreed that, subject to the exceptions below, for a period of 120 days from the date of Admission it will not, without the prior written consent of the Sponsor, directly or indirectly, (i) issue, offer, lend, mortgage, assign, charge, pledge, sell, contract to sell or issue, sell any option or contract to purchase, purchase any option or contract to sell or issue, grant any option, right or warrant to purchase, lend or otherwise transfer or dispose of, any Shares or any interest in Shares or any securities convertible into or exercisable or exchangeable for, or substantially similar to, Shares or any interest in Shares or file any registration statement under U.S. securities laws or publish any prospectus with respect to any of the foregoing; or (ii) enter into any swap or other agreement or transaction that transfers, in whole or in part, any of the economic consequences of ownership of the Shares.

The exceptions to the above restrictions include:

(i) the issue by the Company of any Shares upon the exercise of an option under share option schemes in existence at the date of Admission; and

(ii) the issue by the Company of any Shares upon the conversion of the Convertible Bonds in accordance with their terms (and potentially any accrued but unpaid interest in relation thereto).

10.2 **PSCs**

History of the PSCs

In 2011, the Group acquired three PSCs in southern Chad. The Doseo/Borogop PSC and the DOB/DOI PSC were the first two PSCs signed by any person or company following revisions to the Government of Chad's petroleum law in 2010.

Each PSC provides the Group and Glencore with the exclusive right to explore and develop oil and gas reserves and resources within a specified Contractual Zone. See paragraph 6—"Description of business and operations" in Part VI: "Information on the Group" for a description of the Contractual Zones covered by the PSCs.

Overview

The PSCs are similar with respect to the processes and timelines in which exploration and exploitation are to be approved by the Government of Chad and conducted by the Contractor. The PSCs also set forth similar mechanisms and formulae for the Government of Chad to elect to participate in the Contractor's exploration and exploitation activities, the royalties payable by the Contractor to the Government of Chad and the profit sharing formula between the Contractor and the Government of Chad. The only material differences amongst the three PSCs are the structure of the signing bonuses payable to the Government of Chad by the Contractor, the cost recoverability of certain expenses, the consulting fees paid relating to the DOH PSC and the minimum work commitments.

Exploration and Exploitation Process and Timelines

Below is a description of the process and timelines under the PSCs for development of the Contractual Zones governed by the PSCs.

Stage 1—Exploration Phase

Upon execution, the applicable Contractor under each PSC was granted an EEA for the relevant Contractual Zone.

Each EEA was granted for an initial term of five years. The DOB/DOI PSC was signed on 18 March 2011, the Doseo/Borogop PSC was signed on 19 January 2011 and the DOH PSC was signed on 3 August 2011.

At the end of the Initial Exploration Term (subject to, amongst other things, performance of its minimum work programme (as described below) and compliance with all legal and regulatory requirements) the Contractor is eligible for an extension of the EEA for the Renewal Exploration Term for up to three years, provided that the Contractor applies at that time to retain no more than 50 per cent. of the Contractual Zone and submits the application for renewal a minimum of 120 days prior to the expiration of the Initial Exploration Term. Any areas of a Contractual Zone that have been included in an EXA are exempt from this relinquishment requirement. The EEA may be further extended for up to two years if required by the Contractor to complete a feasibility study in relation to a discovery made by the Contractor in the applicable Contractual Zone prior to the expiry of the Renewal Exploration Term.

The Contractor must carry out a minimum work programme during the Initial Exploration Term that contains work obligations totalling at least U.S.$50 million for each of the DOB/DOI PSC and Doseo/Borogop PSC and at least U.S.$15 million for the DOH PSC. The Contractor must submit annual work programmes and budgets to the Management Committee for approval prior to 30 September each year. As at 31 March 2013, work obligations of approximately U.S.$35.7 million, U.S.$44.7 million and U.S.$14.0 million remained outstanding under each of the DOB/DOI PSC, Doseo/Borogop PSC and DOH PSC, respectively.

If the Renewal Exploration Term is granted, the Contractor must carry out a minimum U.S.$5 million work programme for each of the DOB/DOI PSC and Doseo/Borogop PSC and a minimum of U.S.$1 million for the DOH PSC over the duration of the Renewal Exploration Term and must also continue to submit annual work programmes and budgets in the same level of detail as the work programmes and budgets submitted during the Initial Exploration Term. Any work expenditures made by the Contractor during the Initial Exploration Term in excess of the minimum work programme for the Initial Exploration Term may be applied towards the minimum work obligation for the Renewal Exploration Term.

If the Contractor fails to satisfy the minimum work programme obligation of either the Initial Exploration Term or the Renewal Exploration Term (or the EEA is revoked or forfeited for that period), it must pay to the Government of Chad an amount equal to 50 per cent. of the value of the work not completed within 30 days following the end of the period concerned, the effective date of the relevant total forfeiture or the date of the revocation of the EEA.

Stage 2—Feasibility/Commercial Deposit Phase

If the Contractor determines that one or more hydrocarbon discoveries within the applicable Contractual Zone is a Commercial Deposit, the Contractor may apply for one or more EXAs from the Government of Chad.

Any application to the Government of Chad for an EXA must be accompanied by, amongst other things, a feasibility study, which must contain technical and economic data along with an evaluation and discussion and analysis of such data to support the commerciality of any Commercial Deposit.

Stage 3—Exploitation Phase

If the Contractor makes a hydrocarbon discovery within the Contractual Zone, it must notify the Government of Chad of this discovery as soon as possible and no later than two working days following such discovery. If the Government of Chad is satisfied as to the commerciality of a Commercial Deposit it may issue one or more EXAs. The initial term of an EXA shall be the Initial Exploitation Term of 25 years. The Contractor must pay U.S.$2 million to the Government of Chad within five days of official journal publication of the decree granting authorisation related to the EXA. EXAs were granted by the Government of Chad in respect of the Badila and Mangara Fields in August 2012 and June 2012,

respectively. The Contractor is also entitled to apply for a ten-year extension to the term of each EXA and such extension will be granted if the Contractor has met its contractual obligations under the EXA and has demonstrated that the relevant hydrocarbon deposits will remain commercially exploitable beyond the Initial Exploitation Term. This application for an extension must be submitted at least one year prior to the expiration of the Initial Exploitation Term.

Government of Chad Participation

Upon the approval of an EXA, the Government of Chad may elect to acquire up to a 25 per cent. participating interest in the relevant EXA (referred to as a "back-in" right), either directly or through a public body, including SHT, as was the case in respect of the Badila and Mangara EXAs and as the Group expects it to do in respect of future EXAs. If the Government of Chad elects to participate, it will be obliged to reimburse the Contractor for its proportionate share of all exploration costs attributed to the related Commercial Deposit and to finance its proportionate share of all development and production costs. All costs for which the Government of Chad is responsible to reimburse or finance will be recorded as an advance from the Contractor that accrues interest at LIBOR from the due date of the advance (except petroleum costs arising from petroleum operations prior to the issuance of the relevant EXA for which interest does not accrue) and shall be repayable out of the Government of Chad's proportionate share of Cost Oil (as defined below) for which it is entitled as a result of its participating interest. See "Risks relating to our business and operations" in Part II: "Risk Factors".

Economics of the PSCs

Royalties

Once commercial production has begun, the Contractor is required to pay the Government of Chad a Production Royalty at a rate of 14.25 per cent. for crude oil and 5 per cent. for natural gas. The Production Royalty may, at the Government of Chad's election, be taken either in cash or in kind.

Cost Recovery

The PSCs provide that costs of exploration, appraisal, development and production operations attributed to an EXA may be recovered by the Contractor by receiving a quantity of Cost Oil in each year, the value of which shall not exceed 70 per cent. of the net production after deduction of the Production Royalty for such year. Unrecovered costs in each year are carried forward and may be recovered in subsequent years until all such costs are recovered. If the Cost Oil is less than 70 per cent. of the net production after deduction of the Production Royalty for any given year, the difference between the Cost Oil and 70 per cent. is contributed to Profit Oil.

Profit Sharing

The Profit Oil from each EXA is allocated between the Government of Chad and the Contractor in accordance with an "R-Factor" determined each quarter for each EXA using the following formula:

$$\text{R-Factor} = \frac{\text{CVH}^{(1)} - \text{CCPO}^{(2)}}{\text{CCDO}^{(3)} + \text{CCEO}^{(4)}}$$

Notes:

(1) "CVH" means the cumulative value of hydrocarbons received by the Contractor, whether as Cost Oil or Profit Oil, since the issuance of the EXA up to the last day of the preceding quarter.

(2) "CCPO" means the cumulative costs of production operations since the issuance of the EXA up to the last day of the preceding quarter.

(3) "CCDO" means the cumulative costs of development operations since the issuance of the EXA up to the last day of the preceding quarter.

(4) "CCEO" means the cumulative costs of exploration costs assigned to the applicable EXA.

Profit Oil is shared between the Government of Chad and the Contractor based on the applicable R-Factor as follows:

R-Factor	Percentage of Profit Oil to the Contractor	Percentage of Profit Oil to the Government of Chad
Less than or equal to 2.25	60	40
Between 2.25 and 3	50	50
More than 3	40	60

Infrastructure

The Contractor is entitled to construct and operate pipelines and facilities within the territory of Chad, both inside and outside of its Contractual Zones, in order to transport production of hydrocarbons from the Contractual Zones to the delivery points to purchasers or to the points of export, as applicable. Upon request, and provided the Contractor is in compliance with the terms of the relevant PSC, the Government of Chad shall issue to the Contractor a Transportation Licence and will negotiate and enter into a transportation contract with the Contractor setting out the terms and conditions in respect thereof. The requirement to obtain a Transportation Licence does not apply to the construction of such pipelines and facilities within an EXA or between EXAs.

Mandatory Sales

If the Government of Chad cannot satisfy the domestic market consumption of crude oil out of its share of all crude oil produced within Chad, the Contractor may be required to sell such amount of its crude oil production to the Government of Chad as is required to satisfy such shortfall. The Government of Chad must notify the Contractor at least six months in advance of its desired purchase of the Contractor's crude oil and must indicate the amount needed to meet domestic demand. The obligation of a Contractor to supply the domestic market shall be proportionate to its share of hydrocarbon production relative to total hydrocarbon production within Chad. This calculation is to be carried out on a quarterly basis. Any crude oil required to be sold by the Contractor to the Government of Chad to supply the domestic market shall be sold at market rates as determined in accordance with the terms of the applicable PSC.

Abandonment

Once the Contractor estimates that, in the following year, the cumulative production from an EXA will amount to or exceed 50 per cent. of the proved reserves in that EXA, it is required to submit an abandonment work programme for such EXA. The Contractor is then required to contribute to an abandonment fund for the EXA using a formula detailed in the relevant PSC.

$$\text{Contribution to Abandonment Fund} = \frac{(\text{ECAW}^{(1)} - \text{PCAF}^{(2)}) \times \text{TP}^{(3)}}{\text{PR}^{(4)}}$$

Notes:

(1) "ECAW" means the estimated costs of the abandonment work.

(2) "PCAF" means the previous contributions to the abandonment fund for such EXA.

(3) "TP" means the total production from such EXA during the current year.

(4) "PR" means the proved reserves for such EXA developed and remaining to be produced as of the beginning of the then current year.

Management Committees

The PSCs provide that a management committee (each a "**Management Committee**"), comprised of representatives of the Government of Chad and one representative of the applicable Contractor (all Contractor entities to be represented by one person), must be formed (i) within 30 days of the effective date of the PSC in respect of the applicable EEA and (ii) within 30 days of the issue of each EXA in respect of the issued EXA. Management Committees oversee the petroleum operations in respect of the relevant authorisation and are charged with approving annual work programmes and budgets, monitoring implementation of such work programmes and budgets, and making decisions with respect to all other matters that are expressly required to be submitted in respect of the relevant authorisation.

A Management Committee shall meet at least twice every calendar year. Decisions of a Management Committee shall be by unanimous vote, provided, however, that during the exploration phase any proposition of the Contractor that is not unanimously supported shall nonetheless be adopted and, in respect of any exploitation phase, decisions relating to annual work programmes and budgets may be referred to expert determination (with the Contractor entitled to implement the proposed annual work programmes and budgets in accordance with generally accepted international oil industry practices until a determination is made).

Taxes

The Contractor is required to pay an annual land surface tax to the Government of Chad as follows:

(i) for an EEA, U.S.$1/km^2 for the Initial Exploration Term; U.S.$5/km^2 for the Renewal Exploration Term; and U.S.$10/km^2 for any extension thereafter;

(ii) for an EXA, U.S.$100/km^2 for the Initial Exploitation Term and U.S.$150/km^2 for any Renewal Exploitation Term; and

(iii) for a Transportation Licence, U.S.$45/km^2 during the period of validity.

Upon an assignment of an interest in the EEA, the Contractor is obligated to pay a 25 per cent. tax to the Government of Chad on any gain made from such assignment. The gains tax does not apply to a change of control of the Contractor pursuant to a sale of its shares and is deferred for assignments to affiliates of the Contractor. All equipment and materials imported for use in operations relating to the EEA are exempt from import taxes and duties. All equipment and materials imported for use in operations relating to an EXA are also exempt from import taxes and duties during the first five years after the issuance of such lease. Lastly, the Contractor is not liable to pay any corporate income taxes to the Government of Chad and such amounts shall be deemed to be paid out of the Government of Chad's share of Profit Oil.

Preferential Treatment

The Contractor and its subcontractors must preferentially award Chadian companies construction, goods and services contracts insofar as they are able to offer equivalent conditions in terms of quality, prices, quantities, delivery times, terms of payment, warranties, and after-sales services. Contracts with subcontractors amounting to more than U.S.$500,000 must be submitted to the Chadian Hydrocarbons Minister. The Contractor must also prioritise the recruitment of qualified Chadian personnel who exhibit equivalent qualifications to those of a non-Chadian national.

Equipment

Ownership of all property purchased by the Contractor for petroleum operations is transferred to the Government of Chad free of charge on the earlier of:

- the expiration of the EEA or EXA for which the costs of such assets were allocated as petroleum costs; and
- full reimbursement of the Contractor for all recoverable petroleum costs.

Liability

Subject to certain exceptions, the Contractor must indemnify the Government of Chad for any loss or damage incurred by the Government of Chad attributable to the operations of the Contractor under the PSCs. The Contractor also assumes all liability arising from any loss or injury incurred by any third parties resulting from operations in respect of the PSCs or that is attributable to any civil wrong on the part of the Contractor in connection with PSC operations, but only to the extent that such loss or injury is attributable to any civil wrong on the part of the Contractor or other person for which the Contractor is responsible. However, insofar as the Government of Chad or a public body acquires a share in an EXA, the Government of Chad or public body assumes liability *pro rata* to its share in the EXA.

Termination

The PSCs provide that they may only be subject to early termination where: (i) the parties mutually agree; (ii) the Contractor surrenders all of its rights and obligations derived from the EEA and, where applicable,

all EXAs; or (iii) the EEA and, where applicable, all EXAs are revoked by the Government of Chad pursuant to the default provisions of article 54 of the PSCs.

Pursuant to article 54 of the PSCs, the Government of Chad may terminate the relevant authorisations (EEA and/or EXAs) to which the breach is ascribed, if the Contractor has not remedied, within 60 days of receipt of a notice of default from the Government of Chad, one of the following events of default:

(i) if the Contractor has not submitted to the Management Committee a feasibility study programme for a discovery within 90 days of notification of the discovery to the Government of Chad; if the feasibility study programme has not been commenced within 120 days of its approval by the Management Committee; or if a declaration of commerciality has not been made in respect of the discovery within 18 months of completion of the feasibility study programme (subject to extension for purposes of evaluating a pipeline transportation system for the discovery);

(ii) if the Contractor suspends production operations for a period exceeding 60 consecutive days, other than where such suspension is justified by an event of force majeure or by technical, operational, commercial or security reasons confirmed by the Management Committee, acting reasonably;

(iii) if the Contractor repeatedly and without reasonable justification, on the basis of technical or operational requirements, fails to deliver to the Government of Chad its proportionate share of production where the Government of Chad has elected to take the Production Royalty and its share of Profit Oil in kind;

(iv) if the Contractor repeatedly defaults on its obligations in relation to payments to the Government of Chad on account of the Production Royalty and the Government of Chad's share of Profit Oil, where the Government of Chad has elected to take same in cash;

(v) if the Contractor or an entity comprising the Contractor assigns its rights and obligations in the applicable authorisation in violation of the PSC;

(vi) other than in the context of internal re-structuring, if: (a) the shareholders of an entity comprising the Contractor resolve to liquidate such entity; (b) an entity comprising the Contractor becomes bankrupt; (c) a court of competent jurisdiction orders the liquidation of an entity comprising the Contractor; or (d) a court of competent jurisdiction orders a judicial settlement in respect of an entity comprising the Contractor which is not appealed and is not followed by a settlement with most of its creditors within 90 days following such order (provided the Contractor has otherwise performed its obligations under the PSC during such 90 day period);

(vii) the Contractor has not paid the signing bonus or the EXA issuance bonus within the required time periods; and/or

(viii) any other repeated and significant breach by the Contractor of its obligations under the PSC which threatens public order or public health in a manner that definitively compromises the continuation of a contractual relationship,

provided, however, that in the case of the events of default specified in paragraphs (v) and (vi) above, the default shall be deemed remedied if any entities comprising the Contractor other than the defaulting entity assume the rights and obligations of the defaulting entity and are able to demonstrate the technical and financial capacity necessary therefor. Any termination resulting from the events of default specified in paragraphs (v) and (vi) above shall only apply to the interests of the defaulting entity and not to the interests of any other entity comprising the Contractor.

Applicable Law

The PSCs are governed by Chadian law, as well as principles of accepted international law, provided such principles of international law have not been expressly objected to by the Government of Chad and do not result from conventions which the Government of Chad has not ratified.

Glencore Accession to the PSCs

Pursuant to the terms of the Farm-in Agreement, on 25 February 2013 (i) the Government of Chad, Griffiths DOH, and Glencore DOH entered into an accession agreement to the DOH PSC pursuant to which Glencore DOH acceded to the DOH PSC, (ii) the Government of Chad, PetroChad, and Glencore DOB/DOI entered into an accession agreement to the DOB/DOI PSC pursuant to which Glencore DOB/DOI acceded to the DOB/DOI PSC and (iii) the Government of Chad, Griffiths Chad, and Glencore

Doseo/Borogop entered into an accession agreement to the Doseo/Borogop PSC pursuant to which Glencore Doseo/Borogop acceded to the Doseo/Borogop PSC.

10.3 **Glencore Farm-in**

On 12 December 2012, the Farmors entered into the Farm-in Agreement with the Farmees and the Company as guarantor (together, the "**Farm-in Parties**"). President Déby signed a decree approving the Farm-in Agreement on 4 February 2013, and such decree was ratified by the Chadian National Assembly on 26 April 2013. The Farm-in Completion occurred on 13 June 2013, pursuant to which Glencore paid the Group U.S.$107,458,921 as consideration for its obligations under the Farm-in Agreement, net of the repayment of the Farm-in Advance.

Transferred Interests

Pursuant to the Farm-in Agreement, and subject to the satisfaction of certain conditions precedent and in exchange for the Farm-in Consideration (as defined below):

(i) PetroChad agreed to assign and transfer to Glencore DOB/DOI one third of its undivided legal and beneficial right title and interest in and to the rights, benefits and obligations in:

  (a) the DOB/DOI PSC (which includes one third of the total participating interest in the DOB/DOI EEA and a 25 per cent. participating interest in the Badila and Mangara EXAs);

  (b) the Badila JVA (as defined below);

  (c) the Mangara JVA (as defined below); and

  (d) all corresponding rights, interests, liabilities and obligations relating to the DOB/DOI PSC, Badila JVA and Mangara JVA, together with all rights of Cost Recovery associated therewith;

(ii) Griffiths Chad agreed to assign and transfer to Glencore Doseo/Borogop one third of its undivided legal and beneficial right, title and interest in and to the rights, benefits and obligations in the Doseo/Borogop PSC (which includes one third of the total participating interest in the Doseo/Borogop EEA), together with all corresponding rights, interests, liabilities, obligations and rights of costs recovery associated therewith; and

(iii) Griffiths DOH agreed to assign and transfer to Glencore DOH one-third of its undivided legal and beneficial right, title and interest in and to the rights, benefits and obligations in the DOH PSC (which includes one third of the total participating interest in the DOH EEA), together with all corresponding rights, interests, liabilities, obligations and rights of costs recovery associated therewith.

The interests to be assigned and transferred by the Farmors to the Farmees, as described above, are referred to collectively as the "**Transferred Interests**".

Upon completion of the assignment and transfer of the Transferred Interests, the allocation of participating interests in each PSC (save in respect of the Badila and Mangara EXAs) shall be:

(i) applicable Farmor: 66.67 per cent.; and

(ii) applicable Farmee: 33.33 per cent.,

and the allocation of participating interests in the Badila and Mangara EXAs (disregarding the effect of the Glencore/SHT Transaction) shall be:

(i) PetroChad: 50 per cent.;

(ii) Glencore DOB/DOI: 25 per cent.; and

(iii) SHT: 25 per cent.

Completion of the assignment and transfer of the Transferred Interests is subject to customary conditions precedent, including the approval of the Government of Chad.

Farm-in Consideration

As consideration for the assignment and transfer of the Transferred Interests, the Farmees agreed to pay or procure the payment of the sum total of the amounts (collectively, the "**Farm-in Consideration**") described below.

As consideration for the assignment and transfer of the Transferred Interests in respect of the DOB/DOI EEA, Doseo/Borogop EEA and DOH EEA, on completion of such assignment and transfer the Farmees shall pay U.S.$30,746,700 to the Farmors. This sum is equivalent to one third of all costs agreed by the Farm-in Parties to have been incurred by the Farmors under the PSCs, after their effective dates up to but excluding 1 July 2012, which are not cost recoverable pursuant to the terms of the applicable PSC.

As consideration for the assignment and transfer of the Transferred Interests in the Badila and Mangara EXAs, Glencore DOB/DOI shall carry PetroChad's paying interest share of all costs and expenses payable in respect of the work programmes for the Badila D&E Plan and the Mangara D&E Plan (other than costs and expenses relating to any sole risk activity undertaken by PetroChad) incurred from and including 1 July 2012 (the "**Glencore DOB/DOI Carry**"), subject to the following limitations:

(i) the total amount payable by Glencore DOB/DOI in respect of the Glencore DOB/DOI Carry shall not exceed U.S.$300 million;

(ii) the total amount payable by Glencore DOB/DOI in respect of the Glencore DOB/DOI Carry for the period from and including 1 July 2012 to and including 30 June 2013 shall not exceed U.S.$100 million;

(iii) the total amount payable by Glencore DOB/DOI in respect of the Glencore DOB/DOI Carry for the period from and including 1 July 2013 to and including 30 June 2014 shall not exceed U.S.$100 million; and

(iv) the total amount payable by Glencore DOB/DOI in respect of the Glencore DOB/DOI Carry for the period from and including 1 July 2014 to and including 30 June 2016 shall not exceed U.S.$100 million.

The Farm-in Parties have separately entered into a guarantee pursuant to which Glencore International AG provides a guarantee in respect of the Farmees' obligations to pay the Farm-in Consideration.

Right of first refusal on SHT interest

The Farmors and Farmees have agreed that in the event that SHT intends to assign its entire participating interest in an EXA:

(i) the applicable Farmee shall have the right to acquire the first one-half of SHT's total participating interest in that EXA, and the applicable Farmor shall have no pre-emption right in respect of such interest; and

(ii) each of the applicable Farmor and applicable Farmee shall be entitled to acquire the remaining one-half of SHT's participating interest, pro-rated in accordance with its respective participating interest in such EXA prior to the exercise of any rights by the applicable Farmee outlined in paragraph (i) above.

ITA Project

Subject to completion of the assignment and transfer of the Transferred Interests, PetroChad and Glencore DOB/DOI have agreed in the Farm-in Agreement to develop jointly the necessary pipeline transportation system and related facilities to transport crude oil produced under the Badila EXA and/or the Mangara EXA from the boundary of the relevant Contractual Zone to the connecting flange with the Export Pipeline (the "**ITA Project**").

PetroChad and Glencore DOB/DOI have agreed, *inter alia*, the following in respect of the ITA Project:

(i) PetroChad has appointed PCT to hold its participating interest in the ITA Project;

(ii) Glencore DOB/DOI shall appoint an affiliate to hold its participating interest in the ITA Project;

(iii) the participating interests of PCT and Glencore DOB/DOI shall be equal to their respective paying interest share in the Badila and Mangara EXAs; and

(iv) PCT shall be the operator of the ITA Project.

Other terms

The Farm-in Agreement contains customary undertakings on behalf of the Farmees for the benefit of the Farmors during the period prior to completion of the assignment and transfer of the Transferred Interests.

The Farm-in Agreement also includes customary representations and warranties given by the Farm-in Parties in relation to rights and title and to the transfer of interests, absence of claims or litigation, compliance with agreements, environmental liability, corporate authorities and bribery and corruption. The Farm-in Agreement is governed by and is to be construed in accordance with the laws of England.

Farm-in Completion Letter

Pursuant to the Farm-in Agreement and the Farm-in Completion Letter, the Farm-in Completion took place on 13 June 2013 with the satisfaction of certain conditions precedent thereto being waived by Glencore. The Farm-in Completion Letter is described in paragraph 8—"Glencore Farm-in" in Part VI: "Information on the Group".

10.4 **Farm-in Advance Agreement**

The Farmors, the Company and the Offtake Buyer entered into the Original Farm-in Advance Agreement on 1 March 2013 (together with the Farm-in Advance Amendment Agreement, the "**Farm-in Advance Agreement**"). Pursuant to the Farm-in Advance Agreement, the Offtake Buyer makes available to PetroChad an advance amount of U.S.$100 million (the "**Original Farm-in Advance**") and shall, upon request, pay to PetroChad, for and on behalf of the Farmors, the Original Farm-in Advance in full as advance consideration for its obligations under the Farm-in Agreement.

On 4 March 2013, the Farmors exercised their option under the Farm-in Advance Agreement and the Original Farm-in Advance was advanced by the Offtake Buyer to PetroChad, for and on behalf of the Farmors. The Original Farm-in Advance was set off against the Farm-in Consideration upon the Farm-in Completion.

The Company provides a number of guarantees to the Offtake Buyer under the Farm-in Advance Agreement, including the punctual performance by each Farmor of its obligations pursuant to the Farm-in Agreement, Offtake Agreement and Farm-in Advance Agreement. The Company also undertakes that whenever a Farmor does not pay any amount when due in connection with the Farm-in Advance Agreement, it shall immediately pay on demand that amount as if it were the principal obligor.

The parties to the Farm-in Advance Agreement are subject to a confidentiality undertaking. The Farm-in Advance Agreement includes, amongst other provisions, information undertakings, general undertakings, indemnities, representations and warranties. The Farm-in Advance Agreement is governed by the laws of England.

The Farmors, the Company and the Offtake Buyer entered into the Farm-in Advance Amendment Agreement on 29 May 2013. Pursuant to the Farm-in Advance Agreement, the Offtake Buyer makes available to PetroChad an additional advance amount of U.S.$50 million (the "**Additional Farm-in Advance**") and shall, upon request, pay to PetroChad, for and on behalf of the Farmors, the Additional Farm-in Advance in full as advance consideration for its obligations under the Farm-in Agreement.

On 30 May 2013, the Farmors exercised their option under the Farm-in Advance Agreement and the Additional Farm-in Advance was advanced by the Offtake Buyer to PetroChad, for and on behalf of the Farmors. The Additional Farm-in Advance was set off against the Farm-in Consideration upon the Farm-in Completion.

The Farm-in Advance Amendment Agreement is an amendment to the Original Farm-in Advance Agreement, and the Additional Farm-in Advance was made on substantially the same terms as the Original Farm-in Advance. The Farm-in Advance Amendment Agreement is governed by the laws of England.

Pursuant to the Farm-in Agreement and the Farm-in Completion Letter, the Farm-in Completion took place on 13 June 2013 with the satisfaction of certain conditions precedent thereto being waived by Glencore. The Farm-in Completion Letter is described in paragraph 8—"Glencore Farm-in" in Part VI: "Information on the Group".

10.5 **PIC Agreements**

Pursuant to the Farm-in Agreement, on 12 December 2012, PetroChad and Glencore DOB/DOI (the "**PIC Parties**") entered into an agreement in respect of each of the Badila and Mangara EXAs (each, a "**PIC Agreement**") to establish a paying interest committee (a "**PIC**") to govern certain aspects of the relationship between them and determine certain decisions required pursuant to the DOB/DOI PSC and

the Badila and Mangara JVAs. It is a requirement of the PIC Agreements that a similar agreement be entered into for each future EXA in which Group and Glencore entities are participants.

Each PIC consists of one representative of the Group (a "**Group Representative**") and one representative of Glencore DOB/DOI (a "**Glencore Representative**"). The Group Representative shall be the chairman of the PIC. For a matter to be agreed, both the Group Representative and the Glencore Representative must vote in favour.

The powers and duties of each PIC shall be to consider and make a determination, *inter alia*, on the following matters:

(i) all proposed work programmes and budgets prior to such work programmes and budgets being submitted to a relevant joint venture committee or the Management Committee for approval, as appropriate;

(ii) any proposal for the abandonment of any well that has been drilled and any change in the use or status of a well;

(iii) any proposal for the division, surrender or relinquishment of all or any part of the Badila or Mangara EXA;

(iv) any proposal for extension of the term of the Badila or Mangara EXA;

(v) the identity of a new operator if an operator resigns or is removed in accordance with the provisions of the relevant Joint Venture Agreement;

(vi) any amendments to the relevant PSC or Joint Venture Agreement, to the extent affecting the Badila or Mangara EXA;

(vii) the commitment of the operator to incurring any additional work programme obligations for the joint account;

(viii) any request to forfeit rights and obligations stemming from the Badila or Mangara EXA; and

(ix) the choice of route for any hydrocarbon pipeline transport system originating from the Badila or Mangara EXA.

Unless the PIC determines otherwise, the work programme and budget for the 2014 and 2015 calendar years shall reflect a pre-agreed work programme for such calendar years and such work programme and budget shall be deemed approved by the PIC.

Following a determination by the PIC:

(i) to the extent permitted by the terms of the applicable Joint Venture Agreement and PSC, each of the PIC Parties shall participate and vote at each meeting of the relevant joint venture committee (and procure that their representative on the Management Committee shall participate and vote) in accordance with that determination (including, for the avoidance of doubt, voting by notice and voting by rapid communication, as may be provided by the terms of the applicable Joint Venture Agreement or the PSC);

(ii) in respect of any matters to be submitted to the Management Committee, the PIC Parties shall only procure the submission of such matters to the Management Committee in accordance with that determination; and

(iii) in respect of any matters to be submitted to a joint venture committee, the PIC Parties shall only submit such matters to that joint venture committee in accordance with such determination.

Nothing in the PIC Agreements affects PetroChad's status as operator of the Badila and Mangara EXAs. In addition, if the PIC does not agree on the proposed work programme and budget, either party may submit the activity to the relevant joint venture committee as a sole risk activity.

10.6 **Badila and Mangara Joint Venture Agreements**

Pursuant to the DOB/DOI PSC, on 24 October 2012 and 13 June 2012, respectively, PetroChad and SHT entered into the Badila and Mangara JVAs on substantially identical terms. PetroChad held a 75 per cent. participating interest and SHT held a 25 per cent. participating interest in each of the Badila and Mangara JVAs, respectively.

On 25 February 2013, PetroChad, SHT and Glencore DOB/DOI entered into an assignment agreement and an amendment agreement to each of the Badila and Mangara JVAs to assign (i) one-third of PetroChad's and (ii) 40 per cent. of SHT's respective participating interests in each of the Badila and Mangara JVAs to Glencore DOB/DOI such that, upon completion of the assignments, PetroChad holds 50 per cent., SHT 15 per cent. and Glencore DOB/DOI 35 per cent., respectively, of the participating interests of each of the Badila and Mangara JVAs.

The Badila and Mangara JVAs establish the rights and obligations of the parties thereto with regard to operations under the DOB/DOI PSC and the applicable EXA. In respect of each agreement area, the Badila and Mangara JVAs cover (i) the joint exploration, appraisal, exploitation, development operations and production of petroleum reserves; and (ii) in-field hydrocarbons transportation operations. The Badila and Mangara JVAs use the AIPN 2002 Model Form International Operating Agreement developed by the Association of International Petroleum Negotiators. The Badila and Mangara JVAs set out the role and responsibilities of PetroChad as operator including, *inter alia*, provisions regarding the conduct of operations, administration of employees, provision of information to non-operators, submission of work programmes and budgets, and the circumstances in which the operator may resign or be removed by the non-operators.

The Badila and Mangara JVAs also provide for the establishment of a committee (the "**Badila Joint Venture Committee**" and the "**Mangara Joint Venture Committee**", respectively) to supervise all operations and to make determinations for the purposes of the Badila or Mangara JVA, as the case may be. Determinations of the Badila or Mangara Joint Venture Committee are made in accordance with the mechanism set out in the DOB/DOI PSC and, except where unanimity is required, are subject to a majority vote of committee members holding, in aggregate, at least a 70 per cent. participating interest in the relevant EXA. The power and duties of the Badila and Mangara Joint Venture Committees include, *inter alia*, (i) determinations with regard to operations, work programmes, budgets and strategic decisions for wells; and (ii) appointment of any new operator.

The Badila and Mangara JVAs include customary sole risk provisions that allow a party to propose an activity or programme at its own risk and to use its own finances if the Badila or Mangara Joint Venture Committee, as the case may be, is unable to reach agreement on a matter as a joint operation.

Pursuant to the Badila and Mangara JVAs, any direct or indirect sale or transfer of all or a portion of a participating interest by any party is subject to a preferential right to purchase that interest by the other relevant parties.

10.7 **EEA Joint Venture Agreements**

Pursuant to the terms of the Farm-in Agreement, on 12 December 2012, (i) Griffiths Chad and Glencore Doseo/Borogop entered into the Doseo/Borogop JVA, (ii) Griffiths DOH and Glencore DOH entered into the DOH JVA and (iii) PetroChad and Glencore DOB/DOI entered into the DOB/DOI JVA (each a "**EEA JVA**"). Pursuant to each EEA JVA, Griffiths Chad, Griffiths DOH and PetroChad (each a "**Caracal Participant**"), as applicable, hold 66.67 per cent. of the participating interest and the relevant Glencore Seller holds the remaining 33.33 per cent.

The EEA JVAs establish the rights and obligations of the relevant parties, including those of the Caracal Participant as operator under each EEA JVA, with respect to operations under the Doseo/Borogop PSC, the DOH PSC and the DOB/DOI PSC, including with regard to joint exploration, appraisal, exploitation, development operations and production of hydrocarbon reserves. Each EEA JVA sets out the role and responsibilities of the Caracal Participant as operator, including, *inter alia*, provisions regarding the conduct of operations, administration of employees, acquisition of appropriate consents, approvals and permits, provision of information to non-operators and the circumstances in which the operator may resign or be removed by the non-operators.

Currently, the EEA JVAs are in respect of the whole of the relevant EEA for the relevant PSC. If an EXA is granted in respect of an area in the relevant Contractual Zone, then, pursuant to the relevant PSC, the Government of Chad may exercise its right to back-in to the EXA, either directly or through a public body, and acquire up to a 25 per cent. participating interest in the EXA (as it has done in respect of the Badila and Mangara EXAs and as the Group expects it to do in respect of future EXAs). This would dilute the participating interests of the Caracal Participant to 50 per cent. and the relevant Glencore Seller to 25 per cent. Should the Government of Chad exercise a back-in right in respect of an EXA, a new joint venture agreement, on substantially identical terms as the relevant EEA JVA, will be entered into by the Caracal

Participant, the relevant Glencore Seller and the Government of Chad. However, the Government of Chad may require the Caracal Participant and the relevant Glencore Seller to enter a new joint venture agreement on substantially identical terms as the Badila and Mangara JVAs instead. Should this be the case, the Caracal Participant and the relevant Glencore Seller will enter into an additional supplementary agreement that will contain terms clarifying the rights and obligations of the Caracal Participant and the relevant Glencore Seller with respect to the EXA. Any such supplementary agreement will put the Caracal Participant and the relevant Glencore Seller in the same positions, as between each other, that they would have been in had any new joint venture agreement been on terms similar to the relevant EEA JVA, as opposed to terms similar to the Badila and Mangara JVAs, particularly with regard to work programmes, budgets and default.

The parties have established a committee pursuant to each EEA JVA (each an "**EEA Joint Venture Committee**") to authorise and supervise joint operations and to make certain determinations for the purposes of the relevant EEA JVA. Determinations of each EEA Joint Venture Committee must be authorised by the affirmative vote of two or more committee members holding, in aggregate, at least 70 per cent. of the participating interests in the relevant PSC. The power and duties of each EEA Joint Venture Committee include, *inter alia*, (i) determinations in relation to operations, work programmes, budgets and strategic decisions for wells; and (ii) appointment of any new operator.

The EEA JVAs include customary sole risk provisions that allow a party to propose an activity or programme at its own risk and to use its own finances if the relevant EEA Joint Venture Committee is unable to reach agreement on a matter as a joint operation.

Any direct or indirect sale or transfer of all or a portion of a participating interest by any party is subject to a preferential right to purchase that interest by the other parties to relevant EEA JVA.

10.8 **Offtake arrangements with Glencore**

On 12 December 2012, the Offtake Sellers and the Offtake Buyer entered into the Offtake Agreement.

Pursuant to the terms of the Offtake Agreement, the Offtake Sellers agree to sell and deliver free on board to the Offtake Buyer, and the Offtake Buyer agrees to purchase, receive and pay for, all of the Offtake Sellers' Entitlement which is made available by the operator of the Kribi Terminal for delivery to the Offtake Buyer.

There are no guarantees or warranties contained within the Offtake Agreement with respect to the fitness or suitability for purpose of the crude oil sold thereunder.

Price and payment

The price of the oil sold by the Offtake Sellers to the Offtake Buyer pursuant to the Offtake Agreement is to be determined according to a price calculation formula which is based upon Dated Brent Crude. Payments under the Offtake Agreement shall be made in U.S. dollars.

Term

The term of the Offtake Agreement commences either (i) on the commencement of commercial production or (ii) on the date on which the conditions precedent detailed in the Offtake Agreement thereunder are satisfied or waived, as notified by PetroChad in its role as the sellers' agent (the "**Offtake Sellers' Agent**"), whichever is the earlier to occur. The term shall be for a period of three years if the conditions precedent have not been satisfied by the longstop date specified in the Offtake Agreement, but where the conditions precedent detailed in the Offtake Agreement have been satisfied or waived, the term will be automatically extended and continue to apply until (i) the expiry of all of the PSCs and (if applicable) any additional production sharing contracts in Chad to which the Offtake Agreement applies or (ii) the Glencore Sellers no longer hold at least a 10 per cent. participating interest in a PSC or (if applicable) an additional production sharing contract in Chad to which the Offtake Agreement applies, in which case the Offtake Agreement shall terminate in respect of that PSC or additional production sharing contract only.

The Offtake Agreement is subject to conditions precedent, including Glencore International AG providing an executed parent company guarantee to the Offtake Sellers' Agent in respect of the Offtake Buyer's payment obligations to the Offtake Sellers.

Additional volumes

Additional volumes of crude oil will become subject to the Offtake Agreement in circumstances whereby a Group Seller or one of its affiliates (a "**Group Entity**") and a Glencore Seller or one of its affiliates (a "**Glencore Entity**") both acquire an interest in the same additional production sharing contract in Chad. Additional volumes of crude oil may also be included in the Offtake Sellers' Entitlement to be sold under the Offtake Agreement if either a Group Entity or a Glencore Entity acquires an interest in an additional profit sharing contract and that entity nominates to include such additional entitlement within the scope of the Offtake Agreement.

Marketing

The Offtake Buyer is required to advise the Offtake Sellers' Agent of all potential marketing opportunities that the Offtake Buyer has for the on-sale of the crude oil and to keep the Offtake Sellers' Agent aware of market issues that may affect the price of such on-sales. The Offtake Buyer is obliged to market all crude oil delivered by the Offtake Sellers for on-sale to non-affiliated third parties (on arm's length terms).

Other terms

The parties to the Offtake Agreement are subject to a confidentiality undertaking. The Offtake Agreement contains, amongst other provisions, certain undertakings from the Offtake Buyer with respect to compliance with the lifting conditions and regulations of the Kribi Terminal and chapter XI of International Ship and Port Facility Security Code. The Offtake Agreement is governed by the laws of England.

10.9 **Interconnection Agreement**

The Interconnection Agreement was entered into by PetroChad (as operator of the DOB/DOI PSC) and TOTCO on 25 October 2012 to enable the connection of the Group's transportation infrastructure to transport the Group's production from the Badila and Mangara Fields to the Export Pipeline.

Scope of work

Pursuant to the terms of the Interconnection Agreement, PetroChad and TOTCO agreed, *inter alia* that:

(i) PetroChad shall procure the construction and installation of all facilities (including but not limited to the Connection Pipe) necessary for the transportation of the Group's oil to the physical point(s) on the Export Pipeline in Chad specified in the Interconnection Agreement, and as thereafter may be designated by the TOTCO, at which the Group tenders its oil to TOTCO (the "**Tie-in Point**");

(ii) TOTCO shall procure the construction and installation of all modifications to the Export Pipeline in Chad (including but not limited to any material, metering equipment, hardware and pipelines) that are funded by PetroChad pursuant to the Interconnection Agreement (the "**Tie-in Facilities**"); and

(iii) the commissioning process in respect of the work described in the Interconnection Agreement (the "**Tie-in Work**") shall not be commenced until TOTCO has issued the relevant notice of readiness to PetroChad.

Construction, installation and tie-in

Pursuant to the Interconnection Agreement, PetroChad undertakes to comply with agreed environmental standards and to organise a periodic audit of its compliance. TOTCO shall have the right to suspend its performance under the Interconnection Agreement if, in its sole opinion, PetroChad is found to have breached such undertaking. TOTCO shall have the right to terminate the Interconnection Agreement if PetroChad fails to remedy such breach within 30 business days of receiving notification of such breach from TOTCO.

The Tie-in Work, including any supporting services and inspection and review work associated with the Tie-in Work provided by TOTCO, shall be performed at PetroChad's sole cost and expense on an "at cost" basis. TOTCO shall use reasonable endeavours to allocate costs associated with the construction of the Tie-in Facilities amongst persons using such facilities, other than the shippers existing on the date of the Interconnection Agreement.

PetroChad will be liable for any shut-down caused by the Tie-in Work, other than an agreed shut-down.

Each of PetroChad and TOTCO shall form a team that will administer the implementation of the Tie-in Work, with such teams to meet on a monthly basis to provide each other with a status update of the Tie-in Work.

Operation and Maintenance

Following commissioning, TOTCO shall, at PetroChad's cost and expense, perform all operation and maintenance functions related to the Tie-in Facilities. If the Tie-in Facilities are utilised by persons other than PetroChad, TOTCO shall allocate the operation and maintenance costs between the users of the Tie-in Facilities.

Payment and audit right

PetroChad shall pay for the cost of Tie-in Work in advance based on the prevailing estimated work programme and budget agreed between the parties.

TOTCO shall invoice PetroChad for charges incurred in connection with the operation, maintenance and abandonment of the Tie-in Facilities. Such charges shall be governed by the relevant Transportation Agreement and TOTCO shall have the right to include these charges as part of the transportation tariff payable thereunder.

Abandonment and removal

TOTCO shall be responsible for the removal and abandonment of the Tie-in Facilities and has the right to charge PetroChad for such removal and abandonment. If the equipment is utilised by persons other than PetroChad, TOTCO shall allocate the abandonment cost between the users of the Tie-in Facilities.

PetroChad shall be responsible for the removal and abandonment of the facilities necessary for the transportation of the Group's oil to the Tie-in Point, and undertakes to perform such obligation in compliance with certain agreed environmental standards.

Other Terms

The Interconnection Agreement shall, unless otherwise decided, remain in force until the end of the 12-month period following the removal or abandonment of either the Export Pipeline or the facilities necessary for the transportation of the Group's oil to the Tie-in Point.

The parties to the Interconnection Agreement are subject to a confidentiality undertaking. The Interconnection Agreement includes, amongst other provisions, insurance obligations, indemnities and representations and warranties. The Interconnection Agreement is governed by the laws of England.

Assignment

PetroChad intends to assign its rights and obligations under the Interconnection Agreement to PCT in due course.

10.10 **Facilities Modification Agreement**

The Facilities Modification Agreement was entered into between PetroChad and COTCO on 18 March 2013. The Facilities Modification Agreement provides for certain modifications to the Cameroonian portion of the Export Pipeline to accommodate the transportation of the Group's oil, including, among other things, the installation of metering equipment to measure new oil volumes being shipped in the Export Pipeline.

Scope of work

Modifications

Pursuant to the terms of the Facilities Modification Agreement, COTCO shall procure the performance of:

(i) the necessary modifications to its crude oil topping plants to accommodate the transportation of the Group's crude oil through the Export Pipeline;

(ii) the necessary modifications to its floating storage and offloading facility, which forms part of the Export Pipeline, to accommodate the transportation of the Group's crude oil through the Export Pipeline; and

(iii) a study related to flow assurance in the Export Pipeline for the Group's crude oil.

Mechanical Completion, Commissioning and RFO

Pursuant to the terms of the Facilities Modification Agreement:

(i) COTCO shall complete all activities, after fabrication, assembly, installation and tie-in, which are necessary to make the equipment, facility or system being modified (as outlined in paragraphs (i) and (ii) above) complete, safe and ready to receive the Group's crude oil into the Export Pipeline;

(ii) subject to satisfaction of the relevant conditions precedent and completion of the "Operating, Maintenance and Coordination Procedures", as described below, PetroChad may flow its crude oil from the Connection Pipe into and through the Export Pipeline; and

(iii) COTCO shall commission the facilities modifications described above.

Conditions precedent

No physical work may be carried out under the Facilities Modification Agreement until COTCO has obtained all permits or Government approvals necessary to carry out the agreed scope of work.

No commissioning shall be conducted until:

(i) the Transportation Agreements have become effective; and

(ii) PetroChad has provided TOTCO with the written confirmation of the relevant Government agency that it is has met certain agreed environmental standards.

Construction, Installation and Modification

Pursuant to the Facilities Modification Agreement, the agreed scope of work shall be performed in accordance with established practice for the operation of the Export Pipeline. PetroChad shall have the right to review and approve the design and plans for execution of the modifications. COTCO shall have the right to suspend its performance under the Facilities Modification Agreement if, in its sole opinion, due to the Export Pipeline's essential safety and/or environmental requirements, or in case of emergency situations, until remedial actions and corrective measures, as judged by COTCO, have been taken.

The agreed scope of work shall be performed at PetroChad's sole cost and expense on an "at cost" basis. PetroChad shall also bear the costs arising from the "Operation, Maintenance and Coordination Procedures". COTCO shall use reasonable endeavours to allocate costs associated with the construction of the modified facilities amongst persons using such facilities, other than the shippers existing on the date of the Facilities Modification Agreement.

PetroChad will be liable for any shut-down caused by the agreed scope of work, other than an agreed shut-down.

Each of PetroChad and COTCO shall form a team that will administer the implementation of the Facilities Modification Agreement, with such teams to meet on a monthly basis to provide each other with a status update of the agreed scope of work.

Operation and Maintenance

Once ready for commissioning, COTCO shall, at PetroChad's cost and expense, perform all operation and maintenance functions related to the modified facilities. If the modified facilities are utilised by persons other than PetroChad, COTCO shall allocate the operation and maintenance costs between the users of the modified facilities.

Payment and audit right

PetroChad shall pay for the cost of the agreed scope of work in advance based on the prevailing estimated work programme and budget agreed between the parties.

COTCO shall invoice PetroChad for charges incurred in connection with the operation, maintenance and abandonment of the modified facilities. Such charges shall be governed by the relevant Transportation Agreement and COTCO shall have the right to include these charges as part of the transportation tariff payable thereunder.

Abandonment and removal

COTCO shall be responsible for the removal and abandonment of the modified facilities and has the right to charge PetroChad for such removal and abandonment. If the equipment is utilised by persons other than PetroChad, COTCO shall allocate the abandonment cost between the users of the modified facilities.

Other Terms

The Facilities Modification Agreement shall, unless otherwise decided, remain in force until the end of the 12-month period following the removal or abandonment of either the Export Pipeline or the Connection Pipe.

The Facilities Modification Agreement contains certain provisions enabling PetroChad to inspect the performance of COTCO's obligations thereunder and, once ready for commissioning, the modified facilities of COTCO and the operation thereof, subject to certain conditions.

The parties to the Facilities Modification Agreement are subject to a confidentiality undertaking. The Facilities Modification Agreement includes, amongst other provisions, insurance obligations, indemnities and representations and warranties. The Facilities Modification Agreement is governed by the laws of England.

10.11 **Deed Poll**

The Deed Poll is described in Part XV: "CREST and Depositary Interests".

10.12 **Depositary Agreement**

The Depositary Agreement is described in Part XV: "CREST and Depositary Interests".

11 Properties, leases, plant and drilling equipment

The Group's material assets are its exploration and exploitation claims, licences and permits, further details of which are contained in Part XIX: "GLJ Reports".

12 Litigation and Regulatory Actions

Save in respect of the matters forming the subject of the Special Committee Investigation and subsequent settlement with the PPSC, details of which are set out in Part VI: "Information on the Group", there are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened or which the Group is aware) during the 12 months preceding the date of this Prospectus, nor any regulatory actions imposed within the three years preceding the date of this Prospectus, which may have, or have had, a significant effect on the Company's or the Group's financial position or profitability.

13 Related Party Transactions

Save for the related party transactions set out in the financial information in Note 19 "Related Party Transactions" to the audited consolidated financial statements of the Company as of and for the year ended 2012, there are no related party transactions that were entered into during the period covered by the historical financial information contained in Part XII: "Historical Financial Information" and during the period from 1 April 2013 to 24 June 2013 (being the latest practicable date prior to the publication of this Prospectus).

14 Interests of management and others in material transactions

There are no material interests, direct or indirect, of any Director, executive officer, Senior Manager, any shareholder who beneficially owns, directly or indirectly, more than 10 per cent. of any class or series of the Company's voting securities, or any known associates or affiliates of such persons, in any transaction within the three years before the date of this Prospectus that has materially affected or is reasonably expected to materially affect the Company or any of its subsidiaries.

15 Working Capital

The Company is of the opinion that the Group has sufficient working capital for its present requirements, that is for the next 12 months following the date of this Prospectus.

16 No significant change

Save for (i) the additional U.S.$50 million advance that was advanced by Glencore to the Group on 30 May 2013 as advance consideration for its obligations under the Farm-in Agreement and (ii) the payment of U.S.$107,458,921 million made by Glencore to the Group upon the Farm-in Completion (each as described in Note 10 "Subsequent events" to the unaudited interim consolidated financial statements of the Company as of and for the three months ended 31 March 2013), there has been no significant change in the financial or trading position of the Group since 31 March 2013, the date to which the last published interim financial information of the Company was prepared.

17 Consents

KPMG LLP has given and not withdrawn its written consent to the inclusion in this Prospectus of its audit report dated 27 June 2013, which is set out in Part XII: "Historical Financial Information", and references to it in the form and context in which they appear and has authorised the contents of those parts of this Prospectus which comprise its report for the purposes of Prospectus Rule 5.5.3R(2)(f).

GLJ (in its capacity as an independent competent person) has given and not withdrawn its written consent to the inclusion in this Prospectus of its reports, which are set out in Part XIX: "GLJ Reports", and references to such reports in the form and context in which they appear and has authorised the contents of those parts of this Prospectus which comprise its reports for the purposes of Rule 5.5.3R(2)(f) of the Prospectus Rules.

18 General

The expenses relating to Admission, including professional fees and expenses and the costs of printing documents are estimated to amount to £3.4 million (U.S.$5.2 million) (including VAT) and are payable by the Company.

19 Documents available for inspection

Copies of the following documents are available for inspection during usual business hours on any weekday (Saturdays, Sundays and public holidays excepted) for a period of 12 months following Admission at the offices of the Company in Calgary, Alberta:

(a) the Articles;

(b) the shareholders minutes in the minutes books of the Company from the date of incorporation;

(c) (i) the audited consolidated financial statements of the Company as of and for the years ended 2012, 2011 and 2010 and (ii) the unaudited interim consolidated financial statements of the Company as of and for the three months ended 31 March 2013 and 2012;

(d) GLJ's consent letter, as referred to in paragraph 17—"Consents" above;

(e) the audit report from KPMG LLP which is set out in Part XII: "Historical Financial Information";

(f) the GLJ Reports which are set out in Part XIX: "GLJ Reports"; and

(g) this Prospectus.

Dated: 27 June 2013

PART XVII
DEFINITIONS

Definitions

The following definitions apply throughout this Prospectus unless the context requires otherwise:

1988 Convention	the convention agreement signed in 1988 between the Consortium and Chad to develop the oilfields in the Doba Basin
2004 Convention	the convention agreement signed in 2004 between the Consortium and Chad to develop the oilfields in the Doba Basin
2010 Units	the units issued by the Company in 2010 pursuant to various private subscriptions comprising of one Share and one Purchase Warrant
2011 Liquidity Warrant	those Warrants issued in 2011 that were automatically converted into Shares, for no additional consideration from the holder thereof, because a Liquidity Warrant Liquidity Event had not occurred prior to 31 December 2011
2011 Units	the units issued to Senior Managers in 2011 at a price of C$5.00, with each unit comprised of one Share and two Performance Warrants
2012 Liquidity Warrants	those Warrants issued in 2012 that were automatically converted into Shares, for no additional consideration from the holder thereof, because a Liquidity Warrant Liquidity Event had not occurred prior to 14 March 2013
2013 Incentive Plan	the executive compensation plan of the Company adopted on 9 January 2013 and effective 1 January 2013
Act	the Companies Act 2006, as amended
Additional Farm-in Advance	an advance amount of U.S.$50 million made available by the Offtake Buyer to PetroChad, for and on behalf of the Farmors, pursuant to the Farm-in Advance Agreement
Admission	the admission of the Shares to the premium listing segment of the Official List and to trading on the London Stock Exchange's main market for listed securities
Agent Advisory Options	options granted by the Company to a syndicate of agents in 2011 which entitle the holders thereof to acquire one Share at a price of C$5.00 per Share and expire 24 months after their respective issue dates
AGM	annual general meeting of shareholders
AIM	the Alternative Investment Market, a sub-market of the London Stock Exchange
Ambassador	Chad's Ambassador to Canada
Applicable Canadian Securities Laws	the securities legislation in the Applicable Jurisdictions
Applicable Jurisdictions	each of the provinces of Canada other than Québec
Articles	the articles of association of the Company to be adopted upon Admission
ASX	the Australian Securities Exchange
Audit Committee	the Audit Committee of the Board
Awards	RSUs, PSUs and/or DSUs granted under the 2013 Incentive Plan

Badila D&E Plan	the Badila development and exploitation plan which the Company submitted to the Government of Chad in application for an EXA for the Badila Field on 29 June 2012
Badila EXA	the EXA granted in respect of the Badila Field by the Ministry of Petroleum on 10 August 2012
Badila Field	the Badila field located in the DOB/DOI Contractual Zone
Badila Joint Venture Committee	the joint venture committee established under the Badila JVA
Badila JVA	the joint venture agreement between PetroChad and SHT entered into on 24 October 2012 in respect of the Badila EXA
Blending Export Terminal	the pipeline terminal to which it is contemplated production from the Early Production Facilities, Early Production Facilities Expansion and Mangara CPF will be received and blended to attain Spec Oil for delivery to the Export Pipeline
Board or **Board of Directors**	the board of directors of the Company whose names appear in Part VIII: "Directors, Senior Managers and Corporate Governance"
Business Integrity Policy	the Group's anti-corruption business integrity policy
Cameroon	the Republic of Cameroon
Canadian Prospectus	the final non-offering prospectus filed with each of the Canadian Securities Regulators to enable the Company to become a "reporting issuer" in the Applicable Jurisdictions pursuant to Applicable Canadian Securities Laws
Canadian Securities Regulators	the securities regulatory authorities in the Applicable Jurisdictions
Caracal Participant	PetroChad, Griffiths Chad and Griffiths DOH
CBCA	the Canada Business Corporations Act
CCSRP	the Petroleum Revenue Oversight and Control Committee (also known as the *Collège de Contrôle et de Surveillance des Ressources Pétrolieres*)
CD&A	the compensation discussion and analysis regarding the Company's executive compensation programme
CDS	CDS Clearing and Depositary Services Inc.
Chad	the Republic of Chad
Chadian National Assembly	the national assembly of the Government of Chad
Chevron	Chevron Corporation
CNPC	China National Petroleum Corporation
Code	the Company's Code of Business Conduct and Ethics
Commercial Deposit	a deposit whose economic profitability and technical feasibility have been substantiated by a feasibility study, which, in the Contractor's opinion, will lend itself to development and exploitation under economic conditions, in conformity with international oil industry practices
Company	Caracal Energy Inc.
Compensation Committee	the Human Resources and Compensation Committee of the Board
Compliance Committee	the Compliance Committee of the Board

Confirmatory Law	the law that the Chadian Assembly is required to pass in order to confirm the amount of the PSC Transfer Fee
Connection Pipe	the 16-kilometre, 12-inch dry oil pipeline from the Blending Export Terminal to the Export Pipeline
Consortium	the petroleum companies party to the 1988 Convention to develop the oilfields located in the Doba Basin
Constitution	the constitution of Chad, dated 31 March 1996 as amended in 2005
Contractor	collectively, (i) each of the Company's three subsidiaries which have signed a PSC with the Government of Chad and (ii) Glencore
Contractual Zone	the area in Chad subject to and governed by the terms and conditions of a PSC
Convertible Bonds	U.S.$173.6 million pre-IPO convertible bonds issued by the Company on 13 September 2012
Cost Oil	the costs of exploration, appraisal, development and production operations attributed to an EXA which may be recovered by the Contractor by receiving a quantity of hydrocarbon production from such EXA in each year
COTCO	Cameroon Oil Transportation Company S.A., a joint venture between the Government of Cameroon and EEPCI
COTCO Transportation Agreement	the agreement, expected to be entered into prior to commencement of first production from the Badila Field, between PetroChad (as operator of the DOB/DOI PSC) and COTCO (as the owner and operator of the portion of the Export Pipeline located in Cameroon) for the transportation of crude oil produced from the Badila and Mangara Fields
CPC Taiwan	CPC Corporation, Taiwan
CREST	the UK-based system for the paperless settlement of trades in listed securities, of which Euroclear UK and Ireland is the operator
CSR Policy	the Group's corporate social responsibility policy
Custodian	any custodian appointed by the Depositary
Deed Poll	the deed poll executed on 21 June 2013 by the Depositary in favour of the holders of the Depositary Interests from time to time
Depositary	Computershare Investor Services plc
Depositary Agreement	the agreement entered into on 27 June 2013 between the Company and the Depositary appointing the Depositary
Depositary Interests	the dematerialised depositary interests issued by the Depositary in respect of the underlying Shares
Directors	the directors of the Company whose names appear in Part VIII: "Directors, Senior Managers and Corporate Governance"
Disclosure and Transparency Rules	the disclosure and transparency rules made by the FCA under Part VI of FSMA
Disclosure Policy	the Company's Corporate Disclosure Policy
Doba Basin	the area located in southern Chad which contains the DOB/DOI Contractual Zone and the DOH Contractual Zone

DOB/DOI Contractual Zone	the 2,865 km^2 area comprised of the DOB and DOI blocks in southern Chad that is governed by the DOB/DOI PSC
DOB/DOI EEA	the EEA granted in respect of the DOB/DOI Contractual Zone
DOB/DOI Environmental Impact Assessment	the environmental impact assessment, in respect of operations in the DOB and DOI blocks, approved by the Government of Chad on 13 July 2012
DOB/DOI JVA	the joint venture agreement between Griffiths Chad and Glencore DOB/DOI entered into on 12 December 2012 in respect of the DOB/DOI EEA
DOB/DOI PSC	the production sharing contract dated 18 March 2011 between PetroChad and the Government of Chad
DOB/DOI Transferred Interest	a 33.33 per cent. participating interest in the DOB/DOI PSC and DOB/DOI EEA
DOH Contractual Zone	the 824 km^2 area located in the DOH block in southern Chad that is governed by the DOH PSC
DOH EEA	the EEA granted in respect of the DOH Contractual Zone
DOH JVA	the joint venture agreement between Griffiths Chad and Glencore DOH entered into on 12 December 2012 in respect of the DOH EEA
DOH Ordinance	an ordinance issued by President Déby on 17 August 2011 approving the DOH PSC, which was not ratified by the Chadian National Assembly within the required timeframe
DOH PSC	the production sharing contract dated 3 August 2011 between Griffiths DOH and the Government of Chad
DOH Transferred Interest	a 33.33 per cent. participating interest in the DOH PSC and DOH EEA
Doseo/Borogop Contractual Zone	the 22,414 km^2 area located in the Chari-East Doseo and Borogop blocks in southern Chad that is governed by the Doseo/Borogop PSC
Doseo/Borogop EEA	the EEA granted in respect of the Doseo/Borogop Contractual Zone
Doseo/Borogop JVA	the joint venture agreement between Griffiths Chad and Glencore Doseo/Borogop entered into on 12 December 2012 in respect of the Doseo/Borogop EEA
Doseo/Borogop Pipeline	the proposed pipeline route from the Kibea Field to the tie-in point on the Export Pipeline
Doseo/Borogop Pipeline Concept Study	the concept study in relation to the Doseo/Borogop Pipeline which was completed in April 2013 by an independent engineering firm
Doseo/Borogop Pipeline Engineering Study	the detailed front-end engineering and design study which the Group expects to put to tender in the third quarter of 2013 and have completed in the fourth quarter of 2013
Doseo/Borogop PSC	the production sharing contract dated 19 January 2011 between Griffiths Chad and the Government of Chad
Doseo/Borogop Transferred Interest	a 33.33 per cent. participating interest in the Doseo/Borogop PSC and Doseo/Borogop EEA
DSUs	deferred share units granted under the 2013 Incentive Plan

DTR5	the provisions of Chapter 5 of the Disclosure and Transparency Rules
Early Production Facilities	the two processing facilities in the Badila Field designed to treat initial oil production
Early Production Facilities Expansion	an expansion of the Early Production Facilities, construction of which is expected to commence in late 2013, with commissioning expected to take place in the first quarter of 2014
EEA	the initial exclusive exploration authorisation granted for the Initial Exploration Term to a Contractor under a PSC
EEA Joint Venture Committee	the joint venture committee established pursuant to the relevant EEA JVA
EEA JVAs	the Doseo/Borogop JVA, the DOH JVA and the DOB/DOI JVA
EEPCI	Esso Exploration and Production Chad, Inc., a consortium comprising ExxonMobil, PETRONAS and Chevron
EITI	the Extractive Industries Transparency Initiative
Eligible Grantees	those persons entitled to receive grants of Awards pursuant to the 2013 Incentive Plan, being officers, directors and employees of the Company or its subsidiaries and certain persons engaged to provide ongoing consulting services to the Company or its subsidiaries
Eligible Optionees	those persons entitled to receive grants of Options pursuant to the Option Plan, being officers, directors and employees of the Company or its subsidiaries and any person or company engaged to provide ongoing consulting services to the Company or its subsidiaries
Environmental Plans	the comprehensive environmental and social management plan, waste management plan, oil spill response plan and compensation and resettlement plan that the Group is in the process of implementing
ESPs	electrical submersible pumps
EU	the European Union
EXA	an exclusive exploitation authorisation issued by the Government of Chad to permit the applicable Contractor to conduct development and production activities in the area covered by such EXA for the Initial Exploitation Term
Executive Directors	the executive Directors of the Company
Export Pipeline	the third-party-owned and operated 1,070-kilometre pipeline, completed in 2003, that carries crude oil produced from the Doba Basin in Chad across Cameroon to the Kribi Terminal
ExxonMobil	Exxon Mobil Corporation
Facilities Modification Agreement	the agreement entered into on 18 March 2013 between PetroChad (as operator of the DOB/DOI PSC) and COTCO to make necessary modifications to the portion of the Export Pipeline located in Cameroon
Farmees	Glencore DOB/DOI, Glencore DOH and Glencore Doseo/ Borogop
Farm-in Advance	the Original Farm-in Advance and the Additional Farm-in Advance

Farm-in Advance Agreement	the Original Farm-in Advance Agreement, as amended by the Farm-in Advance Amendment Agreement
Farm-in Advance Amendment Agreement	the amendment agreement relating to the Original Farm-in Advance Agreement entered into between the Farmors, the Company and the Offtake Buyer on 29 May 2013
Farm-in Agreement	the agreement dated 12 December 2012 entered into between the Farm-in Parties, pursuant to which Glencore acquired from the Group a 33.33 per cent. participating interest in each of the PSCs and a 25 per cent. participating interest in the Badila and Mangara EXAs
Farm-in Completion	completion of the assignment and transfer of the Transferred Interests and payment of the Farm-in Consideration pursuant to the Farm-in Agreement and the Farm-in Completion Letter on 13 June 2013
Farm-in Completion Letter	a letter agreement dated 13 June 2013 between Glencore and the Group
Farm-in Consideration	the consideration paid by the Farmees to the Farmors for the assignment and transfer of the Transferred Interests pursuant to the Farm-in Agreement
Farm-in Parties	the Farmees, the Farmors and the Company
Farmors	PetroChad, Griffiths Chad and Griffiths DOH
FCA	the United Kingdom Financial Conduct Authority
Financial Promotions Order	the United Kingdom Financial Services and Markets Act 2000 (Financial Promotion) Order 2005
FSMA	the Financial Services and Markets Act 2000 (as amended)
FTSE	Financial Times Stock Exchange
FTSE Nationality Committee	the committee of FTSE, responsible for determining the nationality of companies included in FTSE indices
FTSE UK Index Series	the set of indices measuring performance of UK companies published by FTSE
GDP	gross domestic product
General Transportation Terms	the set of general terms expected to be applicable to all users of the Export Pipeline
Glencore	Glencore Xstrata plc
Glencore DOB/DOI	Glencore Exploration (DOB/DOI) Ltd.
Glencore DOB/DOI Carry	the portion of PetroChad's paying interest share of all costs and expenses payable in respect of the work programmes for the Badila and Mangara D&E Plans (other than costs and expenses relating to any sole risk activity undertaken by PetroChad) incurred from and including 1 July 2012 that Glencore DOB/DOI agrees to carry pursuant to the Farm-in Agreement
Glencore DOH	Glencore Exploration (DOH) Ltd.
Glencore Doseo/Borogop	Glencore Exploration (Doseo/Borogop) Ltd.
Glencore Entity	a Glencore Seller or one of its affiliates
Glencore Representative	a person or entity representing Glencore
Glencore Sellers	Glencore DOB/DOI, Glencore DOH and Glencore Doseo/Borogop

Glencore/SHT Transaction	the acquisition in June 2013 by Glencore of a 10 per cent. participating interest in the Badila and Mangara EXAs from SHT
Glencore Transferred Interests	the DOB/DOI Transferred Interest, the Doseo/Borogop Transferred Interest and the DOH Transferred Interest
GLJ	GLJ Petroleum Consultants Ltd., the Company's independent reserves and resources evaluator
GLJ Reports	collectively, the GLJ Report on Reserves and Contingent Resources and the GLJ Report on Prospective Resources
GLJ Report on Prospective Resources	the independent competent person's report that evaluates the prospective resources of certain of the Company's properties in Chad, prepared by GLJ dated 28 February 2013 with an effective date of 31 December 2012
GLJ Report on Reserves and Contingent Resources	the independent competent person's report that evaluates the crude oil reserves and contingent resources of certain of the Company's properties in Chad, prepared by GLJ dated 29 January 2013 with an effective date of 31 December 2012
Governance and Nominations Committee	the Governance and Nominations Committee of the Board
Government of Chad	the national government of Chad
Government of Cameroon	the national government of Cameroon
Griffiths Chad	Griffiths Energy (Chad) Ltd., a company incorporated pursuant to the laws of Bermuda and a wholly-owned subsidiary of the Company
Griffiths DOH	Griffiths Energy (DOH) Ltd., a company incorporated pursuant to the laws of Bermuda and a wholly-owned subsidiary of the Company
Group	the Company and its consolidated subsidiaries and subsidiary undertakings from time to time
Group Entity	a Group Seller or one of its affiliates
Group Representative	a person or entity representing the Group
Group Sellers	PetroChad, Griffiths Chad and Griffiths DOH
HDI	the United Nations Human Development Index
Hot Tap	the flow valve connected to the side of the Export Pipeline that allows oil to flow into it
HSE Policy	the Company's health, safety and environment policy
HSE Committee	the HSE committee of the Board
Hugessen	Hugessen Consulting Inc.
IASB	International Accounting Standards Board
IFRS	the International Financial Reporting Standards
IFC	International Finance Corporation
Initial Exploitation Term	the initial 25-year term for which each EXA is granted
Initial Exploration Term	the initial five-year term for which each EEA is granted
Inland Transportation Agreement	the agreement which the Group (via PCT) intends to enter into with the Government of Chad, which is expected to set out the

	terms and conditions in respect of the operation of the ITA Facilities by PCT
Insider Trading Policy	the insider trading policy that the Company will adopt upon Admission
Interconnection Agreement	the agreement dated 25 October 2012 entered into between PetroChad (as operator of the DOB/DOI PSC) and TOTCO to connect the Group's transportation infrastructure to transport the Group's oil from the Badila and Mangara Fields to the Export Pipeline
ITA Facilities	the Blending Export Terminal, Connection Pipe, LACT Unit and Hot Tap
ITA Project	the joint development by PCT and Glencore DOB/DOI of the necessary pipeline transportation system and related facilities to transport crude oil produced under the Badila EEA and/or the Mangara EEA from the boundary of the relevant Contractual Zone to the connecting flange with the Export Pipeline
JSE	the Johannesburg Stock Exchange
Kibea EXA Application	the EXA application and related declaration of commerciality and feasibility study submitted to the Government of Chad on 22 April 2013 to establish commerciality for the Kibea Field
Kibea Field	the Kibea field located in the Doseo/Borogop Contractual Zone
Kribi Terminal	the marine shipping terminal located approximately 11 kilometres off the coast of Cameroon, near Kribi
LACT Unit	the lease automatic custody transfer unit which will act as the final oil measurement point prior to the production from the Badila and Mangara Fields entering the Export Pipeline
LIBOR	London Interbank Offered Rate
Liquidity Warrant Liquidity Event	(a) a public offering pursuant to which the Shares are listed and posted for trading on a recognised Canadian, United States or UK stock exchange; (b) the completion of any transaction as a result of which all or substantially all of the outstanding Shares are exchanged for the securities of another issuer which will be listed on a recognised Canadian, United States or UK stock exchange; or (c) the acquisition of all or substantially all of the outstanding Shares for cash
Listing Rules	the listing rules of the UK Listing Authority made under section 74(4) of the Financial Services Act and Markets Act 2000, as amended
London Stock Exchange	London Stock Exchange plc
Maku Field	the Maku field located in the Doseo/Borogop Contractual Zone
Management Committee	the management committee comprised of one representative of the Government of Chad and one representative of the applicable Contractor (all Contractor entities to be represented by one person), which oversees petroleum operations governed by the applicable PSC

Mangara CPF	the Mangara central processing facility that the Company plans to construct near the Mangara Field
Mangara D&E Plan	the development and exploitation plan which the Company submitted to the Government of Chad in application for an EXA for the Mangara Field on 29 August 2011
Mangara EXA	the EXA granted in respect of the Mangara Field by the Ministry of Petroleum on 1 June 2012
Mangara Field	the Mangara field located in the DOB/DOI Contractual Zone
Mangara Joint Venture Committee	the joint venture committee established under the Mangara JVA
Mangara JVA	the joint venture agreement between PetroChad and SHT entered into on 13 June 2012 in respect of the Mangara EXA
Mangara to Badila Pipeline	the approximately 95-kilometre pipeline that the Company is constructing from the Mangara Field to the Blending Export Terminal, which will be installed in a single trench and is comprised of (i) one 12-inch emulsion pipeline and (ii) one six-inch pipeline to transport fuel gas
Maturity Date	the maturity date of the Convertible Bonds, 30 September 2017
Member States	member states of the EU
Minister for Petroleum	the Minister for Petroleum of the Government of Chad
Ministry of Finance	the Ministry of Finance of the Government of Chad
Ministry of Petroleum	the Ministry of Petroleum and Energy of the Government of Chad
Named Executive Officers or NEOs	the President and Chief Executive Officer, the Chief Financial Officer and each of the three most highly compensated executive officers other than the President and Chief Executive Officer and the Chief Financial Officer
Net Participating Interest	the Group's participating interest multiplied by the gross lease reserves, resources or production, as applicable
NI 52-110	Canada's National Instrument 52-110—Audit Committees
NI 58-101	Canada's National Instrument 58-101—Disclosure of Corporate Governance Practices
Non-Executive Directors	the non-executive Directors of the Company
North Sako Field	the North Sako field located in the Doseo/Borogop Contractual Zone
NP 58-201	Canada's National Policy 58-201—Corporate Governance Guidelines
Official List	the Official List of the UK Listing Authority
Offtake Agreement	the offtake agreement relating to the sale of crude oil dated 12 December 2012 entered into between the Offtake Sellers and the Offtake Buyer
Offtake Buyer	Glencore Energy UK Ltd.
Offtake Sellers	the Glencore Sellers and the Group Sellers
Offtake Sellers' Agent	PetroChad
Offtake Sellers' Entitlement	all of each Offtake Seller's entitlement of crude oil produced under the PSCs, excluding any volumes of crude oil that are required to be delivered to the Government of Chad

OHADA	Organisation for the Harmonisation of Business Law in Africa
OMX	the OMX Exchange, a sub-market of NASDAQ
Option	an option to purchase a Share granted under the Option Plan
Option Plan	the option plan of the Company
Order	a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days
Original Farm-in Advance	an advance amount of U.S.$100 million made available by the Offtake Buyer to PetroChad, for and on behalf of the Farmors, pursuant to the Farm-in Advance Agreement
Original Farm-in Advance Agreement	the agreement dated 1 March 2013 entered into between the Farmors, the Company and the Offtake Buyer, pursuant to which the Offtake Buyer makes available to PetroChad, for and on behalf of the Farmors, the Farm-in Advance as advance consideration for the Offtake Buyers' obligations under the Farm-in Agreement
OSE	the Oslo Stock Exchange
PCT	PetroChad Transportation Ltd., a company incorporated pursuant to the laws of Bermuda and a subsidiary of the Company
Performance Warrant	a performance warrant of the Company
Permit H Zone	a defined geographical area within which the Group's Contractual Zones are located, as specified in the TOTCO Convention of Establishment, signed in 1998 between the Government of Chad and TOTCO
PetroChad	PetroChad (Mangara) Limited, a company incorporated pursuant to the laws of Bermuda and a wholly-owned subsidiary of the Company
PETRONAS	Petroliam Nasional Berhad
PIC	a paying interest committee
PIC Agreement	an agreement establishing a PIC pursuant to the Farm-in Agreement
PIC Parties	PetroChad and Glencore DOB/DOI
PPSC	the Public Prosecution Services of Canada
Principal Register Holder	a holder of the Shares on the Share Register
Priority Fields	the Third Party Fields and the current and future producing assets of the operators of the Export Pipeline
Production Royalty	a royalty to the Government of Chad on net hydrocarbon production at a rate of 14.25 per cent. for crude oil and 5 per cent. for natural gas
Profit Oil	the net production of hydrocarbons after deduction of the Production Royalty and the Cost Oil
Prospectus Directive	EU Prospectus Directive (2003/71/EC) (and amendments thereto, including the 2010 PD Amending Directive, to the extent implemented in the Relevant Member State and includes any relevant implementing measure in the Relevant Member

	State and the expression "2010 PD Amending Directive" means Directive 2010/73/EU)
Prospectus Rules	the rules made for the purposes of Part VI of the FSMA in relation to offers of securities to the public and admission of securities to trading on a regulated market
PSC or **PSCs**	individually or collectively, the DOB/DOI PSC, the Doseo/ Borogop PSC and the DOH PSC
PSC Transfer Fee	the fee payable by the Group to the Government of Chad in order to perfect the transfer of the Glencore Transferred Interests from the Group to Glencore
PSUs	performance share units granted under the 2013 Incentive Plan
Purchase Warrant	a Warrant issued as part of a 2010 Unit, all of which were cancelled in January 2011
QPO	a qualifying public offer under the terms of the Convertible Bonds
RBC Capital Markets	RBC Europe Limited
RCMP	the Royal Canadian Mounted Police
Registrar	Computershare Investor Services Inc.[38]
Relevant Member State	a Member State of the European Economic Area which has implemented the Prospectus Directive
Relevant Shares	the 4 million Shares issued on 15 September 2009 to the spouse of the Ambassador and to two other individuals nominated by the spouse of the Ambassador
Renewal Exploitation Term	an extension of an EXA for an additional term of up to ten-years, subject to satisfaction of certain requirements described in paragraph 7—"PSCs" in Part VI: "Information on the Group"
Renewal Exploration Term	an extension of an EEA for an additional term of up to three years, subject to satisfaction of certain requirements described in paragraph 7—"PSCs" in Part VI: "Information on the Group"
Reserves Committee	the Reserves Committee of the Board
RSUs	restricted share units granted under the 2013 Incentive Plan
SDRT	Stamp Duty and Reserve Tax
Seed Options	those Options to purchase Shares that were reserved by the Board for issuance in January 2011 for the purposes of recruiting a new management team
Senior Managers	the senior managers of the Company, as listed in Part VIII: "Directors, Senior Managers and Corporate Governance"
Share Purchase Loans	loans granted by the Company to certain members of the management team of the Company in July and August 2011
Share Register	principal share register of the Company maintained in Canada
Shares	common shares in the capital of the Company
Shell	Royal Dutch Shell plc

[38] The Company expects to appoint Computershare Investor Services Inc. as its registrar prior to the date of Admission. However, as at the date of this Prospectus, the registrar of the Company is Olympia Trust Company.

SHT	*Société des Hydrocarbures du Tchad*, the national oil company of Chad
Skope	Skope Energy Inc.
Spec Oil	oil meeting Export Pipeline specifications
Special Committee	the special committee of the Board formed to investigate the matters described in paragraph 14—"Special Committee Investigation" in Part VI: "Information on the Group"
Special Committee Investigation	the investigation undertaken by the Special Committee, as described in paragraph 14—"Special Committee Investigation" in Part VI: "Information on the Group"
Sponsor	RBC Capital Markets
Sponsor's Agreement	the sponsor's agreement entered into between the Company, the Sponsor and a Senior Manager in relation to Admission
Sudan	the Republic of Sudan
Tanganyika	Tanganyika Oil Company Ltd.
Tega Field	the Tega field located in the Doseo/Borogop Contractual Zone
Termination Payment	see the paragraph entitled "Termination and Change of Control Benefits" under the heading "Executive Compensation" in paragraph 7.2 of Part XVI: "Additional Information"
Third Party Fields	the fields of a certain third party operator in relation to which access requests have been approved by the operators of the Export Pipeline
Tie-in Facilities	all modifications to the Export Pipeline in Chad (including but not limited to any material, metering equipment, hardware and pipelines) that are funded by PetroChad pursuant to the Interconnection Agreement
Tie-in Point	the physical point(s) on the Export Pipeline in Chad specified in the Interconnection Agreement, and as thereafter may be designated by the TOTCO, at which the Group tenders its oil to TOTCO
Tie-in Work	the work described in the Interconnection Agreement
Total	Total S.A.
TOTCO	Tchad Oil Transportation Company S.A., a joint venture between the Government of Chad and EEPCI
TOTCO Convention of Establishment	the convention of establishment setting out order of priority for use of the Export Pipeline in Chad, signed in 1998 between the Government of Chad and TOTCO
TOTCO Transportation Agreement	the agreement, expected to be entered into prior to the commencement of production from the Badila Field, between PetroChad (as operator of the DOB/DOI PSC) and TOTCO (as the owner and operator of the portion of the Export Pipeline located in Chad) for the transportation of crude oil produced from the Badila and Mangara Fields
Transfer Fee Orders	orders issued by the Minister for Petroleum on 17 May 2013
Transferred Interests	the interests assigned and transferred by the Farmors to the Farmees pursuant to the Farm-in Agreement
Transportation Agreements	the COTCO Transportation Agreement and the TOTCO Transportation Agreement

Transportation Licence	a licence issued to a Contractor by the Government of Chad authorising the construction and operation of pipelines and facilities within the territory of Chad, both inside and outside of its Contractual Zones
TSX	the Toronto Stock Exchange
TSXV	the TSX Venture Exchange
UK	the United Kingdom of Great Britain and Northern Ireland
UK Corporate Governance Code	the UK Corporate Governance Code published by the Financial Reporting Council and dated September 2012, as amended from time to time
UK Listing Authority	the UK Listing Authority, being the FCA acting in its capacity as the competent authority for the purposes of FSMA
United States or **U.S.**	the United States of America, its territories and possessions, any State of the United States of America, and the District of Columbia
U.S. DoJ	the U.S. Department of Justice
U.S. dollars	United States dollars
VAT	value added tax
Waived DOH Conditions	the conditions precedent to the Farm-in Completion that were waived by Glencore pursuant to the Farm-in Completion Letter
Warrant	a warrant to purchase a Share if certain events occur during the term of the Warrant
Whistleblower Policy	the Company's whistleblower policy

PART XVIII

GLOSSARY OF TECHNICAL TERMS

2-D seismic	seismic data acquired in a single traverse or series of traverses. 2-D seismic data provides single cross sections through the subsurface
3-D seismic	seismic data acquired as multiple, closely spaced traverses. 3-D seismic data typically provides a more detailed and accurate image of the subsurface than 2-D seismic data
1C	low estimate contingent resources
1P	proved reserves
2C	best estimate contingent resources
2P	proved plus probable reserves
3C	high estimate contingent resources
3P	proved plus probable plus possible reserves
API	an indication of the specific density of crude oil measured on the American Petroleum Institute scale
appraisal	the phase of petroleum operations immediately following a successful discovery. Appraisal is carried out to determine size, production rate and the most efficient development of a field
barrel or bbl	a unit of volume measurement used for petroleum and its products one barrel of oil; one barrel = 35 Imperial gallons (approx.), or 159 litres (approx.); 7.5 barrels = 1,000 kilograms (approximately depending upon the oil density); 6.29 barrels = one cubic metre
bbl/d	barrels of oil per day
best estimate	is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 per cent. probability that the quantities actually recovered will equal or exceed the best estimate
block	term commonly used to describe areas over which there is a petroleum or production licence or production sharing contract
boe	barrel(s) of oil equivalent
carry	agreement between two parties according to which one of the two agrees to pay for ("carry") all or part of the costs attributable to the other, typically conditional on later reimbursement by the latter to the former
cash flow	cash flow from operations determined in accordance with IFRS
closure	the height from the apex of a reservoir structure to the lowest contour that contains the reservoir structure (spill). Measurements of both the areal closure and the distance from the apex to the lowest closing contour are typically used for the calculations of the estimated hydrocarbon content of a trap
contingent resources	those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies

cost recovery	mechanism determined in a production sharing contract by which the Company (or companies) party to the production sharing contract is enabled to recover present and past costs
Cretaceous	the final period of the Mesozoic era ranging from approximately 65 to 144 million years ago
Dated Brent Crude	the average daily spot values of Brent Crude (the crude oil produced from the Brent system in the North Sea, a price setting benchmark in the world market), averaged on a monthly basis for a given period
declaration of commerciality	document which assesses the production of oil and gas from a field that is commercially and economically viable
decommission or decommissioning	the process or the procedure by which the facilities and the infrastructure related to the production of hydrocarbon from an oil field are demobilised and abandoned
decommissioning charge	cost or charge associated with decommission procedures
discovery	an exploration well which has encountered oil and gas for the first time in a structure
dry well	a well which does not encounter hydrocarbons in economically producible quantities
exploration	the phase of operations which covers the search for oil or gas by carrying out detailed geological and geophysical surveys followed up where appropriate by exploratory drilling
exploration drilling	drilling carried out to determine whether oil and gas are present in a particular area or structure
exploration well	a well in an unproven area or prospect, may also be known as a "wildcat well"
farm-in	a term used to describe when an oil and gas company buys a portion of the acreage in a block from another company, usually in return for consideration and for taking on a portion of the selling company's work commitments
fault	a displacement (vertical, inclined or lateral) below the earth surface that acts to offset rock layers relative to one another. Faulting can create traps for hydrocarbons
field	a defined geographical area consisting of one or more pools
formation	a body of rock identified by lithic characteristics and stratigraphic position which is mappable at the earth's surface or traceable in the subsurface
geophysical	association with the earth science concerned with the physical properties. Geophysical exploration is concerned with measuring the earth's physical properties to delineate structure, rock type and fluid content; these measurements include electrical, seismic, gravity and magnetics
high estimate	is considered to be an optimistic estimate of the quantity of resources that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 per cent. probability that the quantities actually recovered will equal or exceed the high estimate
hydrocarbon	solid, liquid or gas made up of compounds of carbon and hydrogen in varying proportions

infrastructure	oil and gas processing, transportation and off-take facilities
lead	an identified trap that may contain hydrocarbons. A potential hydrocarbon accumulation may be described as a lead or prospect depending on the degree of certainty in that accumulation. A lead generally requires more data to mature it to the prospect level
licence	an exclusive right to explore for petroleum, usually granted by a national governing body
light oil	crude oil with a density greater than 31.1° API
low estimate	is considered to be a conservative estimate of the quantity of resources that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 per cent. probability that the quantities actually recovered will equal or exceed the low estimate
Mbbl	thousand barrels
Mbbl/d	thousand barrels of oil per day
Mcf	thousand cubic feet
migration	the process by which oil and gas moves from source to reservoir
MM	millions
MMbbl	million barrels
MMstb	million stock tank barrels
natural gas	a mixture of lighter hydrocarbons that exist either in gaseous phase or in a solution in crude oil in reservoirs but are gaseous at atmospheric conditions. Natural gas may contain sulphur or other non-hydrocarbon compounds
offshore	that geographic area that lies seaward of the coastline
operator	the company that has legal authority to drill wells and undertake production of oil and gas. The operator is often part of a consortium and acts on behalf of this consortium
P10	an optimistic estimate of the quantity of resources that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 per cent. probability (P10) that the quantities actually recovered will equal or exceed the high estimate
P50	the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 per cent. probability (P50) that the quantities actually recovered will equal or exceed the best estimate
P90	a conservative estimate of the quantity of resources that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 per cent. probability (P90) that the quantities actually recovered will equal or exceed the low estimate

participating interest	the proportion of exploration and production costs each party will bear and the proportion of production each party will receive, as set out in an operating agreement
petroleum	a naturally occurring mixture consisting predominantly of hydrocarbons in the gaseous, liquid or solid phase
play	a conceptual model for a style of hydrocarbon accumulation
possible reserves	are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves
PRMS	2007 Petroleum Resources Management System (as defined by the Society of Petroleum Engineers, American Association of Petroleum Geologists, World Petroleum Council and Society of Petroleum Evaluation Engineers)
probable reserves	those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves
prospect	a geographic or stratigraphic area, in which the Company owns or intends to own one or more oil and gas interests, which is geographically defined on the basis of geological data and which is reasonably anticipated to contain at least one reservoir or part of a reservoir of oil and gas
prospective resources	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
proved reserves	those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves
production sharing contract	production sharing agreement or contract under which the contractor agrees to fund and carry out pre-agreed work programmes on behalf of the concession owner in return for a share of production revenues
psia	pounds per square inch absolute
reserves	estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on (i) analysis of drilling, geological and engineering data, (ii) the use of established technology, and (iii) specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed
reservoir	a porous and permeable subsurface rock formation that contains a separate accumulation of petroleum that is confined by impermeable rock or water barriers and is characterised by a single pressure system where oil and gas has accumulated
resources	a general term that may refer to all or a portion of total resources
rift	region in which the Earth's crust is pulling apart and creating normal faults and down-dropped areas or subsidence

rig	the machine used to drill a wellbore
royalty	a percentage share of production, or the value derived from production, paid from a producing well
seal	a relatively impermeable rock, commonly shale, anhydrite or salt, that forms a barrier or cap above and around reservoir rock such that fluids cannot migrate beyond the reservoir. A seal is a critical component of a complete petroleum system
source	characteristic of organic-rich rocks to contain the precursors to oil and gas, such that the type and quality of expelled hydrocarbon can be assessed
source rock	a rock rich in organic matter which, if given the right conditions, will generate oil or gas. Typical source rocks, usually shales or limestones, contain at least 0.5 per cent. total organic carbon (TOC), although a rich source rock might have as much as 10 per cent. organic matter. Access to a working source rock is necessary for a complete petroleum system
total resources	total petroleum initially-in-place, being 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
trap	a configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not migrate. Traps are described as structural traps (in deformed strata such as folds and faults) or stratigraphic traps (in areas where rock types change, such as unconformities, pinch outs and reefs). A trap is an essential component of a petroleum system
undeveloped reserves	those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production; they must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned
UPIIP	undiscovered petroleum initially-in-place, being that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of undiscovered petroleum initially in place is referred to as prospective resources, the remainder is unrecoverable
upstream	operations stages in the oil and gas industry that involve exploration and production
VFD	variable frequency drive

PART XIX
GLJ REPORTS

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GRIFFITHS ENERGY INTERNATIONAL INC.

RESERVES AND RESOURCE ASSESSMENT AND EVALUATION OF CHADIAN OIL PROPERTIES

COMPETENT PERSON'S REPORT

SUMMARY

Effective December 31, 2012

1132107

CORPORATE SUMMARY

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GLJ Petroleum Consultants

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President & CEO
Jodi L. Anhorn, M.Sc., P. Eng.
Executive Vice President & COO

Officers / Vice Presidents:
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James H. Willmon, P. Eng.

January 29, 2013

Project 1132107

Board of Directors
Griffiths Energy International Inc.
2100, 555 – 4th Avenue SW
Calgary, Alberta T2P 3E7

RBC Europe Limited
Riverbank House
2 Swan Lane
London, United Kingdom
EC4R 3BF

Re: Griffiths Energy International Inc.
Competent Persons Report
Republic of Chad, with Glencore Farm-in
Effective: December 31, 2012

GLJ Petroleum Consultants Ltd. (GLJ) has completed an independent reserves and contingent resources assessment and evaluation of the oil properties of Griffiths Energy International Inc. (the "Company") located in the Republic of Chad. The effective date of this evaluation is December 31, 2012. The Company holds its interests in Chad through Production Sharing Contracts.

This report includes the terms of a farm-in agreement (Glencore Farm-in) yet to close. The Glencore Farm-in provides for the Company to sell a one-third interest in its interests and liabilities in Chad in exchange for Glencore Energy International (Glencore) carrying sunk and future costs of the Company, to a maximum of $330,747,000. The evaluated interest is net of the transfer of a one-third interest to Glencore and accounts for the capital costs carried by Glencore.

This report has been prepared for the Company for the purpose of business and other financial requirements including filing a prospectus in connection with the admission of the Company's common shares to the premium listing segment of the Official List of the Financial Conduct Authority. This evaluation has been prepared in accordance with resource and reserves definitions, standards and guidelines contained in the Petroleum Resources Management System (PRMS) of the Society of Petroleum Engineers (SPE). This report is in accordance with the requirements of the European Securities and Markets Authority as presented in paragraphs 131 to 133 (i) published in March 2011 and the Prospectus Rules of the Financial Conduct Authority of the United Kingdom.

All costs reported within are in U.S. dollars.

GLJ Petroleum Consultants

It is noted that the development project for the Kibea and Maku Fields has a net present value less than 0 at a 10 percent discount rate in the 1C (low estimate case). However, the project is economic at a 10 percent discount factor in the proved plus probable (2P) and proved plus probable plus possible (3P) cases. Given the fact that the Company has informed GLJ of its commitment to develop this project, the recoverable hydrocarbons for these fields were classified as contingent resources for the low estimate (1C) resource level, and as reserves in the 2P and 3P. As a result, no best estimate (2C) or high estimate (3C) contingent resources were assigned.

It is trusted that this evaluation meets your current requirements. Should you have any questions regarding this analysis, please contact the undersigned.

Yours very truly,

GLJ PETROLEUM CONSULTANTS LTD.



Leonard L. Herchen, P. Eng.
Vice President

LLH/jem
Attachments

INDEPENDENT PETROLEUM CONSULTANTS' CONSENT

The undersigned firm of Independent Petroleum Consultants of Calgary, Alberta, Canada has prepared an independent evaluation of the **Griffiths Energy International Inc.'s** (the "Company") Chadian oil resources and hereby gives consent to the use of its name and to the said estimates. The effective date of the evaluation is **December 31, 2012.**

In the course of the evaluation, the Company provided GLJ Petroleum Consultants Ltd. personnel with basic information which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, planned hydrocarbon marketing arrangements, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required to conduct the evaluation and upon which this report is based, were obtained from public records, other operators and from GLJ Petroleum Consultants Ltd. nonconfidential files. The Company has provided a representation letter confirming that all information provided to GLJ Petroleum Consultants Ltd. is correct and complete to the best of its knowledge. In conducting the evaluation, nothing came to GLJ Petroleum Consultants Ltd.'s attention that would suggest that information provided by the Company was not complete and accurate. GLJ Petroleum Consultants Ltd. reserves the right to review all calculations referred to or included in this report and to revise the estimates in light of erroneous data supplied or information existing but not made available which becomes known subsequent to the preparation of this report.

The accuracy of any reserves, resources and production estimate is a function of the quality and quantity of available data and of engineering interpretation and judgment. While reserves, resources and production estimates presented herein are considered reasonable, the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward.

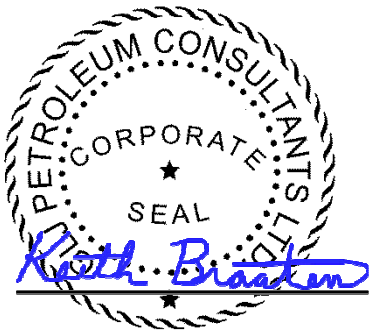
Revenue projections presented in this report are based in part on forecasts of market prices, currency exchange rates, inflation, market demand and government policy which are subject to many uncertainties and may, in future, differ materially from the forecasts utilized herein. Present values of revenues documented in this report do not necessarily represent the fair market value of the reserves and resources evaluated herein.

PERMIT TO PRACTICE
GLJ PETROLEUM CONSULTANTS LTD.

Signature: 

Date: January 29, 2013

PERMIT NUMBER: P 2066
The Association of Professional Engineers
and Geoscientists of Alberta



INTRODUCTION

GLJ Petroleum Consultants (GLJ) was commissioned by Griffiths Energy International Inc. (the "Company") to prepare an independent evaluation of its oil reserves and contingent resources effective December 31, 2012. The locations of the most significant reserves and resources properties are indicated on the attached index map (Map 1). Table SUM-1 summaries the assigned reserves and resources by property.

The evaluation was initiated in December 2012 and completed by January 2013. Estimates of reserves, resources and projections of production were generally prepared using well information, engineering, geophysical and geological information provided by the Company and available as of December 31, 2012. In addition, the Company provided land and fiscal parameters, and capital and operating budgets associated with the evaluated properties. The Company has confirmed that, to the best of its knowledge, all information provided to GLJ is correct and complete as of the effective date.

This evaluation has been prepared in accordance with resource and reserves definitions, procedures, and standards contained in the Society of Petroleum Engineering's Petroleum Resources Management System (PRMS). The resource and reserves definitions used in preparing this report are included herein under "Resource and Reserves Definitions".

Production Sharing Contracts (PSC's)

The Company's reserves and contingent resources are associated with the Company's participation in production sharing contract (PSC) it has entered into with the Republic of Chad. The Republic of Chad holds right to back into a 25 percent participation in the PSC with capital and operating costs carried by the Company. The terms of PSC provide for the Company to earn cost oil and profit oil revenue. Cost oil is earned to recover capital expenditures, operating costs, general and administrative (G&A) and abandonment costs including any carried costs associated with the 25 percent participation held by the Chadian government. Profit oil is a fraction of revenue remaining after royalties and cost oil. Chad's backed in participation is expected to occur through the Société des Hydrocarbures du Tchad (SHT), the state oil company of Chad.

Glencore Farm-in

The evaluation assumes that a farm-in agreement (Glencore Farm-in) between Griffiths and Glencore International AG (Glencore) is in effect as of the effective date. This farm-in agreement allocates one-third of the Company's participation in net entitlement oil and associated liabilities to

Glencore. The Company receives payment from Glencore to recover sunk or carried costs (to a certain maximum). As the recovery of capital associated with the Glencore Farm-in is payable after the effective date, it has been included in the Company's cash flows. The terms of the Glencore Farm-in provide for a payment by Glencore to the Company as follows:

Sunk Costs prior to June 30, 2012	30,746 M$
Costs July 1, 2012 – June 30, 2013	100,000 M$
Costs July 1, 2013 – June 30, 2014	100,000 M$
Costs July 1, 2014 – June 30, 2016	100,000 M$
Total Maximum Carry	330,746 M$

The Glencore carry capital is scheduled as "Other Income" for costs sunk up to the effective date and future capital expenditures presented are net of the Glencore carry.

The carried capital amounts are as follows:

		Glencore Carry Amount (M$)			
Year	**Description**	**1P**	**2P**	**3P**	**Scheduled As**
2012	Sunk Prior to June 30, 2012	30,747	30,747	30,747	Other Income
2012	Sunk costs July 1 to Dec 31, 2012	100,000	100,000	100,000	Other Income
2013	2013 Capital (Badila/Mangara)	68,592	78,592	81,091	Capital reduction
2014	2014Capital (Badila/Mangara)	65,461	78,254	77,533	Capital reduction
2015	2015 Capital (Badila/Mangara)	65,946	43,155	41,375	Capital reduction
2016	2016 Capital (Badila/Mangara)	0	0	0	Capital reduction
	Total	330,747	330,747	330,747	

*Note, all values are in dollars of the day

1P = Total Proved, 2P = Total Proved plus Probable, 3P = Total Proved plus Probable plus Possible.

Evaluated Properties and Inland Transportation Agreement (ITA)

Four fields (Mangara, Badila, Kibea and Maku) were assigned reserves and/or contingent resources. It is anticipated that the Mangara and Badila Fields, located in the DOB and DOI Blocks, respectively, will be served by a single pipeline that moves crude to the export pipeline. In fact, construction of this pipeline has already commenced as of the effective date. It is expected that the Kibea and Maku Fields, located in the Chari East-Doseo Block, will ship oil via a separate pipeline, yet to be built.

Based on the terms of the PSC's, that fraction of the pipelines located between the last field along the route and the tie-in point to the export pipeline must be operated as a separate corporate entity

called an “Inland Transportation Agreement” (ITA). Consequently, two economic entities defined as ITAs were added to the evaluation to model the cash flow associated with each. Capital and operating costs tariff income and income tax associated with each ITA are forecast.

The evaluation was conducted on the basis of the GLJ January 1, 2013 Price Forecast which is summarized in the Product Price and Market Forecasts section of this report.

Tables summarizing production, royalties, costs, revenue projections, reserves, resources and present value estimates for various reserves and resources categories for individual properties and the Company total are provided in the tabbed sections of this Summary Report.

The Evaluation Procedure section outlines general procedures used in preparing this evaluation. The individual property reports, provided under separate cover, provide additional evaluation details. The following summarizes evaluation matters that have been included/excluded in cash flow projections:

- tariff income has been included as “Other Income” and is associated with the ITA,
- the effect on projected revenues of any of the Company’s financial hedging activity has not been included,
- provisions for the abandonment of all of the Company’s wells to which reserves and resources have been attributed have been included; all other abandonment and reclamation costs have not been included,
- general and administrative (G&A) costs and overhead recovery have been included if considered an expense eligible for cost recovery,
- undeveloped land values have not been included,
- bonuses payable from Kibea and Maku are included as “Other Income”,
- recovery of sunk capital costs, associated with the Glencore Farm-in is forecast as “Other Income”.

Economic forecasts are provided on an after tax basis including tax pools provided by the Company in the “After Tax Analysis” section. Only the ITAs are subject to income tax.

Table 1 summarizes total reserves and resources assigned and associated net present value. Gross lease reserves are all reserves associated with the lease. The participating interest refers to the gross lease reserves multiplied by the Company’s participation in the PSC’s (50 percent) i.e. 50 percent of the gross lease reserves or resources. Participating interest is not a recognized term under PRMS and does not reflect the Company interest or entitlement oil. It is presented here for information purposes only. The Company’s reserves and resources are derived from its total

entitlement to cost oil and profit oil associated with its participation is presented as "Total Company Int.", "Working Interest" and "Net After Royalty" interests.

Evaluated Interest

The interest evaluated within this report is the Company's interests net of the Glencore Farm-in agreement. Cash flows presented herein represent the Company's remaining interest, and include the terms of the Glencore Farm-in agreement. Consequently, the interests presented herein assume an assignment of one-third of the Company's original participation to Glencore. That is, the evaluated interest assumes effective participation as follows:

Griffiths Energy International Inc.	50%
Glencore International AG	25%
SHT (back in right)	25%

As defined within the PSC, the SHT's costs are carried proportionately by the Company and Glencore.

Classification of Reserves and Resources for Kibea and Maku

It is noted that the development project for the Kibea and Maku Fields has a net present value less than 0 at a 10 percent discount rate in the 1C (low estimate case). However, the project is economic at a 10 percent discount factor in the proved plus probable (2P) and proved plus probable plus possible (3P) cases. Given the fact that the Company has informed GLJ of its commitment to develop this project, the recoverable hydrocarbons for these Fields were classified as contingent resources for the low estimate (1C) resource level, and as reserves in the 2P and 3P. As a result, no best estimate (2C) or high estimate (3C) contingent resources were assigned.

Table SUM-1
Summary of Reserves and Resources
Effective Date: Dec 31, 2012

Property	Gross Lease (100%) Oil Reserves (MSTB) Proved (1P)	Proved + Probable (2P)	Proved + Probable plus Possible (3P)	Griffiths Net Oil Entitlement (MSTB) Proved (1P)	Proved + Probable (2P)	Proved + Probable plus Possible (3P)	Operator
Badila	17572	30588	50960	5865	8568	12997	Griffiths Energy International Inc.
Kibea*	0	18756	49352	0	6332	14712	Griffiths Energy International Inc.
Maku*	0	7262	16053	0	3415	6966	Griffiths Energy International Inc.
Mangara	11257	32667	84221	5386	13448	29227	Griffiths Energy International Inc.
Total	28829	89272	200586	11251	31765	63902	

Property	Gross Lease (100%) Contingent Resources (Oil) (MSTB) Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	Griffiths Net Entitlement Contingent Resources (Oil) (MSTB) Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	Risk Factor	Operator
Kibea*	5649	0	0	2510	0	0	See Note	Griffiths Energy International Inc.
Maku*	3011	0	0	1439	0	0	See Note	Griffiths Energy International Inc.
Total	8660	0	0	3949	0	0		

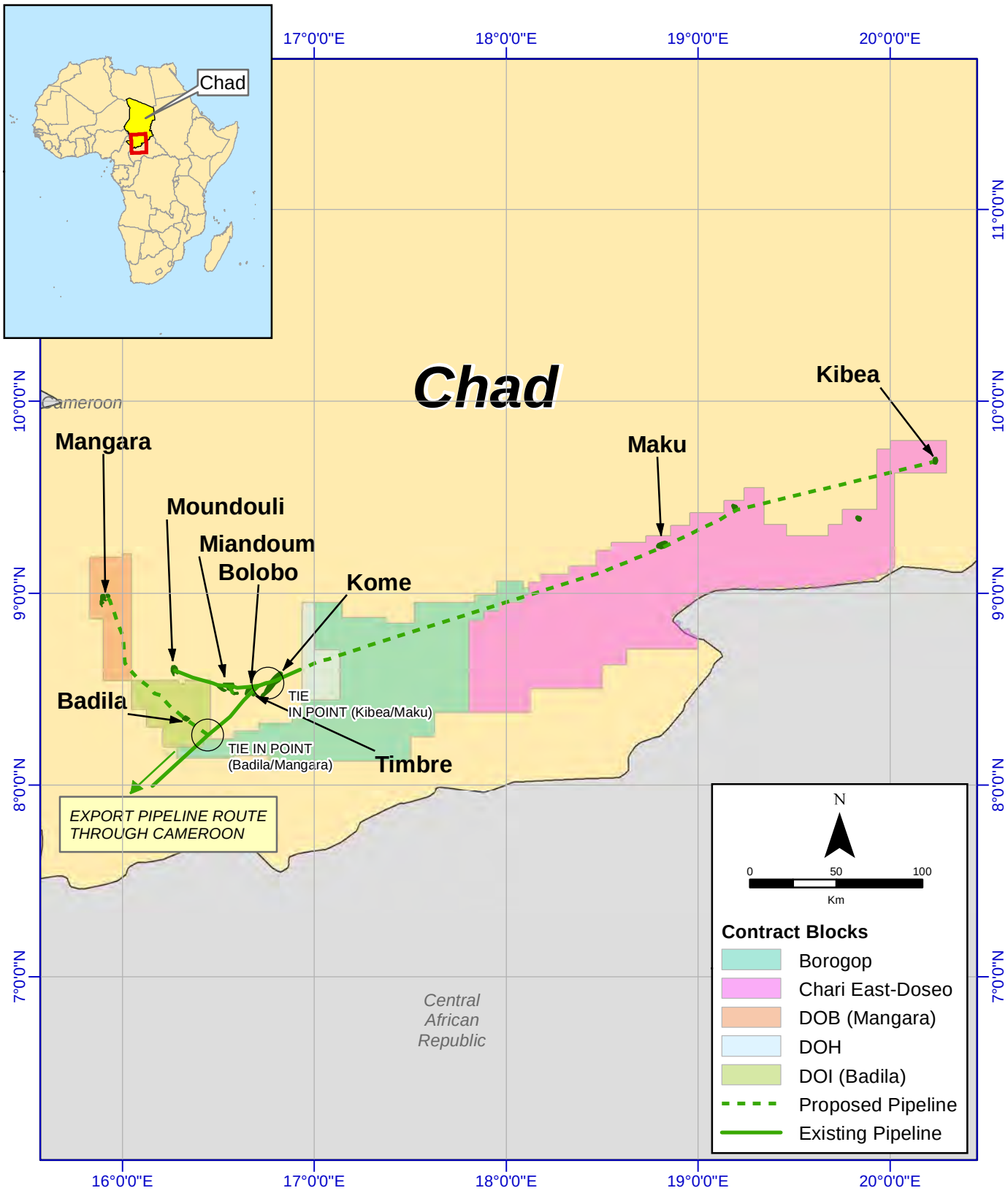
**Notes: Kibea and Maku are define as Sub-Marginal Contingent Resources in the Low Case as the project has a net present value <0 at 10% discount rate. In the Best and High estimate cases, the no contingent resources are assigned because the projects are economic for the associated reserve levels.*

Net Entitlement oil is equivalent to net after royalty.

Map 1
Location Map

Company: Griffiths Energy International Inc.
Property: Corporate

Effective Date: December 31, 2012
Scale: 1: 3,200,000 s1132107/indm01-2



SUMMARY

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Table 1

Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **Summary**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **31-Dec-12**

Summary of Reserves, resources and Values

	Proved Producing	Proved Developed Non-producing	Proved Undeveloped	Total Proved	Total Probable	Total Proved Plus Probable	Total Possible	Total PPP	Low Estimate Contingent Resources
MARKETABLE RESERVES									
Light/Medium Oil (Mbbl)									
Total Gross Lease	0	0	28,829	28,829	60,443	89,272	111,313	200,586	8,660
Participating Interest*	0	0	14,415	14,415	30,222	44,636	55,657	100,293	4,330
Total Company Int.	0	0	11,251	11,251	20,514	31,765	32,138	63,902	3,949
Working Interest	0	0	11,251	11,251	20,514	31,765	32,138	63,902	3,949
Net After Royalty	0	0	11,251	11,251	20,514	31,765	32,138	63,902	3,949
Oil Equivalent (Mbbl)									
Total Gross Lease	0	0	28,829	28,829	60,443	89,272	111,313	200,586	8,660
Participating Interest*	0	0	14,415	14,415	30,222	44,636	55,657	100,293	4,330
Total Company Int.	0	0	11,251	11,251	20,514	31,765	32,138	63,902	3,949
Working Interest	0	0	11,251	11,251	20,514	31,765	32,138	63,902	3,949
Net After Royalty	0	0	11,251	11,251	20,514	31,765	32,138	63,902	3,949
BEFORE TAX PRESENT VALUE (M$)									
0%	0	0	699,100	699,100	969,029	1,668,130	1,674,798	3,342,927	84,975
5%	0	0	619,077	619,077	697,973	1,317,050	1,138,051	2,455,101	27,761
8%	0	0	578,947	578,947	580,884	1,159,831	925,380	2,085,212	3858
10%	0	0	554,870	554,870	516,311	1,071,182	812,843	1,884,025	-8,962
12%	0	0	532,665	532,665	460,393	993,057	718,065	1,711,122	-19,780
15%	0	0	502,438	502,438	389,713	892,150	601,780	1,493,931	-32,959
20%	0	0	458,955	458,955	298,624	757,579	457,668	1,215,247	-48,798
FIRST 6 YEARS BEFORE TAX CASH FLOW (M$)									
2012 (1 Months)	0	0	127,822	127,822	-42627	85,195	-24,702	60,493	-37756
2013	0	0	193741	193741	-64,986	128,754	-37,534	91,220	-120,827
2014	0	0	157,480	157,480	61,572	219,051	107,292	326,343	-26,904
2015	0	0	86,628	86,628	198,839	285,468	116,968	402,435	54,078
2016	0	0	51,926	51,926	226,524	278,450	214,383	492,833	52,989
2017	0	0	40,608	40,608	132,403	173,011	270,139	443,151	44,268

BOE Factors: HVY OIL 1 RES GAS 6 PROPANE 1 ETHANE 1
COND 1 SLN GAS 6 BUTANE 1 SULPHUR 0

*Participating Interest is defined as the Company's participation percentage (50%) multiplied by the gross lease reserves/resources

Run Date: December 07, 2012 16:29:38

1132107 Class (A,B1,B2,C,F,I,O,R,CR1), Griffiths Energy International Inc., GLJ (2013-01), psum 2013-01-28 11:35

Table 2

Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **Summary**
$US Dollars

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

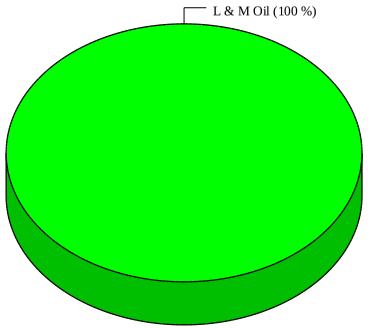
Company Production, Reserves and Present Value Summary

Entity Description	2013 Company Interest Prod'n Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	Company Interest Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Net After Royalty Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Reserve Life Index yrs	Before Income Tax Discounted Present Value (M$) 0%	8%	10%	12%
Proved Producing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Proved Developed Nonproducing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Proved Undeveloped	0	3,633	0	3,633	0	11,251	0	0	11,251	0	11,251	0	0	11,251	8.5	699,100	578,947	554,870	532,665
Total Proved	0	3,633	0	3,633	0	11,251	0	0	11,251	0	11,251	0	0	11,251	8.5	699,100	578,947	554,870	532,665
Probable Producing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Probable Developed Nonproducing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Probable Undeveloped	0	845	0	845	0	20,514	0	0	20,514	0	20,514	0	0	20,514	66.5	969,029	580,884	516,311	460,393
Total Probable	0	845	0	845	0	20,514	0	0	20,514	0	20,514	0	0	20,514	66.5	969,029	580,884	516,311	460,393
Proved Plus Probable Producing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Proved Plus Probable Developed Nonproducing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Proved Plus Probable Undeveloped	0	4,478	0	4,478	0	31,765	0	0	31,765	0	31,765	0	0	31,765	19.4	1,668,130	1,159,831	1,071,182	993,057
Total Proved Plus Probable	0	4,478	0	4,478	0	31,765	0	0	31,765	0	31,765	0	0	31,765	19.4	1,668,130	1,159,831	1,071,182	993,057
Total Possible	0	602	0	602	0	32,138	0	0	32,138	0	32,138	0	0	32,138	146.3	1,674,798	925,380	812,843	718,065
Total PPP	0	5,080	0	5,080	0	63,902	0	0	63,902	0	63,902	0	0	63,902	34.5	3,342,927	2,085,212	1,884,025	1,711,122

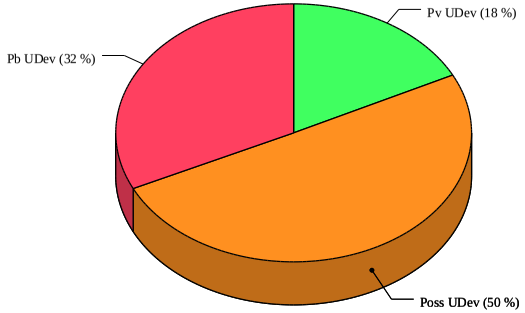
Reserves Characterization

Percentage of Total PPP Company Interest BOE Reserves

Product Types



Reserves Classifications



BOE Factors:

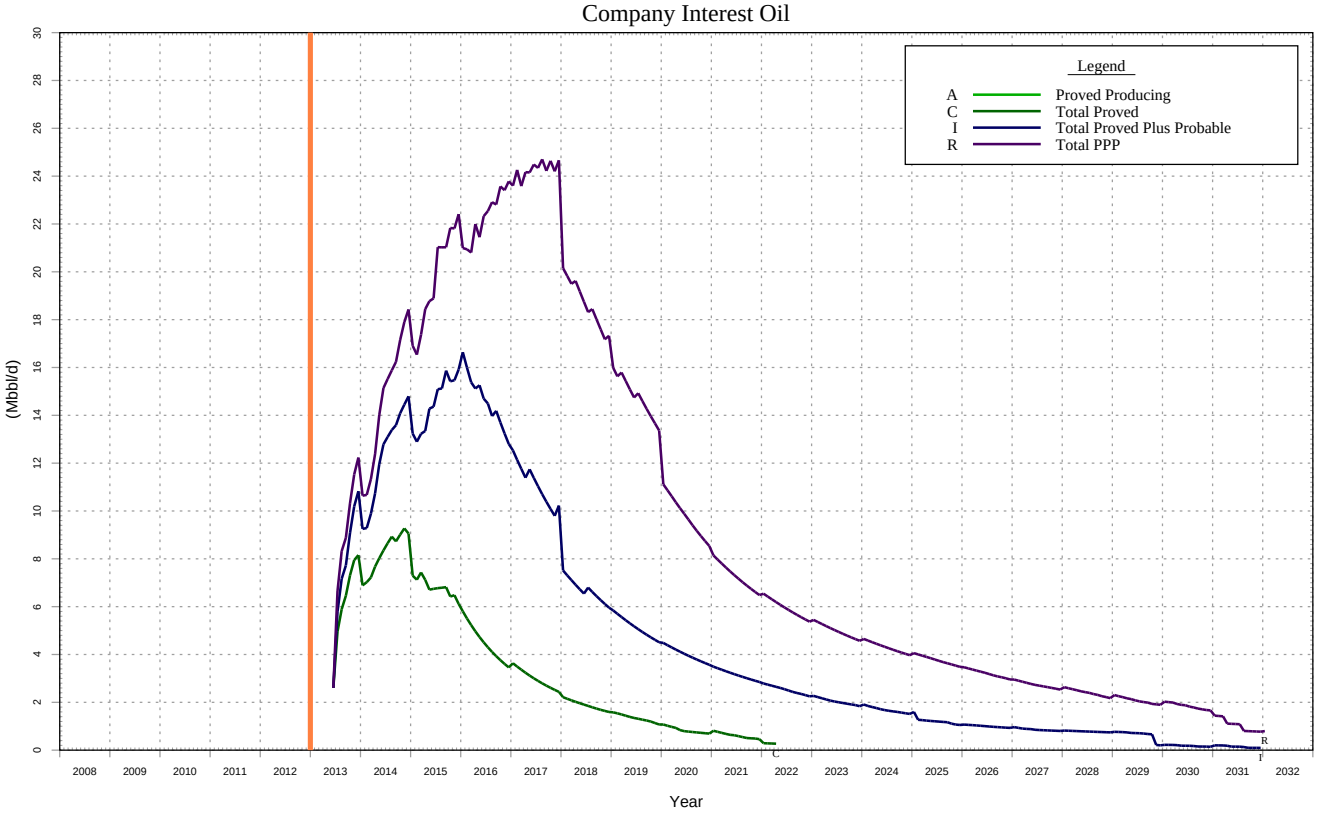
HVY OIL	1.0	RES GAS	6.0	PROPANE	1.0	ETHANE	1.0
COND	1.0	SLN GAS	6.0	BUTANE	1.0	SULPHUR	0.0

Historical and Forecast Production

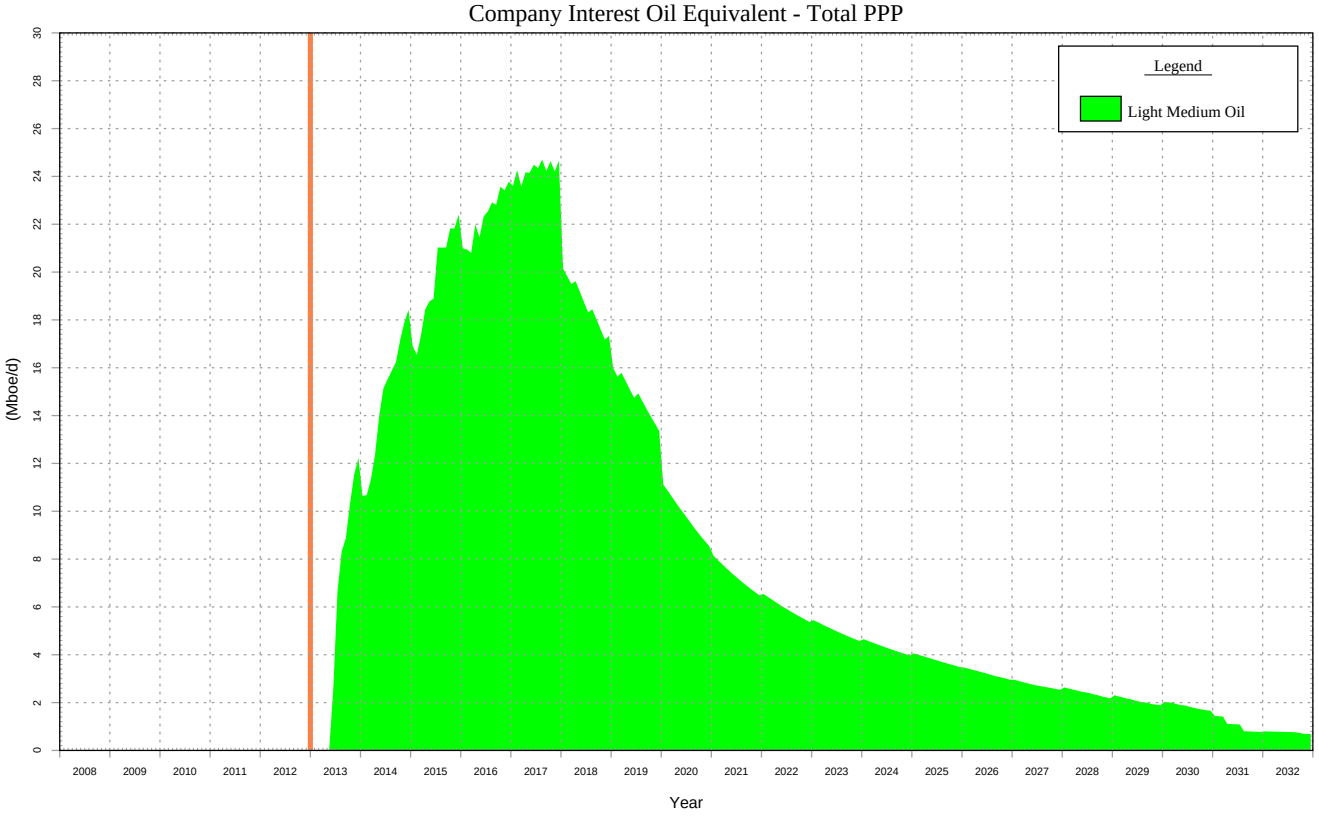
Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **Summary**

Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Company Interest Oil



Company Interest Oil Equivalent - Total PPP



*Note: Historical company interest production is based on current interests in the evaluated reserves entities applied to reported actual gross lease production. Consequently, company actuals may differ from the history shown due to changes in ownership.

Company Interest Oil
1132107 / Jan 28, 2013

Drawing 1

PROVED RESERVES

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Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **Summary**
$US Dollars

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Summary of Reserves and Values

	Proved Producing	Proved Developed Non-producing	Proved Undeveloped	Total Proved Non-producing	Total Proved
MARKETABLE RESERVES					
Light/Medium Oil (Mbbl)					
Total Company Interest	0	0	11,251	11,251	11,251
Working Interest	0	0	11,251	11,251	11,251
Net After Royalty	0	0	11,251	11,251	11,251
Oil Equivalent (Mbbl)					
Total Company Interest	0	0	11,251	11,251	11,251
Working Interest	0	0	11,251	11,251	11,251
Net After Royalty	0	0	11,251	11,251	11,251
BEFORE TAX PRESENT VALUE (M$)					
0%	0	0	699,100	699,100	699,100
5%	0	0	619,077	619,077	619,077
8%	0	0	578,947	578,947	578,947
10%	0	0	554,870	554,870	554,870
12%	0	0	532,665	532,665	532,665
15%	0	0	502,438	502,438	502,438
20%	0	0	458,955	458,955	458,955
FIRST 6 YEARS BEFORE TAX CASH FLOW (M$)					
2013	0	0	127,822	127,822	127,822
2014	0	0	193,741	193,741	193,741
2015	0	0	157,480	157,480	157,480
2016	0	0	86,628	86,628	86,628
2017	0	0	51,926	51,926	51,926
2018	0	0	40,608	40,608	40,608

BOE Factors: HVY OIL 1.0 | COND 1.0 | RES GAS 6.0 | SLN GAS 6.0 | PROPANE 1.0 | BUTANE 1.0 | ETHANE 1.0 | SULPHUR 0.0

Run Date: January 22, 2013 10:03:19

Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **Summary**
$US Dollars

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Company Production, Reserves and Present Value Summary

Entity Description	2013 Company Interest Prod'n Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	Company Interest Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Net After Royalty Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Reserve Life Index yrs	Before Income Tax Discounted Present Value (M$) 0%	8%	10%	12%
Proved Producing																			
DOB/DOI Total																			
Badila	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
ITA Badila/Mangara	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Mangara	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Total: DOB/DOI Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0.0**	**0**	**0**	**0**	**0**
East Doseo Total																			
ITA East Doseo	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Kibea	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Maku	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Total: East Doseo Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0.0**	**0**	**0**	**0**	**0**
Total: Proved Producing	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0.0**	**0**	**0**	**0**	**0**
Proved Developed Nonproducing																			
DOB/DOI Total																			
Badila	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
ITA Badila/Mangara	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Mangara	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Total: DOB/DOI Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0.0**	**0**	**0**	**0**	**0**
East Doseo Total																			
ITA East Doseo	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Kibea	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Maku	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Total: East Doseo Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0.0**	**0**	**0**	**0**	**0**
Total: Proved Developed Nonproducing	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0.0**	**0**	**0**	**0**	**0**
Proved Undeveloped																			
DOB/DOI Total																			
Badila	0	2,602	0	2,602	0	5,865	0	0	5,865	0	5,865	0	0	5,865	6.2	344,088	294,882	284,696	275,192
ITA Badila/Mangara	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	21,249	16,183	15,190	14,282
Mangara	0	1,031	0	1,031	0	5,386	0	0	5,386	0	5,386	0	0	5,386	14.3	333,763	267,882	254,984	243,191
Total: DOB/DOI Total	**0**	**3,633**	**0**	**3,633**	**0**	**11,251**	**0**	**0**	**11,251**	**0**	**11,251**	**0**	**0**	**11,251**	**8.5**	**699,100**	**578,947**	**554,870**	**532,665**
East Doseo Total																			
ITA East Doseo	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0

Company Production, Reserves and Present Value Summary

Entity Description	2013 Company Interest Prod'n Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	Company Interest Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Net After Royalty Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Reserve Life Index yrs	Before Income Tax Discounted Present Value (M$) 0%	8%	10%	12%
Proved Undeveloped (Cont.)																			
East Doseo Total (Cont.)																			
Kibea	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Maku	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Total: East Doseo Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0.0**	**0**	**0**	**0**	**0**
Total: Proved Undeveloped	**0**	**3,633**	**0**	**3,633**	**0**	**11,251**	**0**	**0**	**11,251**	**0**	**11,251**	**0**	**0**	**11,251**	**8.5**	**699,100**	**578,947**	**554,870**	**532,665**
Total Proved Nonproducing																			
DOB/DOI Total																			
Badila	0	2,602	0	2,602	0	5,865	0	0	5,865	0	5,865	0	0	5,865	6.2	344,088	294,882	284,696	275,192
ITA Badila/Mangara	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	21,249	16,183	15,190	14,282
Mangara	0	1,031	0	1,031	0	5,386	0	0	5,386	0	5,386	0	0	5,386	14.3	333,763	267,882	254,984	243,191
Total: DOB/DOI Total	**0**	**3,633**	**0**	**3,633**	**0**	**11,251**	**0**	**0**	**11,251**	**0**	**11,251**	**0**	**0**	**11,251**	**8.5**	**699,100**	**578,947**	**554,870**	**532,665**
East Doseo Total																			
ITA East Doseo	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Kibea	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Maku	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Total: East Doseo Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0.0**	**0**	**0**	**0**	**0**
Total: Total Proved Nonproducing	**0**	**3,633**	**0**	**3,633**	**0**	**11,251**	**0**	**0**	**11,251**	**0**	**11,251**	**0**	**0**	**11,251**	**8.5**	**699,100**	**578,947**	**554,870**	**532,665**
Total Proved																			
DOB/DOI Total																			
Badila	0	2,602	0	2,602	0	5,865	0	0	5,865	0	5,865	0	0	5,865	6.2	344,088	294,882	284,696	275,192
ITA Badila/Mangara	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	21,249	16,183	15,190	14,282
Mangara	0	1,031	0	1,031	0	5,386	0	0	5,386	0	5,386	0	0	5,386	14.3	333,763	267,882	254,984	243,191
Total: DOB/DOI Total	**0**	**3,633**	**0**	**3,633**	**0**	**11,251**	**0**	**0**	**11,251**	**0**	**11,251**	**0**	**0**	**11,251**	**8.5**	**699,100**	**578,947**	**554,870**	**532,665**
East Doseo Total																			
ITA East Doseo	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Kibea	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Maku	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Total: East Doseo Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0.0**	**0**	**0**	**0**	**0**
Total: Total Proved	**0**	**3,633**	**0**	**3,633**	**0**	**11,251**	**0**	**0**	**11,251**	**0**	**11,251**	**0**	**0**	**11,251**	**8.5**	**699,100**	**578,947**	**554,870**	**532,665**

BOE Factors: HVY OIL 1.0 | RES GAS 6.0 | PROPANE 1.0 | ETHANE 1.0 | COND 1.0 | SLN GAS 6.0 | BUTANE 1.0 | SULPHUR 0.0

Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **Summary**
$US Dollars

Reserve Class: **Proved**
Development Class: **Undeveloped**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production			
Year	Company Oil Wells	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	4	3,633	1,326	1,326	91.55
2014	9	8,243	3,009	3,009	89.18
2015	12	6,817	2,488	2,488	89.18
2016	13	4,502	1,643	1,643	89.18
2017	14	2,981	1,088	1,088	86.80
2018	13	1,885	688	688	86.80
2019	13	1,334	487	487	88.08
2020	13	838	306	306	90.01
2021	12	484	177	177	91.98
2022	2	107	39	39	93.97
2023	0	0	0	0	0.00
2024	0	0	0	0	0.00
Sub.			11,251	11,251	89.12
Rem.			0	0	0.00
Tot.			**11,251**	**11,251**	**89.12**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	121,399	0	0	121,399	0	121,399	0	0	0	0	0	121,399	17,004	0	17,004
2014	268,317	0	0	268,317	0	268,317	0	0	0	0	0	268,317	33,183	0	33,183
2015	221,882	0	0	221,882	0	221,882	0	0	0	0	0	221,882	31,564	0	31,564
2016	146,534	0	0	146,534	0	146,534	0	0	0	0	0	146,534	25,939	0	25,939
2017	94,444	0	0	94,444	0	94,444	0	0	0	0	0	94,444	22,248	0	22,248
2018	59,726	0	0	59,726	0	59,726	0	0	0	0	0	59,726	20,524	0	20,524
2019	42,892	0	0	42,892	0	42,892	0	0	0	0	0	42,892	18,159	0	18,159
2020	27,529	0	0	27,529	0	27,529	0	0	0	0	0	27,529	17,231	0	17,231
2021	16,254	0	0	16,254	0	16,254	0	0	0	0	0	16,254	12,568	0	12,568
2022	3,654	0	0	3,654	0	3,654	0	0	0	0	0	3,654	3,452	0	3,452
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sub.	1,002,631	0	0	1,002,631	0	1,002,631	0	0	0	0	0	1,002,631	201,871	0	201,871
Rem.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tot.	**1,002,631**	**0**	**0**	**1,002,631**	**0**	**1,002,631**	**0**	**0**	**0**	**0**	**0**	**1,002,631**	**201,871**	**0**	**201,871**
Disc	770,256	0	0	770,256	0	770,256	0	0	0	0	0	770,256	140,257	0	140,257

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Net Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	104,394	133,901	671	237,624	49,982	59,821	0	109,803	127,822	127,822	121,873
2014	0	0	0	235,133	8,540	1,853	241,821	40,256	7,824	0	48,080	193,741	321,562	289,804
2015	0	0	0	190,318	8,188	1,994	196,512	39,032	0	0	39,032	157,480	479,042	413,896
2016	0	0	0	120,595	5,071	1,384	124,283	37,654	0	0	37,654	86,628	565,670	475,953
2017	0	0	0	72,196	3,028	865	74,359	22,434	0	0	22,434	51,926	617,596	509,768
2018	0	0	0	39,202	2,010	604	40,608	0	0	0	0	40,608	658,204	533,809
2019	0	0	0	24,733	1,380	431	25,682	0	0	0	0	25,682	683,887	547,632
2020	0	0	0	10,299	837	253	10,883	0	0	0	0	10,883	694,770	552,956
2021	0	0	0	3,687	432	85	4,034	0	0	0	0	4,034	698,804	554,751
2022	0	0	0	202	98	4	296	0	0	0	0	296	699,100	554,870
2023	0	0	0	0	0	0	0	0	0	0	0	0	699,100	554,870
2024	0	0	0	0	0	0	0	0	0	0	0	0	699,100	554,870
Sub.	0	0	0	800,760	163,486	8,144	956,102	189,358	67,644	0	257,002	699,100	699,100	554,870
Rem.	0	0	0	0	0	0	0	0	0	0	0	0	699,100	554,870
Tot.	**0**	**0**	**0**	**800,760**	**163,486**	**8,144**	**956,102**	**189,358**	**67,644**	**0**	**257,002**	**699,100**	**699,100**	**554,870**
Disc	0	0	0	629,999	149,703	6,125	773,578	154,889	63,818	0	218,707	554,870	554,870	554,870

SUMMARY OF RESERVES

		Remaining Reserves at Jan 01, 2013				Oil Equivalents			Reserve Life Indic. (yr)		
Product	Units	Working Interest	Roy/NPI Interest	Total Company	Net	Oil Eq. Factor	Company Mboe	% of Total	Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	11,251	0	11,251	11,251	1.000	11,251	100	10.0	8.5	2.5
Total: Oil Eq.	Mboe	11,251	0	11,251	11,251	1.000	11,251	100	10.0	8.5	2.5

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	85.00	6.55	91.55	0.00	12.40	0.00	79.15	1,002,631	100	770,256	100
Total: Oil Eq.	$/boe	85.00	6.55	91.55	0.00	12.82	0.00	78.73	1,002,631	100	770,256	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)		
Entity Name	Initial	Average
Crown Royalty	0.0000	0.0000
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000

	Net Present Value Before Income Tax				
Disc. Rate %	Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/boe
0.0	800,760	956,102	257,002	699,100	62.14
5.0	706,203	855,225	236,148	619,077	55.02
8.0	658,607	804,273	225,326	578,947	51.46
10.0	629,999	773,578	218,707	554,870	49.32
12.0	603,581	745,180	212,516	532,665	47.34
15.0	567,574	706,386	203,948	502,438	44.66
20.0	515,697	650,278	191,323	458,955	40.79

Evaluator: Herchen, Leonard L.
Run Date: January 22, 2013 10:03:19

Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **Summary**
$US Dollars

Reserve Class: **Proved**
Development Class: **Total Nonproducing**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production			
Year	Company Oil Wells	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	4	3,633	1,326	1,326	91.55
2014	9	8,243	3,009	3,009	89.18
2015	12	6,817	2,488	2,488	89.18
2016	13	4,502	1,643	1,643	89.18
2017	14	2,981	1,088	1,088	86.80
2018	13	1,885	688	688	86.80
2019	13	1,334	487	487	88.08
2020	13	838	306	306	90.01
2021	12	484	177	177	91.98
2022	2	107	39	39	93.97
2023	0	0	0	0	0.00
2024	0	0	0	0	0.00
Sub.			11,251	11,251	89.12
Rem.			0	0	0.00
Tot.			**11,251**	**11,251**	**89.12**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	121,399	0	0	121,399	0	121,399	0	0	0	0	0	121,399	17,004	0	17,004
2014	268,317	0	0	268,317	0	268,317	0	0	0	0	0	268,317	33,183	0	33,183
2015	221,882	0	0	221,882	0	221,882	0	0	0	0	0	221,882	31,564	0	31,564
2016	146,534	0	0	146,534	0	146,534	0	0	0	0	0	146,534	25,939	0	25,939
2017	94,444	0	0	94,444	0	94,444	0	0	0	0	0	94,444	22,248	0	22,248
2018	59,726	0	0	59,726	0	59,726	0	0	0	0	0	59,726	20,524	0	20,524
2019	42,892	0	0	42,892	0	42,892	0	0	0	0	0	42,892	18,159	0	18,159
2020	27,529	0	0	27,529	0	27,529	0	0	0	0	0	27,529	17,231	0	17,231
2021	16,254	0	0	16,254	0	16,254	0	0	0	0	0	16,254	12,568	0	12,568
2022	3,654	0	0	3,654	0	3,654	0	0	0	0	0	3,654	3,452	0	3,452
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sub.	1,002,631	0	0	1,002,631	0	1,002,631	0	0	0	0	0	1,002,631	201,871	0	201,871
Rem.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tot.	**1,002,631**	**0**	**0**	**1,002,631**	**0**	**1,002,631**	**0**	**0**	**0**	**0**	**0**	**1,002,631**	**201,871**	**0**	**201,871**
Disc	770,256	0	0	770,256	0	770,256	0	0	0	0	0	770,256	140,257	0	140,257

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Net Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	104,394	133,901	671	237,624	49,982	59,821	0	109,803	127,822	127,822	121,873
2014	0	0	0	235,133	8,540	1,853	241,821	40,256	7,824	0	48,080	193,741	321,562	289,804
2015	0	0	0	190,318	8,188	1,994	196,512	39,032	0	0	39,032	157,480	479,042	413,896
2016	0	0	0	120,595	5,071	1,384	124,283	37,654	0	0	37,654	86,628	565,670	475,953
2017	0	0	0	72,196	3,028	865	74,359	22,434	0	0	22,434	51,926	617,596	509,768
2018	0	0	0	39,202	2,010	604	40,608	0	0	0	0	40,608	658,204	533,809
2019	0	0	0	24,733	1,380	431	25,682	0	0	0	0	25,682	683,887	547,632
2020	0	0	0	10,299	837	253	10,883	0	0	0	0	10,883	694,770	552,956
2021	0	0	0	3,687	432	85	4,034	0	0	0	0	4,034	698,804	554,751
2022	0	0	0	202	98	4	296	0	0	0	0	296	699,100	554,870
2023	0	0	0	0	0	0	0	0	0	0	0	0	699,100	554,870
2024	0	0	0	0	0	0	0	0	0	0	0	0	699,100	554,870
Sub.	0	0	0	800,760	163,486	8,144	956,102	189,358	67,644	0	257,002	699,100	699,100	554,870
Rem.	0	0	0	0	0	0	0	0	0	0	0	0	699,100	554,870
Tot.	**0**	**0**	**0**	**800,760**	**163,486**	**8,144**	**956,102**	**189,358**	**67,644**	**0**	**257,002**	**699,100**	**699,100**	**554,870**
Disc	0	0	0	629,999	149,703	6,125	773,578	154,889	63,818	0	218,707	554,870	554,870	554,870

SUMMARY OF RESERVES

		Remaining Reserves at Jan 01, 2013				Oil Equivalents			Reserve Life Indic. (yr)		
Product	Units	Working Interest	Roy/NPI Interest	Total Company	Net	Oil Eq. Factor	Company Mboe	% of Total	Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	11,251	0	11,251	11,251	1.000	11,251	100	10.0	8.5	2.5
Total: Oil Eq.	Mboe	11,251	0	11,251	11,251	1.000	11,251	100	10.0	8.5	2.5

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	85.00	6.55	91.55	0.00	12.40	0.00	79.15	1,002,631	100	770,256	100
Total: Oil Eq.	$/boe	85.00	6.55	91.55	0.00	12.82	0.00	78.73	1,002,631	100	770,256	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)		
Entity Name	Initial	Average
Crown Royalty	0.0000	0.0000
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000

	Net Present Value Before Income Tax				
Disc. Rate %	Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/boe
0.0	800,760	956,102	257,002	699,100	62.14
5.0	706,203	855,225	236,148	619,077	55.02
8.0	658,607	804,273	225,326	578,947	51.46
10.0	629,999	773,578	218,707	554,870	49.32
12.0	603,581	745,180	212,516	532,665	47.34
15.0	567,574	706,386	203,948	502,438	44.66
20.0	515,697	650,278	191,323	458,955	40.79

Evaluator: Herchen, Leonard L.
Run Date: January 22, 2013 10:03:19

Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **Summary**
$US Dollars

Reserve Class: **Proved**
Development Class: **Total**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production			
Year	Company Oil Wells	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	4	3,633	1,326	1,326	91.55
2014	9	8,243	3,009	3,009	89.18
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2016	13	4,502	1,643	1,643	89.18
2017	14	2,981	1,088	1,088	86.80
2018	13	1,885	688	688	86.80
2019	13	1,334	487	487	88.08
2020	13	838	306	306	90.01
2021	12	484	177	177	91.98
2022	2	107	39	39	93.97
2023	0	0	0	0	0.00
2024	0	0	0	0	0.00
Sub.			11,251	11,251	89.12
Rem.			0	0	0.00
Tot.			**11,251**	**11,251**	**89.12**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	121,399	0	0	121,399	0	121,399	0	0	0	0	0	121,399	17,004	0	17,004
2014	268,317	0	0	268,317	0	268,317	0	0	0	0	0	268,317	33,183	0	33,183
2015	221,882	0	0	221,882	0	221,882	0	0	0	0	0	221,882	31,564	0	31,564
2016	146,534	0	0	146,534	0	146,534	0	0	0	0	0	146,534	25,939	0	25,939
2017	94,444	0	0	94,444	0	94,444	0	0	0	0	0	94,444	22,248	0	22,248
2018	59,726	0	0	59,726	0	59,726	0	0	0	0	0	59,726	20,524	0	20,524
2019	42,892	0	0	42,892	0	42,892	0	0	0	0	0	42,892	18,159	0	18,159
2020	27,529	0	0	27,529	0	27,529	0	0	0	0	0	27,529	17,231	0	17,231
2021	16,254	0	0	16,254	0	16,254	0	0	0	0	0	16,254	12,568	0	12,568
2022	3,654	0	0	3,654	0	3,654	0	0	0	0	0	3,654	3,452	0	3,452
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sub.	1,002,631	0	0	1,002,631	0	1,002,631	0	0	0	0	0	1,002,631	201,871	0	201,871
Rem.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tot.	**1,002,631**	**0**	**0**	**1,002,631**	**0**	**1,002,631**	**0**	**0**	**0**	**0**	**0**	**1,002,631**	**201,871**	**0**	**201,871**
Disc	770,256	0	0	770,256	0	770,256	0	0	0	0	0	770,256	140,257	0	140,257

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Net Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	104,394	133,901	671	237,624	49,982	59,821	0	109,803	127,822	127,822	121,873
2014	0	0	0	235,133	8,540	1,853	241,821	40,256	7,824	0	48,080	193,741	321,562	289,804
2015	0	0	0	190,318	8,188	1,994	196,512	39,032	0	0	39,032	157,480	479,042	413,896
2016	0	0	0	120,595	5,071	1,384	124,283	37,654	0	0	37,654	86,628	565,670	475,953
2017	0	0	0	72,196	3,028	865	74,359	22,434	0	0	22,434	51,926	617,596	509,768
2018	0	0	0	39,202	2,010	604	40,608	0	0	0	0	40,608	658,204	533,809
2019	0	0	0	24,733	1,380	431	25,682	0	0	0	0	25,682	683,887	547,632
2020	0	0	0	10,299	837	253	10,883	0	0	0	0	10,883	694,770	552,956
2021	0	0	0	3,687	432	85	4,034	0	0	0	0	4,034	698,804	554,751
2022	0	0	0	202	98	4	296	0	0	0	0	296	699,100	554,870
2023	0	0	0	0	0	0	0	0	0	0	0	0	699,100	554,870
2024	0	0	0	0	0	0	0	0	0	0	0	0	699,100	554,870
Sub.	0	0	0	800,760	163,486	8,144	956,102	189,358	67,644	0	257,002	699,100	699,100	554,870
Rem.	0	0	0	0	0	0	0	0	0	0	0	0	699,100	554,870
Tot.	**0**	**0**	**0**	**800,760**	**163,486**	**8,144**	**956,102**	**189,358**	**67,644**	**0**	**257,002**	**699,100**	**699,100**	**554,870**
Disc	0	0	0	629,999	149,703	6,125	773,578	154,889	63,818	0	218,707	554,870	554,870	554,870

SUMMARY OF RESERVES

		Remaining Reserves at Jan 01, 2013				Oil Equivalents			Reserve Life Indic. (yr)		
Product	Units	Working Interest	Roy/NPI Interest	Total Company	Net	Oil Eq. Factor	Company Mboe	% of Total	Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	11,251	0	11,251	11,251	0.000	0	0	10.0	8.5	2.5
Total: Oil Eq.	Mboe	11,251	0	11,251	11,251	0.000	0	0	10.0	8.5	2.5

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	85.00	6.55	91.55	0.00	12.40	0.00	79.15	1,002,631	100	770,256	100
Total: Oil Eq.	$/boe	85.00	6.55	91.55	0.00	12.82	0.00	78.73	1,002,631	100	770,256	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)		
Entity Name	Initial	Average
Crown Royalty	0.0000	0.0000
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000

	Net Present Value Before Income Tax				
Disc. Rate %	Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/boe
0.0	800,760	956,102	257,002	699,100	62.14
5.0	706,203	855,225	236,148	619,077	55.02
8.0	658,607	804,273	225,326	578,947	51.46
10.0	629,999	773,578	218,707	554,870	49.32
12.0	603,581	745,180	212,516	532,665	47.34
15.0	567,574	706,386	203,948	502,438	44.66
20.0	515,697	650,278	191,323	458,955	40.79

Evaluator: Herchen, Leonard L.
Run Date: January 22, 2013 10:03:19

PROBABLE AND PROVED PLUS PROBABLE RESERVES

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Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **Summary**
$US Dollars

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Summary of Reserves and Values

	Total Probable	Total Proved Plus Probable
MARKETABLE RESERVES		
Light/Medium Oil (Mbbl)		
Total Company Interest	20,514	31,765
Working Interest	20,514	31,765
Net After Royalty	20,514	31,765
Oil Equivalent (Mbbl)		
Total Company Interest	20,514	31,765
Working Interest	20,514	31,765
Net After Royalty	20,514	31,765
BEFORE TAX PRESENT VALUE (M$)		
0%	969,029	1,668,130
5%	697,973	1,317,050
8%	580,884	1,159,831
10%	516,311	1,071,182
12%	460,393	993,057
15%	389,713	892,150
20%	298,624	757,579
FIRST 6 YEARS BEFORE TAX CASH FLOW (M$)		
2013	-42,627	85,195
2014	-64,986	128,754
2015	61,572	219,051
2016	198,839	285,468
2017	226,524	278,450
2018	132,403	173,011

BOE Factors: HVY OIL 1.0 | COND 1.0 | RES GAS 6.0 | SLN GAS 6.0 | PROPANE 1.0 | BUTANE 1.0 | ETHANE 1.0 | SULPHUR 0.0

Run Date: January 22, 2013 10:03:20

Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **Summary**
$US Dollars

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Company Production, Reserves and Present Value Summary

Entity Description	2013 Company Interest Prod'n Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	Company Interest Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Net After Royalty Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Reserve Life Index yrs	Before Income Tax Discounted Present Value (M$) 0%	8%	10%	12%
Total Probable																			
DOB/DOI Total																			
Badila	0	0	0	0	0	2,704	0	0	2,704	0	2,704	0	0	2,704	7.9	171,823	124,967	116,268	108,455
ITA Badila/Mangara	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	3,505	808	420	103
Mangara	0	845	0	845	0	8,062	0	0	8,062	0	8,062	0	0	8,062	26.1	423,134	302,452	281,404	262,841
Total: DOB/DOI Total	**0**	**845**	**0**	**845**	**0**	**10,766**	**0**	**0**	**10,766**	**0**	**10,766**	**0**	**0**	**10,766**	**34.9**	**598,462**	**428,227**	**398,093**	**371,399**
East Doseo Total																			
ITA East Doseo	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	54,853	17,107	11,432	6,701
Kibea	0	0	0	0	0	6,332	0	0	6,332	0	6,332	0	0	6,332	14.0	266,649	130,419	108,667	90,111
Maku	0	0	0	0	0	3,415	0	0	3,415	0	3,415	0	0	3,415	10.6	49,066	5,131	-1,880	-7,818
Total: East Doseo Total	**0**	**0**	**0**	**0**	**0**	**9,748**	**0**	**0**	**9,748**	**0**	**9,748**	**0**	**0**	**9,748**	**12.6**	**370,568**	**152,657**	**118,219**	**88,994**
Total: Total Probable	**0**	**845**	**0**	**845**	**0**	**20,514**	**0**	**0**	**20,514**	**0**	**20,514**	**0**	**0**	**20,514**	**66.5**	**969,029**	**580,884**	**516,311**	**460,393**
Total Proved Plus Probable																			
DOB/DOI Total																			
Badila	0	2,602	0	2,602	0	8,568	0	0	8,568	0	8,568	0	0	8,568	9.0	515,911	419,849	400,964	383,647
ITA Badila/Mangara	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	24,754	16,991	15,611	14,385
Mangara	0	1,876	0	1,876	0	13,448	0	0	13,448	0	13,448	0	0	13,448	19.6	756,897	570,335	536,388	506,032
Total: DOB/DOI Total	**0**	**4,478**	**0**	**4,478**	**0**	**22,017**	**0**	**0**	**22,017**	**0**	**22,017**	**0**	**0**	**22,017**	**13.5**	**1,297,562**	**1,007,174**	**952,963**	**904,063**
East Doseo Total																			
ITA East Doseo	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	54,853	17,107	11,432	6,701
Kibea	0	0	0	0	0	6,332	0	0	6,332	0	6,332	0	0	6,332	14.0	266,649	130,419	108,667	90,111
Maku	0	0	0	0	0	3,415	0	0	3,415	0	3,415	0	0	3,415	10.6	49,066	5,131	-1,880	-7,818
Total: East Doseo Total	**0**	**0**	**0**	**0**	**0**	**9,748**	**0**	**0**	**9,748**	**0**	**9,748**	**0**	**0**	**9,748**	**12.6**	**370,568**	**152,657**	**118,219**	**88,994**
Total: Total Proved Plus Probable	**0**	**4,478**	**0**	**4,478**	**0**	**31,765**	**0**	**0**	**31,765**	**0**	**31,765**	**0**	**0**	**31,765**	**19.4**	**1,668,130**	**1,159,831**	**1,071,182**	**993,057**

BOE Factors: HVY OIL 1.0 | RES GAS 6.0 | PROPANE 1.0 | ETHANE 1.0
COND 1.0 | SLN GAS 6.0 | BUTANE 1.0 | SULPHUR 0.0

Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **Summary**
$US Dollars

Reserve Class: **Probable**
Development Class: **Total**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production			
Year	Company Oil Wells	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	0	845	308	308	95.15
2014	1	4,050	1,478	1,478	91.24
2015	6	7,713	2,815	2,815	88.58
2016	10	10,157	3,707	3,707	86.83
2017	9	8,113	2,961	2,961	83.43
2018	5	4,805	1,754	1,754	83.13
2019	5	3,803	1,388	1,388	84.47
2020	5	3,177	1,160	1,160	86.79
2021	7	2,672	975	975	89.23
2022	17	2,413	881	881	91.48
2023	19	2,035	743	743	93.71
2024	20	1,688	616	616	95.74
Sub.			18,787	18,787	87.42
Rem.			1,727	1,727	101.18
Tot.			**20,514**	**20,514**	**88.58**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	29,343	0	0	29,343	0	29,343	0	0	0	0	0	29,343	14,645	0	14,645
2014	134,880	0	0	134,880	0	134,880	0	0	0	0	0	134,880	19,767	0	19,767
2015	249,370	0	0	249,370	0	249,370	0	0	0	0	0	249,370	32,331	0	32,331
2016	321,887	0	0	321,887	0	321,887	0	0	0	0	0	321,887	39,497	0	39,497
2017	247,078	0	0	247,078	0	247,078	0	0	0	0	0	247,078	35,225	0	35,225
2018	145,793	0	0	145,793	0	145,793	0	0	0	0	0	145,793	32,296	0	32,296
2019	117,262	0	0	117,262	0	117,262	0	0	0	0	0	117,262	25,883	0	25,883
2020	100,631	0	0	100,631	0	100,631	0	0	0	0	0	100,631	23,415	0	23,415
2021	87,020	0	0	87,020	0	87,020	0	0	0	0	0	87,020	25,848	0	25,848
2022	80,559	0	0	80,559	0	80,559	0	0	0	0	0	80,559	33,486	0	33,486
2023	69,598	0	0	69,598	0	69,598	0	0	0	0	0	69,598	35,732	0	35,732
2024	58,986	0	0	58,986	0	58,986	0	0	0	0	0	58,986	34,686	0	34,686
Sub.	1,642,406	0	0	1,642,406	0	1,642,406	0	0	0	0	0	1,642,406	352,810	0	352,810
Rem.	174,731	0	0	174,731	0	174,731	0	0	0	0	0	174,731	123,197	0	123,197
Tot.	**1,817,137**	**0**	**0**	**1,817,137**	**0**	**1,817,137**	**0**	**0**	**0**	**0**	**0**	**1,817,137**	**476,008**	**0**	**476,008**
Disc	1,092,782	0	0	1,092,782	0	1,092,782	0	0	0	0	0	1,092,782	233,026	0	233,026

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Net Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	14,697	-3,496	-127	11,328	5,268	48,687	0	53,955	-42,627	-42,627	-40,643
2014	0	0	0	115,113	-996	-74	114,191	53,247	125,931	0	179,178	-64,986	-107,613	-96,972
2015	0	0	0	217,039	9,376	616	225,799	164,227	0	0	164,227	61,572	-46,041	-48,455
2016	0	0	0	282,390	21,716	1,264	302,843	104,003	0	0	104,003	198,839	152,798	93,984
2017	0	0	0	211,853	21,940	1,116	232,677	6,153	0	0	6,153	226,524	379,322	241,503
2018	0	0	0	113,497	19,841	935	132,403	0	0	0	0	132,403	511,725	319,889
2019	0	0	0	91,380	15,773	773	106,380	0	0	0	0	106,380	618,105	377,143
2020	0	0	0	77,216	12,246	707	88,755	0	0	0	0	88,755	706,860	420,569
2021	0	0	0	61,172	9,795	701	70,267	0	0	0	0	70,267	777,127	451,823
2022	0	0	0	47,073	8,099	648	54,523	0	0	0	0	54,523	831,650	473,870
2023	0	0	0	33,866	6,631	522	39,975	0	0	0	0	39,975	871,625	488,565
2024	0	0	0	24,300	5,439	403	29,335	0	0	0	0	29,335	900,960	498,369
Sub.	0	0	0	1,289,596	126,362	7,483	1,408,476	332,897	174,618	0	507,516	900,960	900,960	498,369
Rem.	0	0	0	51,534	17,418	882	68,069	0	0	0	0	68,069	969,029	516,311
Tot.	**0**	**0**	**0**	**1,341,130**	**143,780**	**8,365**	**1,476,545**	**332,897**	**174,618**	**0**	**507,516**	**969,029**	**969,029**	**516,311**
Disc	0	0	0	859,756	75,612	4,387	930,982	259,094	155,577	0	414,671	516,311	516,311	516,311

SUMMARY OF RESERVES

		Remaining Reserves at Jan 01, 2013				Oil Equivalents			Reserve Life Indic. (yr)		
Product	Units	Working Interest	Roy/NPI Interest	Total Company	Net	Oil Eq. Factor	Company Mboe	% of Total	Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	20,514	0	20,514	20,514	1.000	20,514	100	19.0	66.5	4.7
Total: Oil Eq.	Mboe	20,514	0	20,514	20,514	1.000	20,514	100	19.0	66.5	4.7

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	85.00	10.15	95.15	0.00	47.07	0.00	48.08	1,817,137	100	1,092,782	100
Total: Oil Eq.	$/boe	85.00	10.15	95.15	0.00	47.49	0.00	47.66	1,817,137	100	1,092,782	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)		
Entity Name	Initial	Average
Crown Royalty	0.0000	0.0000
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000

	Net Present Value Before Income Tax				
Disc. Rate	Prod'n Revenue	Operating Income	Capital Invest.	Cash Flow	
%	M$	M$	M$	M$	$/boe
0.0	1,341,130	1,476,545	507,516	969,029	47.24
5.0	1,058,766	1,155,146	457,173	697,973	34.02
8.0	931,654	1,011,724	430,840	580,884	28.32
10.0	859,756	930,982	414,671	516,311	25.17
12.0	796,240	859,895	399,502	460,393	22.44
15.0	713,958	768,163	378,450	389,713	19.00
20.0	603,728	645,944	347,321	298,624	14.56

Evaluator: Herchen, Leonard L.
Run Date: January 22, 2013 10:03:20

Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **Summary**
$US Dollars

Reserve Class: **Proved Plus Probable**
Development Class: **Total**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production			
Year	Company Oil Wells	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	4	4,478	1,634	1,634	92.23
2014	10	12,294	4,487	4,487	89.85
2015	19	14,530	5,303	5,303	88.86
2016	22	14,658	5,350	5,350	87.55
2017	22	11,094	4,049	4,049	84.34
2018	18	6,690	2,442	2,442	84.16
2019	18	5,138	1,875	1,875	85.41
2020	19	4,015	1,465	1,465	87.46
2021	19	3,156	1,152	1,152	89.65
2022	19	2,519	919	919	91.59
2023	19	2,035	743	743	93.71
2024	20	1,688	616	616	95.74
Sub.			30,038	30,038	88.06
Rem.			1,727	1,727	101.18
Tot.			**31,765**	**31,765**	**88.77**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	150,741	0	0	150,741	0	150,741	0	0	0	0	0	150,741	31,650	0	31,650
2014	403,197	0	0	403,197	0	403,197	0	0	0	0	0	403,197	52,950	0	52,950
2015	471,252	0	0	471,252	0	471,252	0	0	0	0	0	471,252	63,895	0	63,895
2016	468,421	0	0	468,421	0	468,421	0	0	0	0	0	468,421	65,436	0	65,436
2017	341,522	0	0	341,522	0	341,522	0	0	0	0	0	341,522	57,473	0	57,473
2018	205,518	0	0	205,518	0	205,518	0	0	0	0	0	205,518	52,819	0	52,819
2019	160,154	0	0	160,154	0	160,154	0	0	0	0	0	160,154	44,042	0	44,042
2020	128,160	0	0	128,160	0	128,160	0	0	0	0	0	128,160	40,645	0	40,645
2021	103,275	0	0	103,275	0	103,275	0	0	0	0	0	103,275	38,416	0	38,416
2022	84,213	0	0	84,213	0	84,213	0	0	0	0	0	84,213	36,939	0	36,939
2023	69,598	0	0	69,598	0	69,598	0	0	0	0	0	69,598	35,732	0	35,732
2024	58,986	0	0	58,986	0	58,986	0	0	0	0	0	58,986	34,686	0	34,686
Sub.	2,645,037	0	0	2,645,037	0	2,645,037	0	0	0	0	0	2,645,037	554,682	0	554,682
Rem.	174,731	0	0	174,731	0	174,731	0	0	0	0	0	174,731	123,197	0	123,197
Tot.	**2,819,768**	**0**	**0**	**2,819,768**	**0**	**2,819,768**	**0**	**0**	**0**	**0**	**0**	**2,819,768**	**677,879**	**0**	**677,879**
Disc	1,863,038	0	0	1,863,038	0	1,863,038	0	0	0	0	0	1,863,038	373,283	0	373,283

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Net Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	119,092	130,405	544	248,952	55,250	108,508	0	163,758	85,195	85,195	81,230
2014	0	0	0	350,247	7,543	1,779	356,012	93,503	133,755	0	227,258	128,754	213,949	192,832
2015	0	0	0	407,357	17,564	2,610	422,311	203,259	0	0	203,259	219,051	433,000	365,442
2016	0	0	0	402,986	26,787	2,648	427,125	141,657	0	0	141,657	285,468	718,468	569,937
2017	0	0	0	284,050	24,968	1,981	307,036	28,586	0	0	28,586	278,450	996,918	751,271
2018	0	0	0	152,699	21,852	1,539	173,011	0	0	0	0	173,011	1,169,930	853,698
2019	0	0	0	116,112	17,154	1,204	132,062	0	0	0	0	132,062	1,301,992	924,775
2020	0	0	0	87,515	13,083	960	99,638	0	0	0	0	99,638	1,401,630	973,525
2021	0	0	0	64,859	10,227	785	74,301	0	0	0	0	74,301	1,475,931	1,006,574
2022	0	0	0	47,275	8,197	652	54,819	0	0	0	0	54,819	1,530,750	1,028,741
2023	0	0	0	33,866	6,631	522	39,975	0	0	0	0	39,975	1,570,725	1,043,436
2024	0	0	0	24,300	5,439	403	29,335	0	0	0	0	29,335	1,600,060	1,053,239
Sub.	0	0	0	2,090,356	289,849	15,626	2,364,578	522,255	242,263	0	764,518	1,600,060	1,600,060	1,053,239
Rem.	0	0	0	51,534	17,418	882	68,069	0	0	0	0	68,069	1,668,130	1,071,182
Tot.	**0**	**0**	**0**	**2,141,889**	**307,267**	**16,509**	**2,432,648**	**522,255**	**242,263**	**0**	**764,518**	**1,668,130**	**1,668,130**	**1,071,182**
Disc	0	0	0	1,489,755	225,316	10,511	1,704,560	413,983	219,395	0	633,378	1,071,182	1,071,182	1,071,182

SUMMARY OF RESERVES

		Remaining Reserves at Jan 01, 2013				Oil Equivalents			Reserve Life Indic. (yr)		
Product	Units	Working Interest	Roy/NPI Interest	Total Company	Net	Oil Eq. Factor	Company Mboe	% of Total	Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	31,765	0	31,765	31,765	1.000	31,765	100	19.0	19.4	3.8
Total: Oil Eq.	Mboe	31,765	0	31,765	31,765	1.000	31,765	100	19.0	19.4	3.8

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	85.00	7.23	92.23	0.00	18.95	0.00	73.28	2,819,768	100	1,863,038	100
Total: Oil Eq.	$/boe	85.00	7.23	92.23	0.00	19.36	0.00	72.87	2,819,768	100	1,863,038	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)		
Entity Name	Initial	Average
Crown Royalty	0.0000	0.0000
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000

	Net Present Value Before Income Tax				
Disc. Rate %	Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	**Cash Flow** M$	**Cash Flow** $/boe
0.0	2,141,889	2,432,648	764,518	1,668,130	52.52
5.0	1,764,968	2,010,371	693,321	1,317,050	41.46
8.0	1,590,261	1,815,997	656,166	1,159,831	36.51
10.0	1,489,755	1,704,560	633,378	1,071,182	33.72
12.0	1,399,820	1,605,076	612,018	993,057	31.26
15.0	1,281,532	1,474,548	582,398	892,150	28.09
20.0	1,119,425	1,296,223	538,644	757,579	23.85

Evaluator: Herchen, Leonard L.
Run Date: January 22, 2013 10:03:20

POSSIBLE AND PROVED PLUS PROBABLE PLUS POSSIBLE RESERVES

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Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **Summary**
$US Dollars

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Summary of Reserves and Values

	Total Possible	Total PPP
MARKETABLE RESERVES		
Light/Medium Oil (Mbbl)		
Total Company Interest	32,138	63,902
Working Interest	32,138	63,902
Net After Royalty	32,138	63,902
Oil Equivalent (Mbbl)		
Total Company Interest	32,138	63,902
Working Interest	32,138	63,902
Net After Royalty	32,138	63,902
BEFORE TAX PRESENT VALUE (M$)		
0%	1,674,798	3,342,927
5%	1,138,051	2,455,101
8%	925,380	2,085,212
10%	812,843	1,884,025
12%	718,065	1,711,122
15%	601,780	1,493,931
20%	457,668	1,215,247
FIRST 6 YEARS BEFORE TAX CASH FLOW (M$)		
2013	-24,702	60,493
2014	-37,534	91,220
2015	107,292	326,343
2016	116,968	402,435
2017	214,383	492,833
2018	270,139	443,151

BOE Factors: HVY OIL 1.0 COND 1.0 RES GAS 6.0 SLN GAS 6.0 PROPANE 1.0 BUTANE 1.0 ETHANE 1.0 SULPHUR 0.0

Run Date: January 22, 2013 10:03:20

Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **Summary**
$US Dollars

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Company Production, Reserves and Present Value Summary

Entity Description	2013 Company Interest Prod'n Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	Company Interest Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Net After Royalty Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Reserve Life Index yrs	Before Income Tax Discounted Present Value (M$) 0%	8%	10%	12%
Total Possible																			
DOB/DOI Total																			
Badila	0	0	0	0	0	4,429	0	0	4,429	0	4,429	0	0	4,429	27.7	285,945	174,512	156,388	140,796
ITA Badila/Mangara	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	6,476	1,336	709	220
Mangara	0	602	0	602	0	15,779	0	0	15,779	0	15,779	0	0	15,779	71.8	809,296	444,702	394,503	353,162
Total: DOB/DOI Total	**0**	**602**	**0**	**602**	**0**	**20,208**	**0**	**0**	**20,208**	**0**	**20,208**	**0**	**0**	**20,208**	**92.0**	**1,101,718**	**620,550**	**551,600**	**494,178**
East Doseo Total																			
ITA East Doseo	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	24,238	7,700	5,183	3,082
Kibea	0	0	0	0	0	8,380	0	0	8,380	0	8,380	0	0	8,380	28.2	440,496	247,356	215,619	188,317
Maku	0	0	0	0	0	3,550	0	0	3,550	0	3,550	0	0	3,550	23.2	108,346	49,773	40,440	32,487
Total: East Doseo Total	**0**	**0**	**0**	**0**	**0**	**11,930**	**0**	**0**	**11,930**	**0**	**11,930**	**0**	**0**	**11,930**	**26.5**	**573,079**	**304,830**	**261,242**	**223,887**
Total: Total Possible	**0**	**602**	**0**	**602**	**0**	**32,138**	**0**	**0**	**32,138**	**0**	**32,138**	**0**	**0**	**32,138**	**146.3**	**1,674,798**	**925,380**	**812,843**	**718,065**
Total PPP																			
DOB/DOI Total																			
Badila	0	2,602	0	2,602	0	12,997	0	0	12,997	0	12,997	0	0	12,997	13.7	801,856	594,361	557,352	524,443
ITA Badila/Mangara	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	31,231	18,326	16,320	14,605
Mangara	0	2,478	0	2,478	0	29,227	0	0	29,227	0	29,227	0	0	29,227	32.3	1,566,193	1,015,037	930,891	859,193
Total: DOB/DOI Total	**0**	**5,080**	**0**	**5,080**	**0**	**42,224**	**0**	**0**	**42,224**	**0**	**42,224**	**0**	**0**	**42,224**	**22.8**	**2,399,280**	**1,627,725**	**1,504,564**	**1,398,241**
East Doseo Total																			
ITA East Doseo	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	79,091	24,808	16,615	9,784
Kibea	0	0	0	0	0	14,712	0	0	14,712	0	14,712	0	0	14,712	19.6	707,145	377,775	324,286	278,428
Maku	0	0	0	0	0	6,966	0	0	6,966	0	6,966	0	0	6,966	14.7	157,412	54,904	38,560	24,669
Total: East Doseo Total	**0**	**0**	**0**	**0**	**0**	**21,678**	**0**	**0**	**21,678**	**0**	**21,678**	**0**	**0**	**21,678**	**17.7**	**943,647**	**457,487**	**379,461**	**312,881**
Total: Total PPP	**0**	**5,080**	**0**	**5,080**	**0**	**63,902**	**0**	**0**	**63,902**	**0**	**63,902**	**0**	**0**	**63,902**	**34.5**	**3,342,927**	**2,085,212**	**1,884,025**	**1,711,122**

BOE Factors: HVY OIL 1.0 | RES GAS 6.0 | PROPANE 1.0 | ETHANE 1.0
COND 1.0 | SLN GAS 6.0 | BUTANE 1.0 | SULPHUR 0.0

Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **Summary**
$US Dollars

Reserve Class: **Possible**
Development Class: **Total**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production			
Year	Company Oil Wells	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	0	602	220	220	94.76
2014	0	2,338	853	853	91.73
2015	1	5,163	1,884	1,884	91.03
2016	3	7,701	2,811	2,811	90.31
2017	11	13,158	4,802	4,802	87.00
2018	13	11,961	4,366	4,366	86.66
2019	12	9,646	3,521	3,521	87.85
2020	6	5,794	2,115	2,115	89.88
2021	5	4,111	1,500	1,500	92.25
2022	6	3,410	1,245	1,245	94.43
2023	7	2,956	1,079	1,079	96.46
2024	7	2,621	957	957	98.61
Sub.			25,353	25,353	89.71
Rem.			6,785	6,785	113.99
Tot.			**32,138**	**32,138**	**94.84**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	20,814	0	0	20,814	0	20,814	0	0	0	0	0	20,814	16,902	0	16,902
2014	78,285	0	0	78,285	0	78,285	0	0	0	0	0	78,285	17,250	0	17,250
2015	171,545	0	0	171,545	0	171,545	0	0	0	0	0	171,545	25,305	0	25,305
2016	253,855	0	0	253,855	0	253,855	0	0	0	0	0	253,855	40,252	0	40,252
2017	417,825	0	0	417,825	0	417,825	0	0	0	0	0	417,825	52,937	0	52,937
2018	378,334	0	0	378,334	0	378,334	0	0	0	0	0	378,334	55,731	0	55,731
2019	309,286	0	0	309,286	0	309,286	0	0	0	0	0	309,286	49,603	0	49,603
2020	190,074	0	0	190,074	0	190,074	0	0	0	0	0	190,074	42,369	0	42,369
2021	138,413	0	0	138,413	0	138,413	0	0	0	0	0	138,413	35,186	0	35,186
2022	117,532	0	0	117,532	0	117,532	0	0	0	0	0	117,532	30,883	0	30,883
2023	104,077	0	0	104,077	0	104,077	0	0	0	0	0	104,077	28,368	0	28,368
2024	94,344	0	0	94,344	0	94,344	0	0	0	0	0	94,344	26,997	0	26,997
Sub.	2,274,385	0	0	2,274,385	0	2,274,385	0	0	0	0	0	2,274,385	421,783	0	421,783
Rem.	773,405	0	0	773,405	0	773,405	0	0	0	0	0	773,405	482,720	0	482,720
Tot.	**3,047,789**	**0**	**0**	**3,047,789**	**0**	**3,047,789**	**0**	**0**	**0**	**0**	**0**	**3,047,789**	**904,503**	**0**	**904,503**
Disc	1,485,490	0	0	1,485,490	0	1,485,490	0	0	0	0	0	1,485,490	323,400	0	323,400

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Net Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	3,912	-470	-111	3,553	-2,500	30,755	0	28,255	-24,702	-24,702	-23,553
2014	0	0	0	61,035	-1,316	-341	60,060	24,123	73,471	0	97,595	-37,534	-62,236	-56,087
2015	0	0	0	146,240	-1,009	-30	145,262	37,970	0	0	37,970	107,292	45,055	28,458
2016	0	0	0	213,603	3,442	966	216,078	99,111	0	0	99,111	116,968	162,023	112,247
2017	0	0	0	364,889	13,098	2,142	375,844	161,461	0	0	161,461	214,383	376,406	251,860
2018	0	0	0	322,603	17,376	2,471	337,508	67,369	0	0	67,369	270,139	646,545	411,789
2019	0	0	0	259,683	18,471	2,343	275,811	60,369	0	0	60,369	215,442	861,987	527,741
2020	0	0	0	147,705	14,140	1,862	159,983	0	0	0	0	159,983	1,021,971	606,017
2021	0	0	0	103,227	9,098	1,371	110,954	0	0	0	0	110,954	1,132,925	655,369
2022	0	0	0	86,649	6,294	1,076	91,867	0	0	0	0	91,867	1,224,792	692,517
2023	0	0	0	75,708	4,688	911	79,485	0	0	0	0	79,485	1,304,277	721,735
2024	0	0	0	67,348	3,691	818	70,221	0	0	0	0	70,221	1,374,498	745,202
Sub.	0	0	0	1,852,602	87,503	13,478	1,926,627	447,903	104,226	0	552,129	1,374,498	1,374,498	745,202
Rem.	0	0	0	290,684	14,654	5,039	300,300	0	0	0	0	300,300	1,674,798	812,843
Tot.	**0**	**0**	**0**	**2,143,286**	**102,157**	**18,517**	**2,226,927**	**447,903**	**104,226**	**0**	**552,129**	**1,674,798**	**1,674,798**	**812,843**
Disc	0	0	0	1,162,090	48,732	8,005	1,202,817	296,967	93,007	0	389,974	812,843	812,843	812,843

SUMMARY OF RESERVES

		Remaining Reserves at Jan 01, 2013				Oil Equivalents			Reserve Life Indic. (yr)		
Product	Units	Working Interest	Roy/NPI Interest	Total Company	Net	Oil Eq. Factor	Company Mboe	% of Total	Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	32,138	0	32,138	32,138	0.000	0	0	31.0	146.3	6.3
Total: Oil Eq.	Mboe	32,138	0	32,138	32,138	0.000	0	0	31.0	146.3	6.3

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	85.00	9.76	94.76	0.00	76.53	0.00	18.23	3,047,789	100	1,485,490	100
Total: Oil Eq.	$/boe	85.00	9.76	94.76	0.00	76.95	0.00	17.81	3,047,789	100	1,485,490	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)		
Entity Name	Initial	Average
Crown Royalty	0.0000	0.0000
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000

	Net Present Value Before Income Tax				
Disc. Rate %	Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	**Cash Flow** M$	$/boe
0.0	2,143,286	2,226,927	552,129	1,674,798	52.11
5.0	1,541,222	1,598,604	460,552	1,138,051	35.41
8.0	1,294,933	1,341,479	416,099	925,380	28.79
10.0	1,162,090	1,202,817	389,974	812,843	25.29
12.0	1,048,554	1,084,341	366,277	718,065	22.34
15.0	906,770	936,463	334,682	601,780	18.73
20.0	726,263	748,385	290,717	457,668	14.24

Evaluator: Herchen, Leonard L.
Run Date: January 22, 2013 10:03:20

Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **Summary**
$US Dollars

Reserve Class: **PPP**
Development Class: **Total**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production			
Year	Company Oil Wells	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	4	5,080	1,854	1,854	92.53
2014	10	14,632	5,341	5,341	90.16
2015	20	19,693	7,188	7,188	89.43
2016	26	22,360	8,161	8,161	88.50
2017	33	24,252	8,852	8,852	85.78
2018	32	18,651	6,808	6,808	85.76
2019	31	14,784	5,396	5,396	87.00
2020	24	9,809	3,580	3,580	88.89
2021	24	7,267	2,652	2,652	91.12
2022	25	5,929	2,164	2,164	93.22
2023	26	4,991	1,822	1,822	95.34
2024	27	4,309	1,573	1,573	97.48
Sub.			55,391	55,391	88.81
Rem.			8,512	8,512	111.39
Tot.			**63,902**	**63,902**	**91.82**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens														
	Working Interest				Royalty Interest	Company Interest	Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	171,555	0	0	171,555	0	171,555	0	0	0	0	0	171,555	48,551	0	48,551
2014	481,482	0	0	481,482	0	481,482	0	0	0	0	0	481,482	70,200	0	70,200
2015	642,797	0	0	642,797	0	642,797	0	0	0	0	0	642,797	89,200	0	89,200
2016	722,277	0	0	722,277	0	722,277	0	0	0	0	0	722,277	105,688	0	105,688
2017	759,347	0	0	759,347	0	759,347	0	0	0	0	0	759,347	110,409	0	110,409
2018	583,852	0	0	583,852	0	583,852	0	0	0	0	0	583,852	108,551	0	108,551
2019	469,440	0	0	469,440	0	469,440	0	0	0	0	0	469,440	93,645	0	93,645
2020	318,235	0	0	318,235	0	318,235	0	0	0	0	0	318,235	83,014	0	83,014
2021	241,687	0	0	241,687	0	241,687	0	0	0	0	0	241,687	73,602	0	73,602
2022	201,745	0	0	201,745	0	201,745	0	0	0	0	0	201,745	67,822	0	67,822
2023	173,675	0	0	173,675	0	173,675	0	0	0	0	0	173,675	64,100	0	64,100
2024	153,330	0	0	153,330	0	153,330	0	0	0	0	0	153,330	61,683	0	61,683
Sub.	4,919,422	0	0	4,919,422	0	4,919,422	0	0	0	0	0	4,919,422	976,464	0	976,464
Rem.	948,135	0	0	948,135	0	948,135	0	0	0	0	0	948,135	605,917	0	605,917
Tot.	**5,867,557**	**0**	**0**	**5,867,557**	**0**	**5,867,557**	**0**	**0**	**0**	**0**	**0**	**5,867,557**	**1,582,382**	**0**	**1,582,382**
Disc	3,348,529	0	0	3,348,529	0	3,348,529	0	0	0	0	0	3,348,529	696,683	0	696,683

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Net Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	123,003	129,935	433	252,506	52,750	139,263	0	192,013	60,493	60,493	57,678
2014	0	0	0	411,282	6,228	1,437	416,072	117,626	207,226	0	324,852	91,220	151,713	136,746
2015	0	0	0	553,597	16,556	2,580	567,572	241,229	0	0	241,229	326,343	478,056	393,899
2016	0	0	0	616,589	30,229	3,614	643,204	240,768	0	0	240,768	402,435	880,491	682,184
2017	0	0	0	648,938	38,065	4,123	682,881	190,047	0	0	190,047	492,833	1,373,325	1,003,131
2018	0	0	0	475,302	39,227	4,010	510,519	67,369	0	0	67,369	443,151	1,816,475	1,265,487
2019	0	0	0	375,796	35,625	3,547	407,873	60,369	0	0	60,369	347,504	2,163,979	1,452,516
2020	0	0	0	235,221	27,223	2,822	259,622	0	0	0	0	259,622	2,423,601	1,579,542
2021	0	0	0	168,086	19,325	2,156	185,255	0	0	0	0	185,255	2,608,855	1,661,943
2022	0	0	0	133,923	14,491	1,728	146,686	0	0	0	0	146,686	2,755,542	1,721,257
2023	0	0	0	109,574	11,319	1,433	119,460	0	0	0	0	119,460	2,875,002	1,765,171
2024	0	0	0	91,647	9,130	1,221	99,556	0	0	0	0	99,556	2,974,558	1,798,441
Sub.	0	0	0	3,942,957	377,352	29,104	4,291,205	970,158	346,489	0	1,316,647	2,974,558	2,974,558	1,798,441
Rem.	0	0	0	342,218	32,072	5,921	368,369	0	0	0	0	368,369	3,342,927	1,884,025
Tot.	**0**	**0**	**0**	**4,285,176**	**409,424**	**35,025**	**4,659,574**	**970,158**	**346,489**	**0**	**1,316,647**	**3,342,927**	**3,342,927**	**1,884,025**
Disc	0	0	0	2,651,846	274,048	18,516	2,907,377	710,950	312,402	0	1,023,352	1,884,025	1,884,025	1,884,025

SUMMARY OF RESERVES

		Remaining Reserves at Jan 01, 2013				Oil Equivalents			Reserve Life Indic. (yr)		
Product	Units	Working Interest	Roy/NPI Interest	Total Company	Net	Oil Eq. Factor	Company Mboe	% of Total	Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	63,902	0	63,902	63,902	0.000	0	0	31.0	34.5	5.1
Total: Oil Eq.	Mboe	63,902	0	63,902	63,902	0.000	0	0	31.0	34.5	5.1

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	85.00	7.53	92.53	0.00	25.77	0.00	66.76	5,867,557	100	3,348,529	100
Total: Oil Eq.	$/boe	85.00	7.53	92.53	0.00	26.19	0.00	66.34	5,867,557	100	3,348,529	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)		
Entity Name	Initial	Average
Crown Royalty	0.0000	0.0000
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000

	Net Present Value Before Income Tax				
Disc. Rate %	Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	**Cash Flow** M$	$/boe
0.0	4,285,176	4,659,574	1,316,647	3,342,927	52.31
5.0	3,306,190	3,608,975	1,153,873	2,455,101	38.42
8.0	2,885,194	3,157,476	1,072,264	2,085,212	32.63
10.0	2,651,846	2,907,377	1,023,352	1,884,025	29.48
12.0	2,448,374	2,689,417	978,295	1,711,122	26.78
15.0	2,188,301	2,411,011	917,080	1,493,931	23.38
20.0	1,845,688	2,044,607	829,360	1,215,247	19.02

Evaluator: Herchen, Leonard L.
Run Date: January 22, 2013 10:03:20

CONTINGENT RESOURCES

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Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **Summary**
$US Dollars

Resource Class: **Contingent Resources**
Development Class: **Low Estimate**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Summary of Resources and Values

	Low Estimate Contingent Resources
MARKETABLE RESOURCES	
Light/Medium Oil (Mbbl)	
Total Company Interest	3,949
Working Interest	3,949
Net After Royalty	3,949
Oil Equivalent (Mbbl)	
Total Company Interest	3,949
Working Interest	3,949
Net After Royalty	3,949
BEFORE TAX PRESENT VALUE (M$)	
0%	84,975
5%	27,761
8%	3,858
10%	-8,962
12%	-19,780
15%	-32,959
20%	-48,798
FIRST 6 YEARS BEFORE TAX CASH FLOW (M$)	
2013	-37,756
2014	-120,827
2015	-26,904
2016	54,078
2017	52,989
2018	44,268

BOE Factors: HVY OIL 1.0 COND 1.0 RES GAS 6.0 SLN GAS 6.0 PROPANE 1.0 BUTANE 1.0 ETHANE 1.0 SULPHUR 0.0

Run Date: January 22, 2013 10:03:20

Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **Summary**
$US Dollars

Resource Class: **Contingent Resources**
Development Class: **Low Estimate**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Company Production, Resources and Present Value Summary

Entity Description	2013 Company Interest Prod'n Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	Company Interest Resources Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Net After Royalty Resources Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Resource Life Index yrs	Before Income Tax Discounted Present Value (M$) 0%	8%	10%	12%
Summary																			
DOB/DOI Total																			
Badila	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
ITA Badila/Mangara	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Mangara	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0
Total: DOB/DOI Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0.0**	**0**	**0**	**0**	**0**
East Doseo Total																			
ITA East Doseo	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	37,459	12,340	8,386	5,045
Kibea	0	0	0	0	0	2,510	0	0	2,510	0	2,510	0	0	2,510	12.5	51,051	8,253	1,348	-4,525
Maku	0	0	0	0	0	1,439	0	0	1,439	0	1,439	0	0	1,439	7.8	-3,535	-16,735	-18,695	-20,300
Total: East Doseo Total	**0**	**0**	**0**	**0**	**0**	**3,949**	**0**	**0**	**3,949**	**0**	**3,949**	**0**	**0**	**3,949**	**10.3**	**84,975**	**3,858**	**-8,962**	**-19,780**
Total: Summary	**0**	**0**	**0**	**0**	**0**	**3,949**	**0**	**0**	**3,949**	**0**	**3,949**	**0**	**0**	**3,949**	**10.3**	**84,975**	**3,858**	**-8,962**	**-19,780**

BOE Factors:

HVY OIL	1.0	RES GAS	6.0	PROPANE	1.0	ETHANE	1.0
COND	1.0	SLN GAS	6.0	BUTANE	1.0	SULPHUR	0.0

Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **Summary**
$US Dollars

Resource Class: **Contingent Resources**
Development Class: **Low Estimate**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production			
Year	Company Oil Wells	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	0	0	0	0	0.00
2014	0	0	0	0	0.00
2015	4	1,055	385	385	75.29
2016	6	1,995	728	728	75.28
2017	6	1,783	651	651	72.91
2018	6	1,514	552	552	72.91
2019	6	1,157	422	422	74.19
2020	6	913	333	333	76.12
2021	6	654	239	239	78.09
2022	5	456	166	166	80.08
2023	5	386	141	141	82.13
2024	5	332	121	121	84.21
Sub.			3,739	3,739	75.41
Rem.			210	210	87.95
Tot.			**3,949**	**3,949**	**76.08**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	0	0	0	0	0	0	0	0	0	0	0	0	1,502	0	1,502
2014	0	0	0	0	0	0	0	0	0	0	0	0	1,022	0	1,022
2015	29,004	0	0	29,004	0	29,004	0	0	0	0	0	29,004	5,941	0	5,941
2016	54,831	0	0	54,831	0	54,831	0	0	0	0	0	54,831	8,811	0	8,811
2017	47,443	0	0	47,443	0	47,443	0	0	0	0	0	47,443	8,233	0	8,233
2018	40,281	0	0	40,281	0	40,281	0	0	0	0	0	40,281	7,710	0	7,710
2019	31,343	0	0	31,343	0	31,343	0	0	0	0	0	31,343	6,674	0	6,674
2020	25,361	0	0	25,361	0	25,361	0	0	0	0	0	25,361	6,173	0	6,173
2021	18,627	0	0	18,627	0	18,627	0	0	0	0	0	18,627	5,821	0	5,821
2022	13,317	0	0	13,317	0	13,317	0	0	0	0	0	13,317	5,585	0	5,585
2023	11,563	0	0	11,563	0	11,563	0	0	0	0	0	11,563	5,424	0	5,424
2024	10,211	0	0	10,211	0	10,211	0	0	0	0	0	10,211	5,320	0	5,320
Sub.	281,980	0	0	281,980	0	281,980	0	0	0	0	0	281,980	68,214	0	68,214
Rem.	18,485	0	0	18,485	0	18,485	0	0	0	0	0	18,485	13,265	0	13,265
Tot.	**300,465**	**0**	**0**	**300,465**	**0**	**300,465**	**0**	**0**	**0**	**0**	**0**	**300,465**	**81,478**	**0**	**81,478**
Disc	172,728	0	0	172,728	0	172,728	0	0	0	0	0	172,728	42,182	0	42,182

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	**Net Prod'n Revenue** M$	Other Income M$	**Aband. Costs** M$	**Oper. Income** M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	-1,502	-2,667	0	-4,168	13,933	19,655	0	33,588	-37,756	-37,756	-35,999
2014	0	0	0	-1,022	0	0	-1,022	35,768	84,037	0	119,805	-120,827	-158,583	-140,730
2015	0	0	0	23,063	8,389	232	31,220	58,124	0	0	58,124	-26,904	-185,487	-161,930
2016	0	0	0	46,020	15,859	443	61,436	7,358	0	0	7,358	54,078	-131,409	-123,191
2017	0	0	0	39,210	14,169	391	52,989	0	0	0	0	52,989	-78,420	-88,683
2018	0	0	0	32,571	12,030	333	44,268	0	0	0	0	44,268	-34,153	-62,476
2019	0	0	0	24,669	9,199	259	33,608	0	0	0	0	33,608	-544	-44,387
2020	0	0	0	19,189	7,255	209	26,235	0	0	0	0	26,235	25,691	-31,551
2021	0	0	0	12,806	5,822	171	18,457	0	0	0	0	18,457	44,147	-23,342
2022	0	0	0	7,732	4,775	143	12,364	0	0	0	0	12,364	56,511	-18,343
2023	0	0	0	6,139	3,978	121	9,995	0	0	0	0	9,995	66,506	-14,668
2024	0	0	0	4,891	3,368	105	8,153	0	0	0	0	8,153	74,660	-11,944
Sub.	0	0	0	213,767	82,175	2,407	293,534	115,183	103,692	0	218,874	74,660	74,660	-11,944
Rem.	0	0	0	5,220	5,225	130	10,315	0	0	0	0	10,315	84,975	-8,962
Tot.	**0**	**0**	**0**	**218,987**	**87,400**	**2,537**	**303,849**	**115,183**	**103,692**	**0**	**218,874**	**84,975**	**84,975**	**-8,962**
Disc	0	0	0	130,546	48,879	1,446	177,980	95,359	91,582	0	186,941	-8,962	-8,962	-8,962

SUMMARY OF RESOURCES

		Remaining Resources at Jan 01, 2013				Oil Equivalents			Resource Life Indic. (yr)		
Product	Units	Working Interest	Roy/NPI Interest	Total Company	Net	Oil Eq. Factor	Company Mboe	% of Total	Resource Life	Life Index	Half Life
Light/Med Oil	Mbbl	3,949	0	3,949	3,949	1.000	3,949	100	16.0	10.3	5.4
Total: Oil Eq.	Mboe	3,949	0	3,949	3,949	1.000	3,949	100	16.0	10.3	5.4

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	0.00	0.00	0.00	0.00	0.00	0.00	0.00	300,465	100	172,728	100
Total: Oil Eq.	$/boe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	300,465	100	172,728	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)		
Entity Name	Initial	Average
Crown Royalty	0.0000	0.0000
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000

	Net Present Value Before Income Tax				
Disc. Rate %	Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/boe
0.0	218,987	303,849	218,874	84,975	21.52
5.0	167,027	229,542	201,781	27,761	7.03
8.0	143,688	196,492	192,634	3,858	0.98
10.0	130,546	177,980	186,941	-8,962	-2.27
12.0	118,994	161,766	181,545	-19,780	-5.01
15.0	104,138	141,003	173,962	-32,959	-8.35
20.0	84,517	113,736	162,534	-48,798	-12.36

Evaluator: Herchen, Leonard L.
Run Date: January 22, 2013 10:03:20

SPE-PRMS RESOURCE AND RESERVES DEFINITIONS

GLJ Petroleum Consultants (GLJ) has prepared estimates of resources and reserves in accordance with the definitions and standards contained in the Petroleum Resources Management System (SPE-PRMS) prepared by the Society of Petroleum Engineers (SPE). The SPE-PRMS document was reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Evaluation Engineers (SPEE). The SPE-PRMS definitions and guidelines are similar to those contained in the Canadian Oil and Gas Evaluation (COGE) Handbook, which is referenced by the Canadian Securities Administrators in "National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities" and the standards normally used in Canadian oil and gas evaluations. Reserve and resource volumes derived under the SPE-PRMS and COGEH standards would not generally be materially different. The following are excerpts from the SPE-PRMS.

A. Fundamental Resource Definitions

Total Petroleum Initially-In-Place (PIIP) 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 (equivalent to discovered resources) is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

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 (equivalent to undiscovered resources) is that quantity of petroleum estimated, on 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.

B. Uncertainty Categories for Resource Estimates

The range of uncertainty of estimated recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

Low Estimate: There should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

Best Estimate: There should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

High Estimate: There should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines.

These same approaches to describing uncertainty may be applied to reserves, contingent resources, and prospective resources. There may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production. However, it is useful to consider and identify the range of potentially recoverable quantities independently of such risk or consideration of the resource class to which the quantities will be assigned.

C. Reserves Categories

The following summarizes the definitions of each Reserves category in terms of both the deterministic incremental approach and scenario approach and also provides the probability criteria if probabilistic methods are applied.

Proved Reserves
Proved reserves are those quantities of petroleum, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

Probable Reserves
Probable reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated proved plus probable reserves (2P).

In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

Possible Reserves
Possible reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of proved plus probable plus possible (3P) reserves, which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

Development and Production Status

Each of the reserves categories (proved, probable, and possible) may be divided into developed and undeveloped categories.

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

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

Developed Non-producing Reserves
Developed non-producing reserves include shut-in and behind-pipe reserves.

Undeveloped Reserves
Undeveloped reserves are quantities expected to be recovered through future investments.

D. Discovered and Commercial

Discovery Status

A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons.

In this context, “significant” implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume determined by the well(s) and for evaluating the potential for economic recovery.

Commercial Status

Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:

- Evidence to support a reasonable timetable for development;
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria;
- A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development;

- Evidence that the necessary production and transportation facilities are available or can be made available;
- Evidence that legal, contractual, environmental, governmental, and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.

E. Economic Status of Resource Estimates

Projects may be further characterized by their Economic Status. All projects classified as Reserves must be economic under defined conditions. Based on assumptions regarding future conditions and their impact on ultimate economic viability, projects currently classified as Contingent Resources may be broadly divided into two groups:

Marginal Contingent Resources are those quantities associated with technically feasible projects that are either currently economic or projected to be economic under reasonably forecasted improvements in commercial conditions but are not committed for development because of one or more contingencies.

Sub-Marginal Contingent Resources are those quantities associated with discoveries for which analysis indicates that technically feasible development projects would not be economic and/or other contingencies would not be satisfied under current or reasonably forecasted improvements in commercial conditions. These projects nonetheless should be retained in the inventory of discovered resources pending unforeseen major changes in commercial conditions.

Where evaluations are incomplete such that it is premature to clearly define ultimate chance of commerciality, it is acceptable to note that project economic status is “undetermined” (i.e., “contingent resources – economic status undetermined”).

EVALUATION PROCEDURE

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EVALUATION PROCEDURE

The following outlines the methodology employed by GLJ Petroleum Consultants (GLJ) in conducting the evaluation of the Company's oil and gas properties. This evaluation has been prepared in accordance with resource and reserves definitions, standards and guidelines contained in the Petroleum Resources Management System (PRMS) of the Society of Petroleum Engineers (SPE).

INTEREST DESCRIPTIONS

The Company provided GLJ with current PSC information establishing the Company's entitlement to oil. In addition, the Company provided the summary information describing the economic terms of the Glencore Farm-In. The Company provided a representation letter confirming accuracy of land information.

In GLJ's reports, "Company Interest" reserves, resources and values associated with the PSC's, refer to the sum of cost oil and profit oil and are equivalent to "Working Interest" reserves and resources in this case.

Royalty interest reserves and resources include royalty volumes derived only from other working interest or participating owners. Through the terms of the PSC's in which the Company participates, no royalty interests or burdens are earned or paid on cost oil or profit oil attributable to the Company.

WELL DATA

Pertinent interest and offset well data such as drill stem tests, workovers, pressure surveys, production tests, etc., were provided by the Company or were obtained from other operators, public records or GLJ's nonconfidential files.

ACCOUNTING SUMMARY

As the subject fields are non-producing, no operating statements are available. The Company provided GLJ with detailed capital and operating budget information and capital expenditures to date.

PRODUCTION FORECASTS

In establishing all production forecasts, consideration was given to the Company's plans for development drilling and to reserves, resources and well capability. Generally, development drilling in an area was not considered unless there was some indication from the Company's that drilling could be expected.

The on-stream date for currently undeveloped reserves and resources was estimated with consideration given to the following:

- Proximity to existing facilities
- Plans of the Company
- Economics

OTHER INCOME

The following streams are included as "Other Income" in the Company's corporate total economic forecasts:

- Processing Income – No processing income is forecast.
- Tariff income from ITAs.
- Bonuses payable to Chadian government.
- Glencore carry capital for recovery of sunk costs.

ECONOMIC PARAMETERS

Pertinent economic parameters are listed as follows:

a) The effective date is December 31 , 2012.

b) Operating and capital costs were estimated in 2013 dollars and then escalated as summarized in the Product Price and Market Forecasts section of this report.

c) Economic forecasts were prepared for each property on a before income tax basis. Detailed discounting of future cash flow was performed using a discount factor of 10.0 percent with all values discounted annually to December 31, 2012, on a mid-calendar-year basis.

d) Field level overhead charges have been included; G&A expenses have been included and are cost recoverable.

e) It was assumed that the Company would carry the Republic of Chad's 25 percent capital and operating costs and that this carried cost would be cost recoverable. Chad's participation is expected to occur through the Société des Hydrocarbures du Tchad (SHT), the state oil company of Chad.

f) Well abandonment costs for all wells with reserves and resources have been included at the property level. Additional abandonment costs associated with non-reserves wells, lease reclamation costs and facility abandonment and reclamation expenses have not been included in this analysis.

g) No allowance for any hedging activity of the Company was made.

OIL EQUIVALENT OR GAS EQUIVALENT

In this report, quantities of hydrocarbons have been converted to barrels of oil equivalent (boe); or to sales gas equivalent (sge) using factors of 6 Mcf/boe for gas, 1 bbl/boe for all liquids, and 0 boe for sulphur. Users of oil equivalent values are cautioned that while boe based metrics are useful for comparative purposes, they may be misleading when used in isolation.

LIST OF ABBREVIATIONS

AOF	absolute open flow
bbl	barrels
Bcf	billion cubic feet of gas at standard conditions
boe	barrel of oil equivalent, in this evaluation determined using 6 Mcf/boe for gas, 1 bbl/boe for all liquids, and 0 boe for sulphur
bopd	barrels of oil per day
Btu	British thermal units
bwpd	barrels of water per day
DSU	drilling spacing unit
GCA	gas cost allowance
GOC	gas-oil contact
GOR	gas-oil ratio
GORR	gross overriding royalty
GWC	gas-water contact
Mbbl	thousand barrels
Mboe	thousand boe
Mcf	thousand cubic feet of gas at standard conditions

Mcfe	thousand cubic feet of gas equivalent
Mlt	thousand long tons
M$	thousand U.S. dollars
MM$	million U.S. dollars
MMbbl	million barrels
MMboe	million boe
MMBtu	million British thermal units
MMcf	million cubic feet of gas at standard conditions
MRL	maximum rate limitation
Mstb	thousand stock tank barrels
MMstb	million stock tank barrels
NGL	natural gas liquids (ethane, propane, butane and condensate)
NPI	net profits interest
OGIP	original gas-in-place
OOIP	original oil-in-place
ORRI	overriding royalty interest
OWC	oil-water contact
P&NG	petroleum and natural gas
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PVT	pressure-volume-temperature
RLI	reserves life index, calculated by dividing reserves by the forecast of first year production
scf	standard cubic feet
sge	sales gas equivalent – if presented in this evaluation, determined using 1 barrel of oil or natural gas liquid = 6 Mcfe; 0 for sulphur
stb	stock tank barrel
WI	working interest
WTI	West Texas Intermediate

PRODUCT PRICE AND MARKET FORECASTS
January 1, 2013

GLJ Petroleum Consultants has prepared its January 1, 2013 price and market forecasts as summarized in the attached Tables 1 and 2 after a comprehensive review of information. Information sources include numerous government agencies, industry publications, Canadian oil refiners and natural gas marketers. The forecasts presented herein are based on an informed interpretation of currently available data. While these forecasts are considered reasonable at this time, users of these forecasts should understand the inherent high uncertainty in forecasting any commodity or market. These forecasts will be revised periodically as market, economic and political conditions change. These future revisions may be significant. Operating and capital costs were inflated using the inflation rate forecast presented in Table 1.

It is expected that the produced crude can be sold to the West African crude market and will compete with other light crudes in that area. Based on the oil density and historical relationships between Brent crude and West African crudes, it was forecast that the received price for the crude will be 95 percent of Brent, less a forecast pipeline tariff of $6.50/bbl for the export pipeline through Cameroon and an additional ITA tariff. As the ITA tariff is a capital cost and volume dependent, different received prices are forecast in each reserves or resource class.

Table 1
GLJ Petroleum Consultants Ltd.
Crude Oil and Natural Gas Liquids
Price Forecast
Effective January 1, 2013

Year	Inflation %	Bank of Canada Average Noon Exchange Rate USD/CAD	NYMEX WTI Near Month Futures Contract Crude Oil at Cushing Oklahoma Constant 2013 $ USD/bbl	NYMEX WTI Near Month Futures Contract Crude Oil at Cushing Oklahoma Then Current USD/bbl	ICE Brent Near Month Futures Contract Crude Oil FOB North Sea Then Current USD/bbl	Light Sweet Crude Oil (40 API, 0.3%S) at Edmonton Then Current CAD/bbl	Bow River Crude Oil Stream Quality at Hardisty Then Current CAD/bbl	Lloyd Blend Crude Oil Stream Quality at Hardisty Then Current CAD/bbl	WCS Stream Quality at Hardisty Then Current CAD/bbl	Heavy Crude Oil Proxy (12 API) at Hardisty Then Current CAD/bbl	Light Crude Oil (35 API, 1.2%S) at Cromer Then Current CAD/bbl	Medium Crude Oil (29 API, 2.0%S) at Cromer Then Current CAD/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Spec Ethane CAD/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Edmonton Propane CAD/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Edmonton Butane CAD/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Edmonton Pentanes Plus CAD/bbl
2000	2.7	0.673	39.71	30.23	28.41	44.57	35.28	32.61	N/A	27.49	43.28	39.92	N/A	32.15	35.59	46.31
2001	2.5	0.646	33.27	26.00	24.87	39.44	27.69	23.47	N/A	16.77	35.22	31.58	N/A	31.92	31.25	42.48
2002	2.3	0.637	32.52	26.08	25.02	40.33	31.83	30.60	N/A	26.57	37.43	35.48	N/A	21.39	27.08	40.73
2003	2.8	0.716	37.90	31.07	28.47	43.66	32.11	31.18	N/A	26.26	40.09	37.55	N/A	32.14	34.36	44.23
2004	1.8	0.770	49.12	41.38	38.02	52.96	37.43	36.31	N/A	29.11	49.14	45.64	N/A	34.70	39.97	53.94
2005	2.2	0.826	65.93	56.58	55.14	69.02	44.73	43.03	43.74	34.07	62.18	56.77	N/A	43.04	51.80	69.57
2006	2.0	0.882	75.49	66.22	66.16	73.21	51.82	50.36	50.66	41.84	66.38	62.26	N/A	43.85	60.17	75.41
2007	2.2	0.935	80.90	72.39	72.71	77.06	53.64	52.03	52.38	43.42	71.13	65.71	N/A	49.56	61.78	77.38
2008	2.4	0.943	108.98	99.64	98.30	102.89	84.31	82.60	82.95	74.94	96.08	93.10	N/A	58.38	75.33	104.78
2009	0.4	0.880	65.95	61.78	62.50	66.32	60.18	58.40	58.66	54.46	63.84	62.96	N/A	38.03	48.17	68.17
2010	1.8	0.971	84.62	79.52	80.25	77.87	68.45	66.95	67.27	60.76	76.58	73.76	N/A	46.84	65.91	84.27
2011	2.9	1.012	99.46	95.12	110.86	95.53	78.58	76.84	77.14	67.64	92.35	88.33	N/A	53.66	74.42	104.17
2012	1.6	1.001	95.62	94.10	111.60	86.86	74.78	73.22	73.29	63.87	84.76	81.56	N/A	28.97	66.23	101.06
2013 Q1	2.0	1.000	90.00	90.00	110.00	82.50	67.65	66.00	66.20	55.10	80.85	77.55	10.63	28.88	63.53	99.00
2013 Q2	2.0	1.000	90.00	90.00	105.00	85.00	72.25	70.55	70.75	61.39	83.30	79.90	10.63	34.00	65.45	97.75
2013 Q3	2.0	1.000	90.00	90.00	102.50	85.00	72.25	70.55	70.75	62.66	83.30	79.90	11.25	34.00	65.45	93.50
2013 Q4	2.0	1.000	90.00	90.00	102.50	87.50	74.38	72.63	72.83	64.54	85.75	82.25	11.87	39.38	67.38	96.25
2013 Full Year	2.0	1.000	90.00	90.00	105.00	85.00	71.63	69.93	70.13	60.92	83.30	79.90	11.09	34.06	65.45	96.63
2014	2.0	1.000	90.69	92.50	102.50	91.50	77.77	75.94	76.15	68.36	87.84	84.18	12.65	45.75	70.46	97.91
2015	2.0	1.000	91.31	95.00	102.50	94.00	79.90	78.02	78.22	71.10	90.24	86.48	14.20	56.40	72.38	97.76
2016	2.0	1.000	91.88	97.50	102.50	96.50	82.03	80.09	80.29	73.02	92.64	88.78	15.75	57.90	74.31	100.36
2017	2.0	1.000	90.07	97.50	100.00	96.50	82.03	80.09	80.29	73.02	92.64	88.78	16.53	57.90	74.31	100.36
2018	2.0	1.000	88.31	97.50	100.00	96.50	82.03	80.09	80.29	73.02	92.64	88.78	17.46	57.90	74.31	100.36
2019	2.0	1.000	87.50	98.54	101.35	97.54	82.91	80.96	81.16	73.81	93.64	89.74	17.81	58.52	75.11	101.44
2020	2.0	1.000	87.50	100.51	103.38	99.51	84.58	82.59	82.79	75.32	95.53	91.55	18.18	59.71	76.62	103.49
2021	2.0	1.000	87.50	102.52	105.45	101.52	86.29	84.26	84.46	76.87	97.46	93.40	18.55	60.91	78.17	105.58
2022	2.0	1.000	87.50	104.57	107.55	103.57	88.03	85.96	86.16	78.44	99.43	95.28	18.92	62.14	79.75	107.71
2023+	2.0	1.000	87.50	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Historical futures contract price is an average of the daily settlement price of the near month contract over the calendar month.

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Table 2
GLJ Petroleum Consultants Ltd.
Natural Gas and Sulphur
Price Forecast
Effective January 1, 2013

	NYMEX Henry Hub Near Month Contract		Midwest		Alberta Plant Gate				Saskatchewan Plant Gate			British Columbia			Alberta
					Spot									Sulphur	
	Constant 2013 $	Then Current	Price @ Chicago Then Current	AECO/NIT Spot Then Current	Constant 2013 $	Then Current	ARP	Alliance	SaskEnergy	Spot	Sumas Spot	Westcoast Station 2	Spot Plant Gate	FOB Vancouver	Sulphur at Plant Gate
Year	USD/MMBtu	USD/MMBtu	USD/MMBtu	CAD/MMBtu	CAD/MMBtu	CAD/MMBtu	CAD/MMBtu	CAD/MMBtu	CAD/MMBtu	CAD/MMBtu	USD/MMBtu	CAD/MMBtu	CAD/MMBtu	USD/lt	CAD/lt
2000	5.66	4.32	3.96	5.80	6.46	4.93	4.50	N/A	4.79	4.99	4.15	5.06	4.88	38.14	13.59
2001	5.17	4.03	4.45	5.65	7.79	6.07	5.41	5.31	5.72	6.15	4.57	6.32	6.29	18.29	-14.67
2002	4.19	3.36	3.25	4.27	4.84	3.88	3.88	3.65	4.04	3.96	2.68	4.18	3.93	29.38	3.04
2003	6.67	5.47	5.46	6.73	7.92	6.49	6.13	6.15	6.41	6.57	4.66	6.45	6.32	59.81	39.83
2004	7.34	6.18	6.13	6.90	7.95	6.70	6.31	6.39	6.48	6.78	5.26	6.56	6.45	62.99	38.61
2005	10.48	9.00	8.24	9.06	9.80	8.42	8.30	8.27	8.36	8.48	7.13	8.22	8.12	63.50	33.77
2006	7.97	6.99	6.93	6.71	7.94	6.96	6.57	6.36	6.67	7.06	6.27	6.58	6.45	55.07	19.27
2007	7.95	7.12	6.83	6.59	7.19	6.43	6.20	5.86	6.18	6.55	6.52	6.40	6.25	81.66	42.03
2008	9.73	8.90	8.91	8.25	8.66	7.92	7.88	7.83	8.07	8.04	8.33	8.21	8.09	497.39	488.64
2009	4.45	4.16	4.05	4.16	4.26	3.98	3.85	3.23	3.87	4.04	3.91	4.17	4.04	57.06	24.57
2010	4.68	4.40	4.53	4.03	4.18	3.93	3.77	3.31	3.96	4.00	4.31	4.01	3.91	88.94	48.26
2011	4.21	4.03	4.21	3.62	3.67	3.51	3.46	2.84	3.57	3.67	3.93	3.39	3.31	217.16	171.93
2012	2.88	2.83	2.92	2.45	2.26	2.23	2.22	1.65	2.27	2.29	2.77	2.35	2.24	201.03	157.91
2013 Q1	3.60	3.60	3.70	3.24	3.05	3.05	2.99	2.40	3.09	3.16	3.70	3.04	2.87	175.00	132.00
2013 Q2	3.60	3.60	3.70	3.24	3.05	3.05	2.99	2.40	3.09	3.16	3.20	3.04	2.87	175.00	132.00
2013 Q3	3.80	3.80	3.90	3.42	3.23	3.23	3.17	2.60	3.27	3.34	3.40	3.22	3.05	175.00	132.00
2013 Q4	4.00	4.00	4.10	3.60	3.41	3.41	3.34	2.79	3.44	3.52	4.10	3.40	3.23	175.00	132.00
2013 Full Year	3.75	3.75	3.85	3.38	3.19	3.19	3.12	2.55	3.22	3.30	3.60	3.18	3.00	175.00	132.00
2014	4.17	4.25	4.35	3.83	3.56	3.63	3.56	3.03	3.66	3.74	4.10	3.63	3.45	150.00	107.00
2015	4.57	4.75	4.85	4.28	3.92	4.08	4.00	3.51	4.10	4.20	4.60	4.08	3.90	125.00	82.00
2016	4.95	5.25	5.35	4.72	4.27	4.53	4.44	3.99	4.54	4.64	5.10	4.52	4.34	125.00	82.00
2017	5.08	5.50	5.60	4.95	4.39	4.75	4.66	4.23	4.76	4.87	5.35	4.75	4.57	127.50	84.50
2018	5.25	5.80	5.90	5.22	4.55	5.02	4.92	4.52	5.02	5.14	5.65	5.02	4.83	130.05	87.05
2019	5.25	5.91	6.01	5.32	4.54	5.12	5.01	4.62	5.11	5.24	5.76	5.12	4.93	132.65	89.65
2020	5.25	6.03	6.13	5.43	4.55	5.22	5.12	4.74	5.22	5.35	5.88	5.23	5.04	135.30	92.30
2021	5.25	6.15	6.25	5.54	4.55	5.33	5.22	4.85	5.32	5.46	6.00	5.34	5.15	138.01	95.01
2022	5.25	6.27	6.37	5.64	4.55	5.44	5.33	4.97	5.43	5.56	6.12	5.44	5.25	140.77	97.77
2023+	5.25	+2.0%/yr	+2.0%/yr	+2.0%/yr	4.55	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate.
The plant gate price represents the price before raw gas gathering and processing charges are deducted.
AECO-C Spot refers to the one month price averaged for the year.

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AFTER TAX ANALYSIS

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AFTER TAX ANALYSIS

Chadian income taxes were calculated based on current federal tax rates, tax regulations and tax pool information provided by the Company. After tax values for reserves development status or production status subcategories (i.e. developed, undeveloped, producing, non-producing) are calculated by difference. Only the ITA entities are subject to income tax. The PSCs preclude payment of income tax associated with field production.

Tax Pools

Capital costs of 16,430 M$ were expended prior to the effective date and are included as a depreciable cost. Depreciation is 20 percent per year for five years.

Tax Rates

Federal income tax calculations incorporate recently enacted reductions in general corporate income tax rates as follows:

Year	Federal Income Tax Rate
2012+	40.0%

Company total after tax economic forecasts for all reserves categories are attached.

Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **After Tax Analysis**
$US Dollars

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Summary of Reserves and Values

	Proved Producing	Proved Developed Non-producing	Proved Undeveloped	Total Proved	Total Probable	Total Proved Plus Probable	Total Possible	Total PPP	Low Estimate Contingent Resources
MARKETABLE RESERVES									
Light/Medium Oil (Mbbl)									
Total Company Int.	0	0	11,251	11,251	20,514	31,765	32,138	63,902	3,949
Working Interest	0	0	11,251	11,251	20,514	31,765	32,138	63,902	3,949
Net After Royalty	0	0	11,251	11,251	20,514	31,765	32,138	63,902	3,949
Oil Equivalent (Mbbl)									
Total Company Int.	0	0	11,251	11,251	20,514	31,765	32,138	63,902	3,949
Working Interest	0	0	11,251	11,251	20,514	31,765	32,138	63,902	3,949
Net After Royalty	0	0	11,251	11,251	20,514	31,765	32,138	63,902	3,949
BEFORE TAX PRESENT VALUE (M$)									
0%	0	0	699,100	699,100	969,029	1,668,130	1,674,798	3,342,927	84,975
5%	0	0	619,077	619,077	697,973	1,317,050	1,138,051	2,455,101	27,761
8%	0	0	578,947	578,947	580,884	1,159,831	925,380	2,085,212	3,858
10%	0	0	554,870	554,870	516,311	1,071,182	812,843	1,884,025	-8,962
12%	0	0	532,665	532,665	460,393	993,057	718,065	1,711,122	-19,780
15%	0	0	502,438	502,438	389,713	892,150	601,780	1,493,931	-32,959
20%	0	0	458,955	458,955	298,624	757,579	457,668	1,215,247	-48,798
AFTER TAX PRESENT VALUE (M$)									
0%	0	0	694,969	694,969	946,187	1,641,156	1,662,593	3,303,750	70,343
5%	0	0	615,761	615,761	683,905	1,299,666	1,130,666	2,430,332	18,258
8%	0	0	576,016	576,016	570,182	1,146,198	919,806	2,066,004	-3,588
10%	0	0	552,163	552,163	507,337	1,059,500	808,191	1,867,690	-15,327
12%	0	0	530,157	530,157	452,834	982,991	714,164	1,697,155	-25,244
15%	0	0	500,194	500,194	383,825	884,019	598,762	1,482,781	-37,338
20%	0	0	457,071	457,071	294,678	751,748	455,666	1,207,415	-51,883

BOE Factors: HVY OIL 1.0 COND 1.0 RES GAS 6.0 SLN GAS 6.0 PROPANE 1.0 BUTANE 1.0 ETHANE 1.0 SULPHUR 0.0

Run Date: January 22, 2013 10:04:57

Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **After Tax Analysis**
$US Dollars

Reserve Class: **Proved**
Development Class: **Undeveloped**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production			
Year	Company Oil Wells	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	4	3,633	1,326	1,326	91.55
2014	9	8,243	3,009	3,009	89.18
2015	12	6,817	2,488	2,488	89.18
2016	13	4,502	1,643	1,643	89.18
2017	14	2,981	1,088	1,088	86.80
2018	13	1,885	688	688	86.80
2019	13	1,334	487	487	88.08
2020	13	838	306	306	90.01
2021	12	484	177	177	91.98
2022	2	107	39	39	93.97
2023	0	0	0	0	0.00
2024	0	0	0	0	0.00
Sub.			11,251	11,251	89.12
Rem.			0	0	0.00
Tot.			**11,251**	**11,251**	**89.12**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	121,399	0	0	121,399	0	121,399	0	0	0	0	0	121,399	17,004	0	17,004
2014	268,317	0	0	268,317	0	268,317	0	0	0	0	0	268,317	33,183	0	33,183
2015	221,882	0	0	221,882	0	221,882	0	0	0	0	0	221,882	31,564	0	31,564
2016	146,534	0	0	146,534	0	146,534	0	0	0	0	0	146,534	25,939	0	25,939
2017	94,444	0	0	94,444	0	94,444	0	0	0	0	0	94,444	22,248	0	22,248
2018	59,726	0	0	59,726	0	59,726	0	0	0	0	0	59,726	20,524	0	20,524
2019	42,892	0	0	42,892	0	42,892	0	0	0	0	0	42,892	18,159	0	18,159
2020	27,529	0	0	27,529	0	27,529	0	0	0	0	0	27,529	17,231	0	17,231
2021	16,254	0	0	16,254	0	16,254	0	0	0	0	0	16,254	12,568	0	12,568
2022	3,654	0	0	3,654	0	3,654	0	0	0	0	0	3,654	3,452	0	3,452
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sub.	1,002,631	0	0	1,002,631	0	1,002,631	0	0	0	0	0	1,002,631	201,871	0	201,871
Rem.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tot.	**1,002,631**	**0**	**0**	**1,002,631**	**0**	**1,002,631**	**0**	**0**	**0**	**0**	**0**	**1,002,631**	**201,871**	**0**	**201,871**
Disc	770,256	0	0	770,256	0	770,256	0	0	0	0	0	770,256	140,257	0	140,257

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Net Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	104,394	133,901	671	237,624	49,982	59,821	0	109,803	127,822	127,822	121,873
2014	0	0	0	235,133	8,540	1,853	241,821	40,256	7,824	0	48,080	193,741	321,562	289,804
2015	0	0	0	190,318	8,188	1,994	196,512	39,032	0	0	39,032	157,480	479,042	413,896
2016	0	0	0	120,595	5,071	1,384	124,283	37,654	0	0	37,654	86,628	565,670	475,953
2017	0	0	0	72,196	3,028	865	74,359	22,434	0	0	22,434	51,926	617,596	509,768
2018	0	0	0	39,202	2,010	604	40,608	0	0	0	0	40,608	658,204	533,809
2019	0	0	0	24,733	1,380	431	25,682	0	0	0	0	25,682	683,887	547,632
2020	0	0	0	10,299	837	253	10,883	0	0	0	0	10,883	694,770	552,956
2021	0	0	0	3,687	432	85	4,034	0	0	0	0	4,034	698,804	554,751
2022	0	0	0	202	98	4	296	0	0	0	0	296	699,100	554,870
2023	0	0	0	0	0	0	0	0	0	0	0	0	699,100	554,870
2024	0	0	0	0	0	0	0	0	0	0	0	0	699,100	554,870
Sub.	0	0	0	800,760	163,486	8,144	956,102	189,358	67,644	0	257,002	699,100	699,100	554,870
Rem.	0	0	0	0	0	0	0	0	0	0	0	0	699,100	554,870
Tot.	**0**	**0**	**0**	**800,760**	**163,486**	**8,144**	**956,102**	**189,358**	**67,644**	**0**	**257,002**	**699,100**	**699,100**	**554,870**
Disc	0	0	0	629,999	149,703	6,125	773,578	154,889	63,818	0	218,707	554,870	554,870	554,870

AFTER TAX ANALYSIS

Year	Oper. Income M$	Tax Pool Balances Incl. Current Year Additions: CCA M$	COGPE M$	CDE M$	CEE M$	Other M$	Depreciation & Writeoffs: CCA M$	COGPE M$	CDE M$	CEE M$	Other M$	Total M$
2013	237,624	0	0	5,691	0	0	0	0	0	0	0	0
2014	241,821	0	0	5,691	0	0	0	0	0	0	0	0
2015	196,512	0	0	5,691	0	0	0	0	0	0	0	0
2016	124,283	0	0	5,691	0	0	0	0	0	0	0	0
2017	74,359	0	0	5,691	0	0	0	0	0	0	0	0
2018	40,608	0	0	5,691	0	0	0	0	0	0	0	0
2019	25,682	0	0	5,691	0	0	0	0	0	0	0	0
2020	10,883	0	0	5,691	0	0	0	0	0	0	0	0
2021	4,034	0	0	5,691	0	0	0	0	0	0	0	0
2022	296	0	0	5,691	0	0	0	0	0	0	0	0
2023	0	0	0	5,691	0	0	0	0	0	0	0	0
2024	0	0	0	5,691	0	0	0	0	0	0	0	0
Sub.	956,102	0	0	5,691	0	0	0	0	0	0	0	0
Rem.	0	0	0	5,691	0	0	0	0	0	0	0	0
Tot.	**956,102**	**0**	**0**	**5,691**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Disc	773,578						0	0	0	0	0	0

Year	Taxable Income M$	Federal Income Tax M$	Provincial Income Tax M$	ARTD & Investment Credits	Income Tax Payable M$	Net Cash Flow Before Income Tax: Annual M$	Cum. M$	10.0% Dcf M$	Net Cash Flow After Income Tax: Annual M$	Cum. M$	10.0% Dcf M$
2013	2,599	0	0	0	0	127,822	127,822	121,873	127,822	127,822	121,873
2014	7,035	0	0	0	0	193,741	321,562	289,804	193,741	321,562	289,804
2015	6,746	1,226	0	0	1,226	157,480	479,042	413,896	156,254	477,816	412,930
2016	4,178	340	0	0	340	86,628	565,670	475,953	86,289	564,105	474,743
2017	2,495	998	0	0	998	51,926	617,596	509,768	50,928	615,033	507,909
2018	1,656	663	0	0	663	40,608	658,204	533,809	39,946	654,979	531,558
2019	1,137	455	0	0	455	25,682	683,887	547,632	25,228	680,206	545,135
2020	690	276	0	0	276	10,883	694,770	552,956	10,607	690,813	550,325
2021	341	142	0	0	142	4,034	698,804	554,751	3,892	694,705	552,056
2022	63	32	0	0	32	296	699,100	554,870	264	694,969	552,163
2023	0	0	0	0	0	0	699,100	554,870	0	694,969	552,163
2024	0	0	0	0	0	0	699,100	554,870	0	694,969	552,163
Sub.	26,939	4,131	0	0	4,131	699,100	699,100	554,870	694,969	694,969	552,163
Rem.	0	0	0	0	0	0	699,100	554,870	0	694,969	552,163
Tot.	**26,939**	**4,131**	**0**	**0**	**4,131**	**699,100**	**699,100**	**554,870**	**694,969**	**694,969**	**552,163**
Disc	20,616	2,707	0	0	2,707	554,870	554,870	554,870	552,163	552,163	552,163

SUMMARY OF RESERVES

Product	Units	Remaining Reserves at Jan 01, 2013: Working Interest	Roy/NPI Interest	Total Company	Net	Oil Equivalents: Oil Eq. Factor	Company Mboe	% of Total	Reserve Life Indic. (yr): Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	11,251	0	11,251	11,251	1.000	11,251	100	10.0	8.5	2.5
Total: Oil Eq.	Mboe	11,251	0	11,251	11,251	1.000	11,251	100	10.0	8.5	2.5

PRODUCT REVENUE AND EXPENSES

Product	Units	Average First Year Unit Values: Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Net Revenue After Royalties: Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	85.00	6.55	91.55	0.00	12.40	0.00	79.15	1,002,631	100	770,256	100
Total: Oil Eq.	$/boe	85.00	6.55	91.55	0.00	12.82	0.00	78.73	1,002,631	100	770,256	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)			Disc. Rate	Net Present Value Before Income Tax					Net Present Value After Income Tax			
				Prod'n Revenue	Operating Income	Capital Invest.	Cash Flow		Operating Income	Capital Invest.	Cash Flow	
Entity Name	Initial	Average	%	M$	M$	M$	M$	$/boe	M$	M$	M$	$/boe
Crown Royalty	0.0000	0.0000	0.0	800,760	956,102	257,002	699,100	62.14	951,971	257,002	694,969	61.77
Non-crown Royalty	0.0000	0.0000	5.0	706,203	855,225	236,148	619,077	55.02	851,909	236,148	615,761	54.73
Mineral Tax	0.0000	0.0000	8.0	658,607	804,273	225,326	578,947	51.46	801,342	225,326	576,016	51.20
			10.0	629,999	773,578	218,707	554,870	49.32	770,870	218,707	552,163	49.08
			12.0	603,581	745,180	212,516	532,665	47.34	742,673	212,516	530,157	47.12
			15.0	567,574	706,386	203,948	502,438	44.66	704,142	203,948	500,194	44.46
			20.0	515,697	650,278	191,323	458,955	40.79	648,394	191,323	457,071	40.63

Evaluator: Herchen, Leonard L.
Run Date: January 22, 2013 10:04:56

Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **After Tax Analysis**
$US Dollars

Reserve Class: **Proved**
Development Class: **Total**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production			
Year	Company Oil Wells	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	4	3,633	1,326	1,326	91.55
2014	9	8,243	3,009	3,009	89.18
2015	12	6,817	2,488	2,488	89.18
2016	13	4,502	1,643	1,643	89.18
2017	14	2,981	1,088	1,088	86.80
2018	13	1,885	688	688	86.80
2019	13	1,334	487	487	88.08
2020	13	838	306	306	90.01
2021	12	484	177	177	91.98
2022	2	107	39	39	93.97
2023	0	0	0	0	0.00
2024	0	0	0	0	0.00
Sub.			11,251	11,251	89.12
Rem.			0	0	0.00
Tot.			**11,251**	**11,251**	**89.12**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	121,399	0	0	121,399	0	121,399	0	0	0	0	0	121,399	17,004	0	17,004
2014	268,317	0	0	268,317	0	268,317	0	0	0	0	0	268,317	33,183	0	33,183
2015	221,882	0	0	221,882	0	221,882	0	0	0	0	0	221,882	31,564	0	31,564
2016	146,534	0	0	146,534	0	146,534	0	0	0	0	0	146,534	25,939	0	25,939
2017	94,444	0	0	94,444	0	94,444	0	0	0	0	0	94,444	22,248	0	22,248
2018	59,726	0	0	59,726	0	59,726	0	0	0	0	0	59,726	20,524	0	20,524
2019	42,892	0	0	42,892	0	42,892	0	0	0	0	0	42,892	18,159	0	18,159
2020	27,529	0	0	27,529	0	27,529	0	0	0	0	0	27,529	17,231	0	17,231
2021	16,254	0	0	16,254	0	16,254	0	0	0	0	0	16,254	12,568	0	12,568
2022	3,654	0	0	3,654	0	3,654	0	0	0	0	0	3,654	3,452	0	3,452
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sub.	1,002,631	0	0	1,002,631	0	1,002,631	0	0	0	0	0	1,002,631	201,871	0	201,871
Rem.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tot.	**1,002,631**	**0**	**0**	**1,002,631**	**0**	**1,002,631**	**0**	**0**	**0**	**0**	**0**	**1,002,631**	**201,871**	**0**	**201,871**
Disc	770,256	0	0	770,256	0	770,256	0	0	0	0	0	770,256	140,257	0	140,257

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Net Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	104,394	133,901	671	237,624	49,982	59,821	0	109,803	127,822	127,822	121,873
2014	0	0	0	235,133	8,540	1,853	241,821	40,256	7,824	0	48,080	193,741	321,562	289,804
2015	0	0	0	190,318	8,188	1,994	196,512	39,032	0	0	39,032	157,480	479,042	413,896
2016	0	0	0	120,595	5,071	1,384	124,283	37,654	0	0	37,654	86,628	565,670	475,953
2017	0	0	0	72,196	3,028	865	74,359	22,434	0	0	22,434	51,926	617,596	509,768
2018	0	0	0	39,202	2,010	604	40,608	0	0	0	0	40,608	658,204	533,809
2019	0	0	0	24,733	1,380	431	25,682	0	0	0	0	25,682	683,887	547,632
2020	0	0	0	10,299	837	253	10,883	0	0	0	0	10,883	694,770	552,956
2021	0	0	0	3,687	432	85	4,034	0	0	0	0	4,034	698,804	554,751
2022	0	0	0	202	98	4	296	0	0	0	0	296	699,100	554,870
2023	0	0	0	0	0	0	0	0	0	0	0	0	699,100	554,870
2024	0	0	0	0	0	0	0	0	0	0	0	0	699,100	554,870
Sub.	0	0	0	800,760	163,486	8,144	956,102	189,358	67,644	0	257,002	699,100	699,100	554,870
Rem.	0	0	0	0	0	0	0	0	0	0	0	0	699,100	554,870
Tot.	**0**	**0**	**0**	**800,760**	**163,486**	**8,144**	**956,102**	**189,358**	**67,644**	**0**	**257,002**	**699,100**	**699,100**	**554,870**
Disc	0	0	0	629,999	149,703	6,125	773,578	154,889	63,818	0	218,707	554,870	554,870	554,870

AFTER TAX ANALYSIS

		Tax Pool Balances Incl. Current Year Additions					Depreciation & Writeoffs					
Year	Oper. Income M$	CCA M$	COGPE M$	CDE M$	CEE M$	Other M$	CCA M$	COGPE M$	CDE M$	CEE M$	Other M$	Total M$
2013	237,624	0	0	5,691	0	0	0	0	0	0	0	0
2014	241,821	0	0	5,691	0	0	0	0	0	0	0	0
2015	196,512	0	0	5,691	0	0	0	0	0	0	0	0
2016	124,283	0	0	5,691	0	0	0	0	0	0	0	0
2017	74,359	0	0	5,691	0	0	0	0	0	0	0	0
2018	40,608	0	0	5,691	0	0	0	0	0	0	0	0
2019	25,682	0	0	5,691	0	0	0	0	0	0	0	0
2020	10,883	0	0	5,691	0	0	0	0	0	0	0	0
2021	4,034	0	0	5,691	0	0	0	0	0	0	0	0
2022	296	0	0	5,691	0	0	0	0	0	0	0	0
2023	0	0	0	5,691	0	0	0	0	0	0	0	0
2024	0	0	0	5,691	0	0	0	0	0	0	0	0
Sub.	956,102	0	0	5,691	0	0	0	0	0	0	0	0
Rem.	0	0	0	5,691	0	0	0	0	0	0	0	0
Tot.	**956,102**	**0**	**0**	**5,691**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Disc	773,578						0	0	0	0	0	0

		Federal	Provincial			Net Cash Flow Before Income Tax			Net Cash Flow After Income Tax		
Year	Taxable Income M$	Income Tax M$	Income Tax M$	ARTD & Investment Credits	Income Tax Payable M$	Annual M$	Cum. M$	10.0% Dcf M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	2,599	0	0	0	0	127,822	127,822	121,873	127,822	127,822	121,873
2014	7,035	0	0	0	0	193,741	321,562	289,804	193,741	321,562	289,804
2015	6,746	1,226	0	0	1,226	157,480	479,042	413,896	156,254	477,816	412,930
2016	4,178	340	0	0	340	86,628	565,670	475,953	86,289	564,105	474,743
2017	2,495	998	0	0	998	51,926	617,596	509,768	50,928	615,033	507,909
2018	1,656	663	0	0	663	40,608	658,204	533,809	39,946	654,979	531,558
2019	1,137	455	0	0	455	25,682	683,887	547,632	25,228	680,206	545,135
2020	690	276	0	0	276	10,883	694,770	552,956	10,607	690,813	550,325
2021	341	142	0	0	142	4,034	698,804	554,751	3,892	694,705	552,056
2022	63	32	0	0	32	296	699,100	554,870	264	694,969	552,163
2023	0	0	0	0	0	0	699,100	554,870	0	694,969	552,163
2024	0	0	0	0	0	0	699,100	554,870	0	694,969	552,163
Sub.	26,939	4,131	0	0	4,131	699,100	699,100	554,870	694,969	694,969	552,163
Rem.	0	0	0	0	0	0	699,100	554,870	0	694,969	552,163
Tot.	**26,939**	**4,131**	**0**	**0**	**4,131**	**699,100**	**699,100**	**554,870**	**694,969**	**694,969**	**552,163**
Disc	20,616	2,707	0	0	2,707	554,870	554,870	554,870	552,163	552,163	552,163

SUMMARY OF RESERVES

		Remaining Reserves at Jan 01, 2013				Oil Equivalents			Reserve Life Indic. (yr)		
Product	Units	Working Interest	Roy/NPI Interest	Total Company	Net	Oil Eq. Factor	Company Mboe	% of Total	Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	11,251	0	11,251	11,251	1.000	11,251	100	10.0	8.5	2.5
Total: Oil Eq.	Mboe	11,251	0	11,251	11,251	1.000	11,251	100	10.0	8.5	2.5

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	85.00	6.55	91.55	0.00	12.40	0.00	79.15	1,002,631	100	770,256	100
Total: Oil Eq.	$/boe	85.00	6.55	91.55	0.00	12.82	0.00	78.73	1,002,631	100	770,256	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)			Disc. Rate	Net Present Value Before Income Tax					Net Present Value After Income Tax			
				Prod'n Revenue	Operating Income	Capital Invest.	Cash Flow		Operating Income	Capital Invest.	Cash Flow	
Entity Name	Initial	Average	%	M$	M$	M$	M$	$/boe	M$	M$	M$	$/boe
Crown Royalty	0.0000	0.0000	0.0	800,760	956,102	257,002	699,100	62.14	951,971	257,002	694,969	61.77
Non-crown Royalty	0.0000	0.0000	5.0	706,203	855,225	236,148	619,077	55.02	851,909	236,148	615,761	54.73
Mineral Tax	0.0000	0.0000	8.0	658,607	804,273	225,326	578,947	51.46	801,342	225,326	576,016	51.20
			10.0	629,999	773,578	218,707	554,870	49.32	770,870	218,707	552,163	49.08
			12.0	603,581	745,180	212,516	532,665	47.34	742,673	212,516	530,157	47.12
			15.0	567,574	706,386	203,948	502,438	44.66	704,142	203,948	500,194	44.46
			20.0	515,697	650,278	191,323	458,955	40.79	648,394	191,323	457,071	40.63

Evaluator: Herchen, Leonard L.
Run Date: January 22, 2013 10:04:56

Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **After Tax Analysis**
$US Dollars

Reserve Class: **Probable**
Development Class: **Total**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production			
Year	Company Oil Wells	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	0	845	308	308	95.15
2014	1	4,050	1,478	1,478	91.24
2015	6	7,713	2,815	2,815	88.58
2016	10	10,157	3,707	3,707	86.83
2017	9	8,113	2,961	2,961	83.43
2018	5	4,805	1,754	1,754	83.13
2019	5	3,803	1,388	1,388	84.47
2020	5	3,177	1,160	1,160	86.79
2021	7	2,672	975	975	89.23
2022	17	2,413	881	881	91.48
2023	19	2,035	743	743	93.71
2024	20	1,688	616	616	95.74
Sub.			18,787	18,787	87.42
Rem.			1,727	1,727	101.18
Tot.			**20,514**	**20,514**	**88.58**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	29,343	0	0	29,343	0	29,343	0	0	0	0	0	29,343	14,645	0	14,645
2014	134,880	0	0	134,880	0	134,880	0	0	0	0	0	134,880	19,767	0	19,767
2015	249,370	0	0	249,370	0	249,370	0	0	0	0	0	249,370	32,331	0	32,331
2016	321,887	0	0	321,887	0	321,887	0	0	0	0	0	321,887	39,497	0	39,497
2017	247,078	0	0	247,078	0	247,078	0	0	0	0	0	247,078	35,225	0	35,225
2018	145,793	0	0	145,793	0	145,793	0	0	0	0	0	145,793	32,296	0	32,296
2019	117,262	0	0	117,262	0	117,262	0	0	0	0	0	117,262	25,883	0	25,883
2020	100,631	0	0	100,631	0	100,631	0	0	0	0	0	100,631	23,415	0	23,415
2021	87,020	0	0	87,020	0	87,020	0	0	0	0	0	87,020	25,848	0	25,848
2022	80,559	0	0	80,559	0	80,559	0	0	0	0	0	80,559	33,486	0	33,486
2023	69,598	0	0	69,598	0	69,598	0	0	0	0	0	69,598	35,732	0	35,732
2024	58,986	0	0	58,986	0	58,986	0	0	0	0	0	58,986	34,686	0	34,686
Sub.	1,642,406	0	0	1,642,406	0	1,642,406	0	0	0	0	0	1,642,406	352,810	0	352,810
Rem.	174,731	0	0	174,731	0	174,731	0	0	0	0	0	174,731	123,197	0	123,197
Tot.	**1,817,137**	**0**	**0**	**1,817,137**	**0**	**1,817,137**	**0**	**0**	**0**	**0**	**0**	**1,817,137**	**476,008**	**0**	**476,008**
Disc	1,092,782	0	0	1,092,782	0	1,092,782	0	0	0	0	0	1,092,782	233,026	0	233,026

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Net Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	14,697	-3,496	-127	11,328	5,268	48,687	0	53,955	-42,627	-42,627	-40,643
2014	0	0	0	115,113	-996	-74	114,191	53,247	125,931	0	179,178	-64,986	-107,613	-96,972
2015	0	0	0	217,039	9,376	616	225,799	164,227	0	0	164,227	61,572	-46,041	-48,455
2016	0	0	0	282,390	21,716	1,264	302,843	104,003	0	0	104,003	198,839	152,798	93,984
2017	0	0	0	211,853	21,940	1,116	232,677	6,153	0	0	6,153	226,524	379,322	241,503
2018	0	0	0	113,497	19,841	935	132,403	0	0	0	0	132,403	511,725	319,889
2019	0	0	0	91,380	15,773	773	106,380	0	0	0	0	106,380	618,105	377,143
2020	0	0	0	77,216	12,246	707	88,755	0	0	0	0	88,755	706,860	420,569
2021	0	0	0	61,172	9,795	701	70,267	0	0	0	0	70,267	777,127	451,823
2022	0	0	0	47,073	8,099	648	54,523	0	0	0	0	54,523	831,650	473,870
2023	0	0	0	33,866	6,631	522	39,975	0	0	0	0	39,975	871,625	488,565
2024	0	0	0	24,300	5,439	403	29,335	0	0	0	0	29,335	900,960	498,369
Sub.	0	0	0	1,289,596	126,362	7,483	1,408,476	332,897	174,618	0	507,516	900,960	900,960	498,369
Rem.	0	0	0	51,534	17,418	882	68,069	0	0	0	0	68,069	969,029	516,311
Tot.	**0**	**0**	**0**	**1,341,130**	**143,780**	**8,365**	**1,476,545**	**332,897**	**174,618**	**0**	**507,516**	**969,029**	**969,029**	**516,311**
Disc	0	0	0	859,756	75,612	4,387	930,982	259,094	155,577	0	414,671	516,311	516,311	516,311

AFTER TAX ANALYSIS

		Tax Pool Balances Incl. Current Year Additions					Depreciation & Writeoffs					
Year	Oper. Income M$	CCA M$	COGPE M$	CDE M$	CEE M$	Other M$	CCA M$	COGPE M$	CDE M$	CEE M$	Other M$	Total M$
2013	11,328	0	0	0	0	0	0	0	0	0	0	0
2014	114,191	55,332	0	0	0	0	0	0	0	0	0	0
2015	225,799	55,332	0	0	0	0	0	0	0	0	0	0
2016	302,843	55,332	0	0	0	0	0	0	0	0	0	0
2017	232,677	55,332	0	0	0	0	0	0	0	0	0	0
2018	132,403	55,332	0	0	0	0	0	0	0	0	0	0
2019	106,380	55,332	0	0	0	0	0	0	0	0	0	0
2020	88,755	55,332	0	0	0	0	0	0	0	0	0	0
2021	70,267	55,332	0	0	0	0	0	0	0	0	0	0
2022	54,523	55,332	0	0	0	0	0	0	0	0	0	0
2023	39,975	55,332	0	0	0	0	0	0	0	0	0	0
2024	29,335	55,332	0	0	0	0	0	0	0	0	0	0
Sub.	1,408,476	55,332	0	0	0	0	0	0	0	0	0	0
Rem.	68,069	55,332	0	0	0	0	0	0	0	0	0	0
Tot.	**1,476,545**	**55,332**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Disc	930,982						0	0	0	0	0	0

		Federal	Provincial			Net Cash Flow Before Income Tax			Net Cash Flow After Income Tax		
Year	Taxable Income M$	Income Tax M$	Income Tax M$	ARTD & Investment Credits	Income Tax Payable M$	Annual M$	Cum. M$	10.0% Dcf M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	-959	0	0	0	0	-42,627	-42,627	-40,643	-42,627	-42,627	-40,643
2014	-1,714	0	0	0	0	-64,986	-107,613	-96,972	-64,986	-107,613	-96,972
2015	6,524	-1,210	0	0	-1,210	61,572	-46,041	-48,455	62,781	-44,832	-47,501
2016	16,770	298	0	0	298	198,839	152,798	93,984	198,542	153,710	94,724
2017	17,234	281	0	0	281	226,524	379,322	241,503	226,243	379,952	242,060
2018	15,694	230	0	0	230	132,403	511,725	319,889	132,173	512,126	320,309
2019	12,500	4,246	0	0	4,246	106,380	618,105	377,143	102,134	614,260	375,279
2020	9,709	3,884	0	0	3,884	88,755	706,860	420,569	84,872	699,132	416,804
2021	7,787	3,109	0	0	3,109	70,267	777,127	451,823	67,158	766,289	446,676
2022	6,452	2,573	0	0	2,573	54,523	831,650	473,870	51,950	818,239	467,682
2023	5,276	2,110	0	0	2,110	39,975	871,625	488,565	37,865	856,104	481,601
2024	4,335	1,734	0	0	1,734	29,335	900,960	498,369	27,601	883,705	490,825
Sub.	99,608	17,255	0	0	17,255	900,960	900,960	498,369	883,705	883,705	490,825
Rem.	14,082	5,587	0	0	5,587	68,069	969,029	516,311	62,483	946,187	507,337
Tot.	**113,690**	**22,842**	**0**	**0**	**22,842**	**969,029**	**969,029**	**516,311**	**946,187**	**946,187**	**507,337**
Disc	59,813	8,975	0	0	8,975	516,311	516,311	516,311	507,337	507,337	507,337

SUMMARY OF RESERVES

		Remaining Reserves at Jan 01, 2013				Oil Equivalents			Reserve Life Indic. (yr)		
Product	Units	Working Interest	Roy/NPI Interest	Total Company	Net	Oil Eq. Factor	Company Mboe	% of Total	Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	20,514	0	20,514	20,514	1.000	20,514	100	19.0	66.5	4.7
Total: Oil Eq.	Mboe	20,514	0	20,514	20,514	1.000	20,514	100	19.0	66.5	4.7

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	85.00	10.15	95.15	0.00	47.07	0.00	48.08	1,817,137	100	1,092,782	100
Total: Oil Eq.	$/boe	85.00	10.15	95.15	0.00	47.49	0.00	47.66	1,817,137	100	1,092,782	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)			Disc. Rate	Net Present Value Before Income Tax					Net Present Value After Income Tax			
				Prod'n Revenue	Operating Income	Capital Invest.	Cash Flow		Operating Income	Capital Invest.	Cash Flow	
Entity Name	Initial	Average	%	M$	M$	M$	M$	$/boe	M$	M$	M$	$/boe
Crown Royalty	0.0000	0.0000	0.0	1,341,130	1,476,545	507,516	969,029	47.24	1,453,703	507,516	946,187	46.12
Non-crown Royalty	0.0000	0.0000	5.0	1,058,766	1,155,146	457,173	697,973	34.02	1,141,078	457,173	683,905	33.34
Mineral Tax	0.0000	0.0000	8.0	931,654	1,011,724	430,840	580,884	28.32	1,001,022	430,840	570,182	27.80
			10.0	859,756	930,982	414,671	516,311	25.17	922,008	414,671	507,337	24.73
			12.0	796,240	859,895	399,502	460,393	22.44	852,336	399,502	452,834	22.07
			15.0	713,958	768,163	378,450	389,713	19.00	762,275	378,450	383,825	18.71
			20.0	603,728	645,944	347,321	298,624	14.56	641,998	347,321	294,678	14.36

Evaluator: Herchen, Leonard L.
Run Date: January 22, 2013 10:04:57

Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **After Tax Analysis**
$US Dollars

Reserve Class: **Proved Plus Probable**
Development Class: **Total**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production			
Year	Company Oil Wells	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	4	4,478	1,634	1,634	92.23
2014	10	12,294	4,487	4,487	89.85
2015	19	14,530	5,303	5,303	88.86
2016	22	14,658	5,350	5,350	87.55
2017	22	11,094	4,049	4,049	84.34
2018	18	6,690	2,442	2,442	84.16
2019	18	5,138	1,875	1,875	85.41
2020	19	4,015	1,465	1,465	87.46
2021	19	3,156	1,152	1,152	89.65
2022	19	2,519	919	919	91.59
2023	19	2,035	743	743	93.71
2024	20	1,688	616	616	95.74
Sub.			30,038	30,038	88.06
Rem.			1,727	1,727	101.18
Tot.			**31,765**	**31,765**	**88.77**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	150,741	0	0	150,741	0	150,741	0	0	0	0	0	150,741	31,650	0	31,650
2014	403,197	0	0	403,197	0	403,197	0	0	0	0	0	403,197	52,950	0	52,950
2015	471,252	0	0	471,252	0	471,252	0	0	0	0	0	471,252	63,895	0	63,895
2016	468,421	0	0	468,421	0	468,421	0	0	0	0	0	468,421	65,436	0	65,436
2017	341,522	0	0	341,522	0	341,522	0	0	0	0	0	341,522	57,473	0	57,473
2018	205,518	0	0	205,518	0	205,518	0	0	0	0	0	205,518	52,819	0	52,819
2019	160,154	0	0	160,154	0	160,154	0	0	0	0	0	160,154	44,042	0	44,042
2020	128,160	0	0	128,160	0	128,160	0	0	0	0	0	128,160	40,645	0	40,645
2021	103,275	0	0	103,275	0	103,275	0	0	0	0	0	103,275	38,416	0	38,416
2022	84,213	0	0	84,213	0	84,213	0	0	0	0	0	84,213	36,939	0	36,939
2023	69,598	0	0	69,598	0	69,598	0	0	0	0	0	69,598	35,732	0	35,732
2024	58,986	0	0	58,986	0	58,986	0	0	0	0	0	58,986	34,686	0	34,686
Sub.	2,645,037	0	0	2,645,037	0	2,645,037	0	0	0	0	0	2,645,037	554,682	0	554,682
Rem.	174,731	0	0	174,731	0	174,731	0	0	0	0	0	174,731	123,197	0	123,197
Tot.	**2,819,768**	**0**	**0**	**2,819,768**	**0**	**2,819,768**	**0**	**0**	**0**	**0**	**0**	**2,819,768**	**677,879**	**0**	**677,879**
Disc	1,863,038	0	0	1,863,038	0	1,863,038	0	0	0	0	0	1,863,038	373,283	0	373,283

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Net Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	119,092	130,405	544	248,952	55,250	108,508	0	163,758	85,195	85,195	81,230
2014	0	0	0	350,247	7,543	1,779	356,012	93,503	133,755	0	227,258	128,754	213,949	192,832
2015	0	0	0	407,357	17,564	2,610	422,311	203,259	0	0	203,259	219,051	433,000	365,442
2016	0	0	0	402,986	26,787	2,648	427,125	141,657	0	0	141,657	285,468	718,468	569,937
2017	0	0	0	284,050	24,968	1,981	307,036	28,586	0	0	28,586	278,450	996,918	751,271
2018	0	0	0	152,699	21,852	1,539	173,011	0	0	0	0	173,011	1,169,930	853,698
2019	0	0	0	116,112	17,154	1,204	132,062	0	0	0	0	132,062	1,301,992	924,775
2020	0	0	0	87,515	13,083	960	99,638	0	0	0	0	99,638	1,401,630	973,525
2021	0	0	0	64,859	10,227	785	74,301	0	0	0	0	74,301	1,475,931	1,006,574
2022	0	0	0	47,275	8,197	652	54,819	0	0	0	0	54,819	1,530,750	1,028,741
2023	0	0	0	33,866	6,631	522	39,975	0	0	0	0	39,975	1,570,725	1,043,436
2024	0	0	0	24,300	5,439	403	29,335	0	0	0	0	29,335	1,600,060	1,053,239
Sub.	0	0	0	2,090,356	289,849	15,626	2,364,578	522,255	242,263	0	764,518	1,600,060	1,600,060	1,053,239
Rem.	0	0	0	51,534	17,418	882	68,069	0	0	0	0	68,069	1,668,130	1,071,182
Tot.	**0**	**0**	**0**	**2,141,889**	**307,267**	**16,509**	**2,432,648**	**522,255**	**242,263**	**0**	**764,518**	**1,668,130**	**1,668,130**	**1,071,182**
Disc	0	0	0	1,489,755	225,316	10,511	1,704,560	413,983	219,395	0	633,378	1,071,182	1,071,182	1,071,182

AFTER TAX ANALYSIS

Year	Oper. Income M$	Tax Pool Balances Incl. Current Year Additions: CCA M$	COGPE M$	CDE M$	CEE M$	Other M$	Depreciation & Writeoffs: CCA M$	COGPE M$	CDE M$	CEE M$	Other M$	Total M$
2013	248,952	0	0	5,691	0	0	0	0	0	0	0	0
2014	356,012	55,332	0	5,691	0	0	0	0	0	0	0	0
2015	422,311	55,332	0	5,691	0	0	0	0	0	0	0	0
2016	427,125	55,332	0	5,691	0	0	0	0	0	0	0	0
2017	307,036	55,332	0	5,691	0	0	0	0	0	0	0	0
2018	173,011	55,332	0	5,691	0	0	0	0	0	0	0	0
2019	132,062	55,332	0	5,691	0	0	0	0	0	0	0	0
2020	99,638	55,332	0	5,691	0	0	0	0	0	0	0	0
2021	74,301	55,332	0	5,691	0	0	0	0	0	0	0	0
2022	54,819	55,332	0	5,691	0	0	0	0	0	0	0	0
2023	39,975	55,332	0	5,691	0	0	0	0	0	0	0	0
2024	29,335	55,332	0	5,691	0	0	0	0	0	0	0	0
Sub.	2,364,578	55,332	0	5,691	0	0	0	0	0	0	0	0
Rem.	68,069	55,332	0	5,691	0	0	0	0	0	0	0	0
Tot.	**2,432,648**	**55,332**	**0**	**5,691**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Disc	1,704,560						0	0	0	0	0	0

Year	Taxable Income M$	Federal Income Tax M$	Provincial Income Tax M$	ARTD & Investment Credits	Income Tax Payable M$	Net Cash Flow Before Income Tax: Annual M$	Cum. M$	10.0% Dcf M$	Net Cash Flow After Income Tax: Annual M$	Cum. M$	10.0% Dcf M$
2013	1,640	0	0	0	0	85,195	85,195	81,230	85,195	85,195	81,230
2014	5,321	0	0	0	0	128,754	213,949	192,832	128,754	213,949	192,832
2015	13,270	16	0	0	16	219,051	433,000	365,442	219,035	432,984	365,429
2016	20,948	638	0	0	638	285,468	718,468	569,937	284,830	717,815	569,467
2017	19,729	1,279	0	0	1,279	278,450	996,918	751,271	277,171	994,985	749,969
2018	17,351	892	0	0	892	173,011	1,169,930	853,698	172,119	1,167,105	851,867
2019	13,637	4,700	0	0	4,700	132,062	1,301,992	924,775	127,362	1,294,466	920,414
2020	10,399	4,160	0	0	4,160	99,638	1,401,630	973,525	95,479	1,389,945	967,129
2021	8,128	3,251	0	0	3,251	74,301	1,475,931	1,006,574	71,050	1,460,994	998,732
2022	6,515	2,606	0	0	2,606	54,819	1,530,750	1,028,741	52,214	1,513,208	1,019,845
2023	5,276	2,110	0	0	2,110	39,975	1,570,725	1,043,436	37,865	1,551,073	1,033,764
2024	4,335	1,734	0	0	1,734	29,335	1,600,060	1,053,239	27,601	1,578,674	1,042,988
Sub.	126,547	21,386	0	0	21,386	1,600,060	1,600,060	1,053,239	1,578,674	1,578,674	1,042,988
Rem.	14,082	5,587	0	0	5,587	68,069	1,668,130	1,071,182	62,483	1,641,156	1,059,500
Tot.	**140,630**	**26,973**	**0**	**0**	**26,973**	**1,668,130**	**1,668,130**	**1,071,182**	**1,641,156**	**1,641,156**	**1,059,500**
Disc	80,429	11,682	0	0	11,682	1,071,182	1,071,182	1,071,182	1,059,500	1,059,500	1,059,500

SUMMARY OF RESERVES

Product	Units	Remaining Reserves at Jan 01, 2013: Working Interest	Roy/NPI Interest	Total Company	Net	Oil Equivalents: Oil Eq. Factor	Company Mboe	% of Total	Reserve Life Indic. (yr): Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	31,765	0	31,765	31,765	1.000	31,765	100	19.0	19.4	3.8
Total: Oil Eq.	Mboe	31,765	0	31,765	31,765	1.000	31,765	100	19.0	19.4	3.8

PRODUCT REVENUE AND EXPENSES

Product	Units	Average First Year Unit Values: Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Net Revenue After Royalties: Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	85.00	7.23	92.23	0.00	18.95	0.00	73.28	2,819,768	100	1,863,038	100
Total: Oil Eq.	$/boe	85.00	7.23	92.23	0.00	19.36	0.00	72.87	2,819,768	100	1,863,038	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)			Disc. Rate	Net Present Value Before Income Tax					Net Present Value After Income Tax			
				Prod'n Revenue	Operating Income	Capital Invest.	Cash Flow		Operating Income	Capital Invest.	Cash Flow	
Entity Name	Initial	Average	%	M$	M$	M$	M$	$/boe	M$	M$	M$	$/boe
Crown Royalty	0.0000	0.0000	0.0	2,141,889	2,432,648	764,518	1,668,130	52.52	2,405,674	764,518	1,641,156	51.67
Non-crown Royalty	0.0000	0.0000	5.0	1,764,968	2,010,371	693,321	1,317,050	41.46	1,992,987	693,321	1,299,666	40.92
Mineral Tax	0.0000	0.0000	8.0	1,590,261	1,815,997	656,166	1,159,831	36.51	1,802,364	656,166	1,146,198	36.08
			10.0	1,489,755	1,704,560	633,378	1,071,182	33.72	1,692,878	633,378	1,059,500	33.35
			12.0	1,399,820	1,605,076	612,018	993,057	31.26	1,595,009	612,018	982,991	30.95
			15.0	1,281,532	1,474,548	582,398	892,150	28.09	1,466,417	582,398	884,019	27.83
			20.0	1,119,425	1,296,223	538,644	757,579	23.85	1,290,392	538,644	751,748	23.67

Evaluator: Herchen, Leonard L.
Run Date: January 22, 2013 10:04:57

Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **After Tax Analysis**
$US Dollars

Reserve Class: **Possible**
Development Class: **Total**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production			
Year	Company Oil Wells	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	0	602	220	220	94.76
2014	0	2,338	853	853	91.73
2015	1	5,163	1,884	1,884	91.03
2016	3	7,701	2,811	2,811	90.31
2017	11	13,158	4,802	4,802	87.00
2018	13	11,961	4,366	4,366	86.66
2019	12	9,646	3,521	3,521	87.85
2020	6	5,794	2,115	2,115	89.88
2021	5	4,111	1,500	1,500	92.25
2022	6	3,410	1,245	1,245	94.43
2023	7	2,956	1,079	1,079	96.46
2024	7	2,621	957	957	98.61
Sub.			25,353	25,353	89.71
Rem.			6,785	6,785	113.99
Tot.			**32,138**	**32,138**	**94.84**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens														
	Working Interest				Royalty Interest	Company Interest	Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	20,814	0	0	20,814	0	20,814	0	0	0	0	0	20,814	16,902	0	16,902
2014	78,285	0	0	78,285	0	78,285	0	0	0	0	0	78,285	17,250	0	17,250
2015	171,545	0	0	171,545	0	171,545	0	0	0	0	0	171,545	25,305	0	25,305
2016	253,855	0	0	253,855	0	253,855	0	0	0	0	0	253,855	40,252	0	40,252
2017	417,825	0	0	417,825	0	417,825	0	0	0	0	0	417,825	52,937	0	52,937
2018	378,334	0	0	378,334	0	378,334	0	0	0	0	0	378,334	55,731	0	55,731
2019	309,286	0	0	309,286	0	309,286	0	0	0	0	0	309,286	49,603	0	49,603
2020	190,074	0	0	190,074	0	190,074	0	0	0	0	0	190,074	42,369	0	42,369
2021	138,413	0	0	138,413	0	138,413	0	0	0	0	0	138,413	35,186	0	35,186
2022	117,532	0	0	117,532	0	117,532	0	0	0	0	0	117,532	30,883	0	30,883
2023	104,077	0	0	104,077	0	104,077	0	0	0	0	0	104,077	28,368	0	28,368
2024	94,344	0	0	94,344	0	94,344	0	0	0	0	0	94,344	26,997	0	26,997
Sub.	2,274,385	0	0	2,274,385	0	2,274,385	0	0	0	0	0	2,274,385	421,783	0	421,783
Rem.	773,405	0	0	773,405	0	773,405	0	0	0	0	0	773,405	482,720	0	482,720
Tot.	**3,047,789**	**0**	**0**	**3,047,789**	**0**	**3,047,789**	**0**	**0**	**0**	**0**	**0**	**3,047,789**	**904,503**	**0**	**904,503**
Disc	1,485,490	0	0	1,485,490	0	1,485,490	0	0	0	0	0	1,485,490	323,400	0	323,400

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Net Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	3,912	-470	-111	3,553	-2,500	30,755	0	28,255	-24,702	-24,702	-23,553
2014	0	0	0	61,035	-1,316	-341	60,060	24,123	73,471	0	97,595	-37,534	-62,236	-56,087
2015	0	0	0	146,240	-1,009	-30	145,262	37,970	0	0	37,970	107,292	45,055	28,458
2016	0	0	0	213,603	3,442	966	216,078	99,111	0	0	99,111	116,968	162,023	112,247
2017	0	0	0	364,889	13,098	2,142	375,844	161,461	0	0	161,461	214,383	376,406	251,860
2018	0	0	0	322,603	17,376	2,471	337,508	67,369	0	0	67,369	270,139	646,545	411,789
2019	0	0	0	259,683	18,471	2,343	275,811	60,369	0	0	60,369	215,442	861,987	527,741
2020	0	0	0	147,705	14,140	1,862	159,983	0	0	0	0	159,983	1,021,971	606,017
2021	0	0	0	103,227	9,098	1,371	110,954	0	0	0	0	110,954	1,132,925	655,369
2022	0	0	0	86,649	6,294	1,076	91,867	0	0	0	0	91,867	1,224,792	692,517
2023	0	0	0	75,708	4,688	911	79,485	0	0	0	0	79,485	1,304,277	721,735
2024	0	0	0	67,348	3,691	818	70,221	0	0	0	0	70,221	1,374,498	745,202
Sub.	0	0	0	1,852,602	87,503	13,478	1,926,627	447,903	104,226	0	552,129	1,374,498	1,374,498	745,202
Rem.	0	0	0	290,684	14,654	5,039	300,300	0	0	0	0	300,300	1,674,798	812,843
Tot.	**0**	**0**	**0**	**2,143,286**	**102,157**	**18,517**	**2,226,927**	**447,903**	**104,226**	**0**	**552,129**	**1,674,798**	**1,674,798**	**812,843**
Disc	0	0	0	1,162,090	48,732	8,005	1,202,817	296,967	93,007	0	389,974	812,843	812,843	812,843

AFTER TAX ANALYSIS

Year	Oper. Income M$	Tax Pool Balances Incl. Current Year Additions: CCA M$	COGPE M$	CDE M$	CEE M$	Other M$	Depreciation & Writeoffs: CCA M$	COGPE M$	CDE M$	CEE M$	Other M$	Total M$
2013	3,553	0	0	0	0	0	0	0	0	0	0	0
2014	60,060	17,911	0	0	0	0	0	0	0	0	0	0
2015	145,262	17,911	0	0	0	0	0	0	0	0	0	0
2016	216,078	17,911	0	0	0	0	0	0	0	0	0	0
2017	375,844	17,911	0	0	0	0	0	0	0	0	0	0
2018	337,508	17,911	0	0	0	0	0	0	0	0	0	0
2019	275,811	17,911	0	0	0	0	0	0	0	0	0	0
2020	159,983	17,911	0	0	0	0	0	0	0	0	0	0
2021	110,954	17,911	0	0	0	0	0	0	0	0	0	0
2022	91,867	17,911	0	0	0	0	0	0	0	0	0	0
2023	79,485	17,911	0	0	0	0	0	0	0	0	0	0
2024	70,221	17,911	0	0	0	0	0	0	0	0	0	0
Sub.	1,926,627	17,911	0	0	0	0	0	0	0	0	0	0
Rem.	300,300	17,911	0	0	0	0	0	0	0	0	0	0
Tot.	**2,226,927**	**17,911**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Disc	1,202,817						0	0	0	0	0	0

Year	Taxable Income M$	Federal Income Tax M$	Provincial Income Tax M$	ARTD & Investment Credits	Income Tax Payable M$	Net Cash Flow Before Income Tax: Annual M$	Cum. M$	10.0% Dcf M$	Net Cash Flow After Income Tax: Annual M$	Cum. M$	10.0% Dcf M$
2013	-562	0	0	0	0	-24,702	-24,702	-23,553	-24,702	-24,702	-23,553
2014	-1,702	0	0	0	0	-37,534	-62,236	-56,087	-37,534	-62,236	-56,087
2015	-2,638	-16	0	0	-16	107,292	45,055	28,458	107,308	45,071	28,470
2016	-769	-638	0	0	-638	116,968	162,023	112,247	117,605	162,676	112,717
2017	6,020	-567	0	0	-567	214,383	376,406	251,860	214,951	377,627	252,699
2018	9,394	480	0	0	480	270,139	646,545	411,789	269,659	647,286	412,344
2019	10,747	1,629	0	0	1,629	215,442	861,987	527,741	213,814	861,100	527,419
2020	8,217	3,287	0	0	3,287	159,983	1,021,971	606,017	156,697	1,017,797	604,087
2021	5,045	2,018	0	0	2,018	110,954	1,132,925	655,369	108,936	1,126,733	652,542
2022	3,335	1,334	0	0	1,334	91,867	1,224,792	692,517	90,533	1,217,266	689,150
2023	2,399	960	0	0	960	79,485	1,304,277	721,735	78,525	1,295,791	718,016
2024	1,844	738	0	0	738	70,221	1,374,498	745,202	69,483	1,365,274	741,236
Sub.	41,329	9,223	0	0	9,223	1,374,498	1,374,498	745,202	1,365,274	1,365,274	741,236
Rem.	7,296	2,981	0	0	2,981	300,300	1,674,798	812,843	297,319	1,662,593	808,191
Tot.	**48,625**	**12,204**	**0**	**0**	**12,204**	**1,674,798**	**1,674,798**	**812,843**	**1,662,593**	**1,662,593**	**808,191**
Disc	21,417	4,652	0	0	4,652	812,843	812,843	812,843	808,191	808,191	808,191

SUMMARY OF RESERVES

Product	Units	Remaining Reserves at Jan 01, 2013: Working Interest	Roy/NPI Interest	Total Company	Net	Oil Equivalents: Oil Eq. Factor	Company Mboe	% of Total	Reserve Life Indic. (yr): Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	32,138	0	32,138	32,138	1.000	32,138	100	31.0	146.3	6.3
Total: Oil Eq.	Mboe	32,138	0	32,138	32,138	1.000	32,138	100	31.0	146.3	6.3

PRODUCT REVENUE AND EXPENSES

Product	Units	Average First Year Unit Values: Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Net Revenue After Royalties: Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	85.00	9.76	94.76	0.00	76.53	0.00	18.23	3,047,789	100	1,485,490	100
Total: Oil Eq.	$/boe	85.00	9.76	94.76	0.00	76.95	0.00	17.81	3,047,789	100	1,485,490	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)			Disc. Rate	Net Present Value Before Income Tax					Net Present Value After Income Tax			
				Prod'n Revenue	Operating Income	Capital Invest.	Cash Flow		Operating Income	Capital Invest.	Cash Flow	
Entity Name	Initial	Average	%	M$	M$	M$	M$	$/boe	M$	M$	M$	$/boe
Crown Royalty	0.0000	0.0000	0.0	2,143,286	2,226,927	552,129	1,674,798	52.11	2,214,722	552,129	1,662,593	51.73
Non-crown Royalty	0.0000	0.0000	5.0	1,541,222	1,598,604	460,552	1,138,051	35.41	1,591,219	460,552	1,130,666	35.18
Mineral Tax	0.0000	0.0000	8.0	1,294,933	1,341,479	416,099	925,380	28.79	1,335,905	416,099	919,806	28.62
			10.0	1,162,090	1,202,817	389,974	812,843	25.29	1,198,165	389,974	808,191	25.15
			12.0	1,048,554	1,084,341	366,277	718,065	22.34	1,080,440	366,277	714,164	22.22
			15.0	906,770	936,463	334,682	601,780	18.73	933,444	334,682	598,762	18.63
			20.0	726,263	748,385	290,717	457,668	14.24	746,383	290,717	455,666	14.18

Evaluator: Herchen, Leonard L.
Run Date: January 22, 2013 10:04:56

Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **After Tax Analysis**
$US Dollars

Reserve Class: **PPP**
Development Class: **Total**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production			
Year	Company Oil Wells	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	4	5,080	1,854	1,854	92.53
2014	10	14,632	5,341	5,341	90.16
2015	20	19,693	7,188	7,188	89.43
2016	26	22,360	8,161	8,161	88.50
2017	33	24,252	8,852	8,852	85.78
2018	32	18,651	6,808	6,808	85.76
2019	31	14,784	5,396	5,396	87.00
2020	24	9,809	3,580	3,580	88.89
2021	24	7,267	2,652	2,652	91.12
2022	25	5,929	2,164	2,164	93.22
2023	26	4,991	1,822	1,822	95.34
2024	27	4,309	1,573	1,573	97.48
Sub.			55,391	55,391	88.81
Rem.			8,512	8,512	111.39
Tot.			**63,902**	**63,902**	**91.82**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens														
	Working Interest				Royalty Interest	Company Interest	Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	171,555	0	0	171,555	0	171,555	0	0	0	0	0	171,555	48,551	0	48,551
2014	481,482	0	0	481,482	0	481,482	0	0	0	0	0	481,482	70,200	0	70,200
2015	642,797	0	0	642,797	0	642,797	0	0	0	0	0	642,797	89,200	0	89,200
2016	722,277	0	0	722,277	0	722,277	0	0	0	0	0	722,277	105,688	0	105,688
2017	759,347	0	0	759,347	0	759,347	0	0	0	0	0	759,347	110,409	0	110,409
2018	583,852	0	0	583,852	0	583,852	0	0	0	0	0	583,852	108,551	0	108,551
2019	469,440	0	0	469,440	0	469,440	0	0	0	0	0	469,440	93,645	0	93,645
2020	318,235	0	0	318,235	0	318,235	0	0	0	0	0	318,235	83,014	0	83,014
2021	241,687	0	0	241,687	0	241,687	0	0	0	0	0	241,687	73,602	0	73,602
2022	201,745	0	0	201,745	0	201,745	0	0	0	0	0	201,745	67,822	0	67,822
2023	173,675	0	0	173,675	0	173,675	0	0	0	0	0	173,675	64,100	0	64,100
2024	153,330	0	0	153,330	0	153,330	0	0	0	0	0	153,330	61,683	0	61,683
Sub.	4,919,422	0	0	4,919,422	0	4,919,422	0	0	0	0	0	4,919,422	976,464	0	976,464
Rem.	948,135	0	0	948,135	0	948,135	0	0	0	0	0	948,135	605,917	0	605,917
Tot.	**5,867,557**	**0**	**0**	**5,867,557**	**0**	**5,867,557**	**0**	**0**	**0**	**0**	**0**	**5,867,557**	**1,582,382**	**0**	**1,582,382**
Disc	3,348,529	0	0	3,348,529	0	3,348,529	0	0	0	0	0	3,348,529	696,683	0	696,683

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Net Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	123,003	129,935	433	252,506	52,750	139,263	0	192,013	60,493	60,493	57,678
2014	0	0	0	411,282	6,228	1,437	416,072	117,626	207,226	0	324,852	91,220	151,713	136,746
2015	0	0	0	553,597	16,556	2,580	567,572	241,229	0	0	241,229	326,343	478,056	393,899
2016	0	0	0	616,589	30,229	3,614	643,204	240,768	0	0	240,768	402,435	880,491	682,184
2017	0	0	0	648,938	38,065	4,123	682,881	190,047	0	0	190,047	492,833	1,373,325	1,003,131
2018	0	0	0	475,302	39,227	4,010	510,519	67,369	0	0	67,369	443,151	1,816,475	1,265,487
2019	0	0	0	375,796	35,625	3,547	407,873	60,369	0	0	60,369	347,504	2,163,979	1,452,516
2020	0	0	0	235,221	27,223	2,822	259,622	0	0	0	0	259,622	2,423,601	1,579,542
2021	0	0	0	168,086	19,325	2,156	185,255	0	0	0	0	185,255	2,608,855	1,661,943
2022	0	0	0	133,923	14,491	1,728	146,686	0	0	0	0	146,686	2,755,542	1,721,257
2023	0	0	0	109,574	11,319	1,433	119,460	0	0	0	0	119,460	2,875,002	1,765,171
2024	0	0	0	91,647	9,130	1,221	99,556	0	0	0	0	99,556	2,974,558	1,798,441
Sub.	0	0	0	3,942,957	377,352	29,104	4,291,205	970,158	346,489	0	1,316,647	2,974,558	2,974,558	1,798,441
Rem.	0	0	0	342,218	32,072	5,921	368,369	0	0	0	0	368,369	3,342,927	1,884,025
Tot.	**0**	**0**	**0**	**4,285,176**	**409,424**	**35,025**	**4,659,574**	**970,158**	**346,489**	**0**	**1,316,647**	**3,342,927**	**3,342,927**	**1,884,025**
Disc	0	0	0	2,651,846	274,048	18,516	2,907,377	710,950	312,402	0	1,023,352	1,884,025	1,884,025	1,884,025

AFTER TAX ANALYSIS

Year	Oper. Income M$	Tax Pool Balances Incl. Current Year Additions: CCA M$	COGPE M$	CDE M$	CEE M$	Other M$	Depreciation & Writeoffs: CCA M$	COGPE M$	CDE M$	CEE M$	Other M$	Total M$
2013	252,506	0	0	5,691	0	0	0	0	0	0	0	0
2014	416,072	73,243	0	5,691	0	0	0	0	0	0	0	0
2015	567,572	73,243	0	5,691	0	0	0	0	0	0	0	0
2016	643,204	73,243	0	5,691	0	0	0	0	0	0	0	0
2017	682,881	73,243	0	5,691	0	0	0	0	0	0	0	0
2018	510,519	73,243	0	5,691	0	0	0	0	0	0	0	0
2019	407,873	73,243	0	5,691	0	0	0	0	0	0	0	0
2020	259,622	73,243	0	5,691	0	0	0	0	0	0	0	0
2021	185,255	73,243	0	5,691	0	0	0	0	0	0	0	0
2022	146,686	73,243	0	5,691	0	0	0	0	0	0	0	0
2023	119,460	73,243	0	5,691	0	0	0	0	0	0	0	0
2024	99,556	73,243	0	5,691	0	0	0	0	0	0	0	0
Sub.	4,291,205	73,243	0	5,691	0	0	0	0	0	0	0	0
Rem.	368,369	73,243	0	5,691	0	0	0	0	0	0	0	0
Tot.	**4,659,574**	**73,243**	**0**	**5,691**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Disc	2,907,377						0	0	0	0	0	0

Year	Taxable Income M$	Federal Income Tax M$	Provincial Income Tax M$	ARTD & Investment Credits	Income Tax Payable M$	Net Cash Flow Before Income Tax: Annual M$	Cum. M$	10.0% Dcf M$	Net Cash Flow After Income Tax: Annual M$	Cum. M$	10.0% Dcf M$
2013	1,078	0	0	0	0	60,493	60,493	57,678	60,493	60,493	57,678
2014	3,619	0	0	0	0	91,220	151,713	136,746	91,220	151,713	136,746
2015	10,632	0	0	0	0	326,343	478,056	393,899	326,343	478,056	393,899
2016	20,179	0	0	0	0	402,435	880,491	682,184	402,435	880,491	682,184
2017	25,749	712	0	0	712	492,833	1,373,325	1,003,131	492,121	1,372,612	1,002,667
2018	26,744	1,372	0	0	1,372	443,151	1,816,475	1,265,487	441,778	1,814,391	1,264,211
2019	24,383	6,329	0	0	6,329	347,504	2,163,979	1,452,516	341,175	2,155,566	1,447,833
2020	18,616	7,446	0	0	7,446	259,622	2,423,601	1,579,542	252,175	2,407,741	1,571,217
2021	13,172	5,269	0	0	5,269	185,255	2,608,855	1,661,943	179,986	2,587,727	1,651,274
2022	9,850	3,940	0	0	3,940	146,686	2,755,542	1,721,257	142,746	2,730,473	1,708,995
2023	7,676	3,070	0	0	3,070	119,460	2,875,002	1,765,171	116,390	2,846,863	1,751,780
2024	6,179	2,471	0	0	2,471	99,556	2,974,558	1,798,441	97,085	2,943,948	1,784,224
Sub.	167,877	30,610	0	0	30,610	2,974,558	2,974,558	1,798,441	2,943,948	2,943,948	1,784,224
Rem.	21,378	8,568	0	0	8,568	368,369	3,342,927	1,884,025	359,802	3,303,750	1,867,690
Tot.	**189,255**	**39,177**	**0**	**0**	**39,177**	**3,342,927**	**3,342,927**	**1,884,025**	**3,303,750**	**3,303,750**	**1,867,690**
Disc	101,846	16,334	0	0	16,334	1,884,025	1,884,025	1,884,025	1,867,690	1,867,690	1,867,690

SUMMARY OF RESERVES

Product	Units	Remaining Reserves at Jan 01, 2013: Working Interest	Roy/NPI Interest	Total Company	Net	Oil Equivalents: Oil Eq. Factor	Company Mboe	% of Total	Reserve Life Indic. (yr): Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	63,902	0	63,902	63,902	0.000	0	0	31.0	34.5	5.1
Total: Oil Eq.	Mboe	63,902	0	63,902	63,902	0.000	0	0	31.0	34.5	5.1

PRODUCT REVENUE AND EXPENSES

Product	Units	Average First Year Unit Values: Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Net Revenue After Royalties: Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	85.00	7.53	92.53	0.00	25.77	0.00	66.76	5,867,557	100	3,348,529	100
Total: Oil Eq.	$/boe	85.00	7.53	92.53	0.00	26.19	0.00	66.34	5,867,557	100	3,348,529	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)			Disc. Rate	Net Present Value Before Income Tax					Net Present Value After Income Tax			
				Prod'n Revenue	Operating Income	Capital Invest.	Cash Flow		Operating Income	Capital Invest.	Cash Flow	
Entity Name	Initial	Average	%	M$	M$	M$	M$	$/boe	M$	M$	M$	$/boe
Crown Royalty	0.0000	0.0000	0.0	4,285,176	4,659,574	1,316,647	3,342,927	52.31	4,620,397	1,316,647	3,303,750	51.70
Non-crown Royalty	0.0000	0.0000	5.0	3,306,190	3,608,975	1,153,873	2,455,101	38.42	3,584,205	1,153,873	2,430,332	38.03
Mineral Tax	0.0000	0.0000	8.0	2,885,194	3,157,476	1,072,264	2,085,212	32.63	3,138,269	1,072,264	2,066,004	32.33
			10.0	2,651,846	2,907,377	1,023,352	1,884,025	29.48	2,891,042	1,023,352	1,867,690	29.23
			12.0	2,448,374	2,689,417	978,295	1,711,122	26.78	2,675,449	978,295	1,697,155	26.56
			15.0	2,188,301	2,411,011	917,080	1,493,931	23.38	2,399,861	917,080	1,482,781	23.20
			20.0	1,845,688	2,044,607	829,360	1,215,247	19.02	2,036,775	829,360	1,207,415	18.89

Evaluator: Herchen, Leonard L.
Run Date: January 22, 2013 10:04:57

Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **After Tax Analysis**
$US Dollars

Resource Class: **Contingent Resources**
Development Class: **Low Estimate**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production			
Year	Company Oil Wells	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	0	0	0	0	0.00
2014	0	0	0	0	0.00
2015	4	1,055	385	385	75.29
2016	6	1,995	728	728	75.28
2017	6	1,783	651	651	72.91
2018	6	1,514	552	552	72.91
2019	6	1,157	422	422	74.19
2020	6	913	333	333	76.12
2021	6	654	239	239	78.09
2022	5	456	166	166	80.08
2023	5	386	141	141	82.13
2024	5	332	121	121	84.21
Sub.			3,739	3,739	75.41
Rem.			210	210	87.95
Tot.			**3,949**	**3,949**	**76.08**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	0	0	0	0	0	0	0	0	0	0	0	0	1,502	0	1,502
2014	0	0	0	0	0	0	0	0	0	0	0	0	1,022	0	1,022
2015	29,004	0	0	29,004	0	29,004	0	0	0	0	0	29,004	5,941	0	5,941
2016	54,831	0	0	54,831	0	54,831	0	0	0	0	0	54,831	8,811	0	8,811
2017	47,443	0	0	47,443	0	47,443	0	0	0	0	0	47,443	8,233	0	8,233
2018	40,281	0	0	40,281	0	40,281	0	0	0	0	0	40,281	7,710	0	7,710
2019	31,343	0	0	31,343	0	31,343	0	0	0	0	0	31,343	6,674	0	6,674
2020	25,361	0	0	25,361	0	25,361	0	0	0	0	0	25,361	6,173	0	6,173
2021	18,627	0	0	18,627	0	18,627	0	0	0	0	0	18,627	5,821	0	5,821
2022	13,317	0	0	13,317	0	13,317	0	0	0	0	0	13,317	5,585	0	5,585
2023	11,563	0	0	11,563	0	11,563	0	0	0	0	0	11,563	5,424	0	5,424
2024	10,211	0	0	10,211	0	10,211	0	0	0	0	0	10,211	5,320	0	5,320
Sub.	281,980	0	0	281,980	0	281,980	0	0	0	0	0	281,980	68,214	0	68,214
Rem.	18,485	0	0	18,485	0	18,485	0	0	0	0	0	18,485	13,265	0	13,265
Tot.	**300,465**	**0**	**0**	**300,465**	**0**	**300,465**	**0**	**0**	**0**	**0**	**0**	**300,465**	**81,478**	**0**	**81,478**
Disc	172,728	0	0	172,728	0	172,728	0	0	0	0	0	172,728	42,182	0	42,182

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	**Net Prod'n Revenue** M$	Other Income M$	**Aband. Costs** M$	**Oper. Income** M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	-1,502	-2,667	0	-4,168	13,933	19,655	0	33,588	-37,756	-37,756	-35,999
2014	0	0	0	-1,022	0	0	-1,022	35,768	84,037	0	119,805	-120,827	-158,583	-140,730
2015	0	0	0	23,063	8,389	232	31,220	58,124	0	0	58,124	-26,904	-185,487	-161,930
2016	0	0	0	46,020	15,859	443	61,436	7,358	0	0	7,358	54,078	-131,409	-123,191
2017	0	0	0	39,210	14,169	391	52,989	0	0	0	0	52,989	-78,420	-88,683
2018	0	0	0	32,571	12,030	333	44,268	0	0	0	0	44,268	-34,153	-62,476
2019	0	0	0	24,669	9,199	259	33,608	0	0	0	0	33,608	-544	-44,387
2020	0	0	0	19,189	7,255	209	26,235	0	0	0	0	26,235	25,691	-31,551
2021	0	0	0	12,806	5,822	171	18,457	0	0	0	0	18,457	44,147	-23,342
2022	0	0	0	7,732	4,775	143	12,364	0	0	0	0	12,364	56,511	-18,343
2023	0	0	0	6,139	3,978	121	9,995	0	0	0	0	9,995	66,506	-14,668
2024	0	0	0	4,891	3,368	105	8,153	0	0	0	0	8,153	74,660	-11,944
Sub.	0	0	0	213,767	82,175	2,407	293,534	115,183	103,692	0	218,874	74,660	74,660	-11,944
Rem.	0	0	0	5,220	5,225	130	10,315	0	0	0	0	10,315	84,975	-8,962
Tot.	**0**	**0**	**0**	**218,987**	**87,400**	**2,537**	**303,849**	**115,183**	**103,692**	**0**	**218,874**	**84,975**	**84,975**	**-8,962**
Disc	0	0	0	130,546	48,879	1,446	177,980	95,359	91,582	0	186,941	-8,962	-8,962	-8,962

AFTER TAX ANALYSIS

Year	Oper. Income M$	Tax Pool Balances Incl. Current Year Additions: CCA M$	COGPE M$	CDE M$	CEE M$	Other M$	Depreciation & Writeoffs: CCA M$	COGPE M$	CDE M$	CEE M$	Other M$	Total M$
2013	-4,168	0	0	0	0	0	0	0	0	0	0	0
2014	-1,022	43,942	0	0	0	0	0	0	0	0	0	0
2015	31,220	43,942	0	0	0	0	0	0	0	0	0	0
2016	61,436	43,942	0	0	0	0	0	0	0	0	0	0
2017	52,989	43,942	0	0	0	0	0	0	0	0	0	0
2018	44,268	43,942	0	0	0	0	0	0	0	0	0	0
2019	33,608	43,942	0	0	0	0	0	0	0	0	0	0
2020	26,235	43,942	0	0	0	0	0	0	0	0	0	0
2021	18,457	43,942	0	0	0	0	0	0	0	0	0	0
2022	12,364	43,942	0	0	0	0	0	0	0	0	0	0
2023	9,995	43,942	0	0	0	0	0	0	0	0	0	0
2024	8,153	43,942	0	0	0	0	0	0	0	0	0	0
Sub.	293,534	43,942	0	0	0	0	0	0	0	0	0	0
Rem.	10,315	43,942	0	0	0	0	0	0	0	0	0	0
Tot.	**303,849**	**43,942**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Disc	177,980						0	0	0	0	0	0

Year	Taxable Income M$	Federal Income Tax M$	Provincial Income Tax M$	ARTD & Investment Credits	Income Tax Payable M$	Net Cash Flow Before Income Tax: Annual M$	Cum. M$	10.0% Dcf M$	Net Cash Flow After Income Tax: Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	0	0	-37,756	-37,756	-35,999	-37,756	-37,756	-35,999
2014	0	0	0	0	0	-120,827	-158,583	-140,730	-120,827	-158,583	-140,730
2015	7,581	0	0	0	0	-26,904	-185,487	-161,930	-26,904	-185,487	-161,930
2016	14,333	0	0	0	0	54,078	-131,409	-123,191	54,078	-131,409	-123,191
2017	12,805	0	0	0	0	52,989	-78,420	-88,683	52,989	-78,420	-88,683
2018	10,873	309	0	0	309	44,268	-34,153	-62,476	43,959	-34,461	-62,659
2019	8,313	3,325	0	0	3,325	33,608	-544	-44,387	30,283	-4,179	-46,360
2020	6,557	2,623	0	0	2,623	26,235	25,691	-31,551	23,612	19,434	-34,807
2021	5,262	2,105	0	0	2,105	18,457	44,147	-23,342	16,352	35,786	-27,534
2022	4,315	1,726	0	0	1,726	12,364	56,511	-18,343	10,638	46,423	-23,233
2023	3,595	1,438	0	0	1,438	9,995	66,506	-14,668	8,557	54,980	-20,087
2024	3,044	1,217	0	0	1,217	8,153	74,660	-11,944	6,936	61,916	-17,769
Sub.	76,678	12,743	0	0	12,743	74,660	74,660	-11,944	61,916	61,916	-17,769
Rem.	4,722	1,889	0	0	1,889	10,315	84,975	-8,962	8,426	70,343	-15,327
Tot.	**81,400**	**14,632**	**0**	**0**	**14,632**	**84,975**	**84,975**	**-8,962**	**70,343**	**70,343**	**-15,327**
Disc	46,474	6,365	0	0	6,365	-8,962	-8,962	-8,962	-15,327	-15,327	-15,327

SUMMARY OF RESOURCES

Product	Units	Remaining Resources at Jan 01, 2013: Working Interest	Roy/NPI Interest	Total Company	Net	Oil Equivalents: Oil Eq. Factor	Company Mboe	% of Total	Resource Life Indic. (yr): Resource Life	Life Index	Half Life
Light/Med Oil	Mbbl	3,949	0	3,949	3,949	1.000	3,949	100	16.0	10.3	5.4
Total: Oil Eq.	Mboe	3,949	0	3,949	3,949	1.000	3,949	100	16.0	10.3	5.4

PRODUCT REVENUE AND EXPENSES

Product	Units	Average First Year Unit Values: Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Net Revenue After Royalties: Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	0.00	0.00	0.00	0.00	0.00	0.00	0.00	300,465	100	172,728	100
Total: Oil Eq.	$/boe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	300,465	100	172,728	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)			Disc. Rate	Net Present Value Before Income Tax					Net Present Value After Income Tax			
				Prod'n Revenue	Operating Income	Capital Invest.	Cash Flow		Operating Income	Capital Invest.	Cash Flow	
Entity Name	Initial	Average	%	M$	M$	M$	M$	$/boe	M$	M$	M$	$/boe
Crown Royalty	0.0000	0.0000	0.0	218,987	303,849	218,874	84,975	21.52	289,217	218,874	70,343	17.81
Non-crown Royalty	0.0000	0.0000	5.0	167,027	229,542	201,781	27,761	7.03	220,038	201,781	18,258	4.62
Mineral Tax	0.0000	0.0000	8.0	143,688	196,492	192,634	3,858	0.98	189,046	192,634	-3,588	-0.91
			10.0	130,546	177,980	186,941	-8,962	-2.27	171,614	186,941	-15,327	-3.88
			12.0	118,994	161,766	181,545	-19,780	-5.01	156,301	181,545	-25,244	-6.39
			15.0	104,138	141,003	173,962	-32,959	-8.35	136,624	173,962	-37,338	-9.45
			20.0	84,517	113,736	162,534	-48,798	-12.36	110,651	162,534	-51,883	-13.14

Evaluator: Herchen, Leonard L.
Run Date: January 22, 2013 10:04:57

APPENDIX I

CERTIFICATES OF QUALIFICATION

Leonard L. Herchen
G. Gabriella Carrelli
D. Mark Mawdsley
Kelly J. Zukowski
Richard P.B. Kiefer
Roger J. Mahoney
J. Gregory Milne

CERTIFICATION OF QUALIFICATION

I, Leonard L. Herchen, Professional Engineer, 4100, 400 - 3rd Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I am an employee of GLJ Petroleum Consultants Ltd., which company did prepare a detailed analysis of the oil properties of Griffiths Energy International Inc. (the "Company"). The effective date of this evaluation is December 31, 2012.

2. That I do not have, nor do I expect to receive any direct or indirect interest in the securities of the Company or its affiliated companies.

3. That I attended Queen's University and that I graduated with a Bachelor of Science Degree in Engineering Physics in 1989; that I am a Registered Professional Engineer in the Province of Alberta; and, that I have in excess of twenty-three years experience in engineering studies relating to Canadian and International oil and gas fields.

4. That a personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information and records, the files of the Company, and the appropriate provincial regulatory authorities.



CERTIFICATION OF QUALIFICATION

I, G. Gabriella Carrelli, Professional Geologist, 4100, 400 - 3rd Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I am an employee of GLJ Petroleum Consultants Ltd., which company did prepare a detailed analysis of the oil properties of Griffiths Energy International Inc. (the "Company"). The effective date of this evaluation is December 31, 2012.

2. That I do not have, nor do I expect to receive any direct or indirect interest in the securities of the Company or its affiliated companies.

3. That I attended the University of Calgary where I graduated with a Master's Degree in Geology in 2002; that I am a Registered Professional Geologist in the Province of Alberta; and, that I have in excess of twelve years experience in geological studies and evaluations of Canadian and International oil and gas fields.

4. That a personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information and records, the files of the Company, and the appropriate provincial regulatory authorities.



CERTIFICATION OF QUALIFICATION

I, D. Mark Mawdsley, Professional Engineer, 4100, 400 – 3rd Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I am an employee of GLJ Petroleum Consultants Ltd., which company did prepare a detailed analysis of the oil properties of Griffiths Energy International Inc. (the "Company"). The effective date of this evaluation is December 31, 2012.

2. That I do not have, nor do I expect to receive any direct or indirect interest in the securities of the Company or its affiliated companies.

3. That I attended the University of Calgary where I graduated with a Bachelor of Science in Mechanical Engineering in 1982; that I am a Registered Professional Engineer in the Province of Alberta; and, that I have in excess of twenty-eight years experience in engineering studies relating to Western Canadian oil and gas fields.

4. That a personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information and records, the files of the Company, and the appropriate provincial regulatory authorities.



CERTIFICATION OF QUALIFICATION

I, Kelly J. Zukowski, Professional Engineer, 4100, 400 - 3rd Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I am an employee of GLJ Petroleum Consultants Ltd., which company did prepare a detailed analysis of the oil properties of Griffiths Energy International Inc. (the "Company"). The effective date of this evaluation is December 31, 2012.

2. That I do not have, nor do I expect to receive any direct or indirect interest in the securities of the Company or its affiliated companies.

3. That I attended the University of Calgary where I graduated with a Bachelor of Science Degree in Mechanical Engineering in 2003; that I am a Registered Professional Engineer in the Province of Alberta; and, that I have in excess of nine years of experience in engineering studies relating to Western Canadian oil and gas fields.

4. That a personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information and records, the files of the Company, and the appropriate provincial regulatory authorities.



CERTIFICATION OF QUALIFICATION

I, Richard P.B. Kiefer, Engineer In Training, 4100, 400 - 3rd Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I am an employee of GLJ Petroleum Consultants Ltd., which company did prepare a detailed analysis of the oil properties of Griffiths Energy International Inc. (the "Company"). The effective date of this evaluation is December 31, 2012.

2. That I do not have, nor do I expect to receive any direct or indirect interest in the securities of the Company or its affiliated companies.

3. That I attended the University of Calgary where I graduated with a Bachelor's Degree in Chemical Engineering in 2011; and, that I am an Engineer In Training.

4. That a personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information and records, the files of the Company, and the appropriate provincial regulatory authorities.



Richard P. B. Kiefer, E.I.T.

CERTIFICATION OF QUALIFICATION

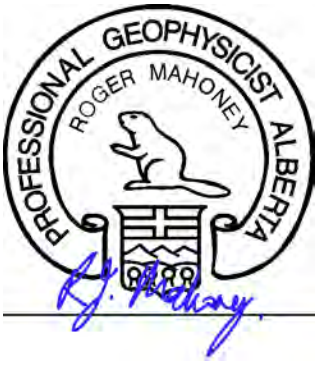
I, Roger J. Mahoney, Professional Geophysicist, c/o 4100, 400 - 3rd Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I have been retained by GLJ Petroleum Consultants Ltd., which company did prepare a detailed analysis of the oil properties of Griffiths Energy International Inc. (the "Company"). The effective date of this evaluation is December 31, 2012.

2. That I do not have, nor do I expect to receive any direct or indirect interest in the securities of the Company or its affiliated companies.

3. That I attended the University of Manchester and that I graduated with a Bachelor of Science Degree in Physics with Honours in 1964; that I am a Registered Professional Geophysicist in the Province of Alberta; and, that I have in excess of forty-six years experience in geophysical studies relating to Canadian and International oil and gas fields.

4. That a personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information and records, the files of the Company, and the appropriate provincial regulatory authorities.



CERTIFICATION OF QUALIFICATION

I, John Gregory Milne, Professional Geophysicist, c/o 4100, 400 - 3rd Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I have been retained by GLJ Petroleum Consultants Ltd., which company did prepare a detailed analysis of the oil properties of Griffiths Energy International Inc. (the "Company"). The effective date of this evaluation is December 31, 2012.

2. That I do not have, nor do I expect to receive any direct or indirect interest in the securities of the Company or its affiliated companies.

3. That I attended the University of Queens and that I graduated with a B Sc Degree in Eng Physics in 1971; that I am a Registered Professional Geophysicist in the Province of Alberta; and, that I have in excess of forty-one years experience in geophysical studies relating to Canadian and International oil and gas fields.

4. That a personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information and records, the files of the Company, and the appropriate provincial regulatory authorities.



GRIFFITHS ENERGY INTERNATIONAL INC.

RESERVES AND RESOURCE ASSESSMENT AND EVALUATION OF CHADIAN OIL PROPERTIES

INDIVIDUAL PROPERTIES

Effective December 31, 2012

INDIVIDUAL PROPERTIES

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BADILA

ITA BADILA/MANGARA

ITA EAST DOSEO

KIBEA

MAKU

MANGARA

GRIFFITHS ENERGY INTERNATIONAL INC.

BADILA

Effective December 31, 2012

Prepared by
Richard P.B. Kiefer, E.I.T.
G.Gabriella Carrelli, P. Geol.
Roger J. Mahoney, P. Geoph.
D. Mark Mawdsley, P. Eng.
Leonard L. Herchen, P. Eng.

The analysis of this property as reported herein was conducted within the context of an evaluation of a distinct group of properties in aggregate. Extraction and use of this analysis outside this context may not be appropriate without supplementary due diligence.

BADILA

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Company: **Griffiths Energy International Inc.**
Property: **Badila**
Currency: **$US Dollars**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Summary of Reserves and Values

	Proved Undeveloped	Proved Plus Probable Undeveloped	PPP Undeveloped
MARKETABLE RESERVES			
Light/Medium Oil (Mbbl)			
Gross Lease	17,572	30,588	50,960
Total Company Interest	5,865	8,568	12,997
Net After Royalty	5,865	8,568	12,997
Oil Equivalent (Mbbl)			
Gross Lease	17,572	30,588	50,960
Total Company Interest	5,865	8,568	12,997
Net After Royalty	5,865	8,568	12,997
BEFORE TAX PRESENT VALUE (M$)			
0%	344,088	515,911	801,856
5%	311,601	451,586	659,279
8%	294,882	419,849	594,361
10%	284,696	400,964	557,352
12%	275,192	383,647	524,443
15%	262,072	360,222	481,446
20%	242,799	326,803	423,021
FIRST 6 YEARS BEFORE TAX CASH FLOW (M$)			
2013	66,737	64,885	61,683
2014	138,592	165,119	175,568
2015	79,554	104,008	114,209
2016	27,109	72,079	111,171
2017	12,081	39,080	89,010
2018	9,665	26,455	65,260

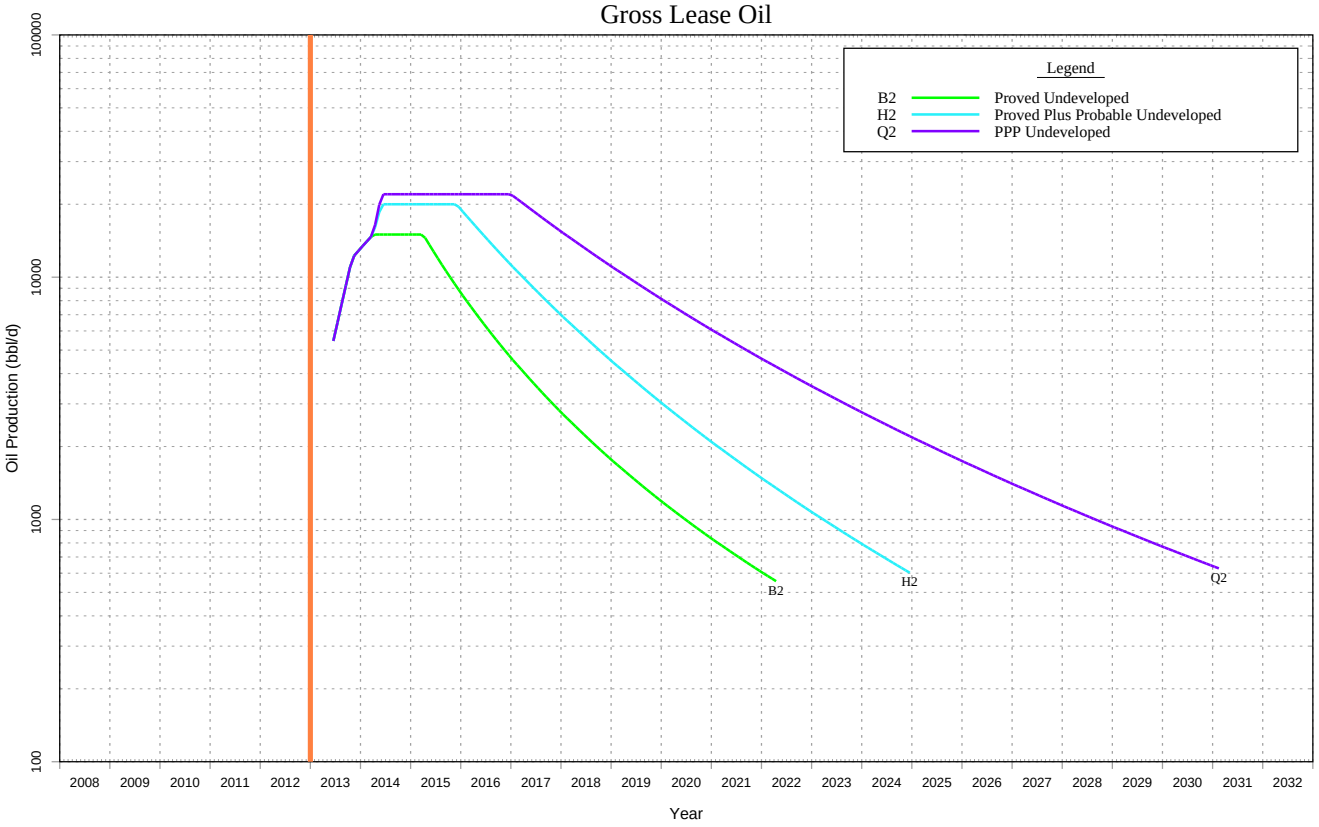
BOE Factors: HVY OIL 1.0 COND 1.0 RES GAS 6.0 SLN GAS 6.0 PROPANE 1.0 BUTANE 1.0 ETHANE 1.0 SULPHUR 0.0

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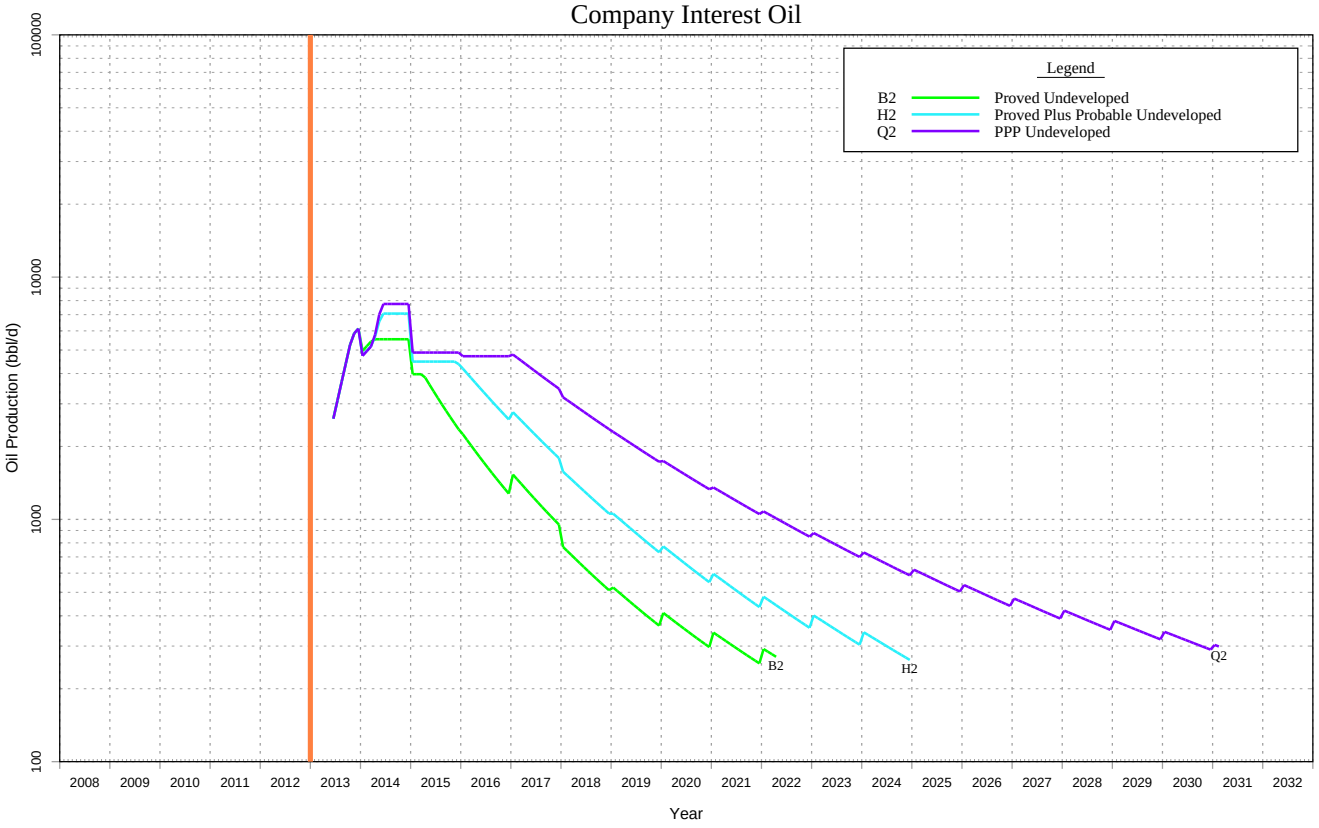
Historical and Forecast Production

Company: **Griffiths Energy International Inc.**
Property: **Badila**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Gross Lease Oil



Company Interest Oil



*Note: Historical company interest production is based on current interests in the evaluated reserves entities applied to reported actual gross lease production. Consequently, company actuals may differ from the history shown due to changes in ownership.

Gross Lease Oil
1132107 / Jan 21, 2013

Company: **Griffiths Energy International Inc.**
Property: **Badila**
Currency: **$US Dollars**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Daily Production, Reserves and Present Value Summary

Entity Description	Reserve Class	2013 Gross Lease Production				2013 Company Interest Production				Gross Lease Reserves					Company Interest Reserves					Before Tax 10% Dcf Present Value M$
		Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	
Proved Undeveloped																				
Badila Total	B2	0	5,450	0	5,450	0	2,602	0	2,602	0	17,572	0	0	17,572	0	5,865	0	0	5,865	336,703
Glencore Carry	B2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	82,343
Other Revenue and Expenses	B2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-134,350
Total: Proved Undeveloped		**0**	**5,450**	**0**	**5,450**	**0**	**2,602**	**0**	**2,602**	**0**	**17,572**	**0**	**0**	**17,572**	**0**	**5,865**	**0**	**0**	**5,865**	**284,696**
Proved Plus Probable Undeveloped																				
Badila Total	H2	0	5,450	0	5,450	0	2,602	0	2,602	0	30,588	0	0	30,588	0	8,568	0	0	8,568	458,582
Glencore Carry	H2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	76,733
Other Revenue and Expenses	H2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-134,350
Total: Proved Plus Probable Undeveloped		**0**	**5,450**	**0**	**5,450**	**0**	**2,602**	**0**	**2,602**	**0**	**30,588**	**0**	**0**	**30,588**	**0**	**8,568**	**0**	**0**	**8,568**	**400,964**
PPP Undeveloped																				
Badila Total	Q2	0	5,450	0	5,450	0	2,602	0	2,602	0	50,960	0	0	50,960	0	12,997	0	0	12,997	615,735
Glencore Carry	Q2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	75,968
Other Revenue and Expenses	Q2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-134,350
Total: PPP Undeveloped		**0**	**5,450**	**0**	**5,450**	**0**	**2,602**	**0**	**2,602**	**0**	**50,960**	**0**	**0**	**50,960**	**0**	**12,997**	**0**	**0**	**12,997**	**557,352**

BOE Factors:

HVY OIL	1.0	RES GAS	6.0	PROPANE	1.0	ETHANE	1.0
COND	1.0	SLN GAS	6.0	BUTANE	1.0	SULPHUR	0.0

GENERAL

The Badila property is located at the southern end of the Republic of Chad's (Chad) Doba Basin, approximately 45 miles north of the country's border with the Central African Republic (Map 1). Griffiths Energy International Inc. (Griffiths) is a party to a Production Sharing Contract (PSC) with the government of Chad, whereby Griffiths earns a variable percentage of oil revenues by providing the majority of the capital required for development drilling, and processing and transportation infrastructure required to exploit the oil reserves evaluated herein.

Griffiths originally held a 75 percent participating interest in the PSC. This evaluation includes the terms of a farm-in agreement (Glencore Farm-in) between Griffiths and Glencore International AG (Glencore). The Glencore Farm-in assigns a one-third fraction of Griffiths' interest in the PSC to Glencore. In exchange, Glencore has agreed to carry a maximum of 330,746 M$ of Griffiths' capital (including recovery of costs sunk as of the effective date). The interests evaluated herein are Griffiths' net interest after the Glencore Farm-in.

Esso Exploration and Production Chad Inc. (Esso) drilled a single exploratory well, Badila-1, on the Badila property in March and April 2002. The well targeted seismically imaged hydrocarbon traps similar to those that are producing oil and gas elsewhere in the Doba Basin (Kome, Bolobo, Miandoum, and Doholo). Though the primary Cretaceous aged objectives, the M and A1 Sands, were water wet due to an inadequate (sandy) seal, the deeper, but thinner C and D Sand sequences contain oil and gas. The C and D Sands decrease in areal extent with depth. Unique to the Doba Basin, Badila-1 encountered a significant column of dry gas in the A2 Sand. This gas may be exploited for local electricity generation to power future Badila and other Doba Basin production operations. After wireline logging, and comprehensive testing using Modular Formation Dynamics Testing (MDT) tools, the Badila-1 well was plugged and abandoned, though it remained available for re-entry for future production testing, or possible recompletion.

The MDT testing performed on Badila-1 provided good evidence of the presence of economic quantities of oil in several of the C and D Sand sequences. In a report dated June 12, 2012, commissioned by Griffiths, Schlumberger Limited (Schlumberger) provided a comprehensive reanalysis of the original, 2002 MDT data. Schlumberger's reanalysis yielded a lower oil-water contact (OWC) in the C3 Sand than did the original analysis from 2002.

Beginning in late March 2012 and continuing through May 2012, Griffiths re-entered the abandoned Badila-1 wellbore for the purpose of perforating and drillstem testing (DST) the C2

and C3 Sands. The original plan to include the C1 Sand in such testing was canceled due to concern that it may be wet. The well was perforated in five intervals within the C2 and C3 Sands and then a successful commingled DST was performed. A peak oil rate of 4025 bopd at a gauge depth flowing pressure of approximately 1900 psia was achieved on May 10, 2012. On-site measurements of the recovered oil indicated an API gravity of 31 degrees. The excellent DST results combined with the original MDT test data now support a proved reserves component. The Badila production forecast in this evaluation was prepared on a total pool basis rather than for individual wells, however the economics were run using the appropriate well counts for each reserves class.

In addition to the new DST data, a new seismic interpretation was submitted by Griffiths for GLJ Petroleum Consultants (GLJ) review. That interpretation was reviewed and accepted by GLJ's geophysical staff.

In late November 2012, the Badila 2 well was spud. As of December 31, 2012, the effective date of this report, the well had not yet reached final total depth and no log or core data from this well was available over the zones of interest. Consequently, as of the effective date, Badila-2 well results were insufficient to influence the geological interpretation as of the effective date.

GEOPHYSICS

General

Griffiths has inherited a large seismic database; in the order of 22,000 kilometres of data. In general the data has been acquired so that the majority of lines over a prospect are dip lines, which indicates that Esso had a good understanding of the structural orientation in the area. The data varies in quality, both signal-to-noise (S/N) ratio and frequency content. No information on the ages of the data was accessed but presumably the quality of data has improved with time.

The data with the broadest frequency spectrum is prefixed by a 'CH', with a spectrum range, 6 db down, of 14 to 54 Hz. It is not known if any noise analyses data will be made available to Griffiths. If not, the field parameters used to record the 'CH' data would provide a framework and a good starting point for the design of shooting parameters for future field work. The remaining data has a variable range of dominant frequencies, the narrowest range, for 6 dB down, being 10 to 26 Hz. The data set is adequate for structural mapping, but not as suitable for undertaking any stratigraphic analysis.

Traditionally, large source and receiver arrays are used in open areas, especially the desert, and these acquisition parameters will preferentially attenuate the higher frequencies. There are some issues with inequalities in T_o (start time of the data) and miss-matching in polarities, but these are minor issues and the seismic database can be used to map the structures accurately. The events were tied to the wells using a combination of checkshot data and well log data. Some of the events identified and associated with the main reservoir units do not tie precisely to that particular unit. There is no single event that can be correlated over the entire area; each area has been mapped using events that are most relevant to that area.

Badila

The Badila structure is a gentle fold that lies northwest of a northeast to southwest trending basement fault. Esso had originally drilled the structure with the Badila-1 well and Griffiths has recently tested high flow rates from the same wellbore.

A loose grid of seismic covers the area. In the immediate vicinity of the Badila-1 well, the seismic grid is spaced approximately 1 by 1.25 kilometres. The data quality can be described as 'fair-good', with there being uniform quality across the structure. The events were tied at the Badila-1

well and GLJ was in agreement with the Griffiths identifications. At the E level the beds onlap the basement high, which results in there being areas of non-deposition. By D time, the entire area of the basement high is interpreted to have a sedimentary cover. The Badila structure was formed by the Santonian squeezing event. On the west side of the structure the dips on the bedding are steeper and an interpreted high angle reverse fault within the sedimentary section is present. This fault trends northwest to southeast, and the resulting structure is quite circular. This is in contrast to many of the structures examined farther east that are oriented southwest to northeast, and have faults parallel to the main axis of the structure.

Three events were depth converted at the structure: the C2, D3 and E Sandstones. Because the structure is relatively small with low relief, a single velocity for each layer, calculated at the Badila-1 well, was used for depth conversion; i.e. C2: 1637 m/sec, D3: 1738 m/sec and E: 1918 m/sec. An additional amplitude map was made at A2 level where a gas zone was encountered in the well. The faulting that was picked by Griffiths was at the C level. However, some of the faults have shallower angles and for these, GLJ picked and used separate faults for different mapped levels.

GEOLOGY

General

The Griffiths PSCs include blocks within two geologic basins in Chad, the Doba and Doseo Basins (Map 1). These basins are separated by an area termed the Borogop uplift which is a large inversion anticlinal trend and is part of the Central African Rift trend, a continental plate boundary crossing through Chad from the Sudan to Cameroon.

The Doba and Doseo Basins were formed as rift basins in the Early Cretaceous (84-144 Ma). The Doba Basin formed as a series of northwest to southwest trending half grabens. The Doseo Basin formed as a large asymmetrical basin with a northwest to southeast oriented rift faulted relay series. The Borogop uplift is the steeply uplifted basin edge fault zone which separates the basins.

Geologic sedimentation occurred during the Aptian through Conician when the two basins underwent a thermal sag phase which provided accommodation space for sediments. It is noteworthy that thermal events also include a phase of sill intrusion dating 97-100 Ma. Sills have been found and sampled along the northern flank of the Doseo Basin.

The Cretaceous provides the multiple reservoirs which have been tested in the two basins. The Cretaceous E interval consists of sediments sourced by axial transport from the east. Sediments drained generally to the west towards Doba and probably ultimately exited the Doba Basin through the Yola Arm of the Benue trough and then onto the south to the Benue forming the proto Niger Delta. The top of the E Sequence is bounded by the D Sequence Boundary (DSB) and is generally a very good high amplitude seismic marker. The Cretaceous D Sequence is a continuation of the same non-marine fluvial and deltaic lacustrine facies as observed in the E Sequence. The Cretaceous C zone overlies the D Sequence and is also composed of fluvial, lacustrine, and deltaic sediments.

The traps evaluated for this work were all four way closed structure and source rocks are provided by the prevalent lacustrine sediments deposited throughout both basins.

Badila Field

The oil initially-in-place (OIIP) for the Badila Field has been determined by volumetric analysis using deterministic methods. The following is a discussion of the methodology and input parameters.

Petrophysical Analysis

GLJ conducted a review of the petrophysical analysis prepared by Griffiths. This review showed it to be broadly similar to earlier studies undertaken by Esso, RPS Group and Ryder Scott. It was decided to define a range of rock properties for the key reservoir units by utilizing a range of low, most likely and high case cut-offs. For the Badila Field, GLJ used "most likely" cutoffs of 8.0 percent porosity and a 65.0 percent water saturation to define wellbore parameters. Low case and high case parameters were also determined by applying different cutoffs.

Mapping

The seismic is of good quality over the Badila structure and a review of the Griffiths interpretation was undertaken to confirm the validity of the depth mapping. GLJ used the provided depth maps for the C2, C3, D3 and D8 reservoirs for the calculation of gross rock volumes for the assignment of reserves to the most significant reservoir units.

Oil-Water Contacts (OWC)

The elevation of the OWC for each sand is an important parameter in the estimate for OIIP for each sand. Due to uncertainty in the formation water resistivity log interpreted OWC may be ambiguous. Plots of pressure versus elevation using MDT data, as well as the logs and test results including PTA analysis were integrated in forming an opinion regarding the elevation of the OWC for each sand at different confidence levels.

The Badila-1 well was drilled into a four-way closure and confirmed the presence of hydrocarbons in the A2, C and D Sands. The well was tested in the C2 and C3 reservoirs this year and had an extensive suite of MDT pressures taken in the past.

C2 Reservoir

The C2 reservoir is 29.3 metres thick with an estimated free water level at -1127.7 metres (5223.7 feet MD) as determined from the MDT data (Map 2).

C3 Reservoir

The C3 reservoir is 72.5 metres thick with an estimated OWC from the MDT pressure work and the logs of -1190 metres (5428.2 feet MD) for the proved case, -1193.0 metres (5438.1 feet MD) for the proved plus probable, and -1197.6 metres (5452.9 feet MD) proved plus probable plus possible case (Map 3).

D3 Reservoir

The D3 reservoir is 27.7 metres thick with an estimated OWC from the MDT pressure work at -1345.5 metres (5938.2 feet MD) (Map 4).

D8 Reservoir

The D8 reservoir is 62.8 metres thick with an estimated free water level at -1455.6 metres (6299.5 feet MD) from the MDT data (Map 5).

RESERVES AND PRODUCTION FORECAST

Badila-1 Drilling and Testing Summary

The Badila-1 exploratory well was drilled by Esso with a spud date of March 5, 2002, reaching a total depth of 8000 feet in basement rock on April 16, 2002. Wireline logging was performed by Schlumberger. Beyond standard logging suites, data collection included MDT pressure and fluid sampling, sidewall coring (SWC), and a vertical seismic profile shoot (VSP). A total of 89 SWCs were obtained and analyzed for porosity, permeability, and geochemical properties. Sidewall cores of the A2 Sand gas reservoir indicate core porosity (φ) ranges from 21 to 28 percent and permeability (k) ranges from 33 to 480 md. Measurements from sidewall cores in the C and D Sands show considerable variation, with core φ ranges of 18 to 32 percent and k ranges of 7 to 2000 md.

Results of the MDT testing were critical in the assignment of reserves to the Badila property. A total of 237 sample points were tested with 112 being deemed valid for pressure gradient analyses. Though the MDT testing records indicate that there were nine fluid samples obtained, fluid analysis was available for only one sample. The PVT analysis of the 450cc sample of oil from the D3 interval at 5820 feet indicates an API oil gravity of approximately 35 degrees, a bubble point pressure of 2000 psia, viscosity of 3.48 cP and gas-oil ratio of approximately 270 scf/stb. The reported formation volume factor was 1.15.

The DST performed in the Spring of 2012 yielded high oil rates from a commingled set of five perforation intervals in the C2 and C3 Sands. The peak rate was 4025 bopd.

MDT Test Analyses

Sufficient MDT data density was acquired to evaluate fluid gradients in all of the C and D Sands where wireline logging supports the presence of hydrocarbons. Plots of the fluid gradients compared to that of water (0.433 psi/ft) were constructed to determine if an OWC was evident in any of the formations. Only the C3 Formation pressure plot defines an OWC (see Plot 3), and because that formation contains the majority of the total Badila property's OIIP, it is important to establish an accurate OWC depth. For this evaluation, GLJ has elected to use the OWC defined by the intersection of the oil gradient and water gradient best-fit lines, for the assignment of proved reserves (dark orange horizontal line on Plot 3). The graphically determined OWC of 5428.2 feet MD, (-1190.0 mSS) is in reasonable agreement with Esso's original (2002) reported value of 5432 feet MD (-1191.2 mSS). Schlumberger's 2012 reanalysis of the MDT data resulted in a substantially deeper OWC (blue horizontal line) at ~5456 feet MD (-1198.5 mSS). The bright

green horizontal line, at 5452.9 feet MD (-1197.6 mSS), illustrates GLJ's OWC pick associated with its proved plus probable plus possible (3P) reserves assignment for the C3 Formation. GLJ's proved plus probable reserves assignment uses an OWC of ~5438 feet MD (light orange horizontal line). The deeper OWC depths used in the probable and possible cases can be supported to some degree, by the log character.

Formation pressure plots for the remainder of the Badila Formations with hydrocarbon potential are included for reference in Appendix I of this report.

DST Results and Analysis

Figure 1, below, illustrating the flow and build-up periods of the 2012 DST, was extracted from a June 1, 2012 Preliminary DST Analysis report prepared by Fekete Associates Inc. (the Fekete Report) for Griffiths. The perforation intervals from the Spring 2012 re-entry are shown in the upper-right corner of the plot. A total of 5490 barrels of oil and 0.9 MMcf of gas were produced during the test, which was followed by a 72 hour pressure build-up period.

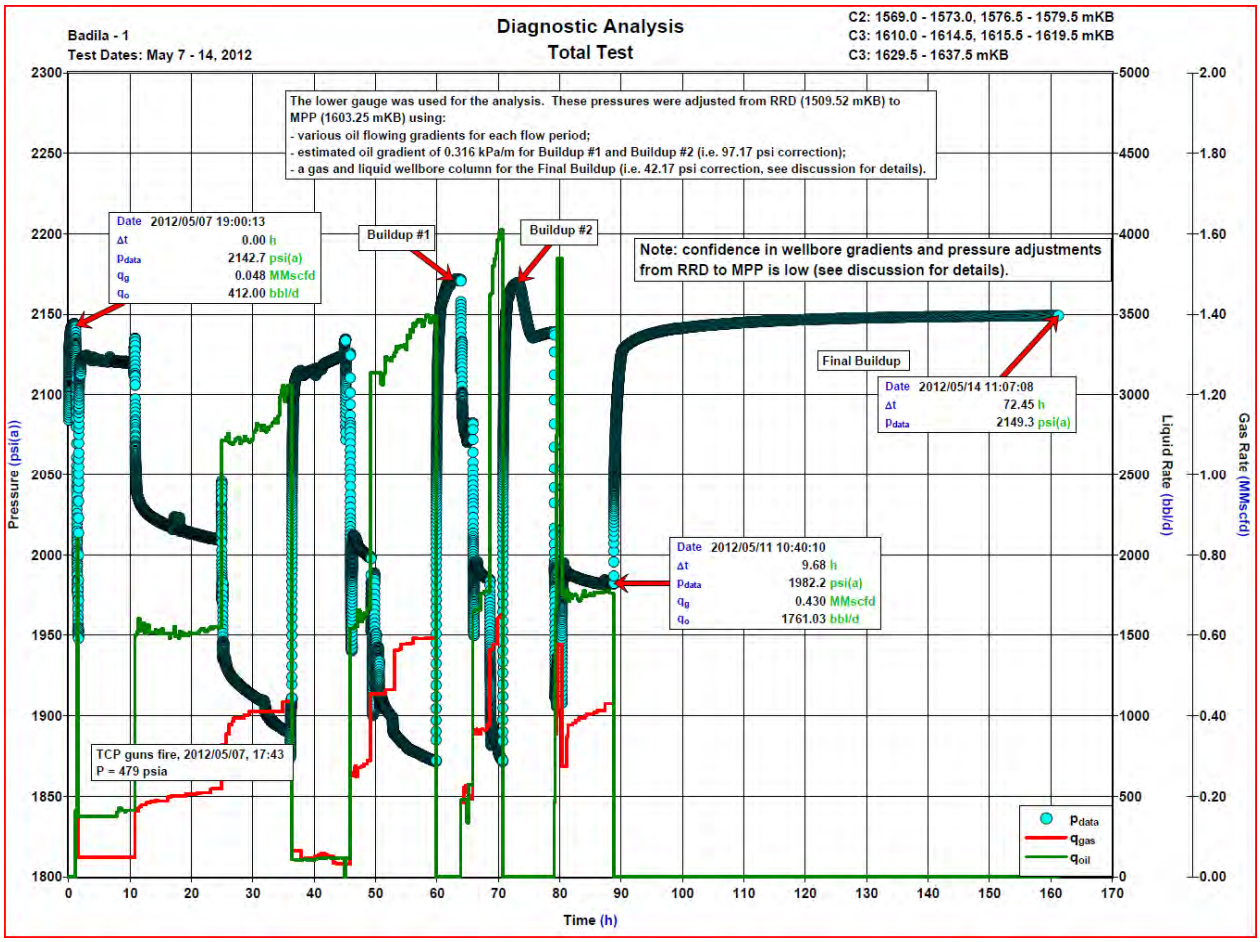


Figure 1 – Badila 1 DST Average Pressures

The following table, (Figure 2) also extracted from the Fekete Report, summarizes the results of the six main flow periods of the test. The test's peak rate of 4025 bopd was achieved on the afternoon of May 10, 2012.

Date	Clock Time	Flowing Time (hrs)	Choke	FTHP (psig)	FBHP (psia)	Oil Rate (bbl/d)	Gas Rate (MMscf/d)	GOR (scf/bbl)
2012/05/07	04:30	9.03	16/64"	300	2119.8	413	0.048	115
2012/05/08	18:45	14.05	32/64"	320	2009.1	1552	0.219	140
2012/05/09	05:58	10.97	48/64"	340	1888.9	3058	0.436	140
2012/05/10	05:43	9.22	56/64"	380	1872.2	3489	0.593	170
2012/05/10	16:35	1.89	56/64"	350	1871.9	4025	0.651	160
2012/05/11	10:40	9.68	32/64"	480	1982.2	1761	0.430	245

Figure 2 – Badila 1 DST Oil Rates

GLJ performed its own analysis of the raw DST data using Kappa's Ecrin™ software. A summary (Figure 3) of selected parameters from Fekete's and GLJ's analyses follows:

Parameter	GLJ	Fekete
Pi (psia)	2108.7	2152.9 – 2173.5
h (feet)	126.1	149
kh (md-ft)	65600	37250 – 70030
k (md)	520	250 – 470
skin	5.48	2.4 – 2.6
Oil mobility (md/cp)	149	116 – 218
boundary distance (ft)	929	500 – 1700
Reservoir description	Homogeneous, 1 constant P boundary	Various (3)
Oil API (degrees)	n/a	31
βo (fraction)	1.16	1.112
μ (cp)	3.48	2.16 – 4.05

Figure 3 – Badila PTA Comparison

Fekete's analyses considered three different reservoir configurations: 1) a two-layer Composite Reservoir Model, 2) a Storage, Skin and Boundaries Model, and 3) a Storage, Skin and Boundaries Model with Limited Size Reservoir. GLJ's configuration was a simple, homogeneous reservoir with one constant-pressure fault. The latter configuration resulted in excellent flow and build-up matching, and supports the assumption that there is aquifer pressure support for the intervals tested. The GLJ analysis yielded a distance to the constant pressure boundary of 929 feet, which is consistent with the OWC offset from the wellbore as seen on Map 3. Results of the

Fekete and GLJ analyses are reasonably compatible and are indicative of a high deliverability oil reservoir. Figure 4 shows the log-log plot for GLJ's PTA analysis.

Badila-1 DST - Log-Log Pressure Derivative Curve (GLJ)

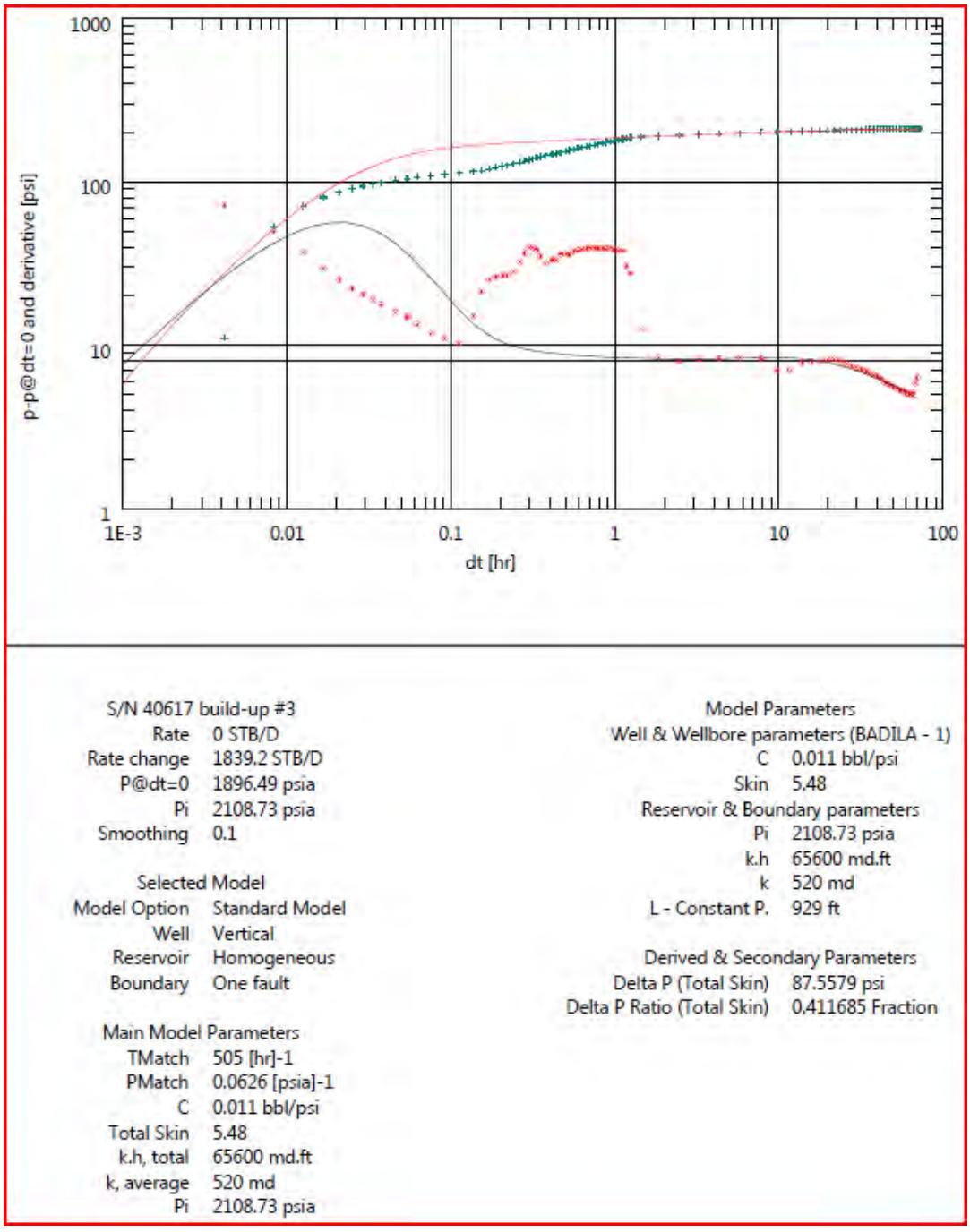


Figure 4 – PTA results Badila 1 PST – (GLJ)

Of particular interest for this evaluation are the permeability to oil, oil mobility and oil formation volume factor (βo). The high oil mobility and permeability suggest that a lower well density will be required to fully exploit the recoverable reserves. For this evaluation, the proved reserves case

assumes a drainage area of approximately 200 acres, while the 3P case assumes a larger drainage area of approximately 260 acres. The oil formation volume factor used in the 2011 year-end evaluation was 1.25, compared to the 1.16 value used in this evaluation. This change adds approximately eight percent to the property's OIIP.

Reserves Assignments

Oil reserves have been volumetrically assigned to the intervals deemed by geophysical, geological and engineering analyses to have economic quantities of OIIP. Petrophysical parameters, including net-to-gross (NTG) pay ratios, were sourced from wireline logs. These parameters are summarized in the Table 2. Gross lease reserves are summarized in Table 1.

GLJ has estimated that the effective drainage area for each Badila well is at least 200 acres given the high permeability, oil mobility, and likely aquifer drive. The maximum total area to be exploited by development wells was defined by the C3 Sand with its areal extent of 2070 (1P) to 2645 (3P) acres.

Production Forecasting

Initial rates for the ten Badila development locations and the original Badila-1 well have been estimated based on the DST flow rates. In the proved, proved plus probable and proved plus probable plus possible cases, the assigned initial rates per well are 5000, 6000, and 7500 barrels per day, respectively. Individual decline profiles were built for each of the ten wells, then a composite forecast for the total group, approximately matching the sum of the individual forecasts, was constructed. It is that composite forecast that is shown in this evaluation. Oil decline parameters, and gross and net company oil production are summarized in Tables 3, and 3.1, respectively.

Griffiths provided the expected scheduling for the drilling of Doba development wells, indicating initial production would be expected approximately five months after drilling commencement. The first well is scheduled for drilling early in 2013 with first production scheduled for July 2013, coincident with the commissioning of the Badila processing and transportation infrastructure. The production profile included herein assumes that Griffiths will commission several drilling rigs to ramp up production quickly to fill the processing infrastructure (3P capacity of approximately 25,000 bopd).

Griffiths intends to maintain reservoir pressure using water injection in addition to the anticipated pressure support of a connected aquifer. A total of eight injectors and three water source wells have been scheduled for drilling and activation, concurrent with the drilling of the new oil wells.

Natural Gas Production

There is no immediate market for the associated gas production, or dry gas production from the A2 interval. It is possible that the gas may be sold to Esso for use as compressor fuel, or as previously mentioned, it may be used for electrical power generation for field operations. No gas production forecast or sales are included in this evaluation.

ECONOMIC ANALYSIS

A summary of economic parameters used in this evaluation, including product pricing, operating expenses and capital costs is provided in Table 4. Additional capital cost detail is presented in Table 4.1. Economic parameters are described in the following sections.

Production Sharing Contract

- Gross oil production is subject to a 14.25 percent royalty.
- Inland transportation agreement (ITA) tariffs are included as a deduction from oil price.

The cost oil recovery ceiling is 70 percent of the gross revenue after deduction of the royalty. The following items can be claimed for cost recovery:

- Capital and operating costs.
- General and administrative costs.
- Abandonment fund.

Twenty- five percent carry of Government of Chad costs are included as cost recoverable amounts to Griffiths. Interest on the 25 percent carry of the Government of Chad was scheduled. Gathering and abandonment costs are scheduled from the effective date as all of these expenses are cost recoverable.

The profits remaining after cost recovery are split between the Contractor and the Government in accordance with the following sharing arrangement:

R Factor	Contractor Share
≤ 2.25	60%
> 2.25 & ≤ 3.00	50%
> 3.00	40%

R-Factor = (cost oil + profit oil – operating cost – abandonment cost)/(capital cost + recovered exploration costs)

Capital and Operating Costs

Well operating costs have been estimated at $10,000 per well month. Variable costs for oil were estimated at $3.00 per barrel. Fixed operating costs include a component for general and

administrative (G&A) costs, as well as facilities operating costs. The G&A costs were scheduled because G&A costs can be recovered as cost oil. G&A costs were scheduled from the effective date of the analysis and were scaled to production and reserves volumes. Facility operating costs were scheduled from first production. Table 4 summarizes the operating cost and G&A cost parameters.

Capital requirements for injection wells (8) and source wells (3) were estimated at 7,000 M$ and 3,500 M$ per well, respectively. Production well capital requirements were estimated to decline from an initial, all-in amount of approximately 11,500 M$, to approximately 10,140 M$ for the last three wells. The initial wells incur higher costs to cover coring and testing operations that will not be performed on the later wells. It is also expected that there will be improvements in the efficiency of drilling and completion operations realized during the 10 well drilling program. Capital to cover the mobilization of the drilling and completion rigs was included at an estimated 5,500 M$. Capital estimates for the production wells were supplied by Griffiths.

Capital was also included for the construction of facilities and pipelines. The 122,700 M$ total includes a 10,000 M$ non-cost-recoverable component for the Export Transportation System (ETS) upgrade. Pipeline capital costs scheduled within this property do not represent 100 percent of the total pipeline costs. Additional pipeline capital is scheduled with the ITA and some costs are already sunk.

The Glencore Farm-in agreement provides for an assignment of one-third of Griffiths' interest in Chad, including the East Doseo Block, to Glencore. In exchange, Glencore agrees to carry up to 330,747 M$ of development capital associated with the Badila and Mangara Fields. Cash flows presented here represent Griffiths' remaining interest, and include the terms of the Glencore Farm-in agreement. The interests presented here assume an assignment of one-third of Griffiths' original participation to Glencore. Chad's participation is expected to occur through the Société des Hydrocarbures du Tchad (SHT), the state oil company of Chad. That is, the evaluated interest assumes participation as follows:

Griffiths Energy International Inc.	50%
Glencore International AG	25%
SHT	25%

As defined within the PSC, the SHT's costs are carried proportionately by Griffiths and Glencore.

The capital recovery associated with the Glencore carry is scheduled as "Other Income" for recovery of sunk costs and as a negative capital amount for future capital. The recovery of carried capital is scheduled as follows:

		Glencore Carry Amount ($M)			
Year	Description	1P	2P	3P	Scheduled As
2012	Sunk Prior to June 30, 2012	6,489	6,489	6,489	Other Income
2012	Sunk costs July 1 to Dec 31, 2012	21,104	21,104	21,104	Other Income
2013	2013 Capital (Badila)	24,070	25,319	25,645	Capital
2014	2014 Capital (Badila)	24,544	24,436	23,899	Capital
2015	2015 Capital (Badila)	14,988	6,475	5,701	Capital
2016	2016 Capital (Badila)	0	0	0	Capital
	Total	91,195	83,822	82,837	

*Note, all values are in dollars of the day

Glencore carry amounts do not affect the cost oil recovery calculation.

Commodity Prices

Oil prices were estimated to be 95 percent of Brent prices, less a $6.50 per bbl transportation fee for the Cameroon to Chad export pipeline less the ITA tariff. The ITA tariff varies for each reserves class. Details on the ITA tariff at Badila and Mangara are presented in the ITA Badila-Mangara report.

Solution gas is considered unmarketable and it was assumed all solution gas would be flared or used as fuel.

Economic forecasts for each of the reserves categories have been included in the Economic Forecasts section of this report.

Other Economic Considerations

This report does not address the following issues:

- Non-reserves well abandonment, wellsite reclamation and facility abandonment/salvage including possible environmental concerns.
- Potential processing income.
- The current condition of field, gathering and processing facilities, i.e. an inspection was not carried out.

PSC Parameters - Badila

Griffiths Energy International Inc (Griffiths) has entered into a Production Sharing Contract with the Republic of Chad.
Key parameters in the economic model* are as follows:

	Griffiths	Glencore	Chad	Comment
Participation	50.00%	25.00%	25.00%	Assumes Chad exercises right to back in for 25% participation
Carry	16.67%	8.33%		Griffiths and Glencore carry 25% of total capital, operating and abandonment costs
Lease Expiry	Dec-36			10 year extension permitted and included in 2P and 3P cases
Oil Royalty	14.25%			Deducted from lease revenue, prior to cost oil and profit oil calculation
Gas Royalty	5%			Deducted from lease revenue, prior to cost oil and profit oil calculation

Allocation of Profit Oil

R Factor		Griffiths	Glencore	SHT	Chad	
Profit Oil Share	$R \leq 2.25$	30%	15%	15%	40%	
Profit Oil Share	$2.25 < R \leq 3.00$	25%	13%	13%	50%	
Profit Oil Share	$R > 3$	20%	10%	10%	60%	
Numerator						Contractor Revenue less Cumulative Operating costs and Cumulative Abandonment Costs
Denominator						Contractor Capital and Recovered Exploration Costs

Abandonment Costs	UOP	Abandonment costs recovered on a Unit of Production Basis.
Bonus	0	No remaining Bonus payable. Bonuses not cost recoverable

Opening Balances of Recoverable Costs

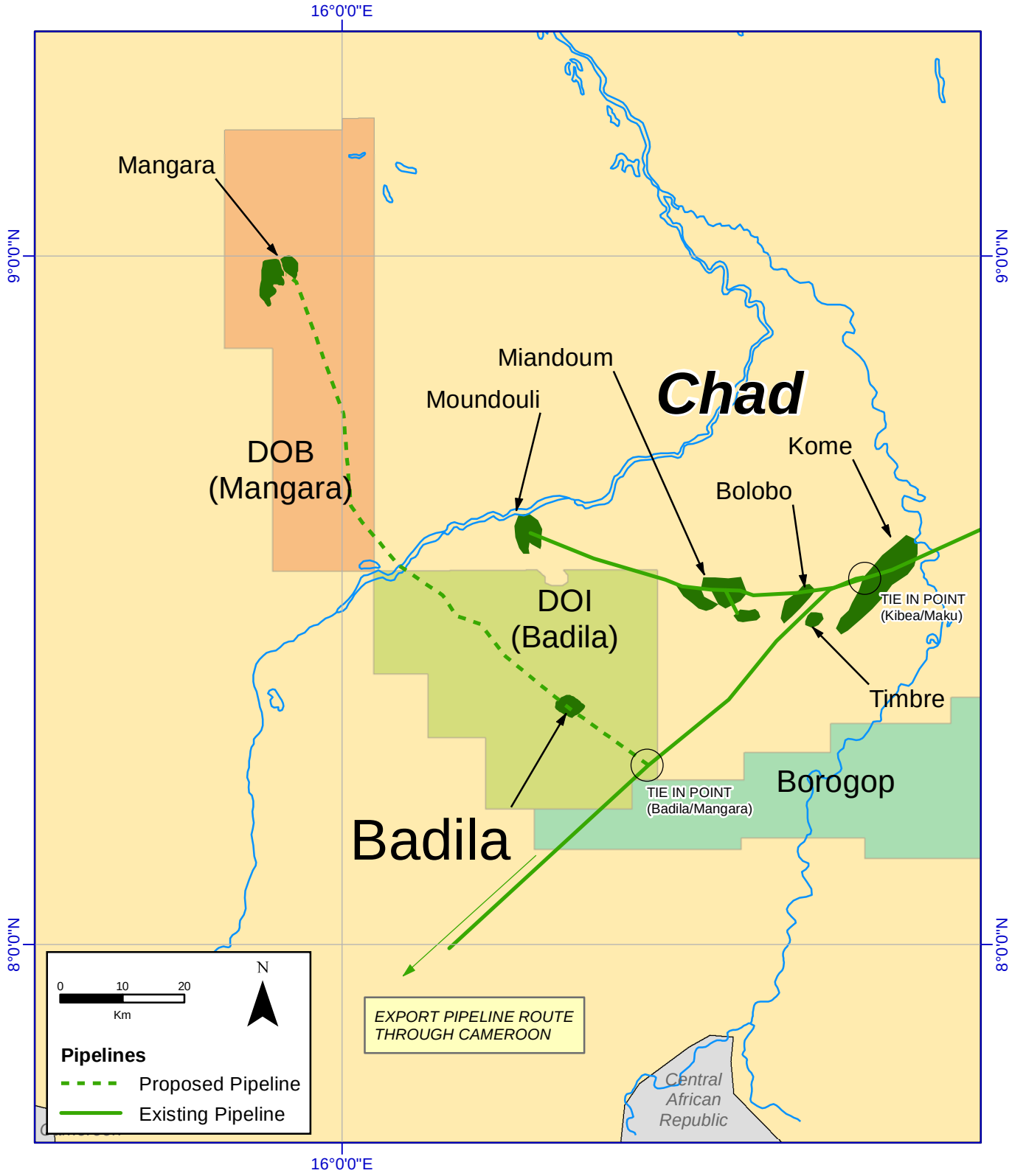
Exploration	$	0
G & A Costs	$	29,628,623
Capital Costs	$	48,555,288

*The economic model used in this report assume that the proposed transaction with Glencore International AG will occur
SHT is the *Société des Hydrocarbures du Tchad*, the state oil company of Chad.

Map 1
Land Map
Badila

Company: Griffiths Energy International Inc.
Property: Badila

Effective Date: December 31, 2012
Scale: 1:900,000 s1132107/badm01



Map 1a

Exclusive Exploitation Authorization Map

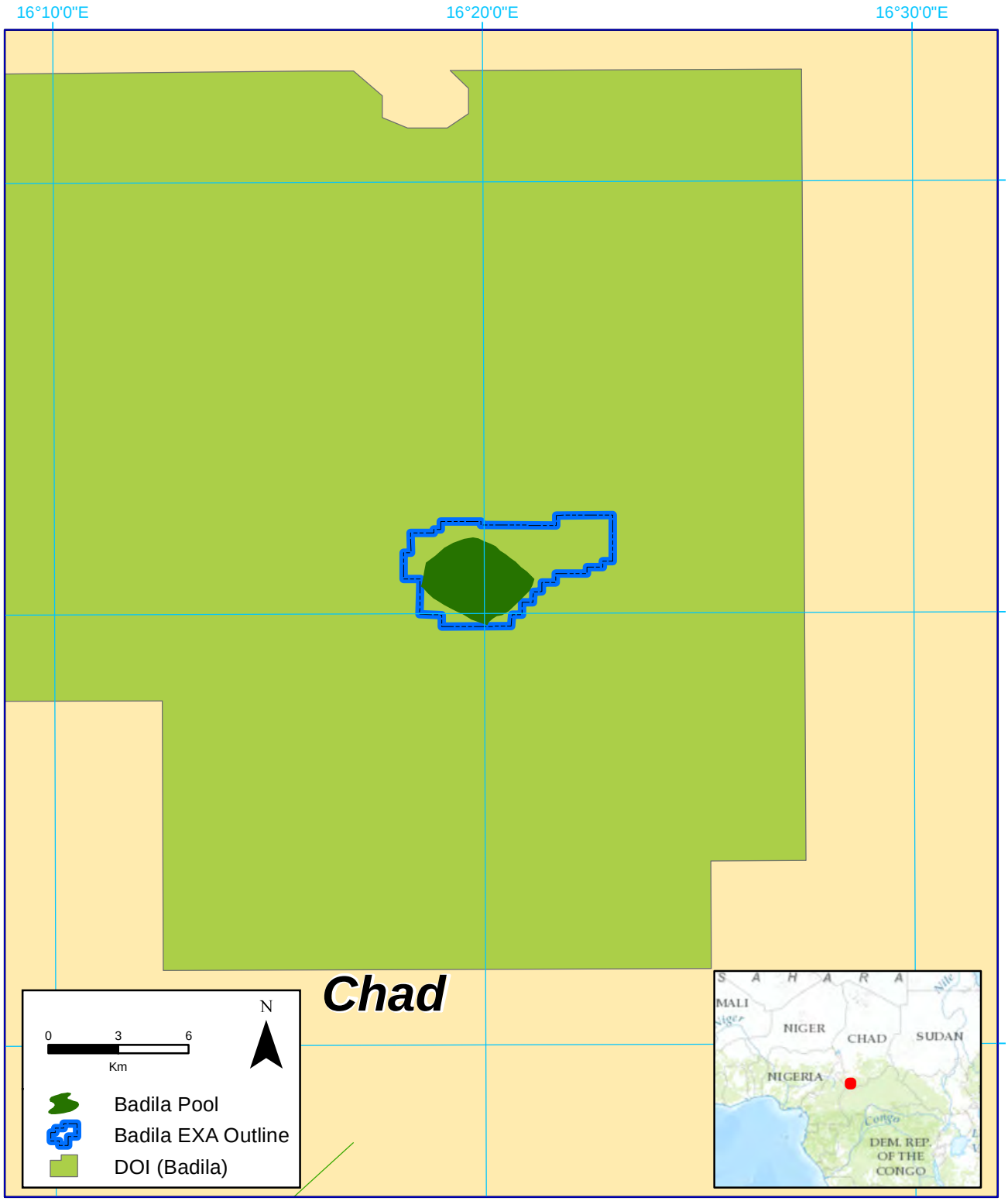
Badila

Company: Griffiths Energy International Inc.

Effective Date: December 31, 2012

Property: Badila

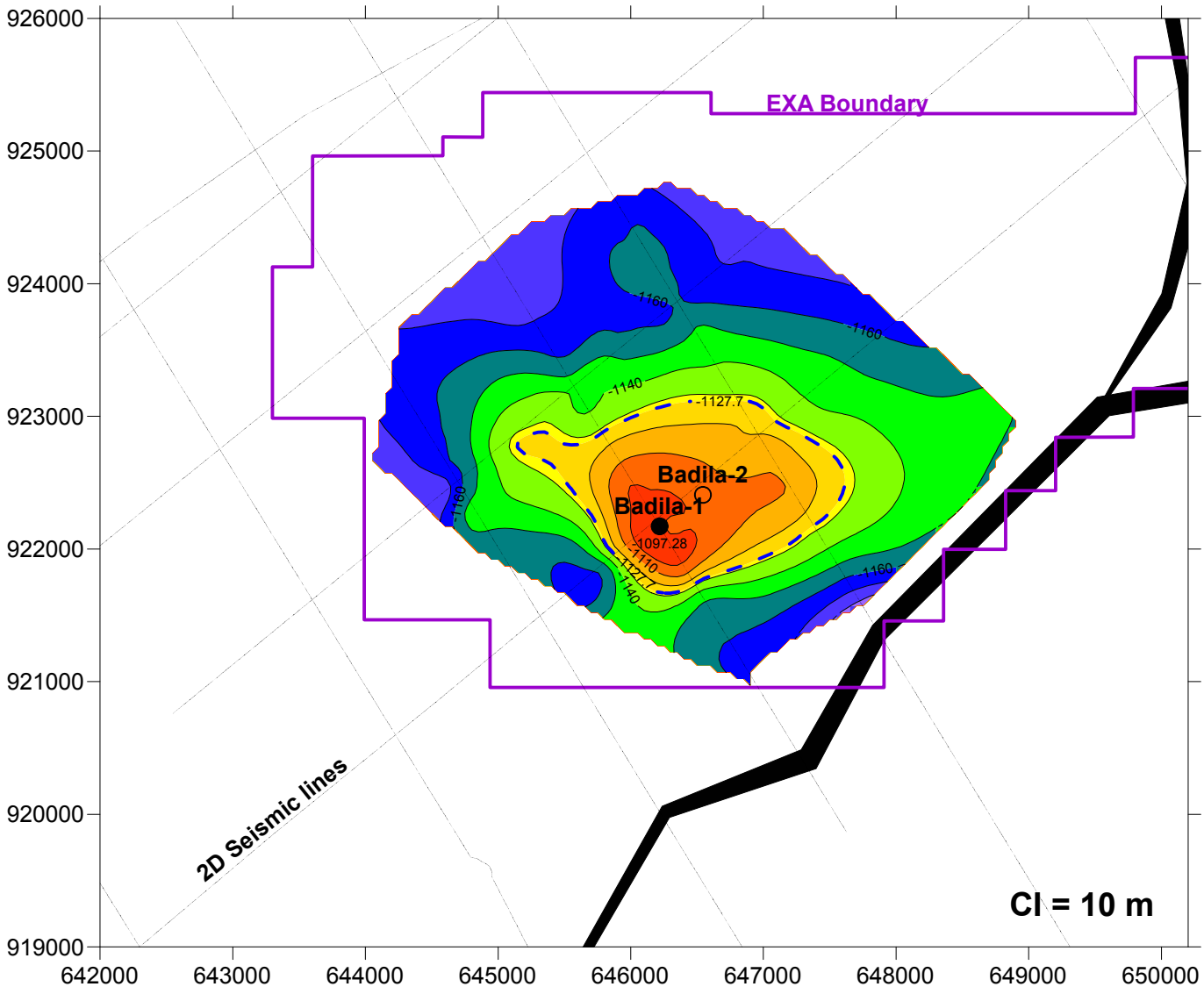
Scale: 1:250,000 s1132107/badm01a



Map 2
Badila Field
Depth Structure Map (metres)
C2 Sand

Company: Griffiths Energy International Inc.
Property: Badila

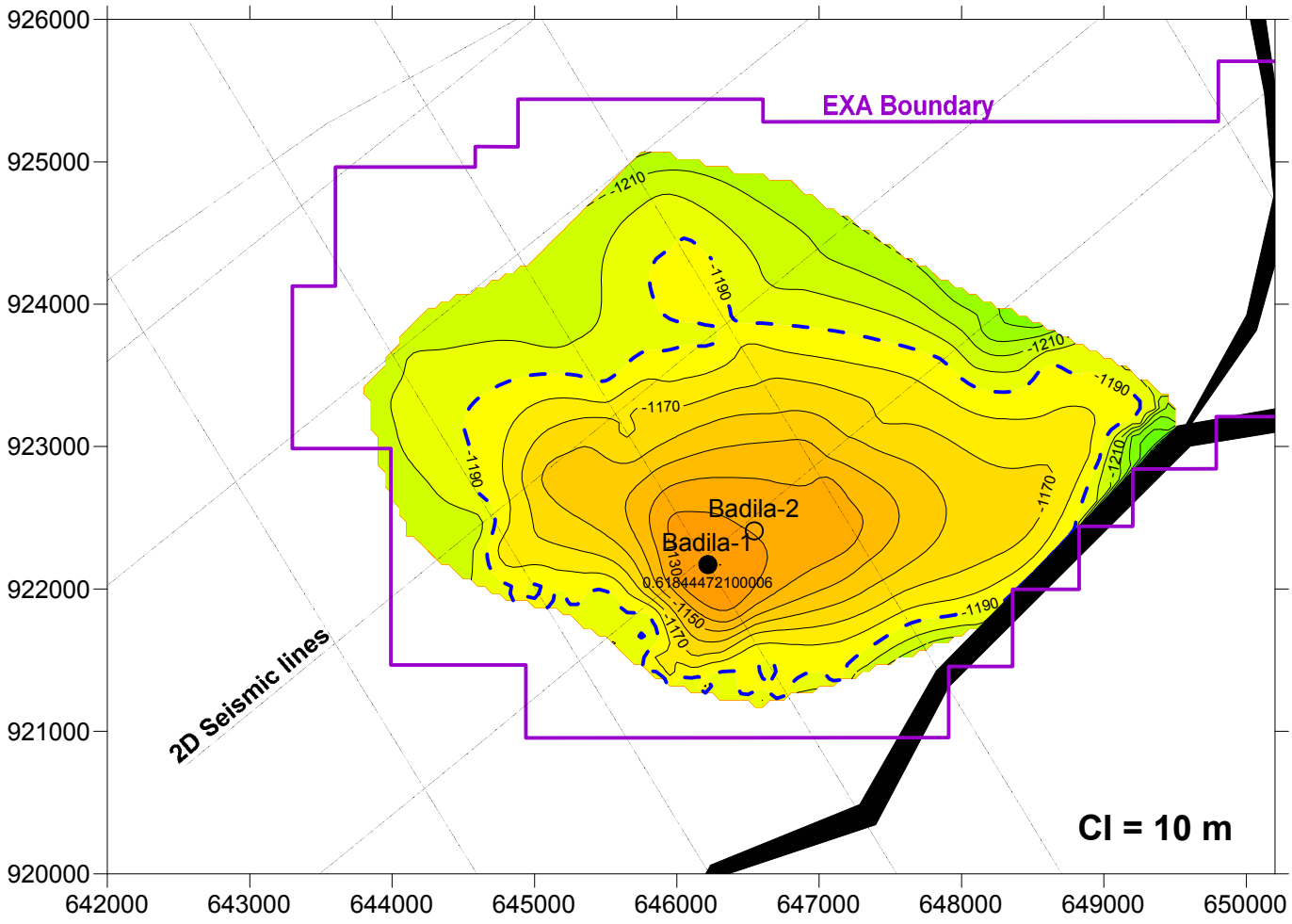
Effective Date: December 31, 2012
Scale: 1:50,000 s1132107



Map 3
Badila Field
Depth Structure Map (metres)
C3 Sand

Company: Griffiths Energy International Inc.
Property: Badila

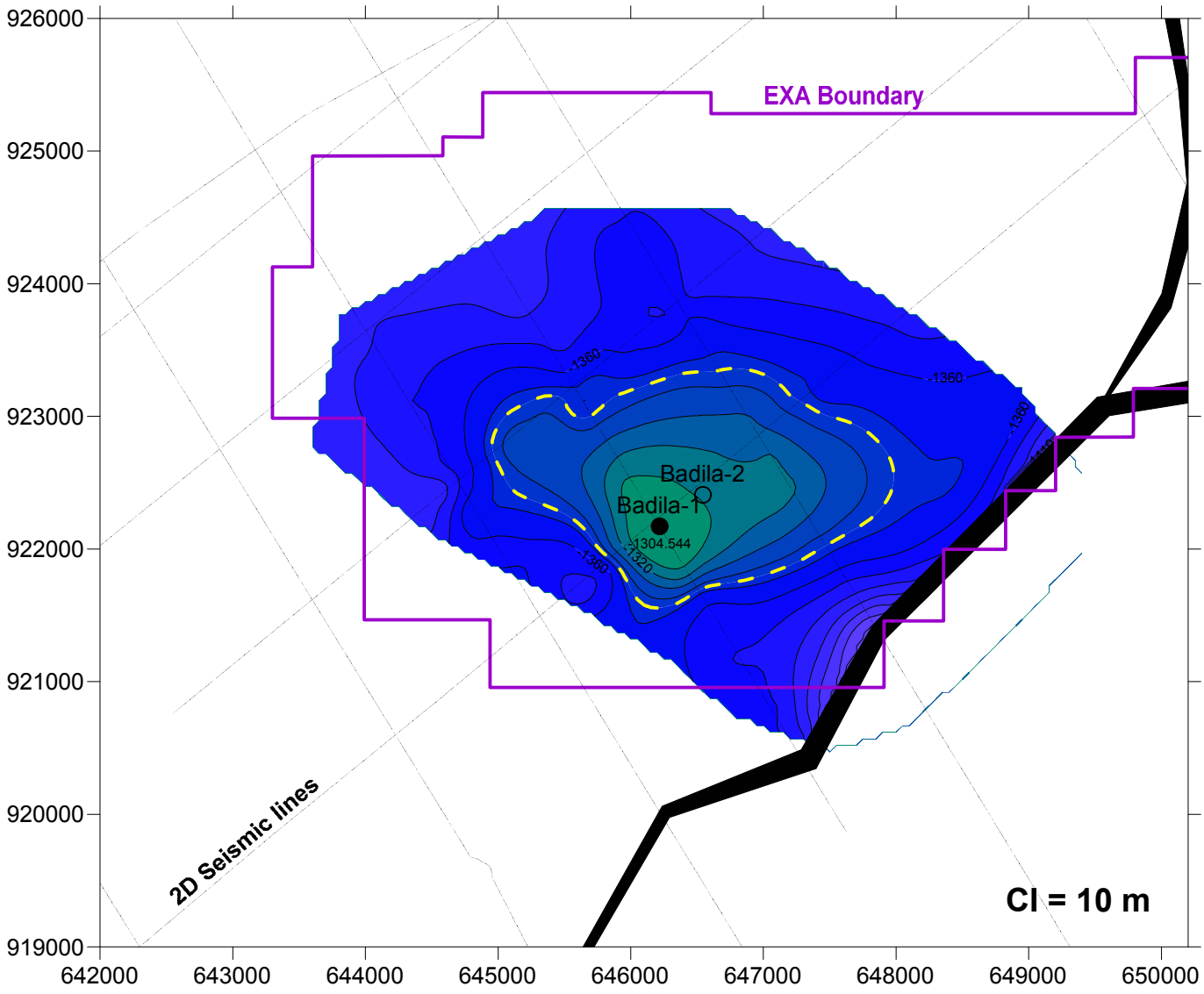
Effective Date: December 31, 2012
Scale: 1:50,000 s1132107



Map 4
Badila Field
Depth Structure Map (metres)
D3 Sand

Company: Griffiths Energy International Inc.
Property: Badila

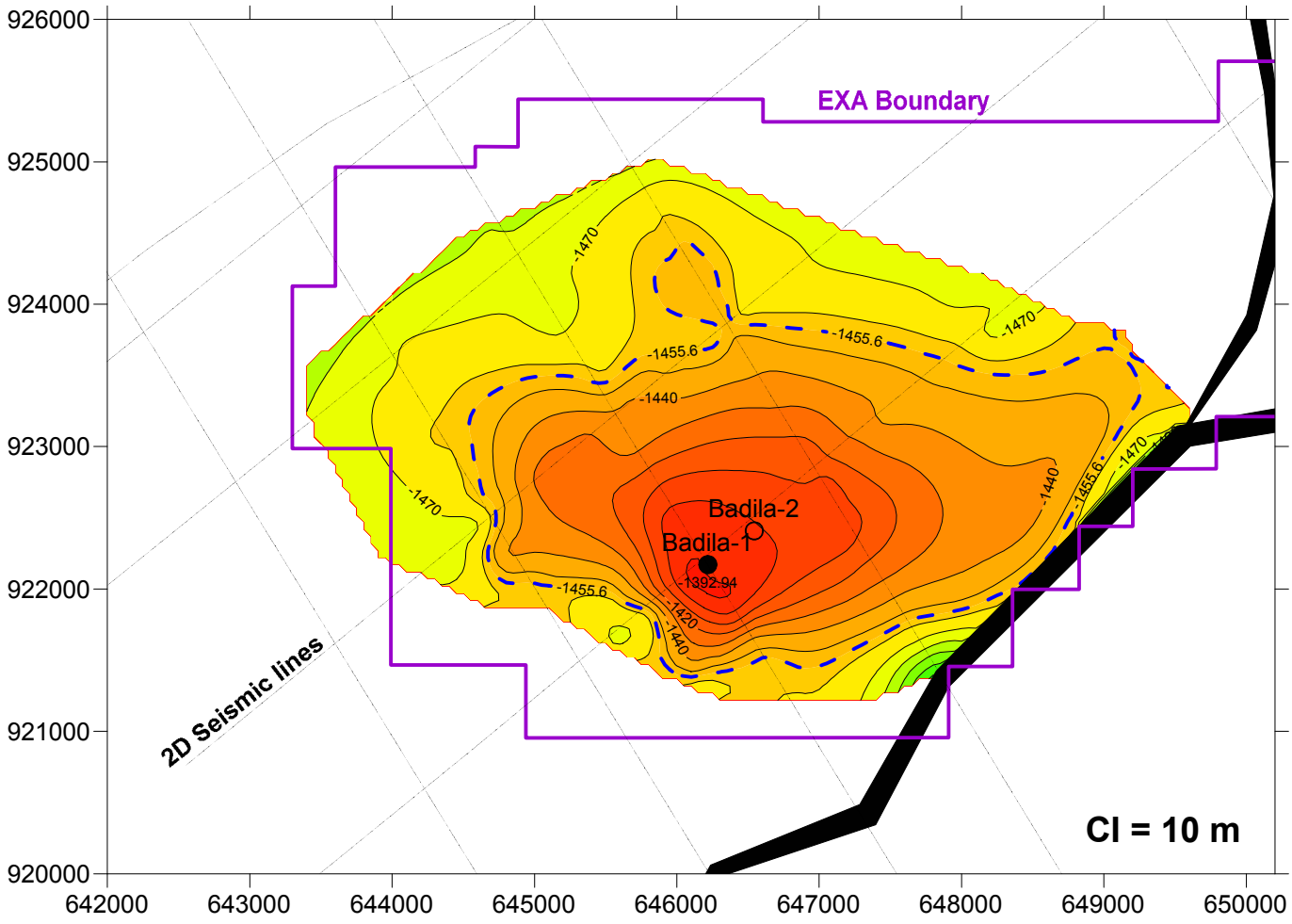
Effective Date: December 31, 2012
Scale: 1:50,000 s1132107



Map 5
Badila Field
Depth Structure Map (metres)
D8 Sand

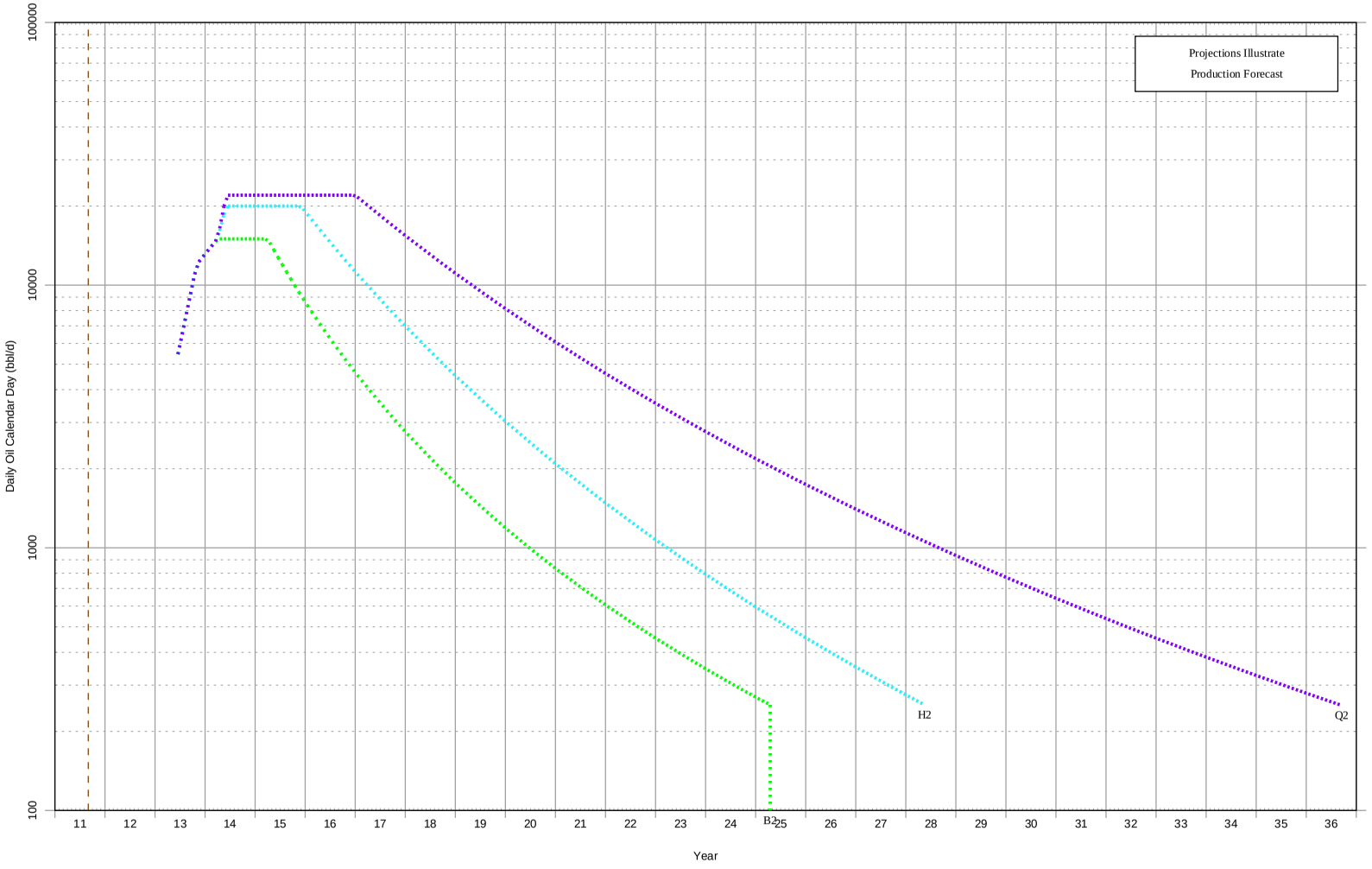
Company: Griffiths Energy International Inc.
Property: Badila

Effective Date: December 31, 2012
Scale: 1:50,000 s1132107



Historical and Forecast Production
Badila - Total Property

Property : Badila



Total Reserves Summary @ 2011/09/01

Reserves Classification		Reserves (Mbbl) Ultimate	Cum Production	Remaining
Pv UDev	B2(R)	17972	0	17972
P + P UDev	H2(R)	31062	0	31062
PPP UDev	Q2(R)	51765	0	51765

Average Production Rates (Last 12 months ending 2011/09/01)

Gas :	0.0 Mcf/d	0.0 Mcf/cd	WGR :	0.0 bbl/MMcf
Oil :	0.0 bbl/d	0.0 bbl/cd	GOR :	0.0 scf/bbl
On Prod :	0.0 days		WC :	0.0 %

Cumulative Production

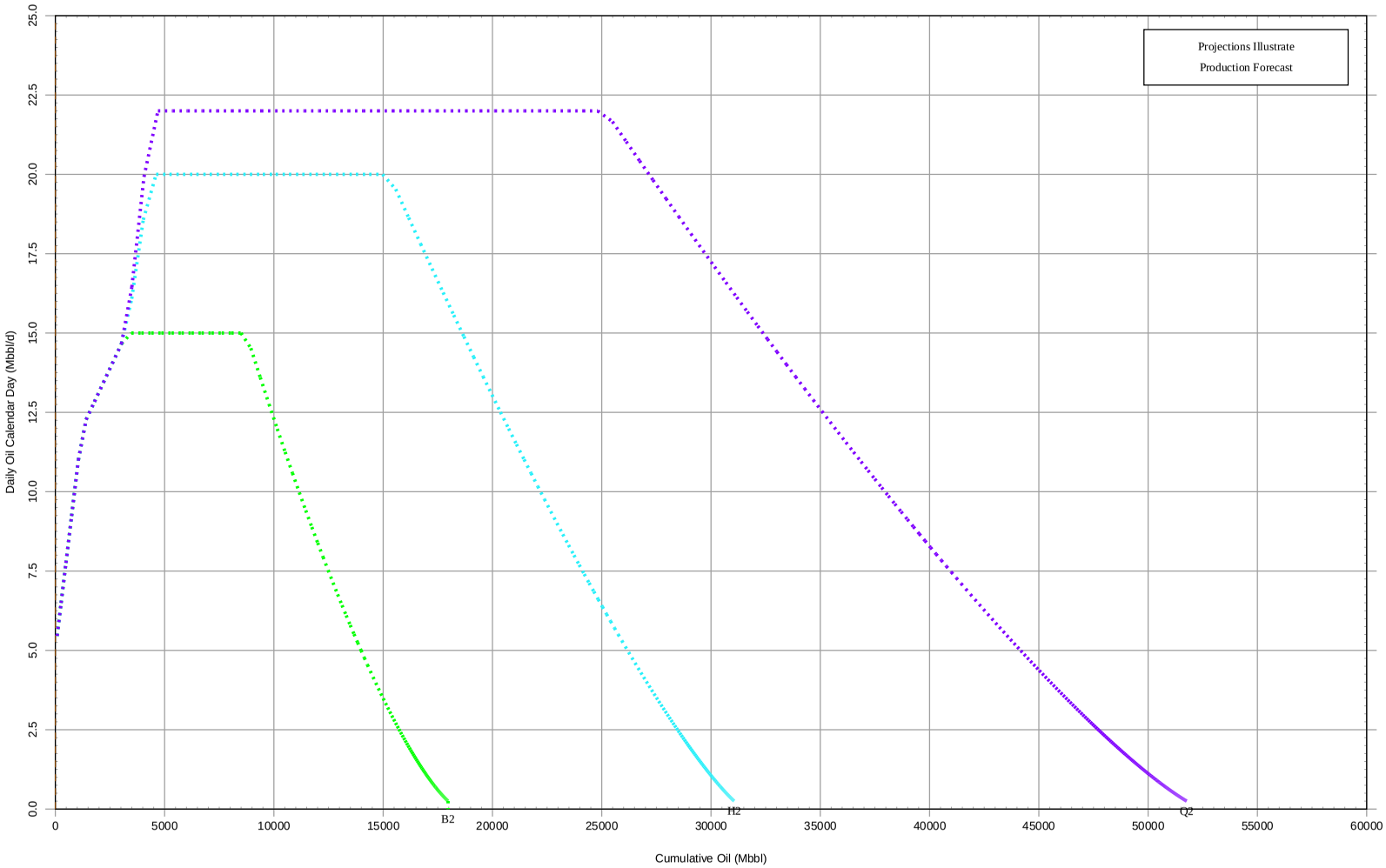
Oil :	0.0 Mbbl	Gas :	0.0 MMcf	Water :	0.0 Mbbl

A-119

Plot 1

Historical and Forecast Production
Badila - Total Property

Property : Badila



Total Reserves Summary @ 2011/09/01

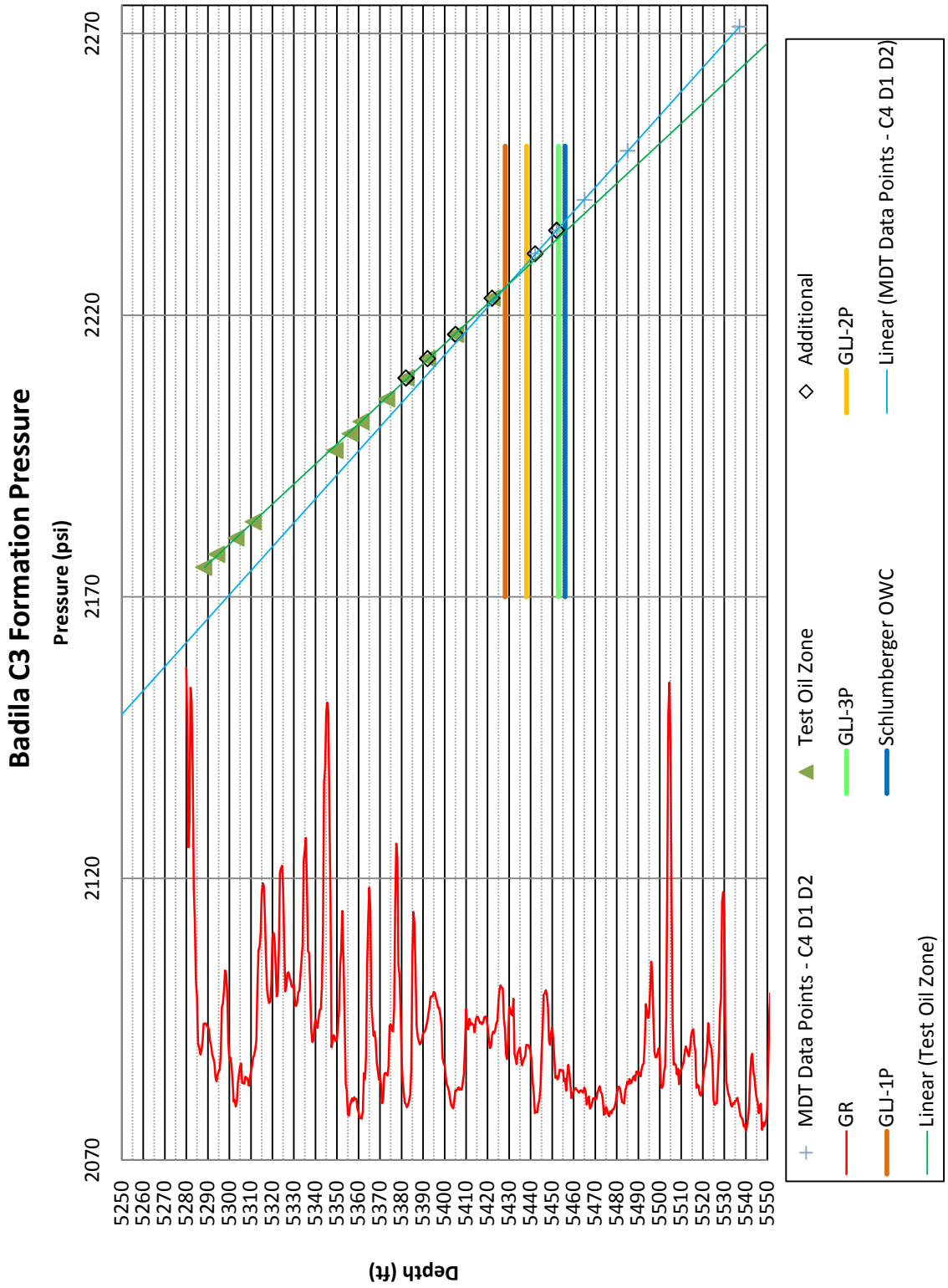
Reserves Classification		Reserves (Mbbl) Ultimate	Cum Production	Remaining
Pv UDev	B2(R)	17972	0	17972
P + P UDev	H2(R)	31062	0	31062
PPP UDev	Q2(R)	51765	0	51765

Average Production Rates (Last 12 months ending 2011/09/01)

Gas :	0.0 Mcf/d	0.0 Mcf/cd	WGR :	0.0 bbl/MMcf
Oil :	0.0 bbl/d	0.0 bbl/cd	GOR :	0.0 scf/bbl
On Prod :	0.0 days		WC :	0.0 %

Cumulative Production

Oil :	0.0 Mbbl	Gas :	0.0 MMcf	Water :	0.0 Mbbl



GLJ Petroleum Consultants

Plot 3

Table 1

Company: **Griffiths Energy International Inc.**
Property: **Badila**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Gross Lease Reserves Summary

Entity Description	Reserve Class	Methodology	Oil (Mbbl) Initial Recoverable	Oil (Mbbl) Cumulative Production	Oil (Mbbl) Reserves	Non-Associated Gas (MMcf) Initial Recoverable	Non-Associated Gas (MMcf) Cumulative Production	Non-Associated Gas (MMcf) Raw Gas	Non-Associated Gas (MMcf) Reserves	Other Gross Lease Reserves Sol'n Gas MMcf	Other Gross Lease Reserves Cond Mbbl	Other Gross Lease Reserves LPG Mbbl	Other Gross Lease Reserves Sulphur Mlt
Proved Undeveloped													
Badila Total	B2	Dec,Vol	17,972	0	17,572 *	0	0	0	0	0	0	0	0
Total: Proved Undeveloped			**17,972**	**0**	**17,572 ***	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Proved Plus Probable Undeveloped													
Badila Total	H2	Dec,Vol	31,062	0	30,588 *	0	0	0	0	0	0	0	0
Total: Proved Plus Probable Undeveloped			**31,062**	**0**	**30,588 ***	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
PPP Undeveloped													
Badila Total	Q2	Dec,Vol	51,765	0	50,960 *	0	0	0	0	0	0	0	0
Total: PPP Undeveloped			**51,765**	**0**	**50,960 ***	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Notes
1. [*] Remaining reserves are less than the estimate due to economic limit.

Table 2

Company: **Griffiths Energy International Inc.**
Property: **Badila**

Effective Date: **December 31, 2012**

Oil Reservoir Parameters

Resource Entity	Zone	Method	Reserve Class	Gross Rock Volume (acre-ft)	Net to Gross	Porosity %	Water Sat'n %	Original Pressure psi	Reservoir Temp. °R	Oil Gravity °API	Oil Solution GOR	Formation Volume Factor	Original Oil In Place Mbbl	Recovery Factor %	Recoverable Reserves Mbbl	Cum Production 2012-12-31 Mbbl	Remaining 2012-12-31 Reserves
Proved Undeveloped																	
Badila Total	C2	Dec,Vol	B2	12473	0.13	22.3	48	-	-	-	-	1.16	1,225	30	368	-	368
Badila Total	C3	Dec,Vol	B2	159630	0.40	22.7	41	-	-	-	-	1.16	57,243	30	17,173	-	17,173
Badila Total	D3	Dec,Vol	B2	3031	0.32	24.6	36	-	-	-	-	1.16	1,017	25	254	-	254
Badila Total	D8	Dec,Vol	B2	67777	0.01	24.8	53	-	-	-	-	1.16	709	25	177	-	177
Total: Proved Undeveloped													**60,194**	**29.9**	**17,972**	**0**	**17,972**
Proved Plus Probable Undeveloped																	
Badila Total	C2	Dec,Vol	H2	30253	0.23	22.4	53	-	-	-	-	1.16	4,962	35	1,737	-	1,737
Badila Total	C3	Dec,Vol	H2	182018	0.50	22.1	44	-	-	-	-	1.16	75,560	35	26,446	-	26,446
Badila Total	D3	Dec,Vol	H2	14621	0.33	24.4	36	-	-	-	-	1.16	4,979	30	1,494	-	1,494
Badila Total	D8	Dec,Vol	H2	88594	0.08	25.6	60	-	-	-	-	1.16	4,618	30	1,385	-	1,385
Total: Proved Plus Probable Undeveloped													**90,119**	**34.4**	**31,062**	**0**	**31,062**
PPP Undeveloped																	
Badila Total	C2	Dec,Vol	Q2	40168	0.23	22.4	53	-	-	-	-	1.16	6,574	40	2,630	-	2,630
Badila Total	C3	Dec,Vol	Q2	215599	0.56	21.5	43	-	-	-	-	1.16	99,348	40	39,739	-	39,739
Badila Total	D3	Dec,Vol	Q2	35332	0.35	24.1	38	-	-	-	-	1.16	12,262	35	4,292	-	4,292
Badila Total	D8	Dec,Vol	Q2	114406	0.24	24.7	68	-	-	-	-	1.16	14,583	35	5,104	-	5,104
Total: PPP Undeveloped													**132,767**	**38.7**	**51,765**	**0**	**51,765**

The reserves calculated above may not match the economic forecasts due to economic limit considerations.

Glossary
B2: Proved Undeveloped
H2: Proved Plus Probable Undeveloped
Q2: PPP Undeveloped

Table 2.1
BADILA-1
SUMMARY OF PETROPHYSICAL ANALYSIS

Well		Datum (m)	Top	Base	Gross Thickness	Low Case			Most Likely Case			High Case		
			MD, m	MD, m	tvd, m	Net Oil (m)	Phi	Sw	Net Oil (m)	Phi	Sw	Net Oil (m)	Phi	Sw
Badila-1	C2	464.51	1561.80	1591.06	29.3	3.7	22.3%	48%	6.9	22.4%	53%	6.9	22.4%	53%
	NGR					***0.13***			***0.23***			***0.23***		
Badila-1	C3	464.51	1591.06	1663.59	72.5	29.0	22.7%	41%	36.40	22.1%	44%	40.80	21.5%	46%
	NGR					***0.40***			***0.50***			***0.56***		
Badila-1	D3	464.51	1769.06	1796.80	27.7	8.8	24.6%	36%	9.1	24.4%	36%	9.7	24.1%	38%
	NGR					***0.32***			***0.33***			***0.35***		
Badila-1	D8	464.51	1857.45	1920.24	62.8	0.8	24.8%	53%	4.7	25.6%	60%	15.0	24.7%	68%
	NGR					***0.01***			***0.08***			***0.24***		

Notes
Low Case = Phi>8%, Sw<55%, Vsh <50%
Most Likely Case = Phi>8%, Sw<65%, Vsh <50%
High Case = Phi>8%, Sw<75%, Vsh <50%

Table 3

Company: **Griffiths Energy International Inc.**
Property: **Badila**
Currency: **$US Dollars**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Gross Lease Daily Oil Production

Entity Description	Reserve Class	Year (bbl/d)												Totals (Mbbl)		
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Subtotal	Remainder	Total
Proved Undeveloped																
Badila Total	B2	5,450	14,765	12,315	6,397	3,608	2,221	1,455	1,002	713	219	0	0	17,572	0	17,572
Total: Proved Undeveloped		**5,450**	**14,765**	**12,315**	**6,397**	**3,608**	**2,221**	**1,455**	**1,002**	**713**	**219**	**0**	**0**	**17,572**	**0**	**17,572**
Proved Plus Probable Undeveloped																
Badila Total	H2	5,450	18,088	19,960	14,792	8,918	5,650	3,719	2,535	1,766	1,265	925	691	30,572	16	30,588
Total: Proved Plus Probable Undeveloped		**5,450**	**18,088**	**19,960**	**14,792**	**8,918**	**5,650**	**3,719**	**2,535**	**1,766**	**1,265**	**925**	**691**	**30,572**	**16**	**30,588**
PPP Undeveloped																
Badila Total	Q2	5,450	19,405	22,000	22,060	18,490	13,127	9,527	7,066	5,302	4,053	3,140	2,470	48,213	2,747	50,960
Total: PPP Undeveloped		**5,450**	**19,405**	**22,000**	**22,060**	**18,490**	**13,127**	**9,527**	**7,066**	**5,302**	**4,053**	**3,140**	**2,470**	**48,213**	**2,747**	**50,960**

Table 3.1

Company: **Griffiths Energy International Inc.**
Property: **Badila**
Currency: **$US Dollars**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Company Daily Oil Production

Entity Description	Reserve Class	Year (bbl/d)												Totals (Mbbl)		
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Subtotal	Remainder	Total
Proved Undeveloped																
Badila Total	B2	2,602	5,454	3,263	1,714	1,215	629	438	351	295	107	0	0	5,865	0	5,865
Total: Proved Undeveloped		**2,602**	**5,454**	**3,263**	**1,714**	**1,215**	**629**	**438**	**351**	**295**	**107**	**0**	**0**	**5,865**	**0**	**5,865**
Proved Plus Probable Undeveloped																
Badila Total	H2	2,602	6,396	4,472	3,328	2,242	1,297	883	657	511	415	350	301	8,560	8	8,568
Total: Proved Plus Probable Undeveloped		**2,602**	**6,396**	**4,472**	**3,328**	**2,242**	**1,297**	**883**	**657**	**511**	**415**	**350**	**301**	**8,560**	**8**	**8,568**
PPP Undeveloped																
Badila Total	Q2	2,602	6,834	4,883	4,728	4,088	2,752	1,998	1,531	1,196	959	785	658	12,050	947	12,997
Total: PPP Undeveloped		**2,602**	**6,834**	**4,883**	**4,728**	**4,088**	**2,752**	**1,998**	**1,531**	**1,196**	**959**	**785**	**658**	**12,050**	**947**	**12,997**

Table 4

Company: **Griffiths Energy International Inc.** Effective Date: **31-Dec-12**

Property: **Badila**

Economic Parameters

A) Price Forecasts and By-Product Data

GLJ (2013-01)

Oil Reference: 95% of BRENTUS

Transport Costs

Proved Undeveloped	$8.20/bbl
Proved plus Probable Undeveloped	$7.52/bbl
Proved plus Probable plus Possible Undeveloped	$7.22/bbl

B) Operating Costs (2013 Dollars)

Well Costs: $10,000 / well / momth

Variable Costs $3.00 / bbl

Fixed Operating Costs and G&A

	Facility Operating Costs			G&A Costs		
Year	Proved M$	Proved+ Probable M$	Proved+ Probable+ Possible M$	Proved M$	Proved+ Probable M$	Proved+ Probable+ Possible M$
2013	4,375	4,375	4,375	5,833	11,667	17,500
2014	7,500	7,500	7,500	5,000	10,000	15,000
2015	7,500	7,500	7,500	2,500	5,000	7,500
2016	7,500	7,500	7,500	2,500	5,000	7,500
2017	7,500	7,500	7,500	2,500	5,000	7,500
2018	7,500	7,500	7,500	2,500	5,000	7,500
2019	7,500	7,500	7,500	1,000	2,000	3,000
2020+	7,500	7,500	7,500	1,000	2,000	3,000

All values are in 2012 dollars

C) Abandonment Costs (2013 Dollars)

	M$
Proved Undeveloped	$ 4,400
Proved plus Probable Undeveloped	$ 4,400
Proved plus Probable plus Possible Undeveloped	$ 4,400

Abandonment costs are scheduled on a unit of production basis.

Table 4.1

Company: **Griffiths Energy International Inc.** Effective Date: **31-Dec-12**
Property: **Badila**

Economic Parameters

D) Capital Costs

Capital Summary (2013 Dollars)

Year	Well/Area	Development Description	Gross Lease Capital Expenditures: Development M$	Tangible M$	Plant & Gath. M$	Total M$	Company Total M$	Capital Interest %
	Proved Undeveloped							
2013	Drilling Capital	Well Capital	25,071	0	0	25,071	16,714	66.67
	Glencore Carry		-24,070	0	0	-24,070	-24,070	100
	Badila	Pipeline & Facilities	0	0	65,835	65,835	43,890	66.67
2014	Drilling Capital	Well Capital	58,262	0	0	58,262	38,842	66.67
	Glencore Carry		-24,063	0	0	-24,063	-24,063	100
	Badila	Pipeline & Facilities	0	0	4,343	4,343	2,895	66.67
2015	Drilling Capital	Well Capital	34,399	0	0	34,399	22,933	66.67
	Glencore Carry		-14,406	0	0	-14,406	-14,406	100
2016	Drilling Capital	Well Capital	21,699	0	0	21,699	14,466	66.67
2017	Drilling Capital	Well Capital	21,000	0	0	21,000	14,000	66.67
	Total: Proved Undeveloped		**97,892**	**0**	**70,178**	**168,070**	**91,201**	**54.26**
	Proved Plus Probable Undeveloped							
2013	Drilling Capital	Well Capital	25,071	0	0	25,071	16,714	66.67
	Glencore Carry		-23,319	0	0	-23,319	-23,319	100
	Badila	Pipeline & Facilities	0	0	65,835	65,835	43,890	66.67
2014	Drilling Capital	Well Capital	58,262	0	0	58,262	38,842	66.67
	Glencore Carry		-23,957	0	0	-23,957	-23,957	100
	Badila	Pipeline & Facilities	0	0	4,343	4,343	2,895	66.67
2015	Drilling Capital	Well Capital	34,399	0	0	34,399	22,933	66.67
	Glencore Carry		-6,224	0	0	-6,224	-6,224	100
2016	Drilling Capital	Well Capital	21,699	0	0	21,699	14,466	66.67
2017	Drilling Capital	Well Capital	21,000	0	0	21,000	14,000	66.67
	Total: Proved Plus Probable Undeveloped		**106,932**	**0**	**70,178**	**177,110**	**100,241**	**56.60**
	PPP Undeveloped							
2013	Drilling Capital	Well Capital	25,071	0	0	25,071	16,714	66.67
	Glencore Carry		-25,645	0	0	-25,645	-25,645	100
	Badila	Pipeline & Facilities	0	0	65,835	65,835	43,890	66.67
2014	Drilling Capital	Well Capital	58,262	0	0	58,262	38,842	66.67
	Glencore Carry		-23,430	0	0	-23,430	-23,430	100
	Badila	Pipeline & Facilities	0	0	4,343	4,343	2,895	66.67
2015	Drilling Capital	Well Capital	34,399	0	0	34,399	22,933	66.67
	Glencore Carry		-5,480	0	0	-5,480	-5,480	100
2016	Drilling Capital	Well Capital	21,699	0	0	21,699	14,466	66.67
2017	Drilling Capital	Well Capital	21,000	0	0	21,000	14,000	66.67
	Total: PPP Undeveloped		**105,876**	**0**	**70,178**	**176,054**	**99,185**	**56.34**

Company: **Griffiths Energy International Inc.**
Property: **Badila**
Currency: **$US Dollars**

Reserve Class: **Proved**
Development Class: **Undeveloped**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production				
Year	Gross Oil Wells	Gross Daily bbl/d	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	2	5,450	2,602	950	950	91.55
2014	6	14,765	5,454	1,991	1,991	89.18
2015	9	12,315	3,263	1,191	1,191	89.18
2016	10	6,397	1,714	625	625	89.17
2017	11	3,608	1,215	443	443	86.80
2018	11	2,221	629	230	230	86.80
2019	11	1,455	438	160	160	88.08
2020	11	1,002	351	128	128	90.01
2021	11	713	295	108	108	91.98
2022	4	219	107	39	39	93.97
Tot.				**5,865**	**5,865**	**89.36**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After Process.	Net Revenue After Royalty	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	M$	M$	Fixed M$	Variable M$	Total M$
2013	86,936	0	0	86,936	0	86,936	0	0	0	0	0	86,936	10,925	0	10,925
2014	177,524	0	0	177,524	0	177,524	0	0	0	0	0	177,524	19,983	0	19,983
2015	106,205	0	0	106,205	0	106,205	0	0	0	0	0	106,205	16,996	0	16,996
2016	55,776	0	0	55,776	0	55,776	0	0	0	0	0	55,776	12,901	0	12,901
2017	38,494	0	0	38,494	0	38,494	0	0	0	0	0	38,494	11,020	0	11,020
2018	19,937	0	0	19,937	0	19,937	0	0	0	0	0	19,937	10,122	0	10,122
2019	14,088	0	0	14,088	0	14,088	0	0	0	0	0	14,088	8,568	0	8,568
2020	11,546	0	0	11,546	0	11,546	0	0	0	0	0	11,546	8,360	0	8,360
2021	9,912	0	0	9,912	0	9,912	0	0	0	0	0	9,912	8,280	0	8,280
2022	3,654	0	0	3,654	0	3,654	0	0	0	0	0	3,654	3,418	0	3,418
Tot.	**524,072**	**0**	**0**	**524,072**	**0**	**524,072**	**0**	**0**	**0**	**0**	**0**	**524,072**	**110,573**	**0**	**110,573**
Disc	416,398	0	0	416,398	0	416,398	0	0	0	0	0	416,398	77,307	0	77,307

				Net				Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	76,011	27,593	333	103,271	36,534	0	0	36,534	66,737	66,737	63,631
2014	0	0	0	157,540	0	921	156,620	18,027	0	0	18,027	138,592	205,329	183,761
2015	0	0	0	89,209	0	783	88,426	8,871	0	0	8,871	79,554	284,884	246,449
2016	0	0	0	42,875	0	415	42,460	15,351	0	0	15,351	27,109	311,992	265,868
2017	0	0	0	27,474	0	239	27,236	15,154	0	0	15,154	12,081	324,074	273,736
2018	0	0	0	9,815	0	150	9,665	0	0	0	0	9,665	333,739	279,458
2019	0	0	0	5,519	0	100	5,419	0	0	0	0	5,419	339,159	282,375
2020	0	0	0	3,186	0	70	3,115	0	0	0	0	3,115	342,274	283,899
2021	0	0	0	1,632	0	51	1,581	0	0	0	0	1,581	343,855	284,602
2022	0	0	0	237	0	4	233	0	0	0	0	233	344,088	284,696
Tot.	**0**	**0**	**0**	**413,499**	**27,593**	**3,066**	**438,026**	**93,938**	**0**	**0**	**93,938**	**344,088**	**344,088**	**284,696**
Disc	0	0	0	339,090	26,309	2,387	363,012	78,316	0	0	78,316	284,696	284,696	284,696

SUMMARY OF RESERVES

		Remaining Reserves at Jan 01, 2013					Oil Equivalents			Reserve Life Indic. (yr)		
Product	Units	Gross	Working Interest	Roy/NPI Interest	Total Company	Net	Oil Eq. Factor	Company Mboe	% of Total	Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	17,572	5,865	0	5,865	5,865	1.000	5,865	100	10.0	6.2	2.0
Total: Oil Eq.	Mboe	17,572	5,865	0	5,865	5,865	1.000	5,865	100	10.0	6.2	2.0

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	85.00	6.55	91.55	0.00	11.50	0.00	80.05	524,072	100	416,398	100
Total: Oil Eq.	$/boe	85.00	6.55	91.55	0.00	11.50	0.00	80.05	524,072	100	416,398	100

INTEREST AND NET PRESENT VALUE SUMMARY

Revenue Interests and Burdens (%)		
Entity Name	Initial	Average
Working Interest	47.7342	33.4334
Capital Interest	54.6622	54.3912
Royalty Interest	0.0000	0.0000
Crown Royalty	0.0000	0.0000
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000

	Net Present Value Before Income Tax				
Disc. Rate %	Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	**Cash Flow** M$	**Cash Flow** $/boe
0.0	413,499	438,026	93,938	344,088	58.67
5.0	372,731	396,971	85,370	311,601	53.13
8.0	351,810	375,862	80,980	294,882	50.28
10.0	339,090	363,012	78,316	284,696	48.54
12.0	327,240	351,030	75,838	275,192	46.92
15.0	310,918	334,506	72,433	262,072	44.69
20.0	287,020	310,268	67,470	242,799	41.40

Evaluator: Herchen, Leonard L.
Run Date: January 21, 2013 13:02:27

Company: **Griffiths Energy International Inc.**
Property: **Badila**
Currency: **$US Dollars**

Reserve Class: **Proved Plus Probable**
Development Class: **Undeveloped**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production				
Year	Gross Oil Wells	Gross Daily bbl/d	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	2	5,450	2,602	950	950	92.23
2014	6	18,088	6,396	2,334	2,334	89.86
2015	9	19,960	4,472	1,632	1,632	89.86
2016	10	14,792	3,328	1,215	1,215	89.86
2017	11	8,918	2,242	818	818	87.48
2018	11	5,650	1,297	473	473	87.48
2019	11	3,719	883	322	322	88.76
2020	11	2,535	657	240	240	90.69
2021	11	1,766	511	186	186	92.66
2022	11	1,265	415	151	151	94.65
2023	11	925	350	128	128	96.70
2024	11	691	301	110	110	98.78
Sub.				8,560	8,560	90.11
Rem.				8	8	100.91
Tot.				**8,568**	**8,568**	**90.12**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens														
	Working Interest				Royalty Interest	Company Interest	Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	87,582	0	0	87,582	0	87,582	0	0	0	0	0	87,582	14,814	0	14,814
2014	209,760	0	0	209,760	0	209,760	0	0	0	0	0	209,760	25,858	0	25,858
2015	146,659	0	0	146,659	0	146,659	0	0	0	0	0	146,659	24,537	0	24,537
2016	109,154	0	0	109,154	0	109,154	0	0	0	0	0	109,154	21,173	0	21,173
2017	71,592	0	0	71,592	0	71,592	0	0	0	0	0	71,592	17,019	0	17,019
2018	41,400	0	0	41,400	0	41,400	0	0	0	0	0	41,400	14,726	0	14,726
2019	28,595	0	0	28,595	0	28,595	0	0	0	0	0	28,595	11,181	0	11,181
2020	21,749	0	0	21,749	0	21,749	0	0	0	0	0	21,749	10,411	0	10,411
2021	17,269	0	0	17,269	0	17,269	0	0	0	0	0	17,269	9,962	0	9,962
2022	14,338	0	0	14,338	0	14,338	0	0	0	0	0	14,338	9,724	0	9,724
2023	12,357	0	0	12,357	0	12,357	0	0	0	0	0	12,357	9,616	0	9,616
2024	10,869	0	0	10,869	0	10,869	0	0	0	0	0	10,869	9,596	0	9,596
Sub.	771,323	0	0	771,323	0	771,323	0	0	0	0	0	771,323	178,617	0	178,617
Rem.	832	0	0	832	0	832	0	0	0	0	0	832	797	0	797
Tot.	**772,154**	**0**	**0**	**772,154**	**0**	**772,154**	**0**	**0**	**0**	**0**	**0**	**772,154**	**179,414**	**0**	**179,414**
Disc	578,150	0	0	578,150	0	578,150	0	0	0	0	0	578,150	117,300	0	117,300

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Net Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	72,768	27,593	191	100,170	35,285	0	0	35,285	64,885	64,885	61,865
2014	0	0	0	183,902	0	648	183,254	18,135	0	0	18,135	165,119	230,003	204,987
2015	0	0	0	122,121	0	729	121,392	17,384	0	0	17,384	104,008	334,012	286,944
2016	0	0	0	87,981	0	551	87,430	15,351	0	0	15,351	72,079	406,090	338,578
2017	0	0	0	54,573	0	339	54,234	15,154	0	0	15,154	39,080	445,170	364,028
2018	0	0	0	26,674	0	219	26,455	0	0	0	0	26,455	471,625	379,690
2019	0	0	0	17,414	0	147	17,267	0	0	0	0	17,267	488,892	388,983
2020	0	0	0	11,338	0	102	11,236	0	0	0	0	11,236	500,128	394,480
2021	0	0	0	7,307	0	73	7,234	0	0	0	0	7,234	507,362	397,698
2022	0	0	0	4,614	0	53	4,561	0	0	0	0	4,561	511,922	399,542
2023	0	0	0	2,741	0	40	2,702	0	0	0	0	2,702	514,624	400,535
2024	0	0	0	1,273	0	21	1,252	0	0	0	0	1,252	515,876	400,954
Sub.	0	0	0	592,706	27,593	3,113	617,186	101,310	0	0	101,310	515,876	515,876	400,954
Rem.	0	0	0	35	0	0	35	0	0	0	0	35	515,911	400,964
Tot.	**0**	**0**	**0**	**592,740**	**27,593**	**3,113**	**617,221**	**101,310**	**0**	**0**	**101,310**	**515,911**	**515,911**	**400,964**
Disc	0	0	0	460,850	26,309	2,268	484,891	83,927	0	0	83,927	400,964	400,964	400,964

SUMMARY OF RESERVES

		Remaining Reserves at Jan 01, 2013					Oil Equivalents			Reserve Life Indic. (yr)		
Product	Units	Gross	Working Interest	Roy/NPI Interest	Total Company	Net	Oil Eq. Factor	Company Mboe	% of Total	Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	30,588	8,568	0	8,568	8,568	1.000	8,568	100	13.0	9.0	2.6
Total: Oil Eq.	Mboe	30,588	8,568	0	8,568	8,568	1.000	8,568	100	13.0	9.0	2.6

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	85.00	7.23	92.23	0.00	15.60	0.00	76.63	772,154	100	578,150	100
Total: Oil Eq.	$/boe	85.00	7.23	92.23	0.00	15.60	0.00	76.63	772,154	100	578,150	100

INTEREST AND NET PRESENT VALUE SUMMARY

Revenue Interests and Burdens (%)		
Entity Name	Initial	Average
Working Interest	47.7342	28.0926
Capital Interest	53.7988	56.2583
Royalty Interest	0.0000	0.0000
Crown Royalty	0.0000	0.0000
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000

	Net Present Value Before Income Tax				
Disc. Rate %	Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/boe
0.0	592,740	617,221	101,310	515,911	60.21
5.0	519,078	543,373	91,786	451,586	52.70
8.0	482,598	506,746	86,897	419,849	49.00
10.0	460,850	484,891	83,927	400,964	46.80
12.0	440,881	464,808	81,162	383,647	44.77
15.0	413,832	437,580	77,359	360,222	42.04
20.0	375,177	398,612	71,808	326,803	38.14

Evaluator: Herchen, Leonard L.
Run Date: January 21, 2013 13:02:29

Company: **Griffiths Energy International Inc.**
Property: **Badila**
Currency: **$US Dollars**

Reserve Class: **PPP**
Development Class: **Undeveloped**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production				
Year	Gross Oil Wells	Gross Daily bbl/d	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	2	5,450	2,602	950	950	92.53
2014	6	19,405	6,834	2,495	2,495	90.16
2015	9	22,000	4,883	1,782	1,782	90.16
2016	10	22,060	4,728	1,726	1,726	90.15
2017	11	18,490	4,088	1,492	1,492	87.78
2018	11	13,127	2,752	1,004	1,004	87.78
2019	11	9,527	1,998	729	729	89.06
2020	11	7,066	1,531	559	559	90.99
2021	11	5,302	1,196	437	437	92.96
2022	11	4,053	959	350	350	94.95
2023	11	3,140	785	287	287	97.00
2024	11	2,470	658	240	240	99.08
Sub.				12,050	12,050	90.40
Rem.				947	947	106.27
Tot.				**12,997**	**12,997**	**91.56**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After Process.	Net Revenue After Royalty	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	M$	M$	Fixed M$	Variable M$	Total M$
2013	87,867	0	0	87,867	0	87,867	0	0	0	0	0	87,867	18,703	0	18,703
2014	224,897	0	0	224,897	0	224,897	0	0	0	0	0	224,897	30,239	0	30,239
2015	160,670	0	0	160,670	0	160,670	0	0	0	0	0	160,670	27,820	0	27,820
2016	155,589	0	0	155,589	0	155,589	0	0	0	0	0	155,589	28,572	0	28,572
2017	130,974	0	0	130,974	0	130,974	0	0	0	0	0	130,974	26,387	0	26,387
2018	88,158	0	0	88,158	0	88,158	0	0	0	0	0	88,158	22,592	0	22,592
2019	64,965	0	0	64,965	0	64,965	0	0	0	0	0	64,965	16,706	0	16,706
2020	50,848	0	0	50,848	0	50,848	0	0	0	0	0	50,848	14,976	0	14,976
2021	40,580	0	0	40,580	0	40,580	0	0	0	0	0	40,580	13,767	0	13,767
2022	33,226	0	0	33,226	0	33,226	0	0	0	0	0	33,226	12,953	0	12,953
2023	27,804	0	0	27,804	0	27,804	0	0	0	0	0	27,804	12,400	0	12,400
2024	23,791	0	0	23,791	0	23,791	0	0	0	0	0	23,791	12,040	0	12,040
Sub.	1,089,368	0	0	1,089,368	0	1,089,368	0	0	0	0	0	1,089,368	237,156	0	237,156
Rem.	100,661	0	0	100,661	0	100,661	0	0	0	0	0	100,661	73,109	0	73,109
Tot.	**1,190,029**	**0**	**0**	**1,190,029**	**0**	**1,190,029**	**0**	**0**	**0**	**0**	**0**	**1,190,029**	**310,265**	**0**	**310,265**
Disc	788,584	0	0	788,584	0	788,584	0	0	0	0	0	788,584	170,781	0	170,781

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	**Net Prod'n Revenue** M$	Other Income M$	**Aband. Costs** M$	**Oper. Income** M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	69,164	27,593	115	96,642	34,959	0	0	34,959	61,683	61,683	58,812
2014	0	0	0	194,658	0	417	194,241	18,672	0	0	18,672	175,568	237,251	210,992
2015	0	0	0	132,850	0	483	132,367	18,158	0	0	18,158	114,209	351,460	300,987
2016	0	0	0	127,017	0	494	126,523	15,351	0	0	15,351	111,171	462,631	380,625
2017	0	0	0	104,586	0	422	104,164	15,154	0	0	15,154	89,010	551,641	438,591
2018	0	0	0	65,565	0	306	65,260	0	0	0	0	65,260	616,901	477,226
2019	0	0	0	48,259	0	226	48,032	0	0	0	0	48,032	664,933	503,077
2020	0	0	0	35,872	0	171	35,700	0	0	0	0	35,700	700,634	520,544
2021	0	0	0	26,813	0	131	26,682	0	0	0	0	26,682	727,316	532,413
2022	0	0	0	20,273	0	102	20,171	0	0	0	0	20,171	747,487	540,569
2023	0	0	0	15,404	0	81	15,323	0	0	0	0	15,323	762,810	546,202
2024	0	0	0	11,752	0	65	11,687	0	0	0	0	11,687	774,497	550,107
Sub.	0	0	0	852,212	27,593	3,013	876,792	102,295	0	0	102,295	774,497	774,497	550,107
Rem.	0	0	0	27,552	0	193	27,359	0	0	0	0	27,359	801,856	557,352
Tot.	**0**	**0**	**0**	**879,764**	**27,593**	**3,206**	**904,151**	**102,295**	**0**	**0**	**102,295**	**801,856**	**801,856**	**557,352**
Disc	0	0	0	617,803	26,309	2,068	642,044	84,691	0	0	84,691	557,352	557,352	557,352

SUMMARY OF RESERVES

		Remaining Reserves at Jan 01, 2013					Oil Equivalents			Reserve Life Indic. (yr)		
Product	Units	Gross	Working Interest	Roy/NPI Interest	Total Company	Net	Oil Eq. Factor	Company Mboe	% of Total	Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	50,960	12,997	0	12,997	12,997	1.000	12,997	100	19.0	13.7	3.7
Total: Oil Eq.	Mboe	50,960	12,997	0	12,997	12,997	1.000	12,997	100	19.0	13.7	3.7

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	85.00	7.53	92.53	0.00	19.70	0.00	72.83	1,190,029	100	788,584	100
Total: Oil Eq.	$/boe	85.00	7.53	92.53	0.00	19.70	0.00	72.83	1,190,029	100	788,584	100

INTEREST AND NET PRESENT VALUE SUMMARY

Revenue Interests and Burdens (%)		
Entity Name	Initial	Average
Working Interest	47.7342	25.6420
Capital Interest	53.5680	56.4963
Royalty Interest	0.0000	0.0000
Crown Royalty	0.0000	0.0000
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000

	Net Present Value Before Income Tax				
Disc. Rate %	Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/boe
0.0	879,764	904,151	102,295	801,856	61.69
5.0	727,536	751,932	92,653	659,279	50.72
8.0	657,745	682,062	87,701	594,361	45.73
10.0	617,803	642,044	84,691	557,352	42.88
12.0	582,181	606,332	81,890	524,443	40.35
15.0	535,483	559,482	78,036	481,446	37.04
20.0	471,723	495,431	72,410	423,021	32.55

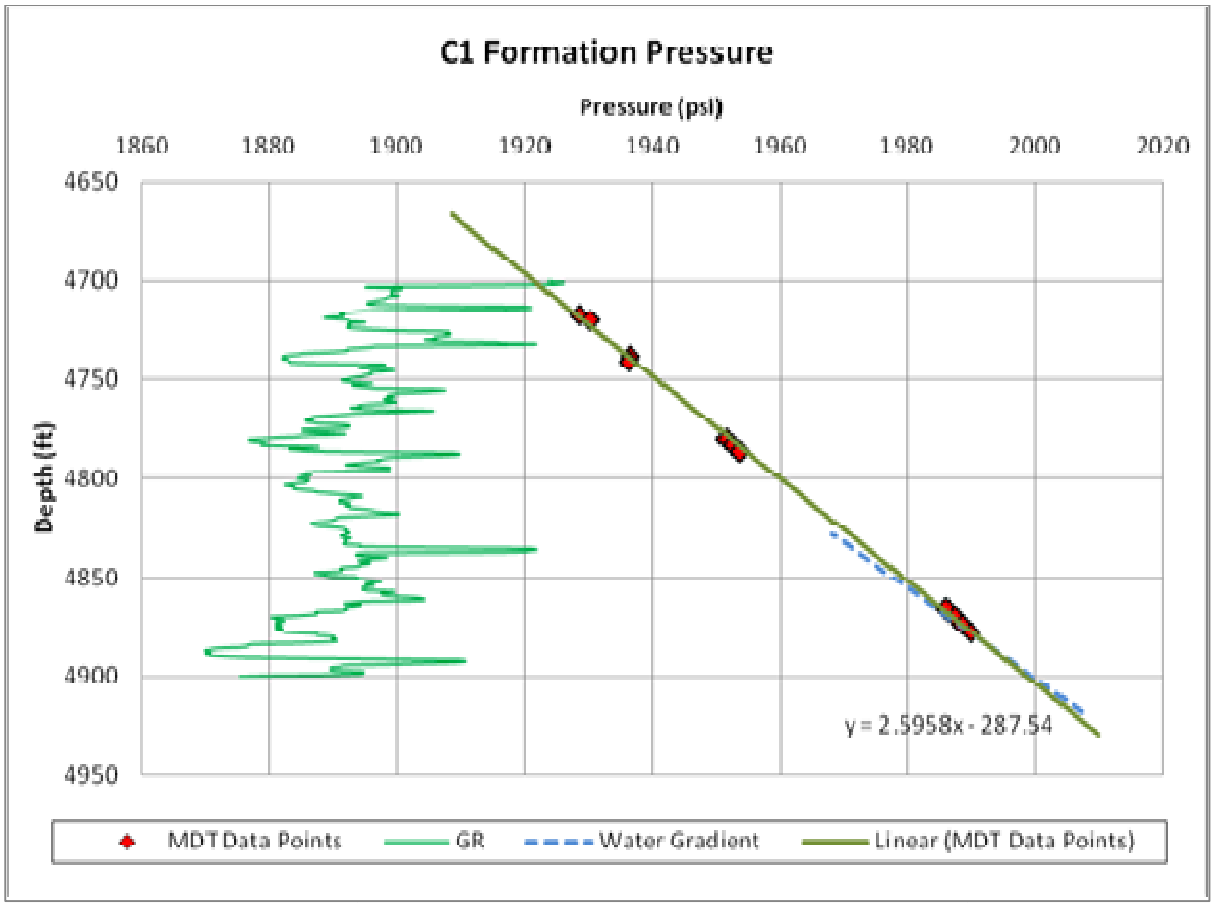
Evaluator: Herchen, Leonard L.
Run Date: January 21, 2013 13:02:31

APPENDIX I

MDT Analyses Supporting Oil-on-Rock Interpretations

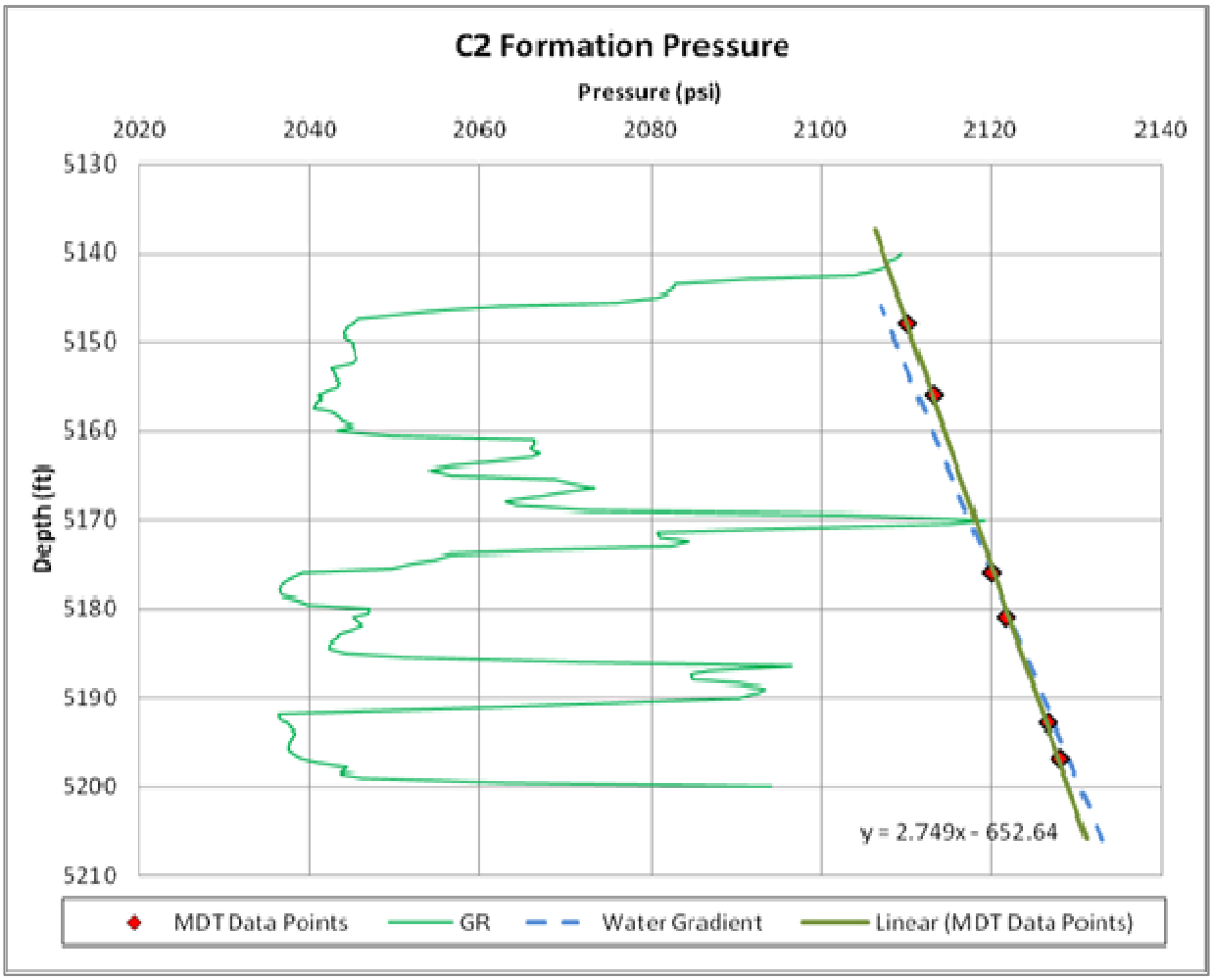
The following formation pressure plots and associated descriptions, coupled with petrophysical data gleaned from open-hole logs, were instrumental in establishing what fraction of the fluid columns in each formation are hydrocarbon saturated. Only the C3 Formation pressure plot (see main discussion pages) shows an obvious OWC, while the remainder presented here support an oil-on-rock interpretation.

C1 Interval



There is an obvious slope difference between the best fit line defined by the MDT reservoir pressures and the water gradient. Despite this supporting evidence, no economic oil reserves have been assigned to the C1 interval because the small volume of OIIP established by geophysical and geological analyses of the feature.

C2 Interval

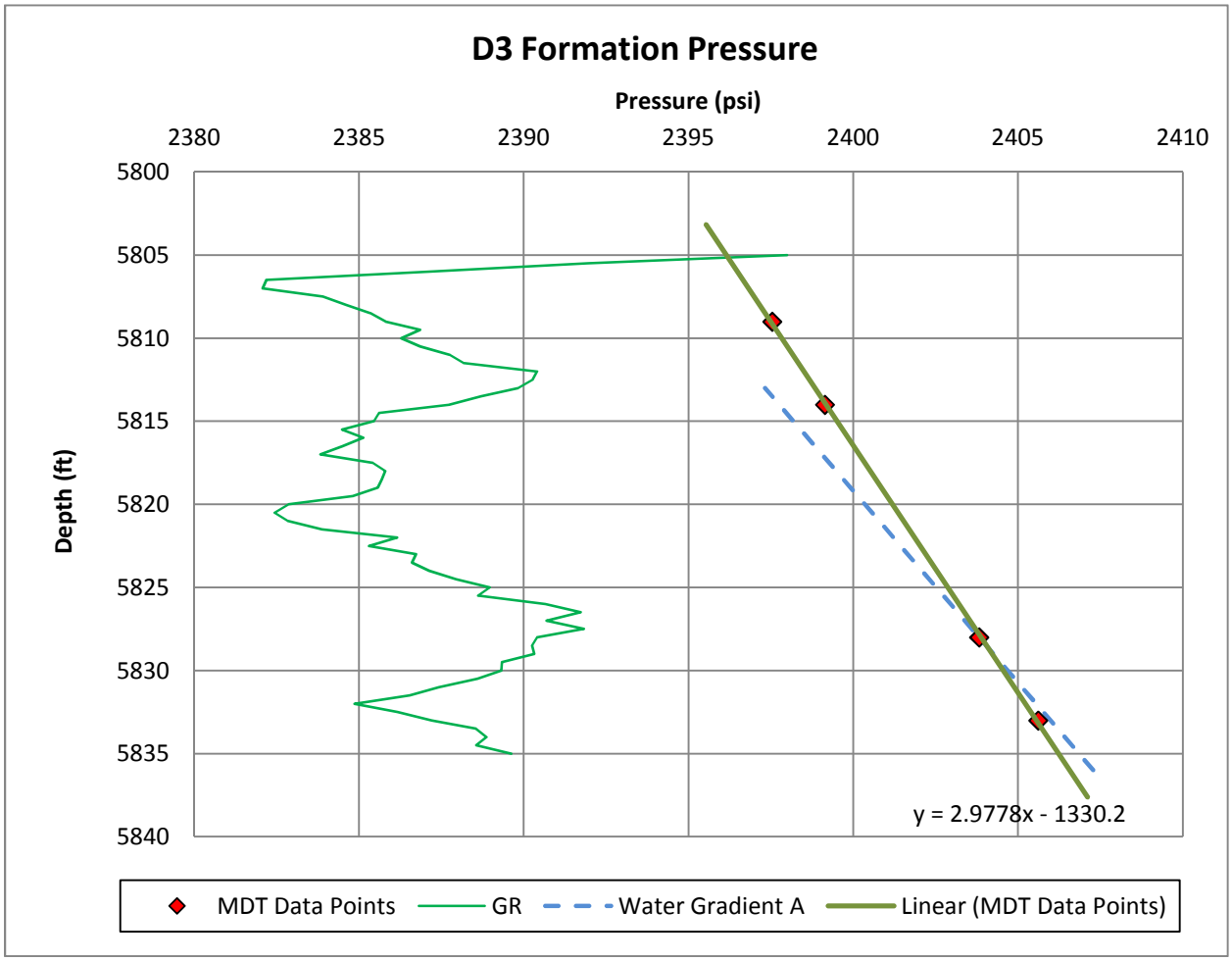


The liquid gradient in the C2 interval conforms to that of oil as shown by the slope difference in the plot above. No OWC was defined by the data, suggesting that the C2 reservoir has an oil-on-rock bottom contact. The C2 interval has been determined to have sufficient OIIP to justify completion of this reservoir in at least one of the development wells scheduled in this evaluation.

C4 through D2 Intervals

The C4 and D1 Sands are most likely wet as illustrated by the good fit of the MDT pressure data with the water gradient shown in the C3 plot (see main discussion). The D2 interval's limited net pay thickness does not result in sufficient OIIP to justify completion costs. None of these three sands have been assigned any oil reserves in this evaluation.

D3 Interval

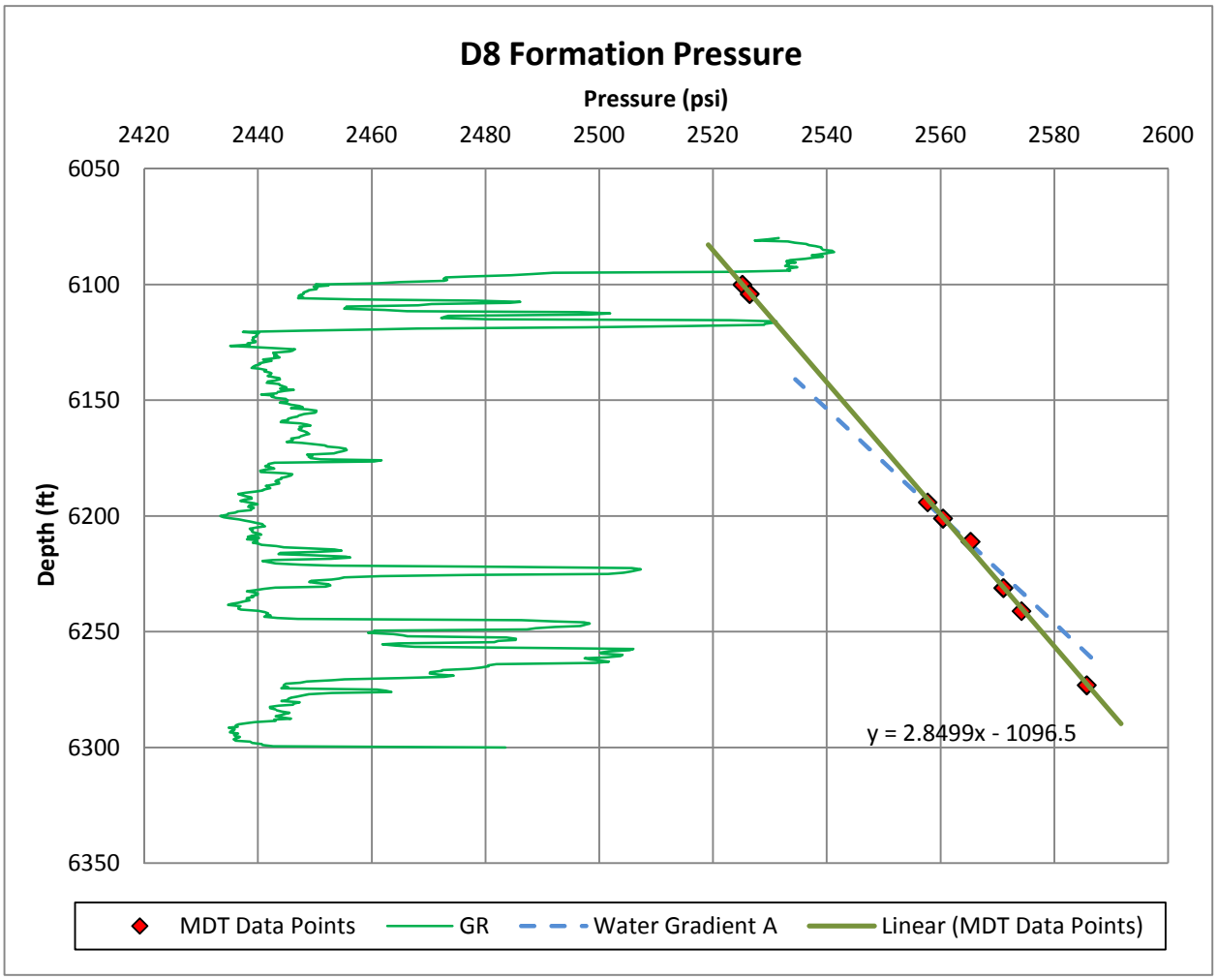


The gradient differences shown in the above plot confirm that the D3 Sand is oil bearing. Geological and geophysical analyses of the D3 support the second largest oil reserves assignment to this interval, second only to the C3 Sand.

D4 to D7 Intervals

Geological analysis of open-hole logs indicates that these intervals have water saturations too high to support economic oil reserves assignments.

D8 Interval



The liquid gradient in the D8 interval conforms to that of oil as shown by the slope difference in the plot above. The D8 interval has been determined to have sufficient OIIP to justify completion of this reservoir in at least one of the development wells scheduled in this evaluation.

GRIFFITHS ENERGY INTERNATIONAL INC.

ITA BADILA/MANGARA

Effective December 31, 2012

Prepared by
Leonard L. Herchen, P. Eng.

The analysis of this property as reported herein was conducted within the context of an evaluation of a distinct group of properties in aggregate. Extraction and use of this analysis outside this context may not be appropriate without supplementary due diligence.

ITA BADILA/MANGARA

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Company: **Griffiths Energy International Inc.**
Property: **ITA Badila/Mangara**
Currency: **$US Dollars**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Summary of Reserves and Values

	Proved Undeveloped	Proved Plus Probable Undeveloped	PPP Undeveloped
BEFORE TAX PRESENT VALUE (M$)			
0%	21,249	24,754	31,231
5%	17,855	19,416	22,054
8%	16,183	16,991	18,326
10%	15,190	15,611	16,320
12%	14,282	14,385	14,605
15%	13,058	12,787	12,462
20%	11,326	10,625	9,720
AFTER TAX PRESENT VALUE (M$)			
0%	17,118	19,295	23,117
5%	14,539	15,448	16,842
8%	13,252	13,664	14,216
10%	12,483	12,637	12,778
12%	11,775	11,716	11,532
15%	10,815	10,503	9,950
20%	9,441	8,833	7,881

BOE Factors: HVY OIL 1.0 | COND 1.0 | RES GAS 6.0 | SLN GAS 6.0 | PROPANE 1.0 | BUTANE 1.0 | ETHANE 1.0 | SULPHUR 0.0

Run Date: January 20, 2013 22:11:52

DISCUSSION

Griffiths Energy International Inc. (Griffiths) has commenced construction of a pipeline that transports crude from Mangara to Badila and then to the LACT Unit. At the LACT Unit, oil is transferred into the Chad to Cameroon pipeline for export to world markets. Planned capacities and distances are presented in Figure 1.

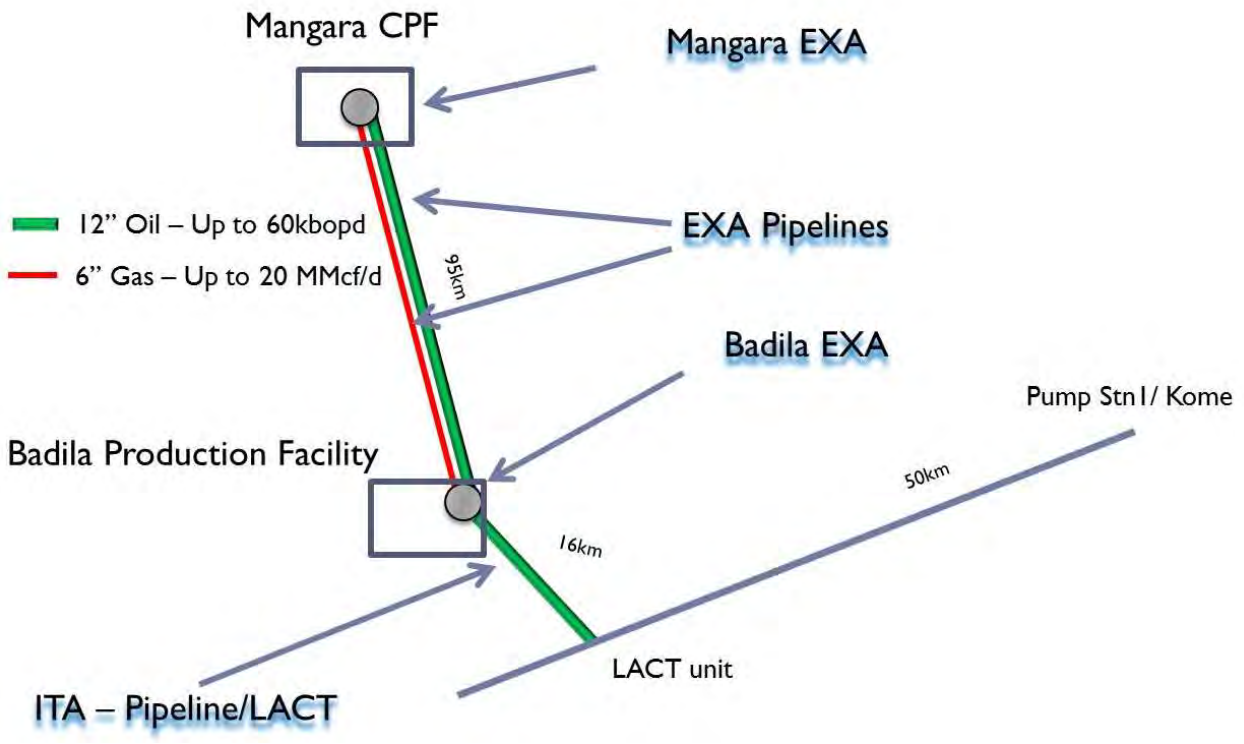


Figure 1 – Pipeline Infrastructure for Badila/Mangara Developments (Source: Griffiths)

Capital and operating costs for the 16 kilometres pipeline and associated facilities unit are not directly recoverable as cost recovery from the Badila and Mangara Fields. Rather, the capital costs and operating cost recovery is scheduled as a tariff, deductable from the received oil price at Badila and Mangara. The tariff paid is earned by a corporate entity, defined as an ITA and is 100 percent owned by PetroChad Transportation. It was assumed, pursuant to the terms of the farm-in agreement between Griffiths and Glencore International AG (Glencore) that PetroChad Transportation itself is 66.67 percent held by Griffiths and 33.33 percent by Glencore. The ITA is liable for the capital and operating costs and earns a tariff.

The tariff was calculated such that the ITA earns an 11 percent after tax rate of return on invested capital. The assumed tax rate was 40 percent. The capital invested was depreciated over five years in the income tax calculation. Based on information provided by Griffiths, the total capital investment is budgeted to be 24.96 MM$ and the operating costs were estimated at $0.30/bbl. Only 8.5 MM$ of gross lease capital is forecast in the cash flow forecasts, as the remainder is sunk capital, invested before the effective date. Using the production forecast from the proved, proved plus probable and proved plus probable plus possible cases, the tariff was scheduled as follows:

Proved	$1.70/bbl
Proved Plus Probable	$1.02/bbl
Proved Plus Probable Plus Possible	$0.72/bbl

This evaluation includes the terms of the farm-in agreement (Glencore Farm-in) between Griffiths and Glencore. Consequently, the capital, operating costs, tariffs and taxes presented herein represent Griffiths' net interest, not the combined Glencore and Griffiths interests. The Glencore Farm-in includes a carry of Griffiths' capital for development at Badila and Mangara but not for capital in the ITA.

Capital costs, operating costs, tariff income and income taxes for each reserves classification are presented in the economic summary section of this report. The tariff income is included as "Other Income".

Company: **Griffiths Energy International Inc.**
Property: **ITA Badila/Mangara**
Currency: **$US Dollars**

Reserve Class: **Proved**
Development Class: **Undeveloped**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	0	0	0	0	0	0	0	0	0	0	0	0	555	0	555
2014	0	0	0	0	0	0	0	0	0	0	0	0	1,505	0	1,505
2015	0	0	0	0	0	0	0	0	0	0	0	0	1,443	0	1,443
2016	0	0	0	0	0	0	0	0	0	0	0	0	893	0	893
2017	0	0	0	0	0	0	0	0	0	0	0	0	533	0	533
2018	0	0	0	0	0	0	0	0	0	0	0	0	354	0	354
2019	0	0	0	0	0	0	0	0	0	0	0	0	243	0	243
2020	0	0	0	0	0	0	0	0	0	0	0	0	147	0	147
2021	0	0	0	0	0	0	0	0	0	0	0	0	91	0	91
2022	0	0	0	0	0	0	0	0	0	0	0	0	35	0	35
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sub.	0	0	0	0	0	0	0	0	0	0	0	0	5,800	0	5,800
Rem.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tot.	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**5,800**	**0**	**5,800**
Disc	0	0	0	0	0	0	0	0	0	0	0	0	4,425	0	4,425

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Net Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	-555	3,154	0	2,599	5,691	0	0	5,691	-3,092	-3,092	-2,948
2014	0	0	0	-1,505	8,540	0	7,035	0	0	0	0	7,035	3,943	3,150
2015	0	0	0	-1,443	8,188	0	6,746	0	0	0	0	6,746	10,689	8,465
2016	0	0	0	-893	5,071	0	4,178	0	0	0	0	4,178	14,867	11,458
2017	0	0	0	-533	3,028	0	2,495	0	0	0	0	2,495	17,362	13,083
2018	0	0	0	-354	2,010	0	1,656	0	0	0	0	1,656	19,018	14,064
2019	0	0	0	-243	1,380	0	1,137	0	0	0	0	1,137	20,155	14,676
2020	0	0	0	-147	837	0	690	0	0	0	0	690	20,845	15,013
2021	0	0	0	-91	432	0	341	0	0	0	0	341	21,186	15,165
2022	0	0	0	-35	98	0	63	0	0	0	0	63	21,249	15,190
2023	0	0	0	0	0	0	0	0	0	0	0	0	21,249	15,190
2024	0	0	0	0	0	0	0	0	0	0	0	0	21,249	15,190
Sub.	0	0	0	-5,800	32,739	0	26,939	5,691	0	0	5,691	21,249	21,249	15,190
Rem.	0	0	0	0	0	0	0	0	0	0	0	0	21,249	15,190
Tot.	**0**	**0**	**0**	**-5,800**	**32,739**	**0**	**26,939**	**5,691**	**0**	**0**	**5,691**	**21,249**	**21,249**	**15,190**
Disc	0	0	0	-4,425	25,041	0	20,616	5,426	0	0	5,426	15,190	15,190	15,190

AFTER TAX ANALYSIS

		Tax Pool Balances Incl. Current Year Additions		Depreciation & Writeoffs		
Year	Oper. Income M$	CEE M$	Other M$	CEE M$	Other M$	Total M$
2013	2,599	0	0	0	0	0
2014	7,035	0	0	0	0	0
2015	6,746	0	0	0	0	0
2016	4,178	0	0	0	0	0
2017	2,495	0	0	0	0	0
2018	1,656	0	0	0	0	0
2019	1,137	0	0	0	0	0
2020	690	0	0	0	0	0
2021	341	0	0	0	0	0
2022	63	0	0	0	0	0
2023	0	0	0	0	0	0
2024	0	0	0	0	0	0
Sub.	26,939	0	0	0	0	0
Rem.	0	0	0	0	0	0
Tot.	**26,939**	**0**	**0**	**0**	**0**	**0**
Disc	20,616			0	0	0

Year	Taxable Income M$	Federal Income Tax M$	Provincial Income Tax M$	ARTD & Investment Credits	Income Tax Payable M$	Net Cash Flow Before Income Tax: Annual M$	Net Cash Flow Before Income Tax: Cum. M$	Net Cash Flow Before Income Tax: 10.0% Dcf M$	Net Cash Flow After Income Tax: Annual M$	Net Cash Flow After Income Tax: Cum. M$	Net Cash Flow After Income Tax: 10.0% Dcf M$
2013	2,599	0	0	0	0	-3,092	-3,092	-2,948	-3,092	-3,092	-2,948
2014	7,035	0	0	0	0	7,035	3,943	3,150	7,035	3,943	3,150
2015	6,746	1,226	0	0	1,226	6,746	10,689	8,465	5,520	9,463	7,499
2016	4,178	340	0	0	340	4,178	14,867	11,458	3,838	13,301	10,249
2017	2,495	998	0	0	998	2,495	17,362	13,083	1,497	14,798	11,224
2018	1,656	663	0	0	663	1,656	19,018	14,064	994	15,792	11,812
2019	1,137	455	0	0	455	1,137	20,155	14,676	682	16,475	12,180
2020	690	276	0	0	276	690	20,845	15,013	414	16,889	12,382
2021	341	142	0	0	142	341	21,186	15,165	198	17,087	12,470
2022	63	32	0	0	32	63	21,249	15,190	31	17,118	12,483
2023	0	0	0	0	0	0	21,249	15,190	0	17,118	12,483
2024	0	0	0	0	0	0	21,249	15,190	0	17,118	12,483
Sub.	26,939	4,131	0	0	4,131	21,249	21,249	15,190	17,118	17,118	12,483
Rem.	0	0	0	0	0	0	21,249	15,190	0	17,118	12,483
Tot.	**26,939**	**4,131**	**0**	**0**	**4,131**	**21,249**	**21,249**	**15,190**	**17,118**	**17,118**	**12,483**
Disc	20,616	2,707	0	0	2,707	15,190	15,190	15,190	12,483	12,483	12,483

INTEREST AND NET PRESENT VALUE SUMMARY

Entity Name	Revenue Interests and Burdens (%): Initial	Revenue Interests and Burdens (%): Average	Disc. Rate %	Net Present Value Before Income Tax: Prod'n Revenue M$	Net Present Value Before Income Tax: Operating Income M$	Net Present Value Before Income Tax: Capital Invest. M$	Net Present Value Before Income Tax: Cash Flow M$	Net Present Value Before Income Tax: Cash Flow $/boe	Net Present Value After Income Tax: Operating Income M$	Net Present Value After Income Tax: Capital Invest. M$	Net Present Value After Income Tax: Cash Flow M$	Net Present Value After Income Tax: Cash Flow $/boe
Working Interest	0.0000	0.0000	0.0	-5,800.0	26,939	5,691	21,249	0.00	22,808	5,691	17,118	0.00
Capital Interest	66.6667	66.6667	5.0	-5,030.9	23,409	5,553	17,855	0.00	20,093	5,553	14,539	0.00
Royalty Interest	0.0000	0.0000	8.0	-4,651.0	21,659	5,476	16,183	0.00	18,728	5,476	13,252	0.00
Crown Royalty	0.0000	0.0000	10.0	-4,425.0	20,616	5,426	15,190	0.00	17,908	5,426	12,483	0.00
Non-crown Royalty	0.0000	0.0000	12.0	-4,217.9	19,659	5,377	14,282	0.00	17,152	5,377	11,775	0.00
Mineral Tax	0.0000	0.0000	15.0	-3,938.2	18,365	5,306	13,058	0.00	16,121	5,306	10,815	0.00
			20.0	-3,540.2	16,520	5,195	11,326	0.00	14,636	5,195	9,441	0.00

Evaluator: Herchen, Leonard L.
Run Date: January 20, 2013 22:11:49

Company: **Griffiths Energy International Inc.**
Property: **ITA Badila/Mangara**
Currency: **$US Dollars**

Reserve Class: **Proved Plus Probable**
Development Class: **Undeveloped**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	0	0	0	0	0	0	0	0	0	0	0	0	685	0	685
2014	0	0	0	0	0	0	0	0	0	0	0	0	2,223	0	2,223
2015	0	0	0	0	0	0	0	0	0	0	0	0	2,671	0	2,671
2016	0	0	0	0	0	0	0	0	0	0	0	0	2,056	0	2,056
2017	0	0	0	0	0	0	0	0	0	0	0	0	1,336	0	1,336
2018	0	0	0	0	0	0	0	0	0	0	0	0	932	0	932
2019	0	0	0	0	0	0	0	0	0	0	0	0	685	0	685
2020	0	0	0	0	0	0	0	0	0	0	0	0	526	0	526
2021	0	0	0	0	0	0	0	0	0	0	0	0	415	0	415
2022	0	0	0	0	0	0	0	0	0	0	0	0	333	0	333
2023	0	0	0	0	0	0	0	0	0	0	0	0	252	0	252
2024	0	0	0	0	0	0	0	0	0	0	0	0	186	0	186
Sub.	0	0	0	0	0	0	0	0	0	0	0	0	12,299	0	12,299
Rem.	0	0	0	0	0	0	0	0	0	0	0	0	199	0	199
Tot.	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**12,498**	**0**	**12,498**
Disc	0	0	0	0	0	0	0	0	0	0	0	0	8,737	0	8,737

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Net Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	-685	2,324	0	1,640	5,691	0	0	5,691	-4,051	-4,051	-3,862
2014	0	0	0	-2,223	7,543	0	5,321	0	0	0	0	5,321	1,270	750
2015	0	0	0	-2,671	9,065	0	6,395	0	0	0	0	6,395	7,665	5,789
2016	0	0	0	-2,056	6,979	0	4,923	0	0	0	0	4,923	12,587	9,315
2017	0	0	0	-1,336	4,534	0	3,198	0	0	0	0	3,198	15,785	11,397
2018	0	0	0	-932	3,163	0	2,231	0	0	0	0	2,231	18,016	12,718
2019	0	0	0	-685	2,324	0	1,640	0	0	0	0	1,640	19,656	13,601
2020	0	0	0	-526	1,785	0	1,259	0	0	0	0	1,259	20,915	14,217
2021	0	0	0	-415	1,410	0	995	0	0	0	0	995	21,910	14,659
2022	0	0	0	-333	1,130	0	797	0	0	0	0	797	22,707	14,982
2023	0	0	0	-252	856	0	604	0	0	0	0	604	23,311	15,204
2024	0	0	0	-186	631	0	445	0	0	0	0	445	23,756	15,352
Sub.	0	0	0	-12,299	41,745	0	29,446	5,691	0	0	5,691	23,756	23,756	15,352
Rem.	0	0	0	-199	1,198	0	999	0	0	0	0	999	24,754	15,611
Tot.	**0**	**0**	**0**	**-12,498**	**42,943**	**0**	**30,445**	**5,691**	**0**	**0**	**5,691**	**24,754**	**24,754**	**15,611**
Disc	0	0	0	-8,737	29,773	0	21,036	5,426	0	0	5,426	15,611	15,611	15,611

AFTER TAX ANALYSIS

		Tax Pool Balances Incl. Current Year Additions		Depreciation & Writeoffs		
Year	Oper. Income M$	CEE M$	Other M$	CEE M$	Other M$	Total M$
2013	1,640	0	0	0	0	0
2014	5,321	0	0	0	0	0
2015	6,395	0	0	0	0	0
2016	4,923	0	0	0	0	0
2017	3,198	0	0	0	0	0
2018	2,231	0	0	0	0	0
2019	1,640	0	0	0	0	0
2020	1,259	0	0	0	0	0
2021	995	0	0	0	0	0
2022	797	0	0	0	0	0
2023	604	0	0	0	0	0
2024	445	0	0	0	0	0
Sub.	29,446	0	0	0	0	0
Rem.	999	0	0	0	0	0
Tot.	**30,445**	**0**	**0**	**0**	**0**	**0**
Disc	21,036			0	0	0

Year	Taxable Income M$	Federal Income Tax M$	Provincial Income Tax M$	ARTD & Investment Credits	Income Tax Payable M$	Net Cash Flow Before Income Tax: Annual M$	Net Cash Flow Before Income Tax: Cum. M$	Net Cash Flow Before Income Tax: 10.0% Dcf M$	Net Cash Flow After Income Tax: Annual M$	Net Cash Flow After Income Tax: Cum. M$	Net Cash Flow After Income Tax: 10.0% Dcf M$
2013	1,640	0	0	0	0	-4,051	-4,051	-3,862	-4,051	-4,051	-3,862
2014	5,321	0	0	0	0	5,321	1,270	750	5,321	1,270	750
2015	6,395	16	0	0	16	6,395	7,665	5,789	6,378	7,649	5,776
2016	4,923	638	0	0	638	4,923	12,587	9,315	4,285	11,934	8,845
2017	3,198	1,279	0	0	1,279	3,198	15,785	11,397	1,919	13,852	10,095
2018	2,231	892	0	0	892	2,231	18,016	12,718	1,338	15,191	10,887
2019	1,640	656	0	0	656	1,640	19,656	13,601	984	16,175	11,417
2020	1,259	504	0	0	504	1,259	20,915	14,217	755	16,930	11,786
2021	995	398	0	0	398	995	21,910	14,659	597	17,527	12,052
2022	797	319	0	0	319	797	22,707	14,982	478	18,005	12,245
2023	604	242	0	0	242	604	23,311	15,204	363	18,368	12,379
2024	445	178	0	0	178	445	23,756	15,352	267	18,635	12,468
Sub.	29,446	5,121	0	0	5,121	23,756	23,756	15,352	18,635	18,635	12,468
Rem.	999	338	0	0	338	999	24,754	15,611	661	19,295	12,637
Tot.	**30,445**	**5,459**	**0**	**0**	**5,459**	**24,754**	**24,754**	**15,611**	**19,295**	**19,295**	**12,637**
Disc	21,036	2,974	0	0	2,974	15,611	15,611	15,611	12,637	12,637	12,637

INTEREST AND NET PRESENT VALUE SUMMARY

Entity Name	Revenue Interests and Burdens (%): Initial	Revenue Interests and Burdens (%): Average	Disc. Rate %	Net Present Value Before Income Tax: Prod'n Revenue M$	Net Present Value Before Income Tax: Operating Income M$	Net Present Value Before Income Tax: Capital Invest. M$	Net Present Value Before Income Tax: Cash Flow M$	Net Present Value Before Income Tax: Cash Flow $/boe	Net Present Value After Income Tax: Operating Income M$	Net Present Value After Income Tax: Capital Invest. M$	Net Present Value After Income Tax: Cash Flow M$	Net Present Value After Income Tax: Cash Flow $/boe
Working Interest	0.0000	0.0000	0.0	-12,498.0	30,445	5,691	24,754	0.00	24,986	5,691	19,295	0.00
Capital Interest	66.6667	66.6667	5.0	-10,327.2	24,969	5,553	19,416	0.00	21,001	5,553	15,448	0.00
Royalty Interest	0.0000	0.0000	8.0	-9,318.0	22,466	5,476	16,991	0.00	19,140	5,476	13,664	0.00
Crown Royalty	0.0000	0.0000	10.0	-8,737.0	21,036	5,426	15,611	0.00	18,062	5,426	12,637	0.00
Non-crown Royalty	0.0000	0.0000	12.0	-8,216.9	19,762	5,377	14,385	0.00	17,093	5,377	11,716	0.00
Mineral Tax	0.0000	0.0000	15.0	-7,532.6	18,094	5,306	12,787	0.00	15,809	5,306	10,503	0.00
			20.0	-6,594.7	15,819	5,195	10,625	0.00	14,028	5,195	8,833	0.00

Evaluator: Herchen, Leonard L.
Run Date: January 20, 2013 22:11:51

Company: **Griffiths Energy International Inc.**
Property: **ITA Badila/Mangara**
Currency: **$US Dollars**

Reserve Class: **PPP**
Development Class: **Undeveloped**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	0	0	0	0	0	0	0	0	0	0	0	0	777	0	777
2014	0	0	0	0	0	0	0	0	0	0	0	0	2,609	0	2,609
2015	0	0	0	0	0	0	0	0	0	0	0	0	3,358	0	3,358
2016	0	0	0	0	0	0	0	0	0	0	0	0	3,425	0	3,425
2017	0	0	0	0	0	0	0	0	0	0	0	0	3,114	0	3,114
2018	0	0	0	0	0	0	0	0	0	0	0	0	2,473	0	2,473
2019	0	0	0	0	0	0	0	0	0	0	0	0	1,907	0	1,907
2020	0	0	0	0	0	0	0	0	0	0	0	0	1,516	0	1,516
2021	0	0	0	0	0	0	0	0	0	0	0	0	1,229	0	1,229
2022	0	0	0	0	0	0	0	0	0	0	0	0	1,019	0	1,019
2023	0	0	0	0	0	0	0	0	0	0	0	0	859	0	859
2024	0	0	0	0	0	0	0	0	0	0	0	0	737	0	737
Sub.	0	0	0	0	0	0	0	0	0	0	0	0	23,023	0	23,023
Rem.	0	0	0	0	0	0	0	0	0	0	0	0	3,607	0	3,607
Tot.	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**26,631**	**0**	**26,631**
Disc	0	0	0	0	0	0	0	0	0	0	0	0	15,680	0	15,680

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Net Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	-777	1,854	0	1,078	5,691	0	0	5,691	-4,613	-4,613	-4,398
2014	0	0	0	-2,609	6,228	0	3,619	0	0	0	0	3,619	-994	-1,262
2015	0	0	0	-3,358	8,015	0	4,657	0	0	0	0	4,657	3,663	2,408
2016	0	0	0	-3,425	8,176	0	4,751	0	0	0	0	4,751	8,414	5,812
2017	0	0	0	-3,114	7,433	0	4,319	0	0	0	0	4,319	12,733	8,625
2018	0	0	0	-2,473	5,903	0	3,430	0	0	0	0	3,430	16,164	10,655
2019	0	0	0	-1,907	4,552	0	2,645	0	0	0	0	2,645	18,809	12,079
2020	0	0	0	-1,516	3,619	0	2,103	0	0	0	0	2,103	20,912	13,108
2021	0	0	0	-1,229	2,933	0	1,704	0	0	0	0	1,704	22,616	13,866
2022	0	0	0	-1,019	2,432	0	1,413	0	0	0	0	1,413	24,029	14,437
2023	0	0	0	-859	2,052	0	1,192	0	0	0	0	1,192	25,221	14,876
2024	0	0	0	-737	1,761	0	1,023	0	0	0	0	1,023	26,244	15,218
Sub.	0	0	0	-23,023	54,958	0	31,935	5,691	0	0	5,691	26,244	26,244	15,218
Rem.	0	0	0	-3,607	8,594	0	4,986	0	0	0	0	4,986	31,231	16,320
Tot.	**0**	**0**	**0**	**-26,631**	**63,552**	**0**	**36,921**	**5,691**	**0**	**0**	**5,691**	**31,231**	**31,231**	**16,320**
Disc	0	0	0	-15,680	37,425	0	21,746	5,426	0	0	5,426	16,320	16,320	16,320

AFTER TAX ANALYSIS

		Tax Pool Balances Incl. Current Year Additions		Depreciation & Writeoffs		
Year	Oper. Income M$	CEE M$	Other M$	CEE M$	Other M$	Total M$
2013	1,078	0	0	0	0	0
2014	3,619	0	0	0	0	0
2015	4,657	0	0	0	0	0
2016	4,751	0	0	0	0	0
2017	4,319	0	0	0	0	0
2018	3,430	0	0	0	0	0
2019	2,645	0	0	0	0	0
2020	2,103	0	0	0	0	0
2021	1,704	0	0	0	0	0
2022	1,413	0	0	0	0	0
2023	1,192	0	0	0	0	0
2024	1,023	0	0	0	0	0
Sub.	31,935	0	0	0	0	0
Rem.	4,986	0	0	0	0	0
Tot.	**36,921**	**0**	**0**	**0**	**0**	**0**
Disc	21,746			0	0	0

Year	Taxable Income M$	Federal Income Tax M$	Provincial Income Tax M$	ARTD & Investment Credits	Income Tax Payable M$	Net Cash Flow Before Income Tax: Annual M$	Net Cash Flow Before Income Tax: Cum. M$	Net Cash Flow Before Income Tax: 10.0% Dcf M$	Net Cash Flow After Income Tax: Annual M$	Net Cash Flow After Income Tax: Cum. M$	Net Cash Flow After Income Tax: 10.0% Dcf M$
2013	1,078	0	0	0	0	-4,613	-4,613	-4,398	-4,613	-4,613	-4,398
2014	3,619	0	0	0	0	3,619	-994	-1,262	3,619	-994	-1,262
2015	4,657	0	0	0	0	4,657	3,663	2,408	4,657	3,663	2,408
2016	4,751	0	0	0	0	4,751	8,414	5,812	4,751	8,414	5,812
2017	4,319	712	0	0	712	4,319	12,733	8,625	3,607	12,021	8,161
2018	3,430	1,372	0	0	1,372	3,430	16,164	10,655	2,058	14,080	9,379
2019	2,645	1,058	0	0	1,058	2,645	18,809	12,079	1,587	15,666	10,233
2020	2,103	841	0	0	841	2,103	20,912	13,108	1,262	16,928	10,851
2021	1,704	682	0	0	682	1,704	22,616	13,866	1,022	17,951	11,306
2022	1,413	565	0	0	565	1,413	24,029	14,437	848	18,799	11,648
2023	1,192	477	0	0	477	1,192	25,221	14,876	715	19,514	11,911
2024	1,023	409	0	0	409	1,023	26,244	15,218	614	20,128	12,117
Sub.	31,935	6,116	0	0	6,116	26,244	26,244	15,218	20,128	20,128	12,117
Rem.	4,986	1,997	0	0	1,997	4,986	31,231	16,320	2,989	23,117	12,778
Tot.	**36,921**	**8,114**	**0**	**0**	**8,114**	**31,231**	**31,231**	**16,320**	**23,117**	**23,117**	**12,778**
Disc	21,746	3,542	0	0	3,542	16,320	16,320	16,320	12,778	12,778	12,778

INTEREST AND NET PRESENT VALUE SUMMARY

Entity Name	Revenue Interests and Burdens (%): Initial	Revenue Interests and Burdens (%): Average	Disc. Rate %	Net Present Value Before Income Tax: Prod'n Revenue M$	Net Present Value Before Income Tax: Operating Income M$	Net Present Value Before Income Tax: Capital Invest. M$	Net Present Value Before Income Tax: Cash Flow M$	Net Present Value Before Income Tax: Cash Flow $/boe	Net Present Value After Income Tax: Operating Income M$	Net Present Value After Income Tax: Capital Invest. M$	Net Present Value After Income Tax: Cash Flow M$	Net Present Value After Income Tax: Cash Flow $/boe
Working Interest	0.0000	0.0000	0.0	-26,630.7	36,921	5,691	31,231	0.00	28,807	5,691	23,117	0.00
Capital Interest	66.6667	66.6667	5.0	-19,908.4	27,607	5,553	22,054	0.00	22,396	5,553	16,842	0.00
Royalty Interest	0.0000	0.0000	8.0	-17,163.2	23,802	5,476	18,326	0.00	19,692	5,476	14,216	0.00
Crown Royalty	0.0000	0.0000	10.0	-15,679.7	21,746	5,426	16,320	0.00	18,203	5,426	12,778	0.00
Non-crown Royalty	0.0000	0.0000	12.0	-14,408.0	19,982	5,377	14,605	0.00	16,909	5,377	11,532	0.00
Mineral Tax	0.0000	0.0000	15.0	-12,811.1	17,768	5,306	12,462	0.00	15,257	5,306	9,950	0.00
			20.0	-10,753.4	14,915	5,195	9,720	0.00	13,075	5,195	7,881	0.00

Evaluator: Herchen, Leonard L.
Run Date: January 20, 2013 22:11:52

GRIFFITHS ENERGY INTERNATIONAL INC.

ITA EAST DOSEO

Effective December 31, 2012

Prepared by
Leonard L. Herchen, P. Eng.

The analysis of this property as reported herein was conducted within the context of an evaluation of a distinct group of properties in aggregate. Extraction and use of this analysis outside this context may not be appropriate without supplementary due diligence.

ITA EAST DOSEO

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Company: **Griffiths Energy International Inc.**
Property: **ITA East Doseo**
Currency: **$US Dollars**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Summary of Reserves and Values

	Proved Plus Probable Undeveloped	PPP Undeveloped	Low Estimate Contingent Resources
BEFORE TAX PRESENT VALUE (M$)			
0%	54,853	79,091	37,459
5%	27,898	40,368	19,716
8%	17,107	24,808	12,340
10%	11,432	16,615	8,386
12%	6,701	9,784	5,045
15%	1,003	1,560	961
20%	-5,772	-8,195	-3,995
AFTER TAX PRESENT VALUE (M$)			
0%	33,339	48,027	22,827
5%	14,482	20,811	10,212
8%	6,801	9,711	4,893
10%	2,724	3,823	2,020
12%	-697	-1,111	-420
15%	-4,843	-7,078	-3,418
20%	-9,810	-14,188	-7,080

BOE Factors: HVY OIL 1.0 | COND 1.0 | RES GAS 6.0 | SLN GAS 6.0 | PROPANE 1.0 | BUTANE 1.0 | ETHANE 1.0 | SULPHUR 0.0

Run Date: January 20, 2013 21:25:17

DISCUSSION

Griffiths Energy International Inc. (Griffiths) plan to construct a pipeline that transports crude from Kibea and Maku to Kome. At Kome, oil is transferred into the Chad-Cameroon pipeline for export to world markets. The total distance from Kibea to Kome is 410 kilometres.

As with the Badila/Mangara developments, it is expected that the pipeline and associated facilities from Maku to Kome, will have to be similarly structured into a separate corporate entity defined as an Inland Transportation Agreement (ITA) named the "ITA East Doseo" by GLJ Petroleum Consultants (GLJ).

Capital and operating costs for the 240 kilometre, Maku to Kome section of the pipeline and associated facilities are not directly recoverable as cost recovery from Maku and Kibea EXA's. Rather, the capital costs and operating cost recovery is scheduled as a tariff, deductable from the received oil price for Maku and Kibea. The tariff paid is earned by a corporate entity, defined as an ITA and is assumed to be 66.67 percent owned by Griffiths and 33.33 percent by Glencore International AG (Glencore). The ITA is liable for the capital and operating costs and earns a tariff.

The tariff was calculated such that the ITA earns an 11 percent after tax rate of return on invested capital. The assumed tax rate was 40 percent and capital invested was depreciated over five years. Based on information provided by Griffiths, the capital investment, operating costs and associated tariffs were estimated as follows:

Reserves Class	Pipeline Diameter (in)	Total Capital MM$	Capital Allocated to ITA MM$	Operating Cost $/bbl	Total/Tariff $/bbl
Low Estimate Contingent Resources	6	110.4	64.62	1.50	15.59
Proved + Probable Reserves	8	139	81.37	1.50	7.85
Proved + Probable + Possible Reserves	12	184	107.71	1.50	4.99

Table 1 Pipeline Capital and Tariff parameters

This evaluation includes the terms of a farm-in agreement (Glencore Farm-in) agreed between Griffiths and Glencore. Specifically, the Glencore Farm-in assigns a one-third fraction of Griffiths' interests to Glencore. Consequently, the capital, operating costs, tariffs and taxes presented herein represent Griffith's net interest, not the combined Glencore and Griffith's

interests. The Glencore Farm-in includes a carry of Griffiths' capital. However, this carry is associated only with the Badila and Mangara properties, not the East Dosea Fields or ITA East Dosea.

Capital costs, operating costs, tariff income and income taxes for each reserves classification are presented in the economic summary section of this report. The tariff income is presented in the "Other Income" column.

Company: **Griffiths Energy International Inc.**
Property: **ITA East Doseo**
Currency: **$US Dollars**

Reserve Class: **Proved Plus Probable**
Development Class: **Undeveloped**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0	0	0	1,623	0	1,623
2016	0	0	0	0	0	0	0	0	0	0	0	0	3,783	0	3,783
2017	0	0	0	0	0	0	0	0	0	0	0	0	3,903	0	3,903
2018	0	0	0	0	0	0	0	0	0	0	0	0	3,569	0	3,569
2019	0	0	0	0	0	0	0	0	0	0	0	0	2,832	0	2,832
2020	0	0	0	0	0	0	0	0	0	0	0	0	2,158	0	2,158
2021	0	0	0	0	0	0	0	0	0	0	0	0	1,684	0	1,684
2022	0	0	0	0	0	0	0	0	0	0	0	0	1,349	0	1,349
2023	0	0	0	0	0	0	0	0	0	0	0	0	1,103	0	1,103
2024	0	0	0	0	0	0	0	0	0	0	0	0	918	0	918
Sub.	0	0	0	0	0	0	0	0	0	0	0	0	22,923	0	22,923
Rem.	0	0	0	0	0	0	0	0	0	0	0	0	3,136	0	3,136
Tot.	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**26,059**	**0**	**26,059**
Disc	0	0	0	0	0	0	0	0	0	0	0	0	14,030	0	14,030

				Net				Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	55,332	0	55,332	-55,332	-55,332	-47,961
2015	0	0	0	-1,623	8,499	0	6,876	0	0	0	0	6,876	-48,456	-42,543
2016	0	0	0	-3,783	19,809	0	16,025	0	0	0	0	16,025	-32,431	-31,063
2017	0	0	0	-3,903	20,434	0	16,531	0	0	0	0	16,531	-15,900	-20,297
2018	0	0	0	-3,569	18,689	0	15,120	0	0	0	0	15,120	-780	-11,346
2019	0	0	0	-2,832	14,829	0	11,997	0	0	0	0	11,997	11,217	-4,889
2020	0	0	0	-2,158	11,298	0	9,140	0	0	0	0	9,140	20,357	-417
2021	0	0	0	-1,684	8,817	0	7,133	0	0	0	0	7,133	27,490	2,756
2022	0	0	0	-1,349	7,067	0	5,718	0	0	0	0	5,718	33,208	5,067
2023	0	0	0	-1,103	5,775	0	4,672	0	0	0	0	4,672	37,880	6,785
2024	0	0	0	-918	4,807	0	3,889	0	0	0	0	3,889	41,769	8,085
Sub.	0	0	0	-22,923	120,023	0	97,101	0	55,332	0	55,332	41,769	41,769	8,085
Rem.	0	0	0	-3,136	16,220	0	13,084	0	0	0	0	13,084	54,853	11,432
Tot.	**0**	**0**	**0**	**-26,059**	**136,243**	**0**	**110,185**	**0**	**55,332**	**0**	**55,332**	**54,853**	**54,853**	**11,432**
Disc	0	0	0	-14,030	73,423	0	59,392	0	47,961	0	47,961	11,432	11,432	11,432

AFTER TAX ANALYSIS

		Tax Pool Balances Incl. Current Year Additions		Depreciation & Writeoffs		
Year	Oper. Income M$	CEE M$	Other M$	CEE M$	Other M$	Total M$
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	6,876	0	0	0	0	0
2016	16,025	0	0	0	0	0
2017	16,531	0	0	0	0	0
2018	15,120	0	0	0	0	0
2019	11,997	0	0	0	0	0
2020	9,140	0	0	0	0	0
2021	7,133	0	0	0	0	0
2022	5,718	0	0	0	0	0
2023	4,672	0	0	0	0	0
2024	3,889	0	0	0	0	0
Sub.	97,101	0	0	0	0	0
Rem.	13,084	0	0	0	0	0
Tot.	**110,185**	**0**	**0**	**0**	**0**	**0**
Disc	59,392			0	0	0

Year	Taxable Income M$	Federal Income Tax M$	Provincial Income Tax M$	ARTD & Investment Credits	Income Tax Payable M$	Net Cash Flow Before Income Tax: Annual M$	Net Cash Flow Before Income Tax: Cum. M$	Net Cash Flow Before Income Tax: 10.0% Dcf M$	Net Cash Flow After Income Tax: Annual M$	Net Cash Flow After Income Tax: Cum. M$	Net Cash Flow After Income Tax: 10.0% Dcf M$
2013	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	-55,332	-55,332	-47,961	-55,332	-55,332	-47,961
2015	6,876	0	0	0	0	6,876	-48,456	-42,543	6,876	-48,456	-42,543
2016	16,025	0	0	0	0	16,025	-32,431	-31,063	16,025	-32,431	-31,063
2017	16,531	0	0	0	0	16,531	-15,900	-20,297	16,531	-15,900	-20,297
2018	15,120	0	0	0	0	15,120	-780	-11,346	15,120	-780	-11,346
2019	11,997	4,045	0	0	4,045	11,997	11,217	-4,889	7,953	7,173	-7,066
2020	9,140	3,656	0	0	3,656	9,140	20,357	-417	5,484	12,657	-4,383
2021	7,133	2,853	0	0	2,853	7,133	27,490	2,756	4,280	16,936	-2,479
2022	5,718	2,287	0	0	2,287	5,718	33,208	5,067	3,431	20,367	-1,092
2023	4,672	1,869	0	0	1,869	4,672	37,880	6,785	2,803	23,170	-62
2024	3,889	1,556	0	0	1,556	3,889	41,769	8,085	2,334	25,504	718
Sub.	97,101	16,265	0	0	16,265	41,769	41,769	8,085	25,504	25,504	718
Rem.	13,084	5,249	0	0	5,249	13,084	54,853	11,432	7,835	33,339	2,724
Tot.	**110,185**	**21,514**	**0**	**0**	**21,514**	**54,853**	**54,853**	**11,432**	**33,339**	**33,339**	**2,724**
Disc	59,392	8,708	0	0	8,708	11,432	11,432	11,432	2,724	2,724	2,724

INTEREST AND NET PRESENT VALUE SUMMARY

Entity Name	Revenue Interests and Burdens (%): Initial	Revenue Interests and Burdens (%): Average	Disc. Rate %	Net Present Value Before Income Tax: Prod'n Revenue M$	Net Present Value Before Income Tax: Operating Income M$	Net Present Value Before Income Tax: Capital Invest. M$	Net Present Value Before Income Tax: Cash Flow M$	Net Present Value Before Income Tax: Cash Flow $/boe	Net Present Value After Income Tax: Operating Income M$	Net Present Value After Income Tax: Capital Invest. M$	Net Present Value After Income Tax: Cash Flow M$	Net Present Value After Income Tax: Cash Flow $/boe
Working Interest	0.0000	0.0000	0.0	-26,058.7	110,185	55,332	54,853	0.00	88,670	55,332	33,339	0.00
Capital Interest	0.0000	66.6667	5.0	-18,746.9	79,325	51,427	27,898	0.00	65,909	51,427	14,482	0.00
Royalty Interest	0.0000	0.0000	8.0	-15,689.5	66,406	49,299	17,107	0.00	56,100	49,299	6,801	0.00
Crown Royalty	0.0000	0.0000	10.0	-14,030.3	59,392	47,961	11,432	0.00	50,684	47,961	2,724	0.00
Non-crown Royalty	0.0000	0.0000	12.0	-12,609.2	53,383	46,682	6,701	0.00	45,985	46,682	-697	0.00
Mineral Tax	0.0000	0.0000	15.0	-10,833.3	45,870	44,867	1,003	0.00	40,024	44,867	-4,843	0.00
			20.0	-8,576.6	36,321	42,092	-5,772	0.00	32,282	42,092	-9,810	0.00

Evaluator: Herchen, Leonard L.
Run Date: January 20, 2013 21:25:14

Company: **Griffiths Energy International Inc.**
Property: **ITA East Doseo**
Currency: **$US Dollars**

Reserve Class: **PPP**
Development Class: **Undeveloped**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0	0	0	2,565	0	2,565
2016	0	0	0	0	0	0	0	0	0	0	0	0	6,625	0	6,625
2017	0	0	0	0	0	0	0	0	0	0	0	0	9,202	0	9,202
2018	0	0	0	0	0	0	0	0	0	0	0	0	10,011	0	10,011
2019	0	0	0	0	0	0	0	0	0	0	0	0	9,334	0	9,334
2020	0	0	0	0	0	0	0	0	0	0	0	0	7,091	0	7,091
2021	0	0	0	0	0	0	0	0	0	0	0	0	4,924	0	4,924
2022	0	0	0	0	0	0	0	0	0	0	0	0	3,623	0	3,623
2023	0	0	0	0	0	0	0	0	0	0	0	0	2,784	0	2,784
2024	0	0	0	0	0	0	0	0	0	0	0	0	2,213	0	2,213
Sub.	0	0	0	0	0	0	0	0	0	0	0	0	58,371	0	58,371
Rem.	0	0	0	0	0	0	0	0	0	0	0	0	7,087	0	7,087
Tot.	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**65,458**	**0**	**65,458**
Disc	0	0	0	0	0	0	0	0	0	0	0	0	34,402	0	34,402

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Net Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	73,243	0	73,243	-73,243	-73,243	-63,486
2015	0	0	0	-2,565	8,540	0	5,975	0	0	0	0	5,975	-67,268	-58,778
2016	0	0	0	-6,625	22,052	0	15,428	0	0	0	0	15,428	-51,840	-47,726
2017	0	0	0	-9,202	30,632	0	21,430	0	0	0	0	21,430	-30,410	-33,770
2018	0	0	0	-10,011	33,324	0	23,314	0	0	0	0	23,314	-7,096	-19,968
2019	0	0	0	-9,334	31,073	0	21,739	0	0	0	0	21,739	14,642	-8,268
2020	0	0	0	-7,091	23,603	0	16,513	0	0	0	0	16,513	31,155	-188
2021	0	0	0	-4,924	16,393	0	11,469	0	0	0	0	11,469	42,624	4,913
2022	0	0	0	-3,623	12,059	0	8,436	0	0	0	0	8,436	51,060	8,324
2023	0	0	0	-2,784	9,267	0	6,483	0	0	0	0	6,483	57,543	10,707
2024	0	0	0	-2,213	7,369	0	5,156	0	0	0	0	5,156	62,699	12,430
Sub.	0	0	0	-58,371	194,313	0	135,942	0	73,243	0	73,243	62,699	62,699	12,430
Rem.	0	0	0	-7,087	23,478	0	16,392	0	0	0	0	16,392	79,091	16,615
Tot.	**0**	**0**	**0**	**-65,458**	**217,791**	**0**	**152,333**	**0**	**73,243**	**0**	**73,243**	**79,091**	**79,091**	**16,615**
Disc	0	0	0	-34,402	114,503	0	80,100	0	63,486	0	63,486	16,615	16,615	16,615

AFTER TAX ANALYSIS

		Tax Pool Balances Incl. Current Year Additions		Depreciation & Writeoffs		
Year	Oper. Income M$	CEE M$	Other M$	CEE M$	Other M$	Total M$
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	5,975	0	0	0	0	0
2016	15,428	0	0	0	0	0
2017	21,430	0	0	0	0	0
2018	23,314	0	0	0	0	0
2019	21,739	0	0	0	0	0
2020	16,513	0	0	0	0	0
2021	11,469	0	0	0	0	0
2022	8,436	0	0	0	0	0
2023	6,483	0	0	0	0	0
2024	5,156	0	0	0	0	0
Sub.	135,942	0	0	0	0	0
Rem.	16,392	0	0	0	0	0
Tot.	**152,333**	**0**	**0**	**0**	**0**	**0**
Disc	80,100			0	0	0

Year	Taxable Income M$	Federal Income Tax M$	Provincial Income Tax M$	ARTD & Investment Credits	Income Tax Payable M$	Net Cash Flow Before Income Tax: Annual M$	Net Cash Flow Before Income Tax: Cum. M$	Net Cash Flow Before Income Tax: 10.0% Dcf M$	Net Cash Flow After Income Tax: Annual M$	Net Cash Flow After Income Tax: Cum. M$	Net Cash Flow After Income Tax: 10.0% Dcf M$
2013	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	-73,243	-73,243	-63,486	-73,243	-73,243	-63,486
2015	5,975	0	0	0	0	5,975	-67,268	-58,778	5,975	-67,268	-58,778
2016	15,428	0	0	0	0	15,428	-51,840	-47,726	15,428	-51,840	-47,726
2017	21,430	0	0	0	0	21,430	-30,410	-33,770	21,430	-30,410	-33,770
2018	23,314	0	0	0	0	23,314	-7,096	-19,968	23,314	-7,096	-19,968
2019	21,739	5,271	0	0	5,271	21,739	14,642	-8,268	16,468	9,372	-11,105
2020	16,513	6,605	0	0	6,605	16,513	31,155	-188	9,908	19,279	-6,257
2021	11,469	4,587	0	0	4,587	11,469	42,624	4,913	6,881	26,160	-3,196
2022	8,436	3,375	0	0	3,375	8,436	51,060	8,324	5,062	31,222	-1,150
2023	6,483	2,593	0	0	2,593	6,483	57,543	10,707	3,890	35,112	280
2024	5,156	2,062	0	0	2,062	5,156	62,699	12,430	3,094	38,205	1,314
Sub.	135,942	24,493	0	0	24,493	62,699	62,699	12,430	38,205	38,205	1,314
Rem.	16,392	6,570	0	0	6,570	16,392	79,091	16,615	9,821	48,027	3,823
Tot.	**152,333**	**31,064**	**0**	**0**	**31,064**	**79,091**	**79,091**	**16,615**	**48,027**	**48,027**	**3,823**
Disc	80,100	12,792	0	0	12,792	16,615	16,615	16,615	3,823	3,823	3,823

INTEREST AND NET PRESENT VALUE SUMMARY

Entity Name	Revenue Interests and Burdens (%): Initial	Revenue Interests and Burdens (%): Average	Disc. Rate %	Net Present Value Before Income Tax: Prod'n Revenue M$	Net Present Value Before Income Tax: Operating Income M$	Net Present Value Before Income Tax: Capital Invest. M$	Net Present Value Before Income Tax: Cash Flow M$	Net Present Value Before Income Tax: Cash Flow $/boe	Net Present Value After Income Tax: Operating Income M$	Net Present Value After Income Tax: Capital Invest. M$	Net Present Value After Income Tax: Cash Flow M$	Net Present Value After Income Tax: Cash Flow $/boe
Working Interest	0.0000	0.0000	0.0	-65,458.0	152,333	73,243	79,091	0.00	121,270	73,243	48,027	0.00
Capital Interest	0.0000	66.6667	5.0	-46,583.2	108,442	68,074	40,368	0.00	88,885	68,074	20,811	0.00
Royalty Interest	0.0000	0.0000	8.0	-38,684.3	90,065	65,257	24,808	0.00	74,968	65,257	9,711	0.00
Crown Royalty	0.0000	0.0000	10.0	-34,402.3	80,100	63,486	16,615	0.00	67,308	63,486	3,823	0.00
Non-crown Royalty	0.0000	0.0000	12.0	-30,739.8	71,576	61,793	9,784	0.00	60,682	61,793	-1,111	0.00
Mineral Tax	0.0000	0.0000	15.0	-26,175.1	60,951	59,391	1,560	0.00	52,313	59,391	-7,078	0.00
			20.0	-20,407.1	47,522	55,718	-8,195	0.00	41,530	55,718	-14,188	0.00

Evaluator: Herchen, Leonard L.
Run Date: January 20, 2013 21:25:15

Company: **Griffiths Energy International Inc.**
Property: **ITA East Doseo**
Currency: **$US Dollars**

Reserve Class: **Contingent Resources**
Development Class: **Low Estimate**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0	0	0	807	0	807
2016	0	0	0	0	0	0	0	0	0	0	0	0	1,526	0	1,526
2017	0	0	0	0	0	0	0	0	0	0	0	0	1,363	0	1,363
2018	0	0	0	0	0	0	0	0	0	0	0	0	1,157	0	1,157
2019	0	0	0	0	0	0	0	0	0	0	0	0	885	0	885
2020	0	0	0	0	0	0	0	0	0	0	0	0	698	0	698
2021	0	0	0	0	0	0	0	0	0	0	0	0	560	0	560
2022	0	0	0	0	0	0	0	0	0	0	0	0	459	0	459
2023	0	0	0	0	0	0	0	0	0	0	0	0	383	0	383
2024	0	0	0	0	0	0	0	0	0	0	0	0	324	0	324
Sub.	0	0	0	0	0	0	0	0	0	0	0	0	8,163	0	8,163
Rem.	0	0	0	0	0	0	0	0	0	0	0	0	503	0	503
Tot.	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**8,666**	**0**	**8,666**
Disc	0	0	0	0	0	0	0	0	0	0	0	0	4,948	0	4,948

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Net Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	43,942	0	43,942	-43,942	-43,942	-38,088
2015	0	0	0	-807	8,389	0	7,581	0	0	0	0	7,581	-36,360	-32,114
2016	0	0	0	-1,526	15,859	0	14,333	0	0	0	0	14,333	-22,027	-21,847
2017	0	0	0	-1,363	14,169	0	12,805	0	0	0	0	12,805	-9,222	-13,507
2018	0	0	0	-1,157	12,030	0	10,873	0	0	0	0	10,873	1,651	-7,070
2019	0	0	0	-885	9,199	0	8,313	0	0	0	0	8,313	9,964	-2,596
2020	0	0	0	-698	7,255	0	6,557	0	0	0	0	6,557	16,521	612
2021	0	0	0	-560	5,822	0	5,262	0	0	0	0	5,262	21,782	2,952
2022	0	0	0	-459	4,775	0	4,315	0	0	0	0	4,315	26,098	4,697
2023	0	0	0	-383	3,978	0	3,595	0	0	0	0	3,595	29,693	6,019
2024	0	0	0	-324	3,368	0	3,044	0	0	0	0	3,044	32,737	7,036
Sub.	0	0	0	-8,163	84,842	0	76,678	0	43,942	0	43,942	32,737	32,737	7,036
Rem.	0	0	0	-503	5,225	0	4,722	0	0	0	0	4,722	37,459	8,386
Tot.	**0**	**0**	**0**	**-8,666**	**90,066**	**0**	**81,400**	**0**	**43,942**	**0**	**43,942**	**37,459**	**37,459**	**8,386**
Disc	0	0	0	-4,948	51,421	0	46,474	0	38,088	0	38,088	8,386	8,386	8,386

AFTER TAX ANALYSIS

		Tax Pool Balances Incl. Current Year Additions		Depreciation & Writeoffs		
Year	Oper. Income M$	CEE M$	Other M$	CEE M$	Other M$	Total M$
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0
2015	7,581	0	0	0	0	0
2016	14,333	0	0	0	0	0
2017	12,805	0	0	0	0	0
2018	10,873	0	0	0	0	0
2019	8,313	0	0	0	0	0
2020	6,557	0	0	0	0	0
2021	5,262	0	0	0	0	0
2022	4,315	0	0	0	0	0
2023	3,595	0	0	0	0	0
2024	3,044	0	0	0	0	0
Sub.	76,678	0	0	0	0	0
Rem.	4,722	0	0	0	0	0
Tot.	**81,400**	**0**	**0**	**0**	**0**	**0**
Disc	46,474			0	0	0

Year	Taxable Income M$	Federal Income Tax M$	Provincial Income Tax M$	ARTD & Investment Credits	Income Tax Payable M$	Net Cash Flow Before Income Tax: Annual M$	Net Cash Flow Before Income Tax: Cum. M$	Net Cash Flow Before Income Tax: 10.0% Dcf M$	Net Cash Flow After Income Tax: Annual M$	Net Cash Flow After Income Tax: Cum. M$	Net Cash Flow After Income Tax: 10.0% Dcf M$
2013	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	-43,942	-43,942	-38,088	-43,942	-43,942	-38,088
2015	7,581	0	0	0	0	7,581	-36,360	-32,114	7,581	-36,360	-32,114
2016	14,333	0	0	0	0	14,333	-22,027	-21,847	14,333	-22,027	-21,847
2017	12,805	0	0	0	0	12,805	-9,222	-13,507	12,805	-9,222	-13,507
2018	10,873	309	0	0	309	10,873	1,651	-7,070	10,564	1,342	-7,253
2019	8,313	3,325	0	0	3,325	8,313	9,964	-2,596	4,988	6,330	-4,569
2020	6,557	2,623	0	0	2,623	6,557	16,521	612	3,934	10,264	-2,644
2021	5,262	2,105	0	0	2,105	5,262	21,782	2,952	3,157	13,421	-1,240
2022	4,315	1,726	0	0	1,726	4,315	26,098	4,697	2,589	16,010	-193
2023	3,595	1,438	0	0	1,438	3,595	29,693	6,019	2,157	18,167	600
2024	3,044	1,217	0	0	1,217	3,044	32,737	7,036	1,826	19,993	1,210
Sub.	76,678	12,743	0	0	12,743	32,737	32,737	7,036	19,993	19,993	1,210
Rem.	4,722	1,889	0	0	1,889	4,722	37,459	8,386	2,833	22,827	2,020
Tot.	**81,400**	**14,632**	**0**	**0**	**14,632**	**37,459**	**37,459**	**8,386**	**22,827**	**22,827**	**2,020**
Disc	46,474	6,365	0	0	6,365	8,386	8,386	8,386	2,020	2,020	2,020

INTEREST AND NET PRESENT VALUE SUMMARY

Entity Name	Revenue Interests and Burdens (%): Initial	Revenue Interests and Burdens (%): Average	Disc. Rate %	Net Present Value Before Income Tax: Prod'n Revenue M$	Net Present Value Before Income Tax: Operating Income M$	Net Present Value Before Income Tax: Capital Invest. M$	Net Present Value Before Income Tax: Cash Flow M$	Net Present Value Before Income Tax: Cash Flow $/boe	Net Present Value After Income Tax: Operating Income M$	Net Present Value After Income Tax: Capital Invest. M$	Net Present Value After Income Tax: Cash Flow M$	Net Present Value After Income Tax: Cash Flow $/boe
Working Interest	0.0000	0.0000	0.0	-8,666.0	81,400	43,942	37,459	0.00	66,768	43,942	22,827	0.00
Capital Interest	0.0000	66.6667	5.0	-6,447.0	60,556	40,841	19,716	0.00	51,053	40,841	10,212	0.00
Royalty Interest	0.0000	0.0000	8.0	-5,481.9	51,491	39,151	12,340	0.00	44,044	39,151	4,893	0.00
Crown Royalty	0.0000	0.0000	10.0	-4,947.8	46,474	38,088	8,386	0.00	40,108	38,088	2,020	0.00
Non-crown Royalty	0.0000	0.0000	12.0	-4,484.0	42,117	37,072	5,045	0.00	36,653	37,072	-420	0.00
Mineral Tax	0.0000	0.0000	15.0	-3,895.8	36,593	35,631	961	0.00	32,213	35,631	-3,418	0.00
			20.0	-3,133.6	29,433	33,428	-3,995	0.00	26,348	33,428	-7,080	0.00

Evaluator: Herchen, Leonard L.
Run Date: January 20, 2013 21:25:17

GRIFFITHS ENERGY INTERNATIONAL INC.

KIBEA

Effective December 31, 2012

Prepared by
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The analysis of this property as reported herein was conducted within the context of an evaluation of a distinct group of properties in aggregate. Extraction and use of this analysis outside this context may not be appropriate without supplementary due diligence.

KIBEA

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Company: **Griffiths Energy International Inc.**
Property: **Kibea**
Currency: **$US Dollars**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Summary of Reserves and Values

	Proved Plus Probable Undeveloped	PPP Undeveloped	Low Estimate Contingent Resources
MARKETABLE RESERVES			
Light/Medium Oil (Mbbl)			
Gross Lease	18,756	49,352	5,649
Total Company Interest	6,332	14,712	2,510
Net After Royalty	6,332	14,712	2,510
Oil Equivalent (Mbbl)			
Gross Lease	18,756	49,352	5,649
Total Company Interest	6,332	14,712	2,510
Net After Royalty	6,332	14,712	2,510
BEFORE TAX PRESENT VALUE (M$)			
0%	266,649	707,145	51,051
5%	170,618	475,926	21,003
8%	130,419	377,775	8,253
10%	108,667	324,286	1,348
12%	90,111	278,428	-4,525
15%	67,090	221,220	-11,752
20%	38,308	149,128	-20,590
FIRST 6 YEARS BEFORE TAX CASH FLOW (M$)			
2013	-35,533	-53,135	-27,282
2014	-59,566	-102,887	-45,453
2015	-12,141	-2,744	-16,673
2016	53,033	83,478	26,617
2017	93,332	175,491	27,450
2018	53,225	158,192	24,814

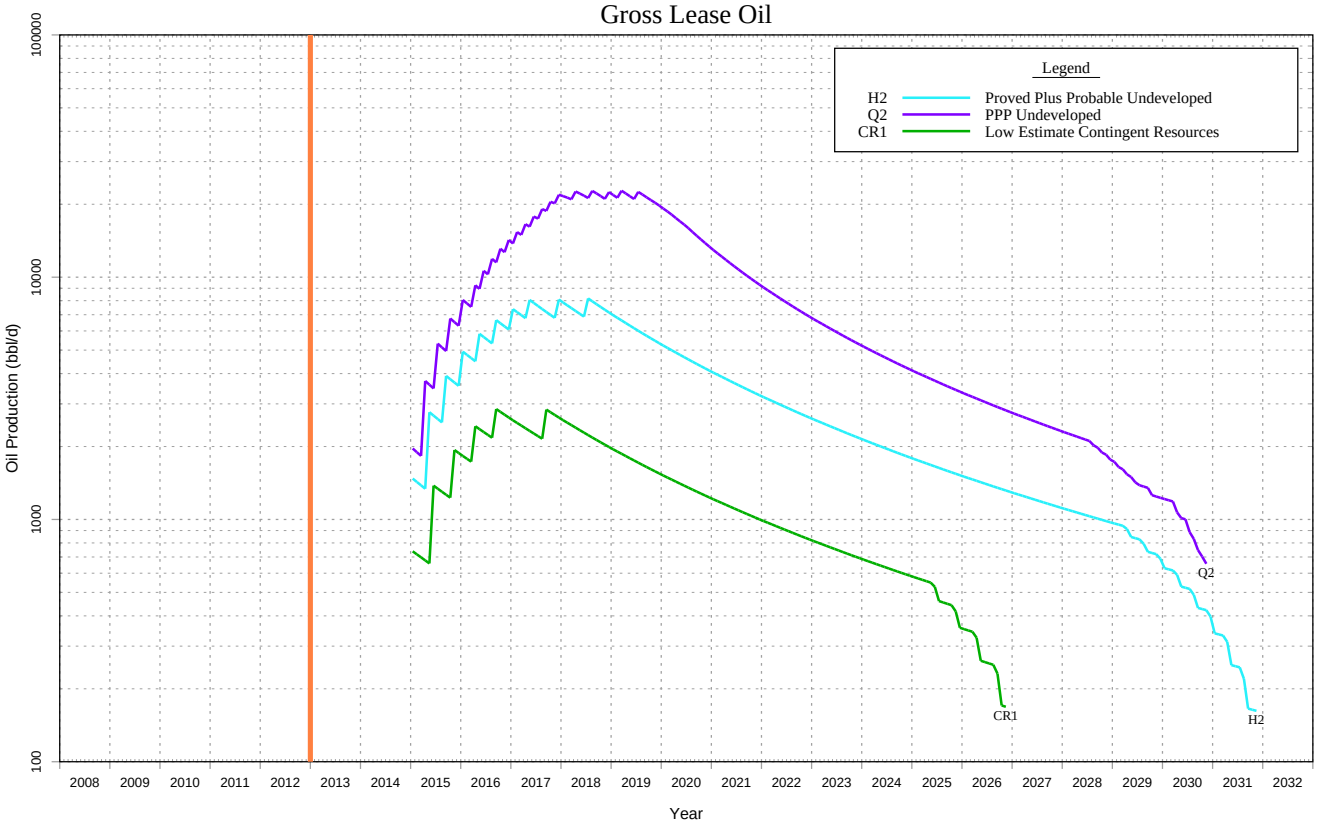
BOE Factors: HVY OIL 1.0 COND 1.0 RES GAS 6.0 SLN GAS 6.0 PROPANE 1.0 BUTANE 1.0 ETHANE 1.0 SULPHUR 0.0

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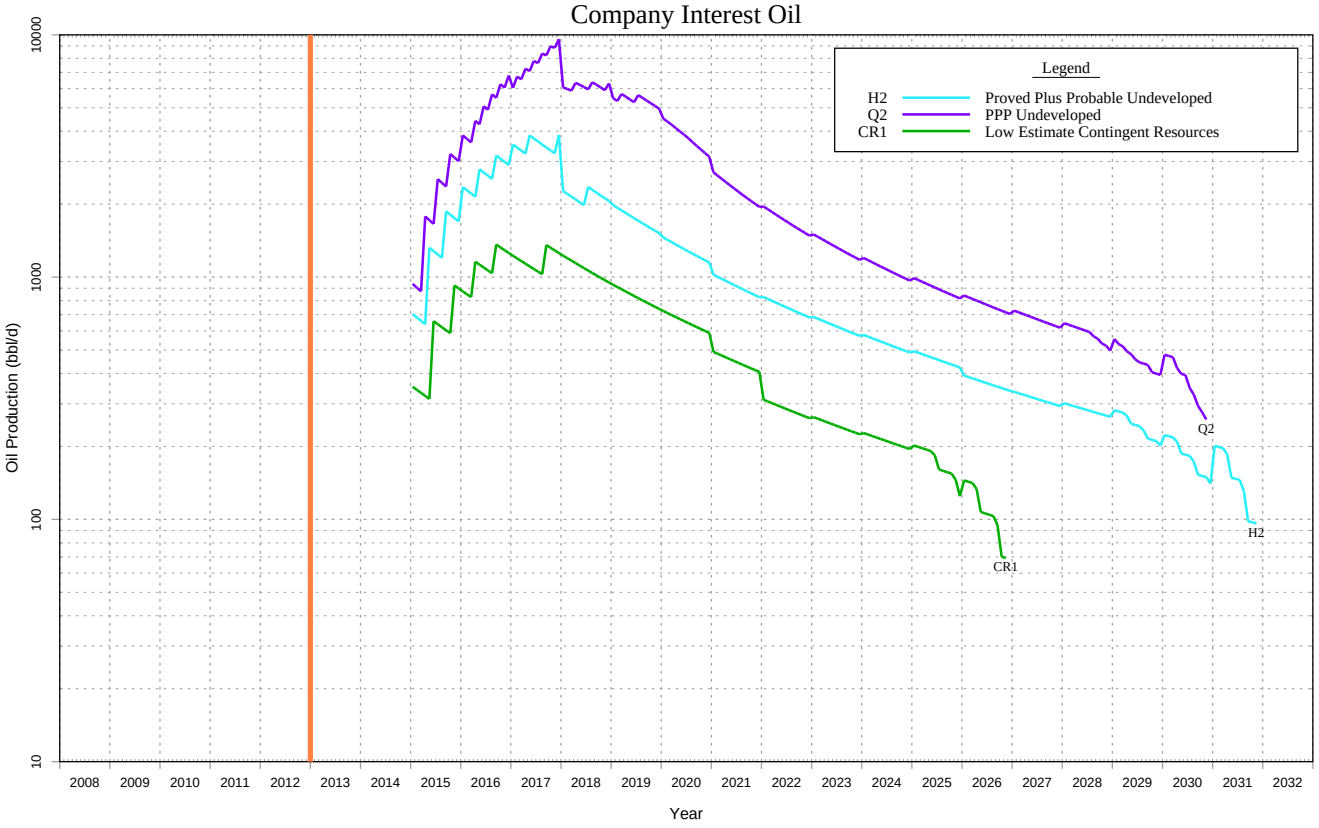
Historical and Forecast Production

Company: **Griffiths Energy International Inc.**
Property: **Kibea**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Gross Lease Oil



Company Interest Oil



*Note: Historical company interest production is based on current interests in the evaluated reserves entities applied to reported actual gross lease production. Consequently, company actuals may differ from the history shown due to changes in ownership.

Company: **Griffiths Energy International Inc.**
Property: **Kibea**
Currency: **$US Dollars**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Daily Production, Reserves and Present Value Summary

Entity Description	Reserve Class	2013 Gross Lease Production				2013 Company Interest Production				Gross Lease Reserves					Company Interest Reserves					Before Tax 10% Dcf Present Value M$
		Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	
Proved Plus Probable Undeveloped																				
Kibea-01	H2	0	0	0	0	0	0	0	0	0	1,884	0	0	1,884	0	722	0	0	722	32,334
Kibea-02	H2	0	0	0	0	0	0	0	0	0	1,884	0	0	1,884	0	708	0	0	708	30,927
Kibea-03	H2	0	0	0	0	0	0	0	0	0	1,884	0	0	1,884	0	692	0	0	692	29,341
Kibea-04	H2	0	0	0	0	0	0	0	0	0	1,884	0	0	1,884	0	676	0	0	676	27,599
Kibea-05	H2	0	0	0	0	0	0	0	0	0	1,884	0	0	1,884	0	657	0	0	657	25,868
Kibea-06	H2	0	0	0	0	0	0	0	0	0	1,884	0	0	1,884	0	637	0	0	637	23,915
Kibea-07	H2	0	0	0	0	0	0	0	0	0	1,884	0	0	1,884	0	616	0	0	616	21,770
Kibea-08	H2	0	0	0	0	0	0	0	0	0	1,875	0	0	1,875	0	587	0	0	587	19,878
Kibea-09	H2	0	0	0	0	0	0	0	0	0	1,858	0	0	1,858	0	528	0	0	528	15,921
Kibea-10	H2	0	0	0	0	0	0	0	0	0	1,835	0	0	1,835	0	510	0	0	510	14,385
Well capital	H2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-79,789
Other Revenue and Expenses	H2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-53,482
Total: Proved Plus Probable Undeveloped		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**18,756**	**0**	**0**	**18,756**	**0**	**6,332**	**0**	**0**	**6,332**	**108,667**
PPP Undeveloped																				
Kibea-01	Q2	0	0	0	0	0	0	0	0	0	2,358	0	0	2,358	0	872	0	0	872	40,173
Kibea-02	Q2	0	0	0	0	0	0	0	0	0	2,358	0	0	2,358	0	858	0	0	858	38,861
Kibea-03	Q2	0	0	0	0	0	0	0	0	0	2,358	0	0	2,358	0	842	0	0	842	37,433
Kibea-04	Q2	0	0	0	0	0	0	0	0	0	2,354	0	0	2,354	0	823	0	0	823	35,867
Kibea-05	Q2	0	0	0	0	0	0	0	0	0	2,347	0	0	2,347	0	801	0	0	801	34,165
Kibea-06	Q2	0	0	0	0	0	0	0	0	0	2,340	0	0	2,340	0	778	0	0	778	32,359
Kibea-07	Q2	0	0	0	0	0	0	0	0	0	2,335	0	0	2,335	0	761	0	0	761	31,061
Kibea-08	Q2	0	0	0	0	0	0	0	0	0	2,330	0	0	2,330	0	743	0	0	743	29,686
Kibea-09	Q2	0	0	0	0	0	0	0	0	0	2,325	0	0	2,325	0	725	0	0	725	28,226
Kibea-10	Q2	0	0	0	0	0	0	0	0	0	2,319	0	0	2,319	0	705	0	0	705	26,675
Kibea-11	Q2	0	0	0	0	0	0	0	0	0	2,358	0	0	2,358	0	717	0	0	717	28,918
Kibea-12	Q2	0	0	0	0	0	0	0	0	0	2,358	0	0	2,358	0	696	0	0	696	27,452
Kibea-13	Q2	0	0	0	0	0	0	0	0	0	2,358	0	0	2,358	0	673	0	0	673	25,909
Kibea-14	Q2	0	0	0	0	0	0	0	0	0	2,358	0	0	2,358	0	650	0	0	650	24,334
Kibea-15	Q2	0	0	0	0	0	0	0	0	0	2,358	0	0	2,358	0	627	0	0	627	22,724
Kibea-16	Q2	0	0	0	0	0	0	0	0	0	2,358	0	0	2,358	0	604	0	0	604	21,076
Kibea-17	Q2	0	0	0	0	0	0	0	0	0	2,358	0	0	2,358	0	585	0	0	585	19,451
Kibea-18	Q2	0	0	0	0	0	0	0	0	0	2,358	0	0	2,358	0	575	0	0	575	18,313
Kibea-19	Q2	0	0	0	0	0	0	0	0	0	2,358	0	0	2,358	0	565	0	0	565	17,093
Kibea-20	Q2	0	0	0	0	0	0	0	0	0	2,358	0	0	2,358	0	560	0	0	560	16,390
Kibea-21	Q2	0	0	0	0	0	0	0	0	0	2,348	0	0	2,348	0	553	0	0	553	15,507
Well capital	Q2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-148,946
Other Revenue and Expenses	Q2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-98,443
Total: PPP Undeveloped		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**49,352**	**0**	**0**	**49,352**	**0**	**14,712**	**0**	**0**	**14,712**	**324,286**
Low Estimate Contingent Resources																				
Kibea-01	CR1	0	0	0	0	0	0	0	0	0	948	0	0	948	0	430	0	0	430	17,065

Daily Production, Reserves and Present Value Summary

Entity Description	Reserve Class	2013 Gross Lease Production Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	2013 Company Interest Production Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	Gross Lease Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Company Interest Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Before Tax 10% Dcf Present Value M$
Low Estimate Contingent Resources (Cont.)																				
Kibea-02	CR1	0	0	0	0	0	0	0	0	0	948	0	0	948	0	427	0	0	427	16,385
Kibea-03	CR1	0	0	0	0	0	0	0	0	0	948	0	0	948	0	424	0	0	424	15,605
Kibea-04	CR1	0	0	0	0	0	0	0	0	0	948	0	0	948	0	421	0	0	421	14,812
Kibea-05	CR1	0	0	0	0	0	0	0	0	0	944	0	0	944	0	416	0	0	416	13,964
Kibea-06	CR1	0	0	0	0	0	0	0	0	0	913	0	0	913	0	394	0	0	394	11,991
Well capital	CR1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-55,093
Other Revenue and Expenses	CR1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-33,382
Total: Low Estimate Contingent Resources		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**5,649**	**0**	**0**	**5,649**	**0**	**2,510**	**0**	**0**	**2,510**	**1,348**

BOE Factors:

HVY OIL	1.0	RES GAS	6.0	PROPANE	1.0	ETHANE	1.0
COND	1.0	SLN GAS	6.0	BUTANE	1.0	SULPHUR	0.0

GENERAL

The Kibea Field is located in the Chari East-Doseo Block within the Doseo Basin in southern Chad. Prior to a farm-in agreement (Glencore Farm-in) between Griffiths Energy International Inc. (Griffiths) and Glencore International AG (Glencore), Griffiths held a 100 percent participation in the Production Sharing Contract (PSC) that encompasses the Block. However, it was assumed that the State will back-in a 25 percent participating interest of the Contractor Share as permitted by the PSC. Griffiths would be the Operator of development in the Block. Map 1 illustrates the location of the Field. Chad's participation is expected to occur through the Société des Hydrocarbures du Tchad (SHT), the state oil company of Chad.

The Glencore Farm-in agreement provides for an assignment of one-third of Griffiths' interests in Chad, including the Chari East-Doseo Block, to Glencore. In exchange, Glencore agrees to carry up to 300,000 M$ of development capital associated with the Badila and Mangara Fields. Cash flows presented herein represent Griffiths' remaining interest and include the terms of the Glencore Farm-in agreement. Consequently, the interests presented herein assume an assignment of one-third of Griffiths' original participation to Glencore. That is, the evaluated interest assumes participation as follows:

Griffiths Energy International Inc.	50%
Glencore International AG	25%
SHT	25%

As defined within the PSC, the Republic of Chad's costs are carried proportionately by Griffiths and Glencore.

The Block was previously explored by Esso Exploration and Production Chad Inc. (Esso) primarily from the late 1970s through mid-1980s with the drilling of nine exploration wells. During this exploration phase the Kibea Field was discovered with the Kibea-1 well in 1986.

The well discovered prospective reservoirs in the D and E Cretaceous Sands, which tested varying degrees of oil productivity, with oil quality ranging from 25 to 40ºAPI. The most prolific test from the discovery well was obtained from the Cretaceous E Sand which tested approximately 2200 bopd at approximately 15 percent drawdown.

As of the effective date of this report, no commercial development had occurred in the Chari East-Doseo Block, and it will require substantial infrastructure to support development of the Kibea Field, as well as other prospects in the Block, should they be successfully drilled. Included in the required infrastructure is a pipeline connecting the Chari East-Doseo resources to existing production facilities operated by Esso at Kome, approximately 410 kilometres to the west. From these facilities, produced volumes would be transported via pipeline to the coast of Cameroon where the oil would be shipped to global markets.

Griffiths has indicated its intention to develop the Kibea and Maku Fields in combination.

Reserves were assigned in the proved plus probable and proved plus probable plus possible reserves categories. However, at a P90 level of confidence, the combined recoverable reserves from Kibea and Maku do not provide a sufficiently high rate of return, measured as a positive net present value at 10 percent discount rate. Consequently, no proved reserves were assigned. Low estimate contingent resources were assigned at the P90 confidence level instead of reserves. No best estimate or high estimate contingent resources were assigned, as those volumes are classified as reserves.

GEOPHYSICS

Griffiths has inherited a large seismic database in the order of 22,000 kilometres of data. In general the data has been acquired so that the majority of lines over a prospect are dip lines, which indicates that Esso had a good understanding of the structural orientation in the area. The data varies in quality, both signal-to-noise (S/N) ratio and frequency content. No information on the ages of the data was accessed but presumably the quality of data has improved with time. The data with the broadest frequency spectrum is prefixed by a 'CH', with a spectrum range, 6 db down of 14 Hz to 54 Hz. It is not known if any noise analyses data will be made available to Griffiths, if not the field parameters used to record the 'CH' data would provide a framework and a good starting point for the design of shooting parameters for future field work. The remaining data has a variable range of dominant frequencies, the narrowest range, for 6 db down, being 10-26 Hz. The data set is adequate for structural mapping, but not as suitable for undertaking any stratigraphic analysis. Traditionally, large source and receiver arrays are used in open areas, especially the desert, and these acquisition parameters will preferentially attenuate the higher frequencies. There are some issues with inequalities in T_o (start time of the data), and mismatching in polarities, but these are minor issues and the seismic database can be used to map the structures accurately. The events were tied to the wells using a combination of checkshot data and well log data. Some of the events identified and associated with the main reservoir units do not tie precisely to that particular unit. There is no single event that can be correlated over the entire area; each area has been mapped using events that are most relevant to that area.

Kibea

The Beche/Kibea area is the most easterly area that has been explored on the Doseo Block. The Kibea well encountered oil in the C, B and E Sands, respectively. The seismic data quality in this area is very good, the best of the 2D control. The data is broadband with a high S/N ratio with the main events being easily identified.

At Kibea the oil is trapped by a fault that is downthrown to the south. This fault is relatively low angle, with the fault intersections at D and C levels being shifted to the north. The rollover is greatest at E level and diminishes up section at D and C levels, probably because of detachments in the shale section. Beche is a similar structure, with northern closure at E level being provided by a fault. At D level, the closure is provided by onlap onto a Basement section, with there being a Basement high to the northwest of the Beche structure.

The two way time (TWT) data was converted to depth using a single velocity computed for each level. The structures extend off the Chari East-Doseo Block to the south, so that the accumulation is not entirely on the Griffiths lands.

GEOLOGY

The Griffiths PSCs include blocks within two geologic basins in Chad, the Doba and Doseo Basins. These basins are separated by an area termed the Borogop uplift which is a large inversion anticlinal trend and is part of the Central African Rift trend, a continental plate boundary crossing through Chad from the Sudan to Cameroon.

The Doba and Doseo Basins were formed as rift basins in the Early Cretaceous (84-144 Ma). The Doba Basin formed as a series of northwest to southwest trending half grabens. The Doseo Basin formed as a large asymmetrical basin with a northwest to southeast oriented rift faulted relay series. The Borogop uplift is the steeply lifted basin edge fault zone which separates the basins.

Geologic sedimentation occurred during the Aptian through Conician when the two basins underwent a thermal sag phase which provided accommodation space for sediments. It is noteworthy that thermal events also include a phase of sill intrusion dating 97-100 Ma. Sills have been found and sampled along the northern flank of the Doseo Basin.

The Cretaceous provides the multiple reservoirs which have been tested in the two basins. The Cretaceous E interval consists of sediments sourced by axial transport from the east. Sediments drained generally to the west towards Doba and probably ultimately exited the Doba Basin through the Yola arm of the Benue trough and then onto the south to the Benue forming the proto Niger Delta. The top of the E Sequence is bounded by the D Sequence Boundary (DSB) and is generally a very good high amplitude seismic marker. The Cretaceous D Sequence is a continuation of the same non-marine fluvial and deltaic lacustrine facies as observed in the E Sequence. The Cretaceous C zone overlies the D sequence and is also composed of fluvial, lacustrine, and deltaic sediments.

The traps evaluated for this work were all four way closed structure, whilst source rocks are provided by the prevalent lacustrine sediments deposited throughout both basins.

Kibea Field

The oil initially-in-place (OIIP) for the Kibea Field has been determined by volumetric analysis using a partially probalistic method. The following is a discussion of the methodology and input parameters.

Petrophysical Analysis

GLJ conducted a review of petrophysical analysis prepared by Griffiths. This showed it to be broadly similar to earlier studies undertaken by Esso, RPS Group and Ryder Scott. It was decided to define a range of rock properties for the key reservoir units by utilizing a range of low, most likely and high case cutoffs. For the Kibea Field GLJ used "most likely" cutoffs of 7.0 percent porosity and a 60.0 percent water saturation to define wellbore parameters. Low case and high case parameters were also determined by applying different cutoffs.

Mapping

The seismic quality is good over the Kibea structure but quite sparse at about a 1.75 kilometre spacing at the Kibea-1 well. A review of the Griffiths interpretation was undertaken to confirm the validity of the depth mapping. GLJ used the provided depth map for the C Flooding Surface (CFS) event to map the reservoirs for the calculation of Gross Rock Volumes for the assignment of contingent resources.

Oil-Water Contacts

The Kibea-1 well was tested in the D and E Sands, but only the bottom two E Sands tested at good rates. Both sands have oil on rock with no identified oil-water contacts (OWC). Depth maps were generated for these two sands and are discussed below.

Main E Sand Reservoir

The Main E Sand is a 30.8 metre thick sand with a lowest known hydrocarbon (LKH) logged at -2558.2 metres, this contact was used for the proved oil-initially-in-place (OIIP) calculation. The mapped spill point is interpreted to be at -2640 metres and this was used for the P05 OIIP calculation (Map 2).

Lower E Sand Reservoir

The Lower E Sand is an 8.5 metre thick sand with an LKH logged at -2584.6. This contact was used for the proved OIIP calculation. The mapped spill point is interpreted to be at -2690 metres and this was used for the P05 OIIP calculation (Map 3).

RESERVES, RESOURCE AND PRODUCTION FORECAST

The key points of interest in the evaluation are discussed below.

Well Tests

The well tests conducted on the Kibea-1 well are summarized in the following Figure:

Sand	Test 1	Test 2	Test 2A	Test 3	Test 3A	Test 3B	Test 4	Test 4A
D Sand (Top 2767.94 mMD)							2768.2-2777.0 mMD 61bopd / 25°API 0.2% WCT	2768.2-2777.0 2788.9-2796.2 mMD 27 bopd / 27°API <0.1% WCT
D Sand (Top 2784.87 mMD)								
E Sand (Top 2857.15 mMD)				2857.2-2865.7 mMD 38 bopd / 41°API <0.1% WCT	2857.2-2865.7 2891.3-2900.5 mMD 43bopd / 35°API 0.7% WCT	2857.2-2865.7 2891.3-2900.5 2905.4-2914.8 mMD 51 bopd / 30°API <0.1% WCT		
E Sand (Top 2890.81 mMD)								
E Sand (Top 2905.30 mMD)								
E Sand (Top 2930.43 mMD)		2932.2-2946.2 mMD 1310 bopd / 35°API 0.2% WCT	2932.2-2946.2 2946.8-2959.3 mMD 2196 bopd / 34°API <0.1% WCT					
E Sand (Top 2979.13 mMD)	2982.2-2987.0 mMD 450 bopd / 33°API 0.3% WCT							

Figure 1 – Kibea Test Summary

Based on Repeat Formation Test (RFT) data obtained upon the drilling of the discovery well, all prospective sands are normally pressured. RFT results are presented in Figure 2 below.

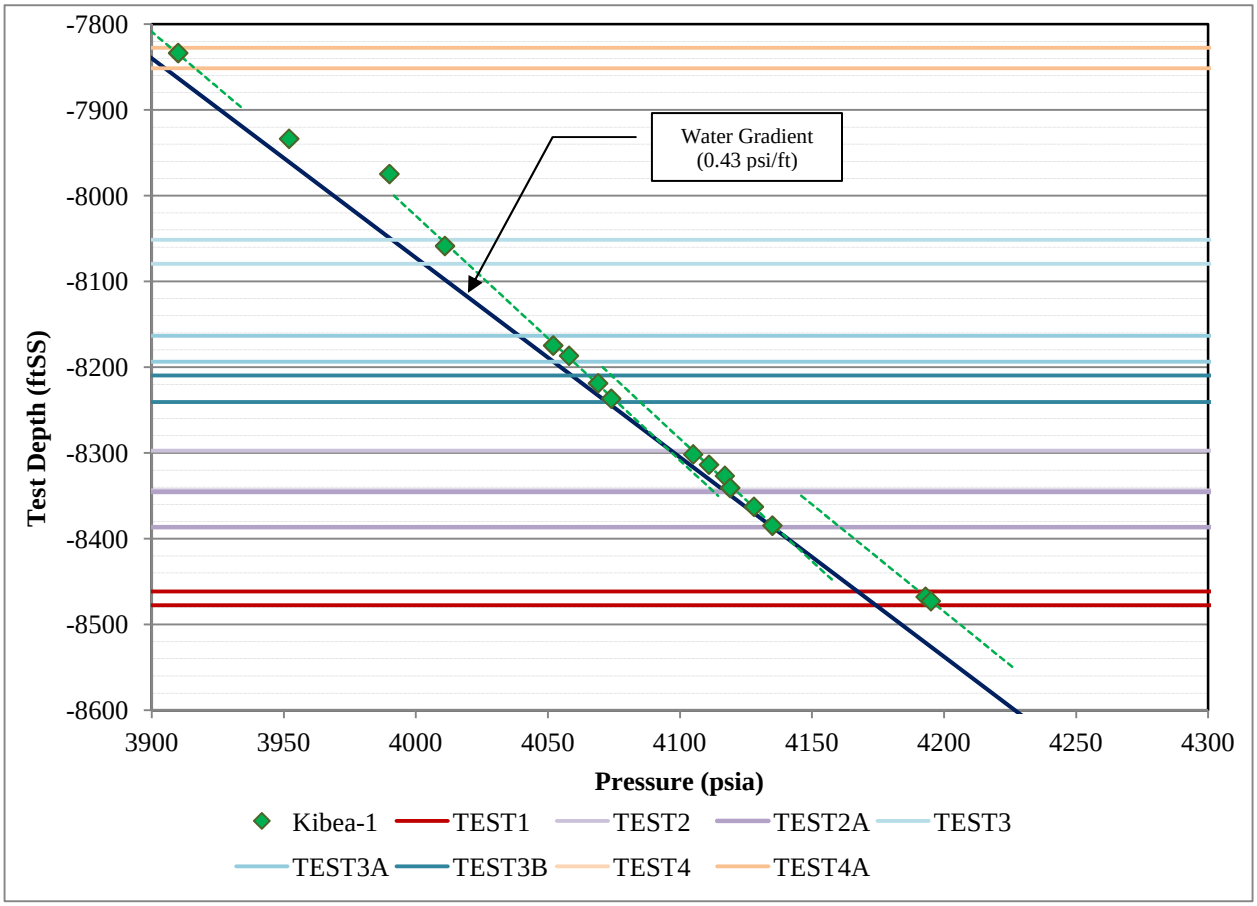


Figure 2 – Kibea-1 RFT data.

Based on the limited gas production shown during the well tests, and a lack of evidence of gas on open hole logs, no gas cap has been identified by GLJ on any of the respective sands.

Fluid Properties

No detailed Pressure Volume Temperature (PVT) analysis was available from the initial tests at Kibea-1, aside from reported oil gravity measurements. Test 1 reported an initial gas-oil ratio (GOR) of 30 scf/bbl from bottom-hole samples, however this value would imply the oil is substantially undersaturated and though possible, GLJ considers this to be highly unlikely. Therefore, we applied the formation volume factor of 1.4 derived from standard correlations.

Oil Initially-in-Place

For the two sands which tested at the strongest rates, Main E Sand (Top 2979.13 mMD) and Lower E Sand (Top 2930.43 mMD), OIIP estimates for the P90, P50 and P10 confidence levels were prepared as follows.

P90 and P05 estimates of OIIP were estimated volumetrically based on mapped rock volumes down to LKH and filled to spill mapped volumes, respectively. These maps were based on extensive 2D seismic data. These volumes are summarized on Table 2.1 and presented as Plot 3 and 4 on a Probit Scale. From this depiction, P90, P50 and P10 volumes were interpolated for the low, estimate contingent resource and proved plus probable and proved plus possible reserves categories.

The remaining E and D Sands which tested at poor rates and indicated limited permeability were not assigned reserves or contingent resources. It is expected that adequate depletion of these zones would require independent wellbores and expected rates and recoverable from these zones are likely to be inadequate to recover invested capital.

Recovery Factor

For the lowest tested E Sand, recovery factors of 15, 25 and 30 percent were assigned to the P10, P50 and P90 reserves categories, respectively. The Main E Sand target was assigned recovery factors of 20, 25 and 35 percent for the same respective categories. The recovery factors assigned assume enhanced recovery is conducted through waterflood to various degrees of effectiveness. The Lower E Sand recovery was reduced from that assigned to the Main E due to slightly poorer reservoir quality. All parameters are presented in Table 2.1.

Production and Development Forecast

Construction of the main pipeline and drilling of the initial production wells are forecast to commence in 2013 to allow for first oil production in January 2015. Continued development is forecast through to 2017 (in the proved plus probable plus possible case). Forecast annual production volumes are presented in Tables 3 and 3.1 and are shown as Plots 1 and 2.

ECONOMIC ANALYSIS

Economic parameters, including operating costs, development capital, product pricing and abandonment costs, are presented in Tables 4, 4.1 and 4.2.

Well operating costs were estimated at $10,000 per well/month. Variable costs for oil were estimated at $3.00/bbl. Fixed operating costs include a component for General and Administrative (G&A) costs, as well as facilities operating costs. The G&A costs were scheduled because they can be recovered as cost oil. G&A costs were scheduled from the effective date of the analysis and scaled to production and reserves volumes. Facility operating costs were scheduled from first production. Costs were derived from information provided by Griffiths.

In addition to development capital associated with drilling and development within the Kibea Field a portion of total pipeline costs were allocated to the Kibea Field. Specifically, 41.5 percent of the pipeline costs were allocated to Kibea and Maku, with the remaining 58.5 percent allocated to the associated East Doseo ITA. Of the pipeline costs allocated to Kibea and Maku, 70 percent were allocated to Kibea.

Griffiths' interest in Chad are economic interests earned through participation in PSCs. Currently, Griffiths' and Glencore's participation in the PSCs is 100 percent, however, the terms of the PSCs allow the government of Chad to back-in to a 25 percent participation as its option. This evaluation assumes that the option to back-in is exercised by the government of Chad. The PSC was modelled assuming that Griffiths and Glencore have a 75 percent participation in the PSC. In addition, it was assumed, as permitted by the terms of the PSC, that Griffiths and Glencore will carry the capital, operating and abandonment costs of the government Chad's 25 percent participation. This carried capital is cost recoverable.

As is typical of the PSCs, Griffiths' economic interest in the gross lease recoverable resources was based on the sum of cost oil and profit oil earned from total revenue. No net royalty is deducted from Griffiths' interest oil in such circumstances. Therefore, Griffiths' gross and net resources were equal. In addition, the terms of the PSC preclude the payment of income tax by Griffiths. Consequently, the before tax and after tax cash flow are also equal.

Key parameters of the PSC are:

- State Back-in Participation: 25%
- State "Royalty" Oil: 14.25%

- Participation in Profit Oil:

R Factor	Contractor Share
≤ 2.25	60%
> 2.25 & ≤ 3.00	50%
> 3.00	40%

- R Factor Numerator: Contractor revenue less operating costs and abandonment allocation.
- R Factor Denominator: Contractor capital costs and recovered exploration costs.
- Abandonment Cost Allocation: Well abandonment costs prorate per fraction of reserves produced.
- No income taxes levied.
- PSC participants carry costs associated with the 25 percent Government of Chad participation. Carried costs are cost recoverable.
- $10,000,000 of signature bonus expenditure recoverable.
- $2,000,000 bonus payable by contractors to Chad included as “Other Income”. The bonus is not cost recoverable.

Commodity Prices

Oil prices were estimated to be 95 percent of Brent prices, less a $6.50 per barrel transportation fee for the Cameroon to Chad export pipeline less the ITA tariff. The ITA tariff varies in each reserves class. Details on the ITA tariff for Kibea and Maku are presented in the report in the ITA East Doseo report.

Solution gas is considered unmarketable and it was assumed all solution gas would be flared, used as fuel or re-injected.

Other Economic Considerations

This report does not address the following issues:

- Non-resource well abandonment, wellsite reclamation and facility abandonment/salvage including possible environmental concerns.
- Potential processing income.
- The current condition of field, gathering and processing facilities, i.e. an inspection was not carried out.

PSC Parameters - Kibea

Griffiths Energy International Inc (Griffiths) has entered into a Production Sharing Contract with the Republic of Chad.
Key parameters in the economic model* are as follows:

	Griffiths	Glencore	Chad	Comment
Participation	50.00%	25.00%	25.00%	Assumes Chad exercises right to back in for 25% participation
Carry	16.67%	8.33%		Griffiths and Glencore carry 25% of total capital, operating and abandonment costs
Lease Expiry	Dec-36			10 year extension permitted and included in 2P and 3P cases
Oil Royalty	14.25%			Deducted from lease revenue, prior to cost oil and profit oil calculation
Gas Royalty	5%			Deducted from lease revenue, prior to cost oil and profit oil calculation

Allocation of Profit Oil

R Factor		Griffiths	Glencore	SHT	Chad	
Profit Oil Share	$R \leq 2.25$	30%	15%	15%	40%	
Profit Oil Share	$2.25 < R \leq 3.00$	25%	13%	13%	50%	
Profit Oil Share	$R > 3$	20%	10%	10%	60%	
Numerator						Cumulative Contractor Revenue less Cumulative Operating costs and Cumulative Abandonment Costs
Denominator						Contractor Capital and Recovered Exploration Costs
Abandonment Costs		UOP	UOP			Abandonment costs recovered on a Unit of Production Basis, Chad costs carried by Griffiths and Glencore.
Bonus		$ 1,333,333	$ 666,667			Remaining Bonus payable to Chad government. Not cost recoverable.

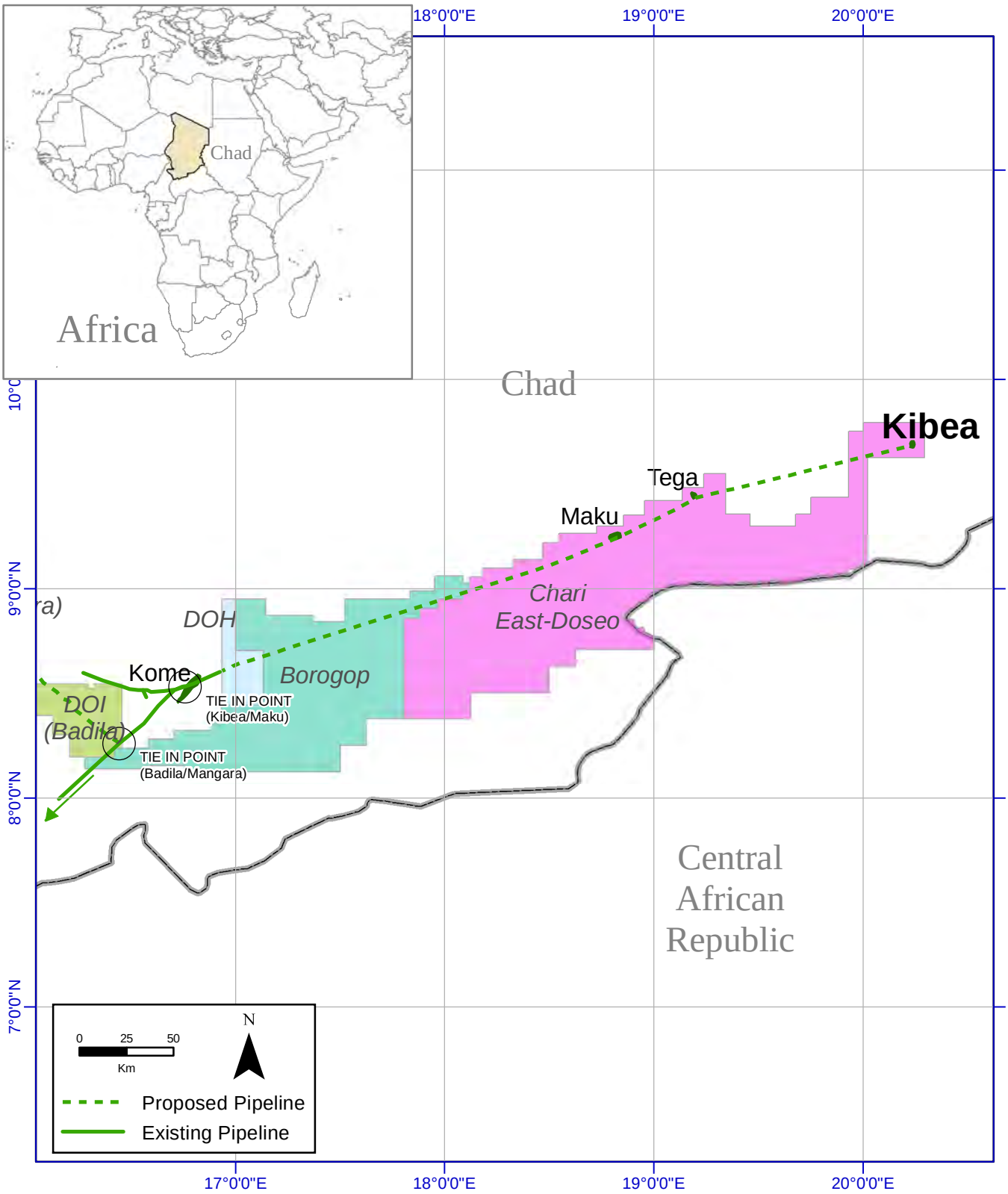
Opening Balances of Recoverable Costs		
Signature Bonus Recoverable	$ 10,000,000	Recoverable Portion of $40,000,000 Signature Bonus
Exploration	$ 0	
Capital Costs	$ 0	

*The economic model used in this report assume that the proposed transaction with Glencore International AG will occur
SHT is the *Société des Hydrocarbures du Tchad* , the state oil company of Chad.

Map 1
Land Map
Kibea

Company: Griffiths Energy International Inc.
Property: Kibea

Effective Date: December 31, 2012
Scale: 1:3,000,000 s1132107/kibm01

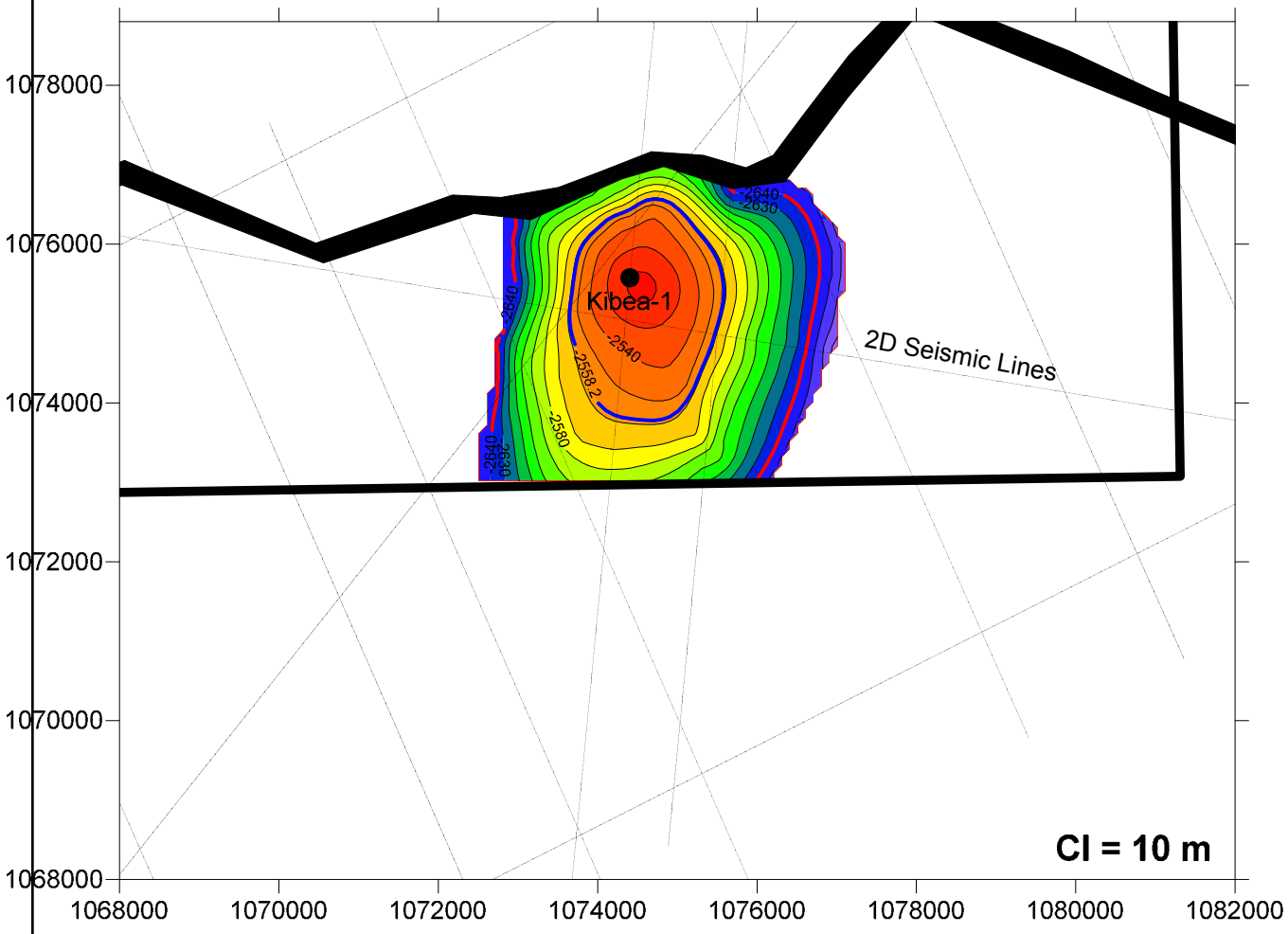


GLJ Petroleum Consultants

Map 2
Kibea Field
Depth Structure Map (metres)
Main E Sand

Company: Griffiths Energy International Inc.
Property: Kibea

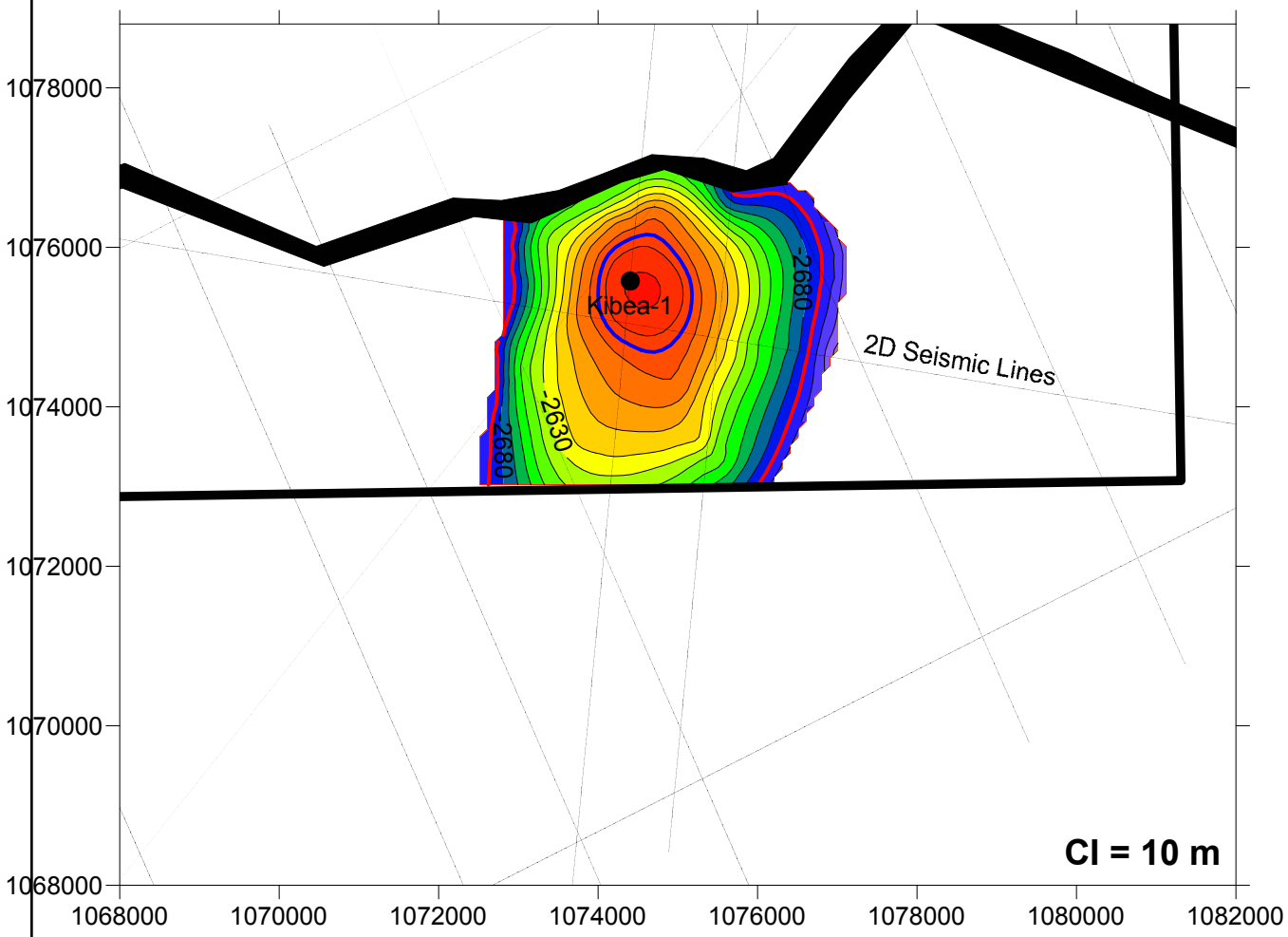
Effective Date: December31, 2012
Scale: 1:90,000 s1132107



Map 3
Kibea Field
Depth Structure Map (metres)
Lower E Sand

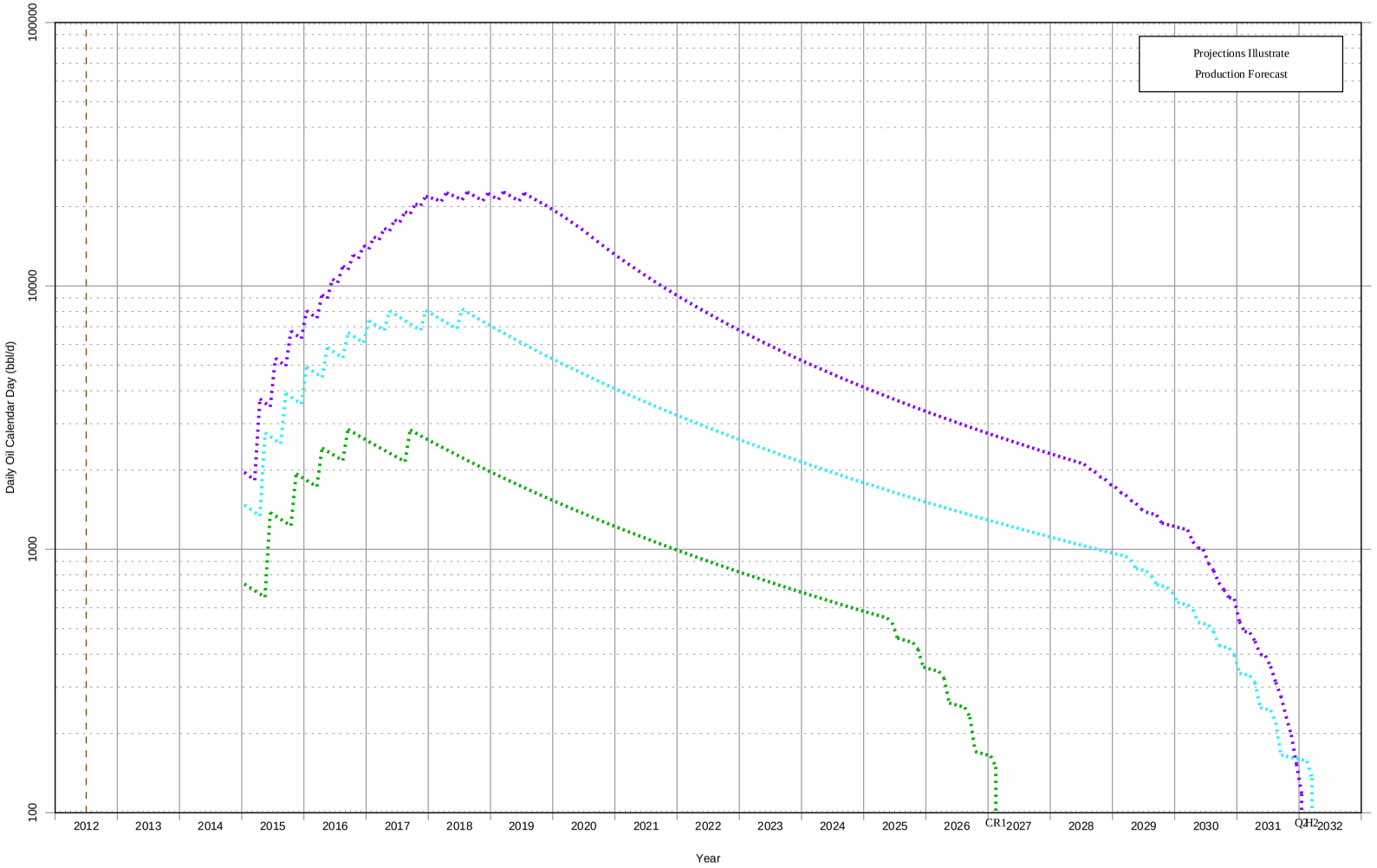
Company: Griffiths Energy International Inc.
Property: Kibea

Effective Date: December 31, 2012
Scale: 1:90,000 s1132107



Historical and Forecast Production
Kibea - Total Property

Property : Kibea



Total Reserves Summary @ 2012/07/01

Reserves Classification		Reserves (Mbbl) Ultimate	Cum Production	Remaining
P + P UDev	H2(R)	18835	0	18835
PPP UDev	Q2(R)	49510	0	49510
Low Estimate ...	CR1(R)	5687	0	5687

Average Production Rates (Last 12 months ending 2012/07/01)

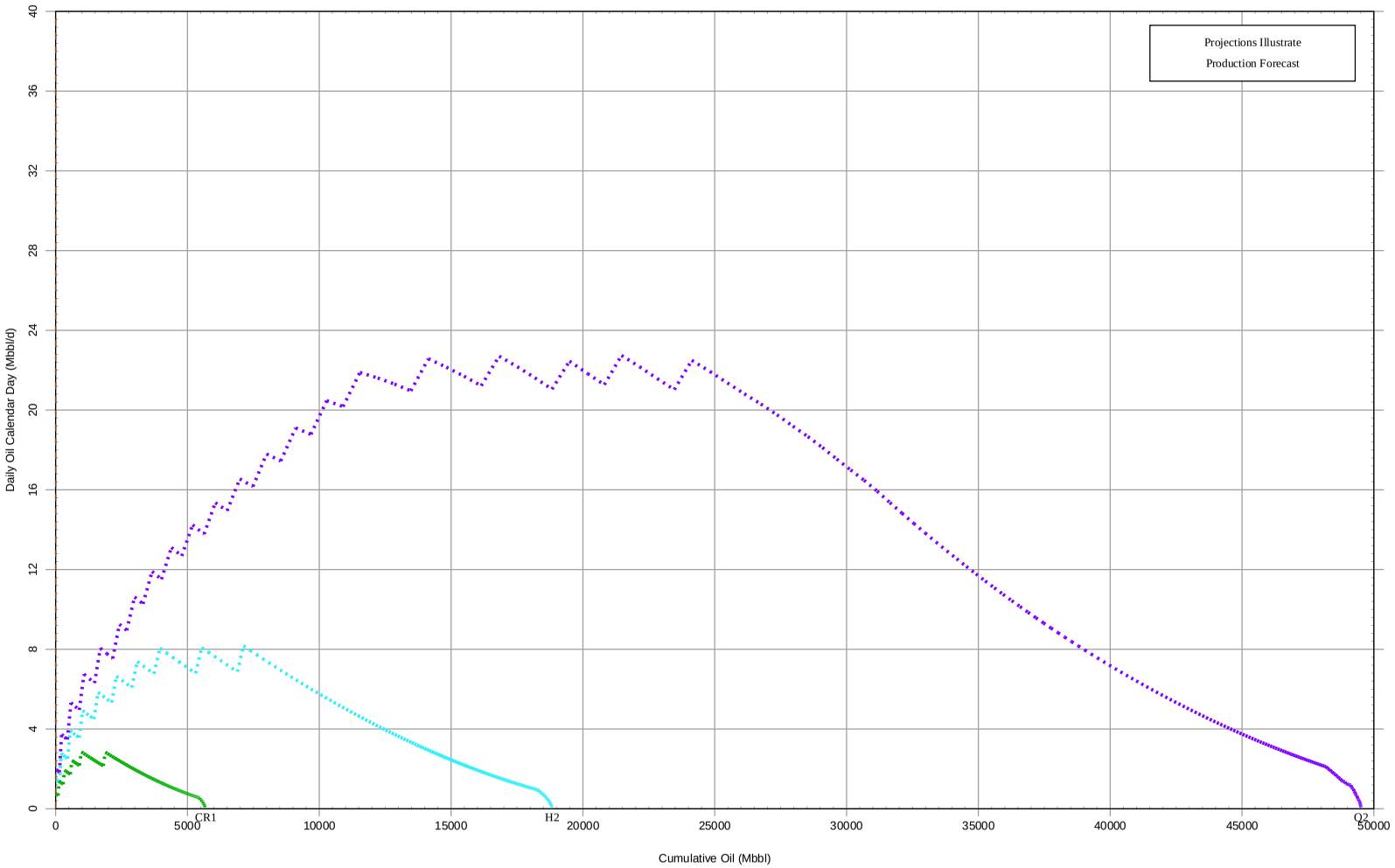
Gas :	0.0 Mcf/d	0.0 Mcf/cd	WGR :	0.0 bbl/MMcf
Oil :	0.0 bbl/d	0.0 bbl/cd	GOR :	0.0 scf/bbl
On Prod :	0.0 days		WC :	0.0 %

Cumulative Production

Oil :	0.0 Mbbl	Gas :	0.0 MMcf	Water :	0.0 Mbbl

Historical and Forecast Production
Kibea - Total Property

Property : Kibea



Total Reserves Summary @ 2012/07/01

Reserves Classification		Reserves (Mbbl) Ultimate	Cum Production	Remaining
P + P UDev	H2(R)	18835	0	18835
PPP UDev	Q2(R)	49510	0	49510
Low Estimate ...	CR1(R)	5687	0	5687

Average Production Rates (Last 12 months ending 2012/07/01)

Gas :	0.0 Mcf/d	0.0 Mcf/cd	WGR :	0.0 bbl/MMcf
Oil :	0.0 bbl/d	0.0 bbl/cd	GOR :	0.0 scf/bbl
On Prod :	0.0 days		WC :	0.0 %

Cumulative Production

Oil :	0.0 Mbbl	Gas :	0.0 MMcf	Water :	0.0 Mbbl

Last Month of Data: **Alta.:** 2012-11 **Sask.:** 2012-11 **B.C.:** 2012-11 **Man.:** 2012-10

Well List and Production Summary

#	Well Location	Regulatory Field Pool	Current Status	RigRel yr-mm	Production Dates First yr-mm	Last yr-mm	Inj yr-mm	Last Quarter Production Statistics Prod Days	Oil bbl/d	Gas Mcf/d	GOR scf/bbl	WGR bbl/MMcf	WC %	Cumulative Production Oil Mbbl	Gas MMcf	Water Mbbl
1	KIBEA-1			1986-05				0	0	0				0	0	0
	Total								**0**	**0**				**0**	**0**	**0**

Table 2

Company: **Griffiths Energy International Inc.**
Property: **Kibea**
Currency: **$US Dollars**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Gross Lease Reserves Summary

Entity Description	Reserve Class	Methodology	Oil (Mbbl) Initial Recoverable	Oil (Mbbl) Cumulative Production	Oil (Mbbl) Reserves	Non-Associated Gas (MMcf) Initial Recoverable	Non-Associated Gas (MMcf) Cumulative Production	Non-Associated Gas (MMcf) Raw Gas	Non-Associated Gas (MMcf) Reserves	Other Gross Lease Reserves Sol'n Gas MMcf	Other Gross Lease Reserves Cond Mbbl	Other Gross Lease Reserves LPG Mbbl	Other Gross Lease Reserves Sulphur Mlt
Proved Plus Probable Undeveloped													
Kibea-01	H2	Dec	1,884	0	1,884	0	0	0	0	0	0	0	0
Kibea-02	H2	Dec	1,884	0	1,884	0	0	0	0	0	0	0	0
Kibea-03	H2	Dec	1,884	0	1,884	0	0	0	0	0	0	0	0
Kibea-04	H2	Dec	1,884	0	1,884	0	0	0	0	0	0	0	0
Kibea-05	H2	Dec	1,884	0	1,884	0	0	0	0	0	0	0	0
Kibea-06	H2	Dec	1,884	0	1,884	0	0	0	0	0	0	0	0
Kibea-07	H2	Dec	1,884	0	1,884	0	0	0	0	0	0	0	0
Kibea-08	H2	Dec	1,884	0	1,875 *	0	0	0	0	0	0	0	0
Kibea-09	H2	Dec	1,884	0	1,858 *	0	0	0	0	0	0	0	0
Kibea-10	H2	Dec	1,879	0	1,835 *	0	0	0	0	0	0	0	0
Total: Proved Plus Probable Undeveloped			**18,835**	**0**	**18,756 ***	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
PPP Undeveloped													
Kibea-01	Q2	Dec	2,358	0	2,358	0	0	0	0	0	0	0	0
Kibea-02	Q2	Dec	2,358	0	2,358	0	0	0	0	0	0	0	0
Kibea-03	Q2	Dec	2,358	0	2,358	0	0	0	0	0	0	0	0
Kibea-04	Q2	Dec	2,358	0	2,354 *	0	0	0	0	0	0	0	0
Kibea-05	Q2	Dec	2,358	0	2,347 *	0	0	0	0	0	0	0	0
Kibea-06	Q2	Dec	2,358	0	2,340 *	0	0	0	0	0	0	0	0
Kibea-07	Q2	Dec	2,358	0	2,335 *	0	0	0	0	0	0	0	0
Kibea-08	Q2	Dec	2,358	0	2,330 *	0	0	0	0	0	0	0	0
Kibea-09	Q2	Dec	2,358	0	2,325 *	0	0	0	0	0	0	0	0
Kibea-10	Q2	Dec	2,358	0	2,319 *	0	0	0	0	0	0	0	0
Kibea-11	Q2	Dec	2,358	0	2,358	0	0	0	0	0	0	0	0
Kibea-12	Q2	Dec	2,358	0	2,358	0	0	0	0	0	0	0	0
Kibea-13	Q2	Dec	2,358	0	2,358	0	0	0	0	0	0	0	0
Kibea-14	Q2	Dec	2,358	0	2,358	0	0	0	0	0	0	0	0
Kibea-15	Q2	Dec	2,358	0	2,358	0	0	0	0	0	0	0	0
Kibea-16	Q2	Dec	2,358	0	2,358	0	0	0	0	0	0	0	0
Kibea-17	Q2	Dec	2,358	0	2,358	0	0	0	0	0	0	0	0
Kibea-18	Q2	Dec	2,358	0	2,358	0	0	0	0	0	0	0	0
Kibea-19	Q2	Dec	2,358	0	2,358	0	0	0	0	0	0	0	0
Kibea-20	Q2	Dec	2,358	0	2,358	0	0	0	0	0	0	0	0
Kibea-21	Q2	Dec	2,350	0	2,348 *	0	0	0	0	0	0	0	0
Total: PPP Undeveloped			**49,510**	**0**	**49,352 ***	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Low Estimate Contingent Resources													
Kibea-01	CR1	Dec	948	0	948	0	0	0	0	0	0	0	0
Kibea-02	CR1	Dec	948	0	948	0	0	0	0	0	0	0	0
Kibea-03	CR1	Dec	948	0	948	0	0	0	0	0	0	0	0
Kibea-04	CR1	Dec	948	0	948	0	0	0	0	0	0	0	0
Kibea-05	CR1	Dec	948	0	944 *	0	0	0	0	0	0	0	0
Kibea-06	CR1	Dec	947	0	913 *	0	0	0	0	0	0	0	0
Total: Low Estimate Contingent Resources			**5,687**	**0**	**5,649 ***	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Notes
1. [*] Remaining reserves are less than the estimate due to economic limit.

Table 2.1
Oil Reservoir Parameters
Kibea
Effective Date: December 31, 2012

Description	Zone	Area (acres)	Net Pay (feet)	GRV (acre-ft)	NTG	NRV (acre-ft)	Porosity	Water Satur'n	Formation Volume Factor	Original Oil-In-Place (mstb)	Recovery Factor	Original Recoverable Reserves (mstb)	Cumulative Oil Prod'n to 12-12-31 (mstb)	Remaining Reserves (mstb)
P90	Lower E	329	13.2	6019	0.723	4352	11.4%	26.1%	1.4	2032				
P05	Lower E	3443	25.0	92834	0.928	86150	10.6%	30.1%	1.4	35439				
P90	Main E	1013	52.1	55886	0.945	52787	11.5%	20.0%	1.4	26911				
P05	Main E	3409	86.4	305373	0.964	294483	11.5%	20.5%	1.4	148544				
P90	Lower E									2032	15.0%	305	0	
P50	Lower E	860	18.8	19695	0.819	16139	11.0%	28.0%	1.4	7106	25.0%	1777	0	
P10	Lower E	2465	24.3	65452	0.916	59950	10.7%	29.9%	1.4	24851	30.0%	7455	0	
P90	Main E									26911	20.0%	5382	0	
P50	Main E	1643	68.2	117520	0.954	112098	11.5%	20.2%	1.4	56864	30.0%	17059	0	
P10	Main E	2822	84.4	247159	0.963	238058	11.5%	20.5%	1.4	120157	35.0%	42055	0	
Low Estimate Contingent Resources										28943	19.6%	5687	0	5687
Proved plus Probable Undeveloped Reserves										63970	29.4%	18836	0	18836
Proved plus Probable plus Possible Undeveloped Reserves										145008	34.1%	49510	0	49510

Note: For P10 and P50 cases:

- Net Pay, NTG, Porosity, Water Saturation, and FVF are linearily interpolated from the P05 and P90 parameters
- NRV is back-calculated from the OOIP using interpolated parameters
- GRV is back-calculated from NRV using the interpolated NTG value
- Area is back-calculated from NRV using the interpolated Net Pay value

Table 2.2
KIBEA-1
SUMMARY OF PETROPHYSICAL ANALYSIS

Kibea-1 Zones	Datum (ft)	Top MD, ft	Base MD, ft	Gross Thickness tvd, ft	Low Case (P90)				P05 Case			
					Net Oil (ft)	NTG	Phi	Sw	Net Oil (ft)	NTG	Phi	Sw
Top E Sand Pt3A&B	1322	9374	9402	28.2	23.5	***0.83***	12.5%	37%	27.3	***0.97***	11.9%	39%
Top E Sand Pt3A&B -2	1322	9484	9517	33.1	8.8	***0.26***	11.4%	33%	9.6	***0.29***	11.3%	35%
Top E Sand Pt3B	1322	9532	9564	32.0	4.72	***0.15***	11.7%	46%	7.09	***0.22***	11.6%	51%
Top E Sand Pt2 (Main)	1322	9614	9715	101.1	29.1	***0.29***	11.5%	20%	29.7	***0.29***	11.5%	21%
Top E Sand Pt1 (Lwr)	1322	9774	9802	28.0	6.2	***0.22***	11.4%	26%	7.9	***0.28***	10.6%	30%

Table 3

Company: **Griffiths Energy International Inc.**
Property: **Kibea**
Currency: **$US Dollars**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Gross Lease Daily Oil Production

Entity Description	Reserve Class	Year (bbl/d) 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Totals (Mbbl) Subtotal	Remainder	Total
Proved Plus Probable Undeveloped																
Kibea-01	H2	0	0	1,245	879	645	491	383	307	249	206	173	147	1,725	159	1,884
Kibea-02	H2	0	0	886	981	710	535	415	330	266	219	183	155	1,708	176	1,884
Kibea-03	H2	0	0	470	1,104	788	586	451	356	285	234	194	164	1,690	194	1,884
Kibea-04	H2	0	0	0	1,248	876	645	491	384	306	249	206	173	1,672	212	1,884
Kibea-05	H2	0	0	0	886	979	711	535	416	329	266	219	184	1,652	232	1,884
Kibea-06	H2	0	0	0	470	1,101	788	587	452	355	286	234	195	1,631	253	1,884
Kibea-07	H2	0	0	0	0	1,245	877	645	492	383	307	250	207	1,608	276	1,884
Kibea-08	H2	0	0	0	0	886	979	711	537	415	329	266	220	1,585	290	1,875
Kibea-09	H2	0	0	0	0	125	1,206	853	631	480	376	301	246	1,540	318	1,858
Kibea-10	H2	0	0	0	0	0	686	1,036	748	558	431	341	276	1,488	348	1,835
Total: Proved Plus Probable Undeveloped		**0**	**0**	**2,600**	**5,568**	**7,356**	**7,504**	**6,107**	**4,654**	**3,628**	**2,903**	**2,367**	**1,966**	**16,298**	**2,458**	**18,756**
PPP Undeveloped																
Kibea-01	Q2	0	0	1,633	1,119	802	599	462	366	294	241	201	169	2,148	210	2,358
Kibea-02	Q2	0	0	1,289	1,222	866	642	491	387	309	253	210	177	2,134	224	2,358
Kibea-03	Q2	0	0	906	1,341	939	690	524	410	326	265	219	184	2,119	239	2,358
Kibea-04	Q2	0	0	477	1,478	1,022	743	560	435	345	279	230	192	2,103	251	2,354
Kibea-05	Q2	0	0	0	1,636	1,115	802	599	463	365	294	241	201	2,086	261	2,347
Kibea-06	Q2	0	0	0	1,289	1,219	867	643	493	386	310	253	210	2,069	271	2,340
Kibea-07	Q2	0	0	0	1,037	1,297	915	674	514	401	321	261	217	2,058	277	2,335
Kibea-08	Q2	0	0	0	767	1,382	967	707	537	417	333	270	224	2,045	285	2,330
Kibea-09	Q2	0	0	0	477	1,475	1,023	743	562	434	345	279	231	2,033	292	2,325
Kibea-10	Q2	0	0	0	167	1,577	1,083	782	587	452	358	289	238	2,020	300	2,319
Kibea-11	Q2	0	0	0	0	1,830	1,579	933	605	416	302	227	176	2,215	143	2,358
Kibea-12	Q2	0	0	0	0	1,507	1,703	1,009	646	440	317	237	183	2,205	153	2,358
Kibea-13	Q2	0	0	0	0	1,173	1,812	1,097	692	467	334	248	191	2,195	163	2,358
Kibea-14	Q2	0	0	0	0	838	1,900	1,196	744	497	352	260	199	2,185	173	2,358
Kibea-15	Q2	0	0	0	0	504	1,962	1,308	800	529	372	273	208	2,174	184	2,358
Kibea-16	Q2	0	0	0	0	170	1,995	1,435	863	564	393	287	217	2,163	195	2,358
Kibea-17	Q2	0	0	0	0	0	1,507	1,703	1,011	644	441	317	238	2,139	219	2,358
Kibea-18	Q2	0	0	0	0	0	838	1,899	1,197	739	495	351	260	2,110	248	2,358
Kibea-19	Q2	0	0	0	0	0	170	1,995	1,438	860	563	392	287	2,082	276	2,358
Kibea-20	Q2	0	0	0	0	0	0	1,677	1,645	967	622	427	309	2,061	297	2,358
Kibea-21	Q2	0	0	0	0	0	0	1,008	1,863	1,140	711	478	341	2,023	325	2,348
Total: PPP Undeveloped		**0**	**0**	**4,305**	**10,533**	**17,717**	**21,797**	**21,446**	**16,258**	**10,994**	**7,900**	**5,951**	**4,652**	**44,367**	**4,985**	**49,352**
Low Estimate Contingent Resources																
Kibea-01	CR1	0	0	634	463	349	271	215	175	144	120	102	87	934	14	948
Kibea-02	CR1	0	0	397	526	390	300	236	190	155	129	109	93	922	26	948
Kibea-03	CR1	0	0	122	601	440	334	260	208	169	139	117	99	908	40	948
Kibea-04	CR1	0	0	0	497	498	373	288	228	184	151	125	106	894	54	948
Kibea-05	CR1	0	0	0	236	568	419	320	251	200	163	135	114	879	65	944
Kibea-06	CR1	0	0	0	0	236	568	419	320	250	200	163	135	837	76	913
Total: Low Estimate Contingent Resources		**0**	**0**	**1,154**	**2,323**	**2,481**	**2,264**	**1,738**	**1,373**	**1,102**	**903**	**751**	**634**	**5,374**	**275**	**5,649**

Table 3.1

Company: **Griffiths Energy International Inc.**
Property: **Kibea**
Currency: **$US Dollars**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Company Daily Oil Production

Entity Description	Reserve Class	Year (bbl/d)												Totals (Mbbl)		
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Subtotal	Remainder	Total
Proved Plus Probable Undeveloped																
Kibea-01	H2	0	0	594	420	308	141	109	86	63	53	46	40	679	43	722
Kibea-02	H2	0	0	423	468	339	154	118	92	68	57	48	42	660	48	708
Kibea-03	H2	0	0	224	527	376	169	128	99	72	60	51	44	640	53	692
Kibea-04	H2	0	0	0	596	418	186	139	107	78	65	55	47	617	59	676
Kibea-05	H2	0	0	0	423	467	205	152	116	83	69	58	50	593	65	657
Kibea-06	H2	0	0	0	224	526	227	167	126	90	74	62	53	565	71	637
Kibea-07	H2	0	0	0	0	594	253	183	137	97	79	66	56	535	80	616
Kibea-08	H2	0	0	0	0	423	282	202	150	105	85	71	60	503	85	587
Kibea-09	H2	0	0	0	0	60	348	243	176	122	97	80	67	435	93	528
Kibea-10	H2	0	0	0	0	0	198	295	209	142	111	90	75	408	101	510
Total: Proved Plus Probable Undeveloped		**0**	**0**	**1,241**	**2,658**	**3,511**	**2,164**	**1,737**	**1,299**	**920**	**751**	**626**	**533**	**5,635**	**697**	**6,332**
PPP Undeveloped																
Kibea-01	Q2	0	0	779	534	351	168	116	86	61	52	45	39	815	57	872
Kibea-02	Q2	0	0	615	583	380	180	123	91	65	55	47	41	796	62	858
Kibea-03	Q2	0	0	433	640	412	194	131	96	68	57	49	43	775	67	842
Kibea-04	Q2	0	0	228	706	448	208	140	102	72	60	51	45	752	71	823
Kibea-05	Q2	0	0	0	781	489	225	150	109	76	63	54	47	728	73	801
Kibea-06	Q2	0	0	0	615	534	243	161	116	81	67	57	49	702	76	778
Kibea-07	Q2	0	0	0	495	568	257	169	121	84	69	58	50	683	78	761
Kibea-08	Q2	0	0	0	366	606	271	177	126	87	72	60	52	664	80	743
Kibea-09	Q2	0	0	0	228	646	287	186	132	91	74	62	54	643	82	725
Kibea-10	Q2	0	0	0	80	691	304	196	138	95	77	65	55	621	84	705
Kibea-11	Q2	0	0	0	0	802	443	234	142	87	65	51	41	681	37	717
Kibea-12	Q2	0	0	0	0	660	478	253	152	92	68	53	43	657	39	696
Kibea-13	Q2	0	0	0	0	514	509	275	163	98	72	56	44	631	42	673
Kibea-14	Q2	0	0	0	0	367	533	300	175	104	76	58	46	606	45	650
Kibea-15	Q2	0	0	0	0	221	551	328	188	111	80	61	48	579	48	627
Kibea-16	Q2	0	0	0	0	74	560	360	203	118	85	64	50	553	51	604
Kibea-17	Q2	0	0	0	0	0	423	427	237	135	95	71	55	527	58	585
Kibea-18	Q2	0	0	0	0	0	235	476	281	155	107	78	60	508	67	575
Kibea-19	Q2	0	0	0	0	0	48	500	338	180	122	88	67	490	75	565
Kibea-20	Q2	0	0	0	0	0	0	420	386	202	134	96	72	478	81	560
Kibea-21	Q2	0	0	0	0	0	0	253	437	238	153	107	79	463	90	553
Total: PPP Undeveloped		**0**	**0**	**2,055**	**5,028**	**7,764**	**6,117**	**5,377**	**3,818**	**2,300**	**1,705**	**1,331**	**1,081**	**13,350**	**1,362**	**14,712**
Low Estimate Contingent Resources																
Kibea-01	CR1	0	0	303	221	166	129	103	84	58	38	33	29	425	5	430
Kibea-02	CR1	0	0	190	251	186	143	113	91	63	41	35	31	417	9	427
Kibea-03	CR1	0	0	58	287	210	159	124	99	68	44	38	33	409	14	424
Kibea-04	CR1	0	0	0	237	238	178	137	109	74	48	41	35	401	20	421
Kibea-05	CR1	0	0	0	113	271	200	153	120	81	52	44	38	391	25	416
Kibea-06	CR1	0	0	0	0	113	271	200	153	101	63	53	45	365	29	394
Total: Low Estimate Contingent Resources		**0**	**0**	**551**	**1,109**	**1,184**	**1,081**	**830**	**655**	**447**	**286**	**244**	**211**	**2,408**	**102**	**2,510**

Table 4

Company: **Griffiths Energy International Inc.** Effective Date: **31-Dec-12**

Property: **Kibea**

Economic Parameters

A) Price Forecasts and By-Product Data

GLJ (2013-01)

Oil Reference: 95% of BRENTUS

Transport Costs

Low Estimate Contingent Resources	$22.08/bbl
Proved plus Probable Undeveloped	$14.35/bbl
Proved plus Probable plus Possible Undeveloped	$11.49/bbl

Transport Costs are $6.50/bbl for export pipeline plus ITA tarriff

B) Operating Costs (2013 Dollars)

Well Costs: $10,000 / well / momth
Variable Costs $3.00 / bbl

Fixed Operating Costs and G&A

	Facility Operating Costs			G&A Costs		
Year	Proved M$	Proved+ Probable M$	Proved+ Probable+ Possible M$	Proved M$	Proved+ Probable M$	Proved+ Probable+ Possible M$
2013	0	0	0	1,500	3,750	7,500
2014	0	0	0	1,000	2,000	5,000
2015	1,500	3,000	7,500	1,000	2,000	5,000
2016	1,500	3,000	7,500	1,000	2,000	5,000
2017	1,500	3,000	7,500	500	1,000	2,500
2018	1,500	3,000	7,500	500	1,000	2,500
2019	1,500	3,000	7,500	250	500	1,250
2020+	1,500	3,000	7,500	250	500	1,250

All values are in 2012 dollars

C) Abandonment Costs (2013 Dollars)

	M$
Proved Undeveloped	$ 2,000
Proved plus Probable Undeveloped	$ 3,000
Proved plus Probable plus Possible Undeveloped	$ 15,000

Abandonment costs are scheduled on a unit of production basis.

Table 4.1

Company: **Griffiths Energy International Inc.** Effective Date: **31-Dec-12**
Property: **Kibea**

Economic Parameters

D) Capital Costs

Capital Summary (2013 Dollars)

Year	Well/Area	Development Description	Gross Lease Capital Expenditures: Development M$	Development Tangible M$	Plant & Gath. M$	Total M$	Company Total M$	Capital Interest %
	Low Estimate Contingent Resources							
2013	Kibea		-	-	17,271	17,271	11,514	66.67
	Well capital		20,900	-	-	20,900	13,933	66.67
2014	Kibea		-	-	34,542	34,542	23,028	66.67
	Well capital		31,800	-	-	31,800	21,200	66.67
2015	Well capital		42,200	-	-	42,200	28,133	66.67
	Total: Low Estimate Contingent Resources		**94,900**	**0**	**51,813**	**146,713**	**97,809**	**66.67**
	Proved Plus Probable Undeveloped							
2013	Kibea		-	-	26,648	26,648	17,765	66.67
	Well capital		20,900	-	-	20,900	13,933	66.67
2014	Kibea		-	-	53,296	53,296	35,531	66.67
	Well capital		31,800	-	-	31,800	21,200	66.67
2015	Well capital		63,000	-	-	63,000	42,000	66.67
2016	Well capital		26,300	-	-	26,300	17,533	66.67
	Total: Proved Plus Probable Undeveloped		**142,000**	**0**	**79,944**	**221,944**	**147,963**	**66.67**
	PPP Undeveloped							
2013	Kibea		-	-	49,302	49,302	32,868	66.67
	Well capital		20,900	-	-	20,900	13,933	66.67
2014	Kibea		-	-	98,603	98,603	65,736	66.67
	Well capital		47,700	-	-	47,700	31,800	66.67
2015	Well capital		78,900	-	-	78,900	52,600	66.67
2016	Well capital		78,900	-	-	78,900	52,600	66.67
2017	Well capital		52,000	-	-	52,000	34,667	66.67
	Total: PPP Undeveloped		**278,400**	**0**	**147,905**	**426,305**	**284,203**	**66.67**

Table 4.2
Griffiths Energy International Inc.
Kibea Property
Capital Cost Breakdown
by Reserves Class

	Amounts (M$)		
Category, (well counts**)**	**CR1**	**2P**	**3P**
Oil Wells, (6/10/21**)**	72,900	114,500	228,900
Injector/Service Wells, (4,5,9**)**	22,000	27,500	49,500
Facilities & Pipelines	51,813	79,944	147,905
Totals	**146,713**	**221,944**	**426,305**

Company: **Griffiths Energy International Inc.**
Property: **Kibea**
Currency: **$US Dollars**

Reserve Class: **Proved Plus Probable**
Development Class: **Undeveloped**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production				
Year	Gross Oil Wells	Gross Daily bbl/d	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	0	0	0	0	0	0.00
2014	0	0	0	0	0	0.00
2015	3	2,600	1,241	453	453	83.03
2016	6	5,568	2,658	970	970	83.03
2017	9	7,356	3,511	1,282	1,282	80.65
2018	10	7,504	2,164	790	790	80.65
2019	10	6,107	1,737	634	634	81.93
2020	10	4,654	1,299	474	474	83.86
2021	10	3,628	920	336	336	85.83
2022	10	2,903	751	274	274	87.82
2023	10	2,367	626	229	229	89.87
2024	10	1,966	533	194	194	91.95
Sub.				5,635	5,635	83.09
Rem.				697	697	98.86
Tot.				**6,332**	**6,332**	**84.82**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	0	0	0	0	0	0	0	0	0	0	0	0	2,501	0	2,501
2014	0	0	0	0	0	0	0	0	0	0	0	0	1,701	0	1,701
2015	37,617	0	0	37,617	0	37,617	0	0	0	0	0	37,617	5,956	0	5,956
2016	80,541	0	0	80,541	0	80,541	0	0	0	0	0	80,541	8,671	0	8,671
2017	103,359	0	0	103,359	0	103,359	0	0	0	0	0	103,359	9,716	0	9,716
2018	63,695	0	0	63,695	0	63,695	0	0	0	0	0	63,695	10,148	0	10,148
2019	51,935	0	0	51,935	0	51,935	0	0	0	0	0	51,935	8,733	0	8,733
2020	39,751	0	0	39,751	0	39,751	0	0	0	0	0	39,751	7,689	0	7,689
2021	28,824	0	0	28,824	0	28,824	0	0	0	0	0	28,824	6,966	0	6,966
2022	24,080	0	0	24,080	0	24,080	0	0	0	0	0	24,080	6,473	0	6,473
2023	20,543	0	0	20,543	0	20,543	0	0	0	0	0	20,543	6,125	0	6,125
2024	17,879	0	0	17,879	0	17,879	0	0	0	0	0	17,879	5,883	0	5,883
Sub.	468,225	0	0	468,225	0	468,225	0	0	0	0	0	468,225	80,563	0	80,563
Rem.	68,891	0	0	68,891	0	68,891	0	0	0	0	0	68,891	34,407	0	34,407
Tot.	**537,116**	**0**	**0**	**537,116**	**0**	**537,116**	**0**	**0**	**0**	**0**	**0**	**537,116**	**114,970**	**0**	**114,970**
Disc	293,019	0	0	293,019	0	293,019	0	0	0	0	0	293,019	53,764	0	53,764

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Net Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	-2,501	-1,333	0	-3,834	13,933	17,765	0	31,699	-35,533	-35,533	-33,879
2014	0	0	0	-1,701	0	0	-1,701	21,624	36,241	0	57,865	-59,566	-95,099	-85,510
2015	0	0	0	31,661	0	105	31,556	43,697	0	0	43,697	-12,141	-107,240	-95,077
2016	0	0	0	71,869	0	230	71,639	18,607	0	0	18,607	53,033	-54,207	-57,087
2017	0	0	0	93,642	0	310	93,332	0	0	0	0	93,332	39,125	3,693
2018	0	0	0	53,547	0	323	53,225	0	0	0	0	53,225	92,350	35,204
2019	0	0	0	43,201	0	268	42,934	0	0	0	0	42,934	135,283	58,311
2020	0	0	0	32,062	0	208	31,854	0	0	0	0	31,854	167,137	73,896
2021	0	0	0	21,858	0	166	21,693	0	0	0	0	21,693	188,830	83,545
2022	0	0	0	17,608	0	135	17,473	0	0	0	0	17,473	206,302	90,610
2023	0	0	0	14,418	0	112	14,306	0	0	0	0	14,306	220,608	95,869
2024	0	0	0	11,996	0	95	11,901	0	0	0	0	11,901	232,509	99,846
Sub.	0	0	0	387,662	-1,333	1,952	384,377	97,861	54,007	0	151,867	232,509	232,509	99,846
Rem.	0	0	0	34,484	0	345	34,139	0	0	0	0	34,139	266,649	108,667
Tot.	**0**	**0**	**0**	**422,146**	**-1,333**	**2,297**	**418,516**	**97,861**	**54,007**	**0**	**151,867**	**266,649**	**266,649**	**108,667**
Disc	0	0	0	239,255	-1,271	1,175	236,808	79,789	48,352	0	128,141	108,667	108,667	108,667

SUMMARY OF RESERVES

		Remaining Reserves at Jan 01, 2013					Oil Equivalents			Reserve Life Indic. (yr)		
Product	Units	Gross	Working Interest	Roy/NPI Interest	Total Company	Net	Oil Eq. Factor	Company Mboe	% of Total	Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	18,756	6,332	0	6,332	6,332	1.000	6,332	100	19.0	14.0	5.6
Total: Oil Eq.	Mboe	18,756	6,332	0	6,332	6,332	1.000	6,332	100	19.0	14.0	5.6

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	0.00	0.00	0.00	0.00	0.00	0.00	0.00	537,116	100	293,019	100
Total: Oil Eq.	$/boe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	537,116	100	293,019	100

INTEREST AND NET PRESENT VALUE SUMMARY

Revenue Interests and Burdens (%)		
Entity Name	Initial	Average
Working Interest	0.0000	33.5167
Capital Interest	66.6667	66.6667
Royalty Interest	0.0000	0.0000
Crown Royalty	0.0000	0.0000
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000

	Net Present Value Before Income Tax				
Disc. Rate %	Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/boe
0.0	422,146	418,516	151,867	266,649	42.11
5.0	312,609	309,699	139,081	170,618	26.94
8.0	265,348	262,739	132,320	130,419	20.60
10.0	239,255	236,808	128,141	108,667	17.16
12.0	216,619	214,312	124,202	90,111	14.23
15.0	187,922	185,790	118,700	67,090	10.59
20.0	150,703	148,795	110,487	38,308	6.05

Evaluator: Herchen, Leonard L.
Run Date: January 21, 2013 14:44:45

Company: **Griffiths Energy International Inc.**
Property: **Kibea**
Currency: **$US Dollars**

Reserve Class: **PPP**
Development Class: **Undeveloped**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production				
Year	Gross Oil Wells	Gross Daily bbl/d	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	0	0	0	0	0	0.00
2014	0	0	0	0	0	0.00
2015	4	4,305	2,055	750	750	85.89
2016	10	10,533	5,028	1,835	1,835	85.89
2017	16	17,717	7,764	2,834	2,834	83.51
2018	19	21,797	6,117	2,233	2,233	83.51
2019	21	21,446	5,377	1,963	1,963	84.79
2020	21	16,258	3,818	1,394	1,394	86.72
2021	21	10,994	2,300	839	839	88.69
2022	21	7,900	1,705	622	622	90.68
2023	21	5,951	1,331	486	486	92.73
2024	21	4,652	1,081	395	395	94.81
Sub.				13,350	13,350	85.82
Rem.				1,362	1,362	101.36
Tot.				**14,712**	**14,712**	**87.26**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After Process.	Net Revenue After Royalty	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	M$	M$	Fixed M$	Variable M$	Total M$
2013	0	0	0	0	0	0	0	0	0	0	0	0	5,001	0	5,001
2014	0	0	0	0	0	0	0	0	0	0	0	0	3,401	0	3,401
2015	64,419	0	0	64,419	0	64,419	0	0	0	0	0	64,419	12,106	0	12,106
2016	157,609	0	0	157,609	0	157,609	0	0	0	0	0	157,609	17,484	0	17,484
2017	236,645	0	0	236,645	0	236,645	0	0	0	0	0	236,645	22,211	0	22,211
2018	186,468	0	0	186,468	0	186,468	0	0	0	0	0	186,468	26,496	0	26,496
2019	166,406	0	0	166,406	0	166,406	0	0	0	0	0	166,406	26,092	0	26,092
2020	120,850	0	0	120,850	0	120,850	0	0	0	0	0	120,850	22,264	0	22,264
2021	74,446	0	0	74,446	0	74,446	0	0	0	0	0	74,446	18,207	0	18,207
2022	56,441	0	0	56,441	0	56,441	0	0	0	0	0	56,441	15,871	0	15,871
2023	45,039	0	0	45,039	0	45,039	0	0	0	0	0	45,039	14,455	0	14,455
2024	37,403	0	0	37,403	0	37,403	0	0	0	0	0	37,403	13,564	0	13,564
Sub.	1,145,726	0	0	1,145,726	0	1,145,726	0	0	0	0	0	1,145,726	197,151	0	197,151
Rem.	138,043	0	0	138,043	0	138,043	0	0	0	0	0	138,043	72,318	0	72,318
Tot.	**1,283,769**	**0**	**0**	**1,283,769**	**0**	**1,283,769**	**0**	**0**	**0**	**0**	**0**	**1,283,769**	**269,469**	**0**	**269,469**
Disc	696,757	0	0	696,757	0	696,757	0	0	0	0	0	696,757	126,940	0	126,940

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	**Net Prod'n Revenue** M$	Other Income M$	**Aband. Costs** M$	**Oper. Income** M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	-5,001	-1,333	0	-6,334	13,933	32,868	0	46,801	-53,135	-53,135	-50,663
2014	0	0	0	-3,401	0	0	-3,401	32,436	67,050	0	99,486	-102,887	-156,022	-139,843
2015	0	0	0	52,312	0	331	51,981	54,725	0	0	54,725	-2,744	-158,766	-142,006
2016	0	0	0	140,124	0	827	139,297	55,820	0	0	55,820	83,478	-75,288	-82,206
2017	0	0	0	214,434	0	1,419	213,016	37,524	0	0	37,524	175,491	100,203	32,079
2018	0	0	0	159,972	0	1,781	158,192	0	0	0	0	158,192	258,395	125,732
2019	0	0	0	140,314	0	1,787	138,528	0	0	0	0	138,528	396,922	200,288
2020	0	0	0	98,586	0	1,382	97,204	0	0	0	0	97,204	494,126	247,848
2021	0	0	0	56,239	0	953	55,286	0	0	0	0	55,286	549,413	272,439
2022	0	0	0	40,570	0	699	39,872	0	0	0	0	39,872	589,284	288,562
2023	0	0	0	30,584	0	537	30,047	0	0	0	0	30,047	619,332	299,607
2024	0	0	0	23,839	0	428	23,411	0	0	0	0	23,411	642,743	307,431
Sub.	0	0	0	948,575	-1,333	10,143	937,099	194,438	99,918	0	294,356	642,743	642,743	307,431
Rem.	0	0	0	65,725	0	1,323	64,402	0	0	0	0	64,402	707,145	324,286
Tot.	**0**	**0**	**0**	**1,014,300**	**-1,333**	**11,466**	**1,001,501**	**194,438**	**99,918**	**0**	**294,356**	**707,145**	**707,145**	**324,286**
Disc	0	0	0	569,817	-1,271	5,858	562,688	148,946	89,456	0	238,402	324,286	324,286	324,286

SUMMARY OF RESERVES

		Remaining Reserves at Jan 01, 2013					Oil Equivalents			Reserve Life Indic. (yr)		
Product	Units	Gross	Working Interest	Roy/NPI Interest	Total Company	Net	Oil Eq. Factor	Company Mboe	% of Total	Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	49,352	14,712	0	14,712	14,712	1.000	14,712	100	18.0	19.6	5.9
Total: Oil Eq.	Mboe	49,352	14,712	0	14,712	14,712	1.000	14,712	100	18.0	19.6	5.9

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,283,769	100	696,757	100
Total: Oil Eq.	$/boe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,283,769	100	696,757	100

INTEREST AND NET PRESENT VALUE SUMMARY

Revenue Interests and Burdens (%)		
Entity Name	Initial	Average
Working Interest	0.0000	29.6435
Capital Interest	66.6667	66.6667
Royalty Interest	0.0000	0.0000
Crown Royalty	0.0000	0.0000
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000

	Net Present Value Before Income Tax				
Disc. Rate %	Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/boe
0.0	1,014,300	1,001,501	294,356	707,145	48.07
5.0	749,036	739,690	263,764	475,926	32.35
8.0	633,682	625,775	248,000	377,775	25.68
10.0	569,817	562,688	238,402	324,286	22.04
12.0	514,349	507,884	229,456	278,428	18.93
15.0	443,990	438,351	217,132	221,220	15.04
20.0	352,832	348,234	199,105	149,128	10.14

Evaluator: Herchen, Leonard L.
Run Date: January 21, 2013 14:45:09

Company: **Griffiths Energy International Inc.**
Property: **Kibea**
Currency: **$US Dollars**

Reserve Class: **Contingent Resources**
Development Class: **Low Estimate**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production				
Year	Gross Oil Wells	Gross Daily bbl/d	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	0	0	0	0	0	0.00
2014	0	0	0	0	0	0.00
2015	3	1,154	551	201	201	75.28
2016	5	2,323	1,109	405	405	75.28
2017	6	2,481	1,184	432	432	72.91
2018	6	2,264	1,081	394	394	72.91
2019	6	1,738	830	303	303	74.19
2020	6	1,373	655	239	239	76.12
2021	6	1,102	447	163	163	78.09
2022	6	903	286	104	104	80.08
2023	6	751	244	89	89	82.13
2024	6	634	211	77	77	84.21
Sub.				2,408	2,408	75.35
Rem.				102	102	87.17
Tot.				**2,510**	**2,510**	**75.83**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	0	0	0	0	0	0	0	0	0	0	0	0	501	0	501
2014	0	0	0	0	0	0	0	0	0	0	0	0	341	0	341
2015	15,131	0	0	15,131	0	15,131	0	0	0	0	0	15,131	2,430	0	2,430
2016	30,477	0	0	30,477	0	30,477	0	0	0	0	0	30,477	3,646	0	3,646
2017	31,511	0	0	31,511	0	31,511	0	0	0	0	0	31,511	3,829	0	3,829
2018	28,762	0	0	28,762	0	28,762	0	0	0	0	0	28,762	3,731	0	3,731
2019	22,470	0	0	22,470	0	22,470	0	0	0	0	0	22,470	3,280	0	3,280
2020	18,211	0	0	18,211	0	18,211	0	0	0	0	0	18,211	3,039	0	3,039
2021	12,741	0	0	12,741	0	12,741	0	0	0	0	0	12,741	2,868	0	2,868
2022	8,354	0	0	8,354	0	8,354	0	0	0	0	0	8,354	2,752	0	2,752
2023	7,304	0	0	7,304	0	7,304	0	0	0	0	0	7,304	2,671	0	2,671
2024	6,493	0	0	6,493	0	6,493	0	0	0	0	0	6,493	2,619	0	2,619
Sub.	181,452	0	0	181,452	0	181,452	0	0	0	0	0	181,452	31,707	0	31,707
Rem.	8,882	0	0	8,882	0	8,882	0	0	0	0	0	8,882	4,912	0	4,912
Tot.	**190,334**	**0**	**0**	**190,334**	**0**	**190,334**	**0**	**0**	**0**	**0**	**0**	**190,334**	**36,620**	**0**	**36,620**
Disc	108,809	0	0	108,809	0	108,809	0	0	0	0	0	108,809	18,927	0	18,927

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Net Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	-501	-1,333	0	-1,834	13,933	11,514	0	25,447	-27,282	-27,282	-26,012
2014	0	0	0	-341	0	0	-341	21,624	23,489	0	45,113	-45,453	-72,735	-65,410
2015	0	0	0	12,701	0	104	12,597	29,270	0	0	29,270	-16,673	-89,408	-78,548
2016	0	0	0	26,830	0	213	26,617	0	0	0	0	26,617	-62,790	-59,481
2017	0	0	0	27,682	0	232	27,450	0	0	0	0	27,450	-35,340	-41,605
2018	0	0	0	25,030	0	216	24,814	0	0	0	0	24,814	-10,526	-26,914
2019	0	0	0	19,190	0	169	19,021	0	0	0	0	19,021	8,495	-16,677
2020	0	0	0	15,172	0	136	15,036	0	0	0	0	15,036	23,530	-9,320
2021	0	0	0	9,873	0	112	9,762	0	0	0	0	9,762	33,292	-4,978
2022	0	0	0	5,602	0	93	5,509	0	0	0	0	5,509	38,801	-2,750
2023	0	0	0	4,632	0	79	4,553	0	0	0	0	4,553	43,355	-1,077
2024	0	0	0	3,874	0	68	3,806	0	0	0	0	3,806	47,160	195
Sub.	0	0	0	149,745	-1,333	1,422	146,990	64,827	35,003	0	99,830	47,160	47,160	195
Rem.	0	0	0	3,969	0	78	3,891	0	0	0	0	3,891	51,051	1,348
Tot.	**0**	**0**	**0**	**153,714**	**-1,333**	**1,500**	**150,881**	**64,827**	**35,003**	**0**	**99,830**	**51,051**	**51,051**	**1,348**
Disc	0	0	0	89,882	-1,271	833	87,778	55,093	31,338	0	86,430	1,348	1,348	1,348

SUMMARY OF RESERVES

		Remaining Reserves at Jan 01, 2013					Oil Equivalents			Reserve Life Indic. (yr)		
Product	Units	Gross	Working Interest	Roy/NPI Interest	Total Company	Net	Oil Eq. Factor	Company Mboe	% of Total	Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	5,649	2,510	0	2,510	2,510	1.000	2,510	100	14.0	12.5	5.6
Total: Oil Eq.	Mboe	5,649	2,510	0	2,510	2,510	1.000	2,510	100	14.0	12.5	5.6

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	0.00	0.00	0.00	0.00	0.00	0.00	0.00	190,334	100	108,809	100
Total: Oil Eq.	$/boe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	190,334	100	108,809	100

INTEREST AND NET PRESENT VALUE SUMMARY

Revenue Interests and Burdens (%)		
Entity Name	Initial	Average
Working Interest	0.0000	44.1821
Capital Interest	66.6667	66.6667
Royalty Interest	0.0000	0.0000
Crown Royalty	0.0000	0.0000
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000

	Net Present Value Before Income Tax				
Disc. Rate %	Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	**Cash Flow** M$	**Cash Flow** $/boe
0.0	153,714	150,881	99,830	51,051	20.34
5.0	116,077	113,675	92,672	21,003	8.37
8.0	99,292	97,081	88,828	8,253	3.29
10.0	89,882	87,778	86,430	1,348	0.54
12.0	81,640	79,629	84,154	-4,525	-1.80
15.0	71,087	69,197	80,949	-11,752	-4.68
20.0	57,244	55,513	76,104	-20,590	-8.20

Evaluator: Herchen, Leonard L.
Run Date: January 21, 2013 14:45:17

GRIFFITHS ENERGY INTERNATIONAL INC.

MAKU

Effective December 31, 2012

Prepared by
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Leonard L. Herchen, P. Eng.

The analysis of this property as reported herein was conducted within the context of an evaluation of a distinct group of properties in aggregate. Extraction and use of this analysis outside this context may not be appropriate without supplementary due diligence.

MAKU

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RFT Summary		

Company: **Griffiths Energy International Inc.**
Property: **Maku**
Currency: **$US Dollars**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Summary of Reserves and Values

	Proved Plus Probable Undeveloped	PPP Undeveloped	Low Estimate Contingent Resources
MARKETABLE RESERVES			
Light/Medium Oil (Mbbl)			
Gross Lease	7,262	16,053	3,011
Total Company Interest	3,415	6,966	1,439
Net After Royalty	3,415	6,966	1,439
Oil Equivalent (Mbbl)			
Gross Lease	7,262	16,053	3,011
Total Company Interest	3,415	6,966	1,439
Net After Royalty	3,415	6,966	1,439
BEFORE TAX PRESENT VALUE (M$)			
0%	49,066	157,412	-3,535
5%	18,143	85,183	-12,958
8%	5,131	54,904	-16,735
10%	-1,880	38,560	-18,695
12%	-7,818	24,669	-20,300
15%	-15,085	7,552	-22,169
20%	-23,884	-13,518	-24,213
FIRST 6 YEARS BEFORE TAX CASH FLOW (M$)			
2013	-20,676	-35,309	-10,475
2014	-57,683	-94,946	-31,432
2015	-22,595	-25,115	-17,813
2016	23,507	42,250	13,128
2017	39,914	71,718	12,733
2018	25,738	67,991	8,581

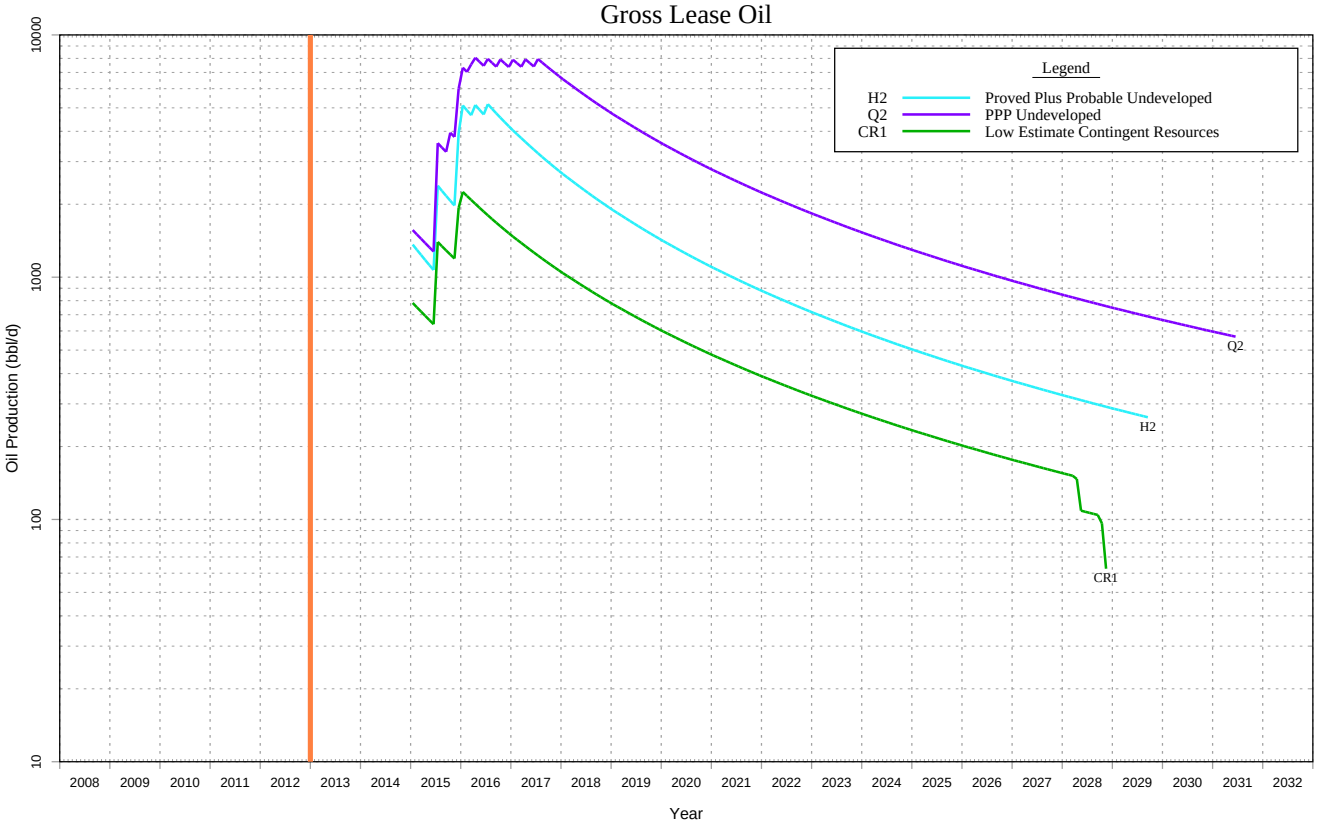
BOE Factors: HVY OIL 1.0 COND 1.0 RES GAS 6.0 SLN GAS 6.0 PROPANE 1.0 BUTANE 1.0 ETHANE 1.0 SULPHUR 0.0

Run Date: January 21, 2013 15:30:55

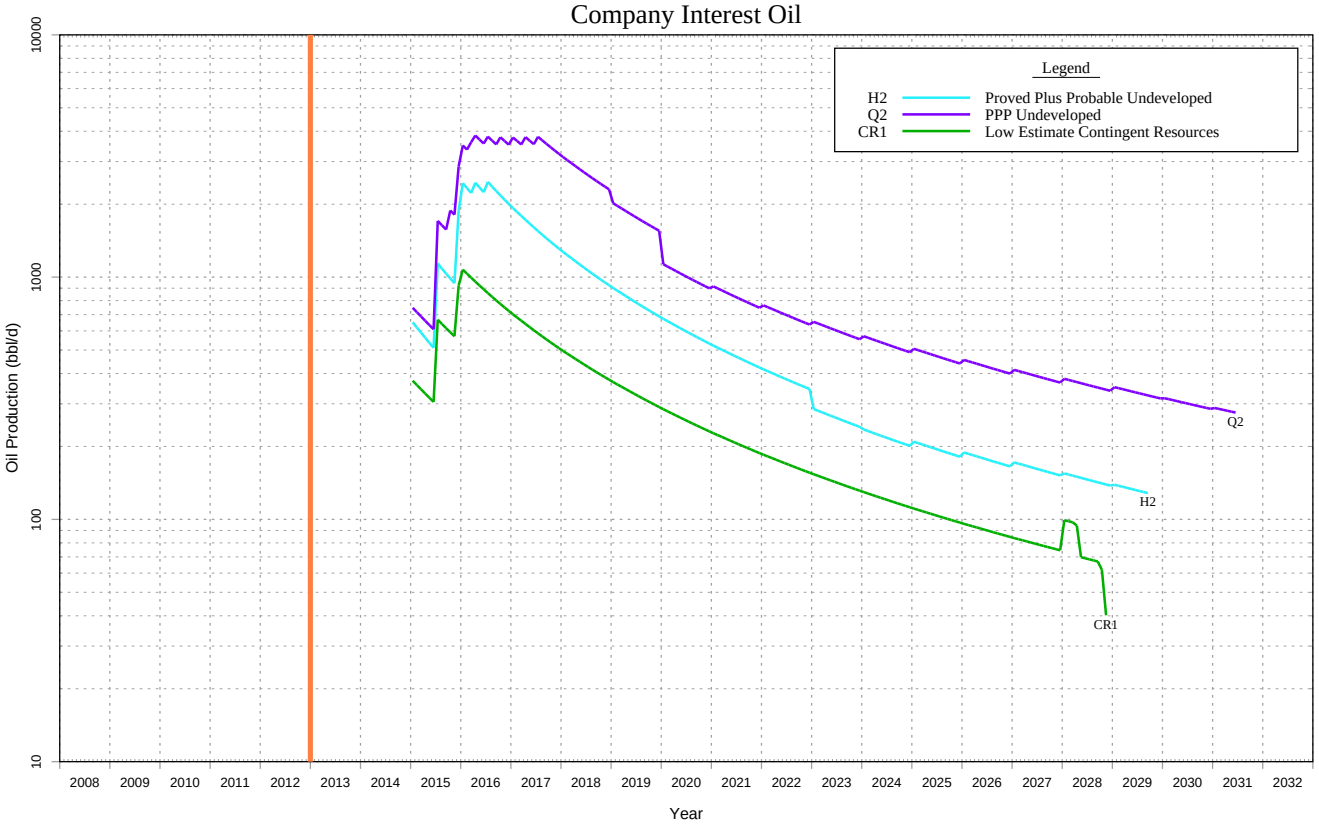
Historical and Forecast Production

Company: **Griffiths Energy International Inc.**
Property: **Maku**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Gross Lease Oil



Company Interest Oil



*Note: Historical company interest production is based on current interests in the evaluated reserves entities applied to reported actual gross lease production. Consequently, company actuals may differ from the history shown due to changes in ownership.

Gross Lease Oil
1132107 / Jan 22, 2013

Company: **Griffiths Energy International Inc.**
Property: **Maku**
Currency: **$US Dollars**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Daily Production, Reserves and Present Value Summary

Entity Description	Reserve Class	2013 Gross Lease Production				2013 Company Interest Production				Gross Lease Reserves					Company Interest Reserves					Before Tax 10% Dcf Present Value M$
		Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	
Proved Plus Probable Undeveloped																				
Maku-03	H2	0	0	0	0	0	0	0	0	0	667	0	0	667	0	314	0	0	314	12,604
Maku-04	H2	0	0	0	0	0	0	0	0	0	667	0	0	667	0	314	0	0	314	12,604
Maku-05	H2	0	0	0	0	0	0	0	0	0	663	0	0	663	0	312	0	0	312	12,088
Maku-06	H2	0	0	0	0	0	0	0	0	0	663	0	0	663	0	312	0	0	312	12,088
Maku-07	H2	0	0	0	0	0	0	0	0	0	659	0	0	659	0	310	0	0	310	11,584
Maku-08	H2	0	0	0	0	0	0	0	0	0	659	0	0	659	0	310	0	0	310	11,584
Maku-09	H2	0	0	0	0	0	0	0	0	0	658	0	0	658	0	309	0	0	309	11,473
Maku-10	H2	0	0	0	0	0	0	0	0	0	659	0	0	659	0	310	0	0	310	11,584
Maku-11	H2	0	0	0	0	0	0	0	0	0	658	0	0	658	0	309	0	0	309	11,473
Maku-12	H2	0	0	0	0	0	0	0	0	0	656	0	0	656	0	308	0	0	308	11,114
Maku-13	H2	0	0	0	0	0	0	0	0	0	654	0	0	654	0	307	0	0	307	10,727
Well Capital	H2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-79,833
Other Revenue and Expenses	H2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-50,970
Total: Proved Plus Probable Undeveloped		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**7,262**	**0**	**0**	**7,262**	**0**	**3,415**	**0**	**0**	**3,415**	**-1,880**
PPP Undeveloped																				
Maku-03	Q2	0	0	0	0	0	0	0	0	0	903	0	0	903	0	400	0	0	400	15,672
Maku-04	Q2	0	0	0	0	0	0	0	0	0	903	0	0	903	0	400	0	0	400	15,672
Maku-05	Q2	0	0	0	0	0	0	0	0	0	898	0	0	898	0	395	0	0	395	15,072
Maku-06	Q2	0	0	0	0	0	0	0	0	0	898	0	0	898	0	395	0	0	395	15,072
Maku-07	Q2	0	0	0	0	0	0	0	0	0	893	0	0	893	0	390	0	0	390	14,509
Maku-08	Q2	0	0	0	0	0	0	0	0	0	893	0	0	893	0	390	0	0	390	14,509
Maku-09	Q2	0	0	0	0	0	0	0	0	0	892	0	0	892	0	389	0	0	389	14,389
Maku-10	Q2	0	0	0	0	0	0	0	0	0	893	0	0	893	0	390	0	0	390	14,509
Maku-11	Q2	0	0	0	0	0	0	0	0	0	892	0	0	892	0	389	0	0	389	14,389
Maku-12	Q2	0	0	0	0	0	0	0	0	0	889	0	0	889	0	385	0	0	385	13,880
Maku-13	Q2	0	0	0	0	0	0	0	0	0	887	0	0	887	0	382	0	0	382	13,327
Maku-14	Q2	0	0	0	0	0	0	0	0	0	898	0	0	898	0	395	0	0	395	15,072
Maku-15	Q2	0	0	0	0	0	0	0	0	0	895	0	0	895	0	392	0	0	392	14,740
Maku-16	Q2	0	0	0	0	0	0	0	0	0	890	0	0	890	0	386	0	0	386	14,058
Maku-17	Q2	0	0	0	0	0	0	0	0	0	884	0	0	884	0	378	0	0	378	12,719
Maku-18	Q2	0	0	0	0	0	0	0	0	0	880	0	0	880	0	374	0	0	374	12,051
Maku-19	Q2	0	0	0	0	0	0	0	0	0	877	0	0	877	0	369	0	0	369	11,551
Maku-20	Q2	0	0	0	0	0	0	0	0	0	886	0	0	886	0	369	0	0	369	11,105
Well Capital	Q2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-125,886
Other Revenue and Expenses	Q2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-87,849
Total: PPP Undeveloped		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**16,053**	**0**	**0**	**16,053**	**0**	**6,966**	**0**	**0**	**6,966**	**38,560**
Low Estimate Contingent Resources																				
Maku-03	CR1	0	0	0	0	0	0	0	0	0	435	0	0	435	0	208	0	0	208	7,096
Maku-04	CR1	0	0	0	0	0	0	0	0	0	435	0	0	435	0	208	0	0	208	7,096
Maku-05	CR1	0	0	0	0	0	0	0	0	0	431	0	0	431	0	206	0	0	206	6,715

Daily Production, Reserves and Present Value Summary

Entity Description	Reserve Class	2013 Gross Lease Production Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	2013 Company Interest Production Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	Gross Lease Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Company Interest Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Before Tax 10% Dcf Present Value M$
Low Estimate Contingent Resources (Cont.)																				
Maku-06	CR1	0	0	0	0	0	0	0	0	0	431	0	0	431	0	206	0	0	206	6,715
Maku-07	CR1	0	0	0	0	0	0	0	0	0	428	0	0	428	0	204	0	0	204	6,343
Maku-08	CR1	0	0	0	0	0	0	0	0	0	428	0	0	428	0	204	0	0	204	6,343
Maku-09	CR1	0	0	0	0	0	0	0	0	0	425	0	0	425	0	203	0	0	203	6,236
Well Capital	CR1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-40,267
Other Revenue and Expenses	CR1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-24,972
Total: Low Estimate Contingent Resources		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**3,011**	**0**	**0**	**3,011**	**0**	**1,439**	**0**	**0**	**1,439**	**-18,695**

BOE Factors:

HVY OIL	1.0	RES GAS	6.0	PROPANE	1.0	ETHANE	1.0
COND	1.0	SLN GAS	6.0	BUTANE	1.0	SULPHUR	0.0

GENERAL

The Maku Field is located in the Chari East-Doseo Block within the Doseo Basin in southern Chad. Prior to a farm-in agreement (Glencore Farm-in) between Griffiths Energy International Inc. (Griffiths) and Glencore International AG (Glencore), Griffiths held a 100 percent participation in the Production Sharing Contract (PSC) that encompasses the Block. However, it was assumed that the State will back-in a 25 percent participation of the Contractor Share as permitted by the PSC. Griffiths would be the Operator of development in the Block. Map 1 illustrates the location of the Field. Chad's participation is expected to occur through the Société des Hydrocarbures du Tchad (SHT), the state oil company of Chad.

The Glencore Farm-in agreement provides for an assignment of one-third of Griffiths' interest in Chad, including the Chari East-Doseo Block to Glencore. In exchange, Glencore agrees to carry up to 300,000 M$ of development capital associated with the Badila and Mangara Fields. Cash flows presented here represent Griffiths' remaining interest, and include the terms of the Glencore Farm-in agreement. The interests evaluated herein assume an assignment of one-third of Griffiths' original participation to Glencore. That is, the evaluated interest assumes participation as follows:

Griffiths Energy International Inc.	50%
Glencore International AG	25%
SHT	25%

As defined within the PSC, the Republic of Chad's costs are carried proportionately by Griffiths and Glencore.

The Block was previously explored by Esso Exploration and Production Chad Inc. (Esso) primarily from the late 1970s through mid-1980s with the drilling of nine exploration wells. During this exploration phase the Maku Field was discovered with the Maku-1 well in 1985. The field was delineated further with the drilling of Maku-2 in 1986. DST-1 in Maku-2 was reported to produce 208 bbls of "formation fluid" with a salinity of 550 ppm. Although the reported fluid salinity is not consistent with either the drilling fluid or expected formation salinity, an RFT sample taken within the same interval had a reported salinity of 23,000 to 32,000 ppm, as compared to the drilling fluid salinity of 72,000 to 93,000 ppm. GLJ has interpreted these tested sands in the Maku-2 well as wet.

The Maku-1 well discovered reservoir in the Cretaceous C Sands, which tested 29ºAPI oil, at a rate of 1100 bopd at 40 percent drawdown. Tests from the well also produced significant levels of gas,

with initial rates of 2800 scf/bbl which subsequently increased to approximately 11,200 scf/bbl following the completion of an additional test interval in the identified gas cap.

As of the effective date of this report, no commercial development had occurred in the Chari East-Doseo Block, and it will require substantial infrastructure to support development of the Maku Field, as well as other prospects in the Block. Included in the required infrastructure is a planned pipeline connecting the Chari East-Doseo resources to the Chad-Cameroon pipeline at Kome, approximately 240 kilometers to the west. From these facilities, produced volumes would be transported via pipeline to the coast of Cameroon where the oil would be shipped to other global markets.

Griffiths has indicated its intention to develop the Maku Field, in combination with the Kibea Field. As the Kibea and Maku Fields will share pipeline infrastructure, both fields must be economic to be developed on a combined basis given the total capital investment in order for recoverable volumes to be classified as reserves. Because the combined cash flow was only economic in the proved plus probable and proved plus probable plus possible reserves cases, no reserves have been assigned in the proved case. Instead, recoverable oil in the low estimate case was classified as contingent resources, not as reserves. Further, as there are no identified gas markets in Chad, no gas reserves nor resource volumes were attributed to the recoverable portion of in-place gas volumes either in solution or the gas cap.

GEOPHYSICS

Griffiths has inherited a large seismic data base; in the order of 22,000 kilometres of data. In general the data has been acquired so that the majority of lines over a prospect are dip lines, which indicates that Esso had a good understanding of the structural orientation in the area. The data varies in quality, both signal/noise (S/N) ratio and frequency content. No information on the ages of the data was accessed but presumably the quality of data has improved with time. The data with the broadest frequency spectrum is prefixed by a 'CH', with a spectrum range, 6 db down of 14 to 54 Hz. It is not known if any noise analyses data will be made available to Griffiths, if not the field parameters used to record the 'CH' data would provide a framework and a good starting point for the design of shooting parameters for future field work. The remaining data has a variable range of dominant frequencies, the narrowest range, for 6 db down, being 10 to 26 Hz. The data set is adequate for structural mapping, but not as suitable for undertaking any stratigraphic analysis. Traditionally, large source and receiver arrays are used in open areas, especially the desert, and these acquisition parameters will preferentially attenuate the higher frequencies. There are some issues with inequalities in T_o (start time of the data), and mis-matching in polarities, but these are minor issues and the seismic data base can be used to map the structures accurately. The events were tied to the wells using a combination of checkshot data and well log data. Some of the events identified and associated with the main reservoir units do not tie precisely to that particular unit. There is no single event that can be correlated over the entire area; each area has been mapped using events that are most relevant to that area.

Maku

The Maku structure has two wells; Maku-1 is designated as an oil well and Maku-2 tested water. The C Sand reservoir is immediately below the C Sand Flooding Surface (CFS), with the CFS being tied to a peak and the reservoir sand being tied to a trough. The overall data quality can be described as fair, with the amplitude spectrum being narrow band. In spite of this tendency for the data to 'ring', the CFS event is strong and can be correlated across the data. The synthetic at the Maku-1 well has a good tie to the shallow Upper Albian Unconformity and also to the CFS event. The strike line through the Maku-1 well shows a narrow graben and a slightly wider horst immediately south of the well. The next line to the east has good definition on the southern fault of the graben but the displacement on the other two faults is not clear. The next line to the east, which intersects the Maku-2 well, shows the same pattern, with only displacement on the fault forming the south arm of the graben being supported. GLJ Petroleum Consultants (GLJ)

interprets the graben to terminate just east of the Maku-1 well. The two wells are considered to be in communication, with no fault separation.

The two way time (TWT) to the CFS event was converted to depth using a half velocity of 1000 m/sec, which is the approximate average of the velocities computed to tie the two wells. As can be seen on the map, the crest of the structure is south of the Maku-1 well.

GEOLOGY

The Griffiths PSCs include blocks within two geologic basins in Chad, the Doba and Doseo Basins. These basins are separated by an area termed the Borogop uplift which is a large inversion anticlinal trend and is part of the Central African Rift trend, a continental plate boundary crossing through Chad from the Sudan to Cameroon.

The Doba and Doseo Basins were formed as rift basins in the Early Cretaceous (84-144 Ma). The Doba Basin formed as a series of northwest to southwest trending half grabens. The Doseo Basin formed as a large asymmetrical basin with a northwest to southeast oriented rift faulted relay series. The Borogop uplift is the steeply lifted basin edge fault zone which separates the basins.

Geologic sedimentation occurred during the Aptian through Conician when the two basins underwent a thermal sag phase which provided accommodation space for sediments. It is noteworthy that thermal events also include a phase of sill intrusion dating 97-100 Ma. Sills have been found and sampled along the northern flank of the Doseo Basin.

The Cretaceous provides the multiple reservoirs which have been tested in the two basins. The Cretaceous E interval consists of sediments sourced by axial transport from the east. Sediments drained generally to the west towards Doba and probably ultimately exited the Doba Basin through the Yola arm of the Benue trough and then onto the south to the Benue forming the proto Niger Delta. The top of the E Sequence is bounded by the D Sequence Boundary (DSB) and is generally a very good high amplitude seismic marker. The Cretaceous D Sequence is a continuation of the same non-marine fluvial and deltaic lacustrine facies as observed in the E Sequence. The Cretaceous C zone overlies the D Sequence and is also composed of fluvial, lacustrine and deltaic sediments.

The traps evaluated for this work were all four way closed structure, whilst source rocks are provided by the prevalent lacustrine sediments deposited throughout both basins.

Maku Field

The oil initially-in-place (OIIP) for the Maku Field has been determined by volumetric analysis using deterministic methods. The following is a discussion of the methodology and input parameters.

Petrophysical Analysis

GLJ conducted a review of petrophysical analysis prepared by Griffiths. This showed it to be broadly similar to earlier studies undertaken by Esso, RPS Group and Ryder Scott. It was decided to define a range of rock properties for the key reservoir units by utilizing a range of low, most likely and high case cut-offs. For the Maku Field GLJ used "most likely" cutoffs of 7.0 percent porosity and a 60.0 percent water saturation to define wellbore parameters. Low case and high case parameters were also determined by applying different cutoffs.

The Maku-1 and Maku-2 wells were correlated to determine which intervals were tested and to determine if there is any indication of bypassed pay or water contacts (Figure 1). The wells were not tested in the same zone, and the Maku-1 well test indicates a gas cap, which is not seen at Maku-2.

Mapping

The seismic quality is good over the Maku structure but quite sparse at about a 2 kilometre spacing over the Maku Field. A review of the Griffiths interpretation was undertaken to confirm the validity of the depth mapping. GLJ used the provided depth map for the CFS event to map the reservoirs for the calculation of Gross Rock Volumes for the assignment of contingent resources. However, the faults were modified to reflect GLJ's view of their terminations.

Gas-Oil and Oil-Water Contacts

The Maku Field has been drilled and tested by two wells; Maku-1 and Maku-2. Maku-1 identified a gas-oil contact (GOC) at -1114.1 metres and a lowest known hydrocarbon (LKH) at -1128.3 metres in a C Sand reservoir unit. Maku-2 was drilled to the northeast and tested water. The contingent resources have been constrained to the south of the mapped fault which intersects the edge of the four way closure (Map 2). They have also been constrained to not include the Maku-2 well, which GLJ views as being wet and of poor reservoir quality. The gas cap has also been accounted for and removed from the gross oil volume calculations.

C Sand Reservoir

The C Sand shows a LKH on logs at -1128.3 metres, this contact was used for the proved OIIP calculation (Map 2). The mapped spill point is interpreted to be at -1200 metres and this was used for the high estimate OIIP calculation (Map 2).

Gross Oil Pay

For the contingent resources and reserves estimates, gross oil pay maps were generated for the C Sand reservoir utilizing the different contact scenarios outlined above (Maps 3 and 4). A P90 (high confidence) map was generated based on lowest known oil and is presented on Map 3. A P02 (highly unlikely map) was generated based the structure being filled to spill.

RESERVES, RESOURCES AND PRODUCTION FORECAST

The key points of interest in the reserves and resource evaluation are discussed below.

Well Tests

The well tests conducted on the Maku-1 well are summarized as follows:

Sand	Test 1	Test 1A
C Sand	1494.7-1500.8 m MD 1,100 bopd / 29ºAPI 0.8% WCT 2,800 scf/bbl	1494.7-1500.8 1485.0-1486.2 m MD 720 bopd / 29ºAPI <0.1% WCT 11,200 scf/bbl

Three intervals were also tested at Maku-2; however all three intervals tested near 100 percent water with only trace oil. These intervals were not considered in the resource evaluation.

Pressure Depth Analysis

A detailed review of the repeat formation test (RFT) data was conducted and pressure depth plots and related commentary is presented in Appendix I. A key conclusion is that the RFT data supports the conclusion that the tested zones in Maku-2 are not in hydraulic communication with tested zones in Maku-1.

Fluid Properties

No detailed PVT analysis was available from the initial tests at Maku-1, aside from reported oil gravity measurements. A formation volume factor of 1.23 was used based on standard correlations.

Oil Initially-in-Place (OIIP)

P90 and P02 estimates of OIIP were estimated volumetrically based on mapped rock volumes down to LKH and filled to spill mapped volumes, respectively. These maps were based on extensive 2D seismic data. These volumes are summarized on Table 2.1 and presented as Plot 3 on a Probit Scale. From this depiction P90, P50 and P10 volumes were interpolated for the low estimate contingent resources category and for the proved plus probable and proved plus probable plus possible reserves

categories. The filled-to-spill volume was defined as a P02 (very unlikely) because of stratigraphic and pressure variances between Maku-1 and Maku-2. Consequently, the P02 map was considered to be an optimistic interpretation, less likely than a P10 interpretation.

Recovery Factor

The C Sand was assigned recovery factors of 15, 20 and 25 percent in the low estimate, proved plus probable and proved plus probable plus possible cases, respectively. The recovery factors assigned were based on the assumption that the gas cap interacts with oil recovery.

Production and Development Forecast

Construction of the main pipeline and drilling of the initial production wells is forecast to commence in 2014 to allow for first oil production in January 2015. Continued development is forecast through 2017. Forecast annual production volumes are presented in Tables 3 and 3.1, and are shown as Plots 1 and 2.

ECONOMIC ANALYSIS

Economic parameters, including operating costs, development capital, product pricing and abandonment costs, are presented in Tables 4, 4.1 and 4.2.

Well operating costs were estimated at $10,000 per well per month. Variable costs for oil were estimated at $3.00/bbl. Fixed operating costs include a component for general and administrative (G&A) costs, as well as facilities operating costs. The G&A costs were scheduled because they can be recovered as cost oil. G&A costs were scheduled from the effective date of the analysis and scaled to production and reserves volumes. Facility operating costs were scheduled from first production. Fixed and G&A costs are summarized in Table 4.

In addition to development capital associated with drilling and development within the Maku Field, a portion of total pipeline costs were allocated to the Maku Field. Specifically, 41.5 percent of the pipeline costs were allocated to Kibea and Maku, the remaining 58.5 percent allocated to the associated East Doseo ITA. Of the pipeline costs allocated to Kibea and Maku, 30 percent were allocated to Maku.

Griffiths' interest in Chad are economic interests earned through participation in PSCs. Currently, Griffiths' and Glencore's participation in the PSCs is 100 percent, however, the terms of the PSCs allow the government of Chad to back-in to a 25 percent participation in the PSC as its option. This evaluation assumes that the option to back-in is exercised by the government of Chad.

Consequently, the PSC was modelled assuming that Griffiths and Glencore have a 75 percent participation in the PSC. In addition, it was assumed, as permitted by the terms of the PSC, that Griffiths and Glencore will carry the capital, operating and abandonment costs of the government Chad's 25 percent participation. This carried capital is cost recoverable.

As is common with PSCs, Griffiths' economic interest in the gross lease recoverable resources was based on the sum of cost oil and profit oil earned from total revenue. No royalty is payable by Griffiths in such circumstances. Therefore, Griffiths' gross and net resources were equal. In addition, the terms of the PSC preclude the payment of income tax by Griffiths. The before tax and after tax cash flow are also equal.

Key parameters of the PSC are:

- State Back-in Participation: 25%
- State "Royalty" Oil: 14.25%

- Participation in Profit Oil:

R Factor	Contractor Share
≤ 2.25	60%
> 2.25 & ≤ 3.00	50%
> 3.00	40%

- R Factor Numerator: Contractor Cumulative Revenue less Cumulative Operating Costs and Cumulative Abandonment Allocation.
- R Factor Denominator: Contractor Capital Costs and recovered exploration costs.
- Abandonment Cost Allocation: Well abandonment costs prorate per fraction of reserves produced.
- No income taxes levied.
- 25 percent carry of partner capital included as recoverable cost to Griffiths.
- PSC participants carry costs associated with 25 percent partner participation. Carried costs are cost recoverable.
- $2,000,000 bonus payable by contractors to Chad included as “Other Income”. The bonus is not cost recoverable.

Commodity Prices

Oil prices were estimated to be 95 percent of Brent prices, less a $6.50 per barrel transportation fee for the Cameroon to Chad export pipeline less the ITA tariff. The ITA tariff varies in each reserves class. Details on the ITA tariff at for Kibea and Maku are presented in the report in the ITA East Dosea report.

Solution gas is considered unmarketable and it was that assumed all solution gas would be flared, used as fuel or re-injected.

Other Economic Considerations

This report does not address the following issues:

- Non-reserves and non-resource well abandonment, wellsite reclamation and facility abandonment/salvage including possible environmental concerns.
- Potential processing income.
- The current condition of field, gathering and processing facilities, i.e. an inspection was not carried out.

PSC Parameters - Maku

Griffiths Energy International Inc (Griffiths) has entered into a Production Sharing Contract with the Republic of Chad.
Key parameters in the economic model* are as follows:

	Griffiths	Glencore	Chad	Comment
Participation	50.00%	25.00%	25.00%	Assumes Chad exercises right to back in for 25% participation
Carry	16.67%	8.33%		Griffiths and Glencore carry 25% of total capital, operating and abandonment costs
Lease Expiry	Dec-36			10 year extension permitted and included in 2P and 3P cases
Oil Royalty	14.25%			Deducted from lease revenue, prior to cost oil and profit oil calculation
Gas Royalty	5%			Deducted from lease revenue, prior to cost oil and profit oil calculation

Allocation of Profit Oil

R Factor	Griffiths	Glencore	SHT	Chad	
Profit Oil Share R ≤ 2.25	30%	15%	15%	40%	
Profit Oil Share 2.25 < R ≤ 3.00	25%	13%	13%	50%	
Profit Oil Share R > 3	20%	10%	10%	60%	
Numerator					Cumulative Contractor Revenue less Cumulative Operating costs and Cumulative Abandonment Costs
Denominator					Contractor Capital and Recovered Exploration Costs

Abandonment Costs	UOP	UOP	Abandonment costs recovered on a Unit of Production Basis.
Bonus	$ 1,333,333	$ 666,667	Remaining Bonus payable to Chad government. Not cost recoverable.

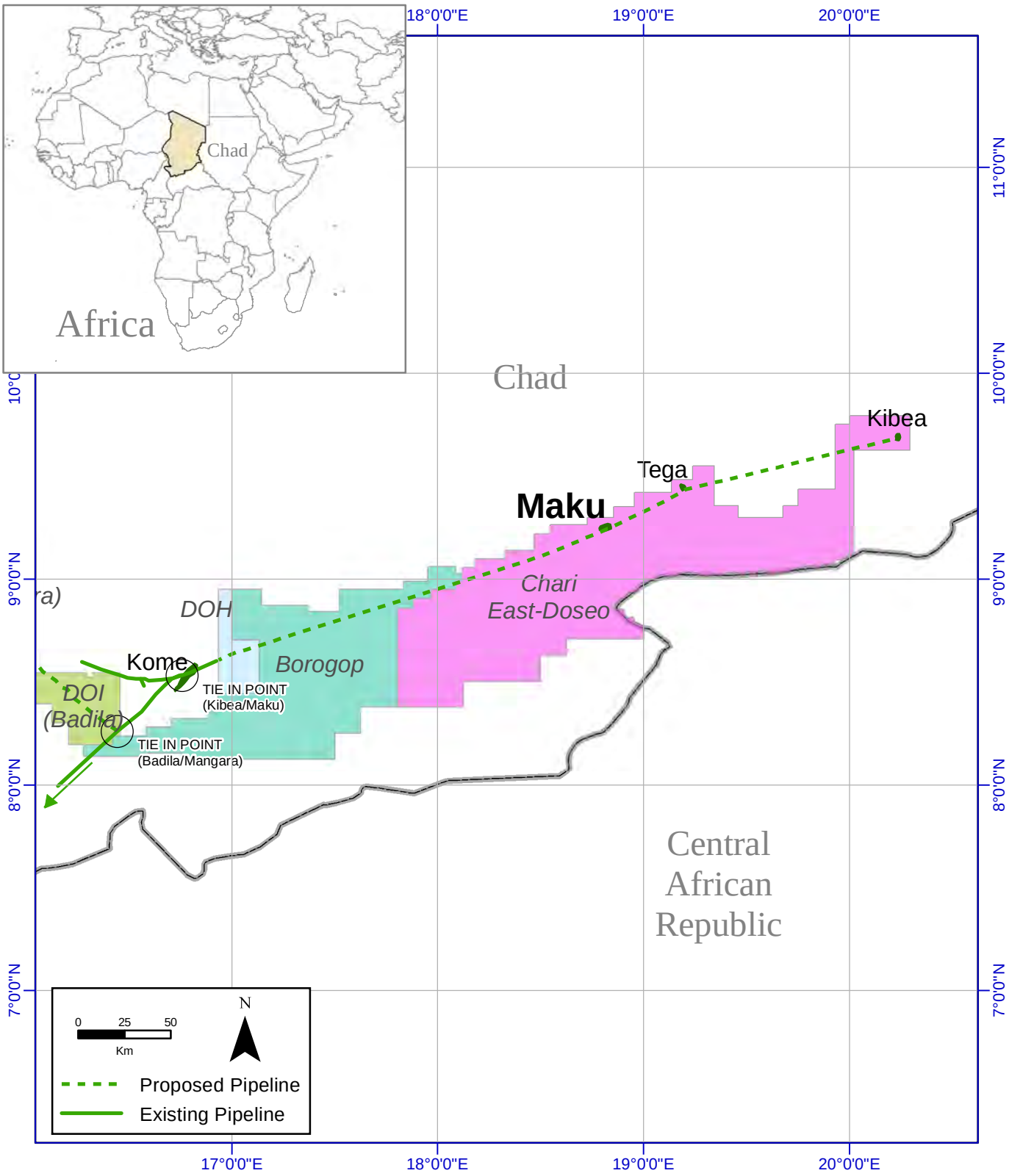
Opening Balances of Recoverable Costs	
Exploration	$ 0
Capital Costs	$ 0

*The economic model used in this report assume that the proposed transaction with Glencore International AG will occur
SHT is the *Société des Hydrocarbures du Tchad* , the state oil company of Chad.

Map 1
Land Map
Maku

Company: Griffiths Energy International Inc.
Property: Maku

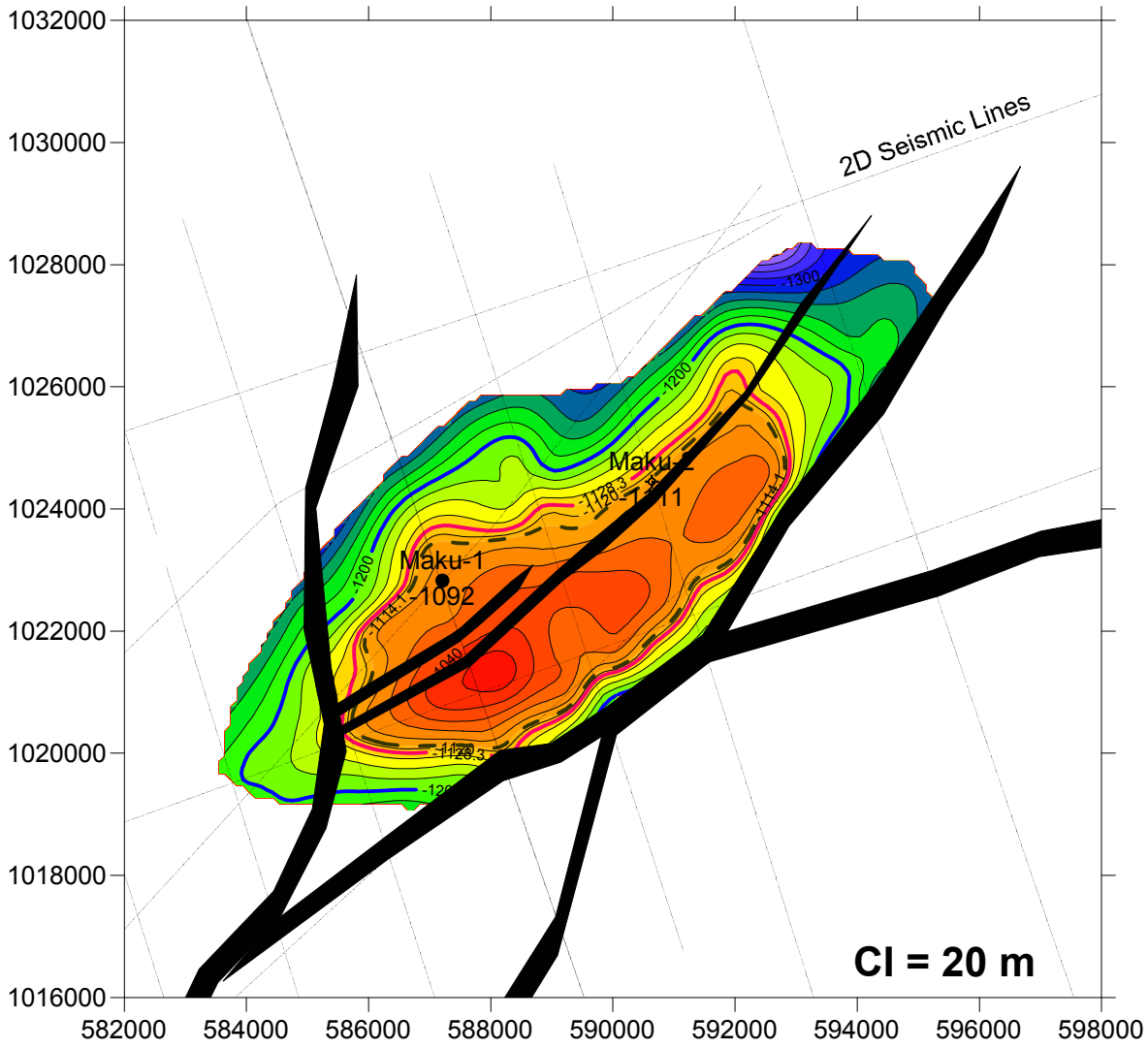
Effective Date: December 31, 2012
Scale: 1:3,000,000 s1132107/makm01



Map 2
Maku Field
Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: Maku

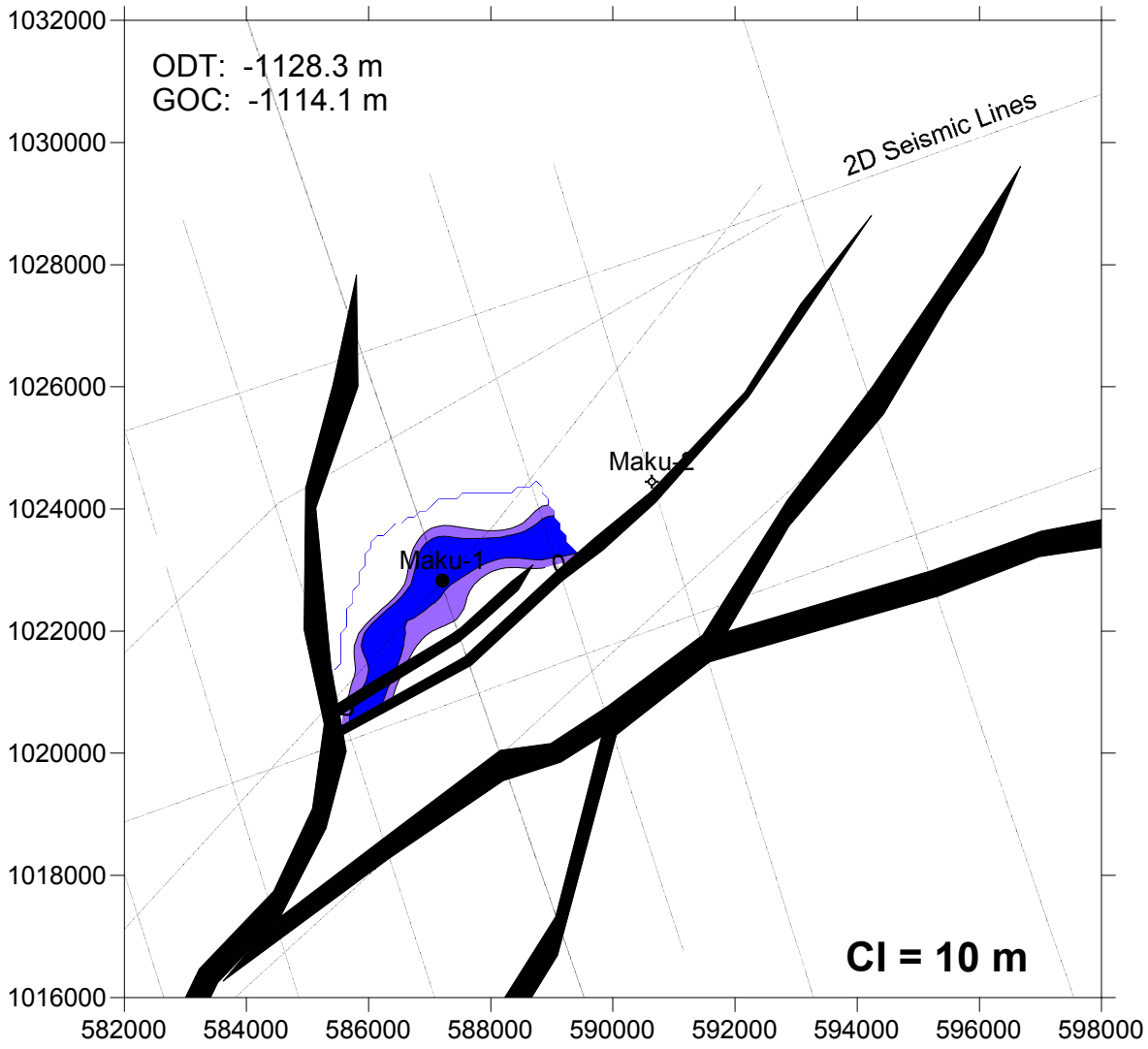
Effective Date: December 31, 2012
Scale: 1:120,000 s1132107



Map 3
Maku Field
Gross Oil Pay Map (metres)
C Sand - P90 (Low Case)

Company: Griffiths Energy International Inc.
Property: Maku

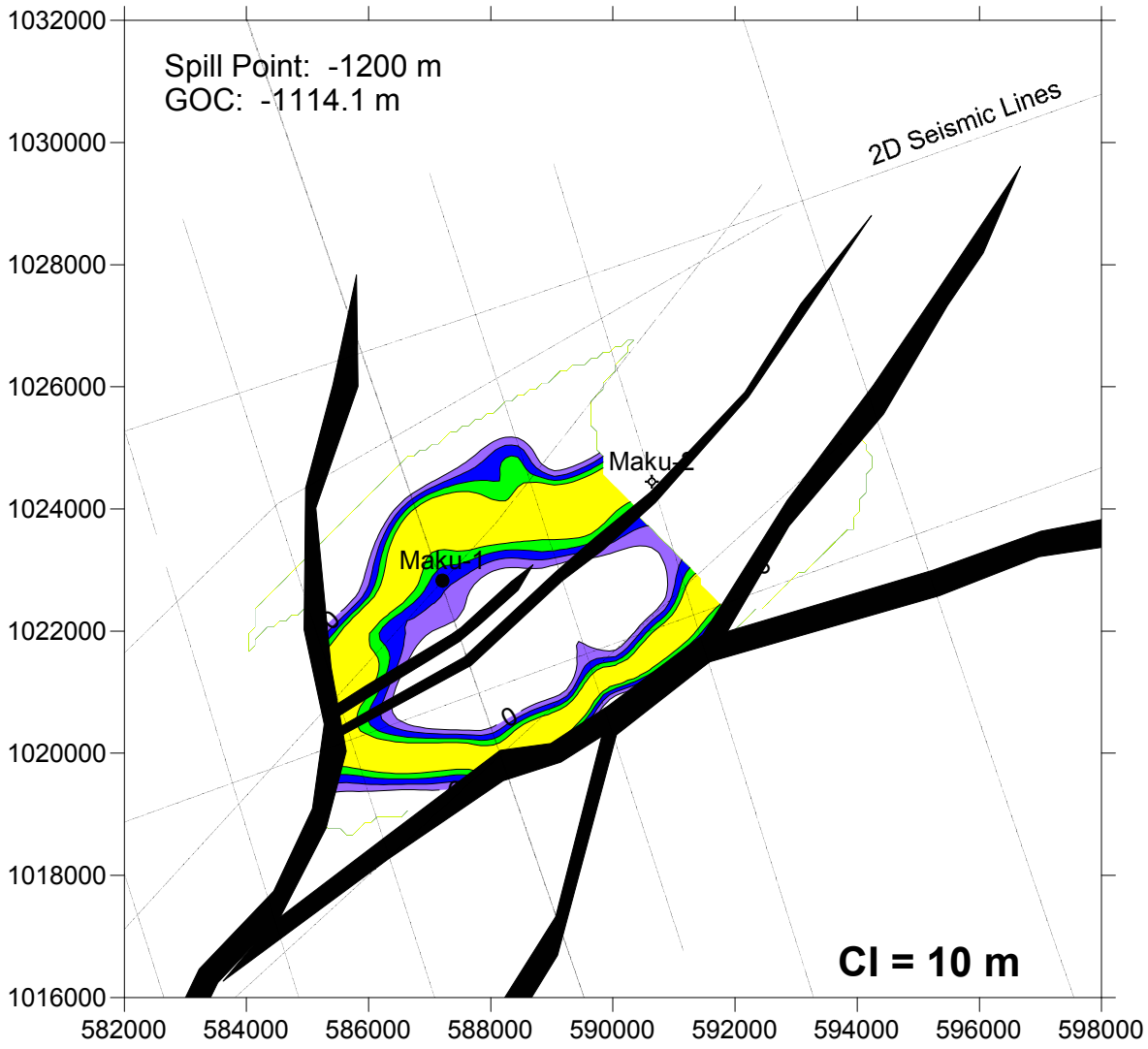
Effective Date: December 31, 2012
Scale: 1:120,000 s1132107



Map 4
Maku Field
Gross Oil Pay Map (metres)
C Sand - P02 Case

Company: Griffiths Energy International Inc.
Property: Maku

Effective Date: December 31, 2012
Scale: 1:120,000 s1132107



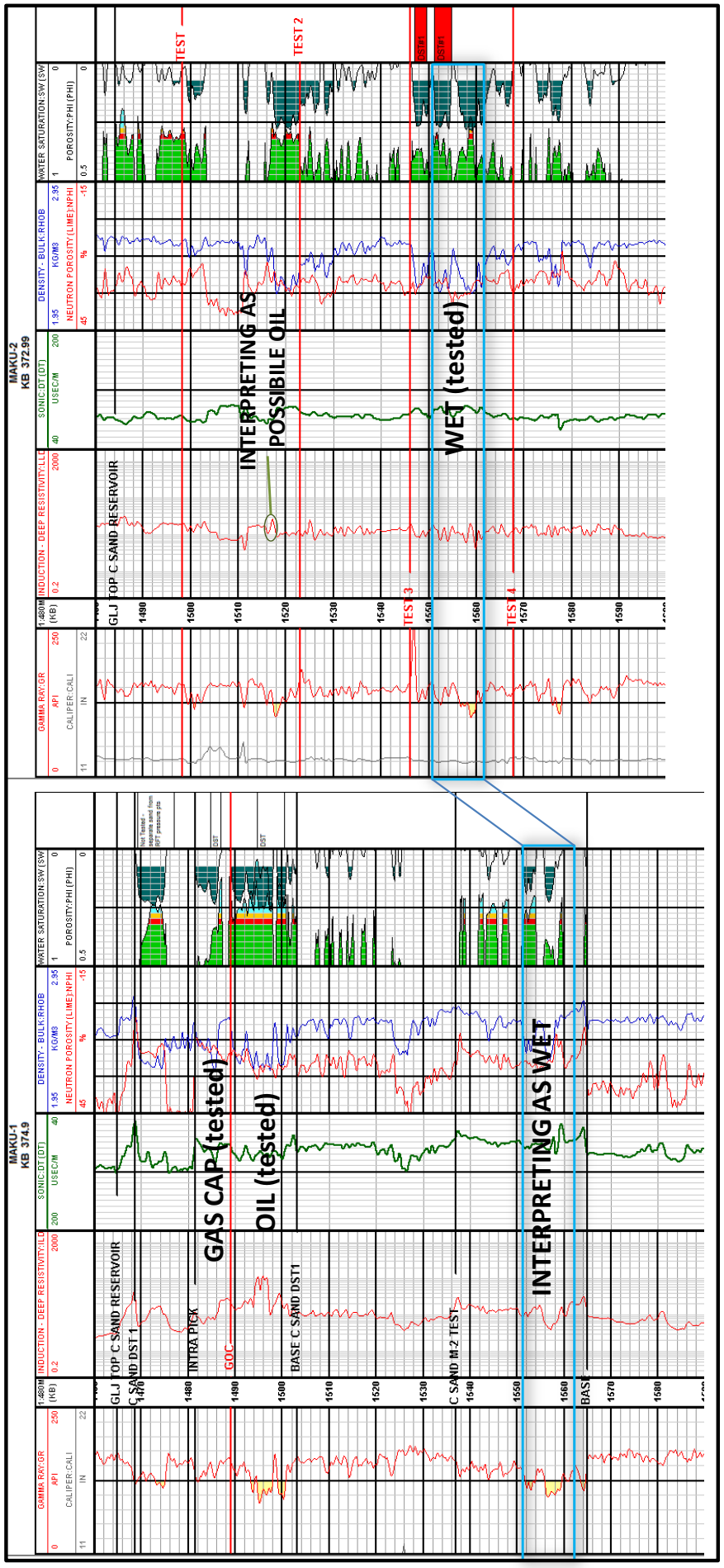
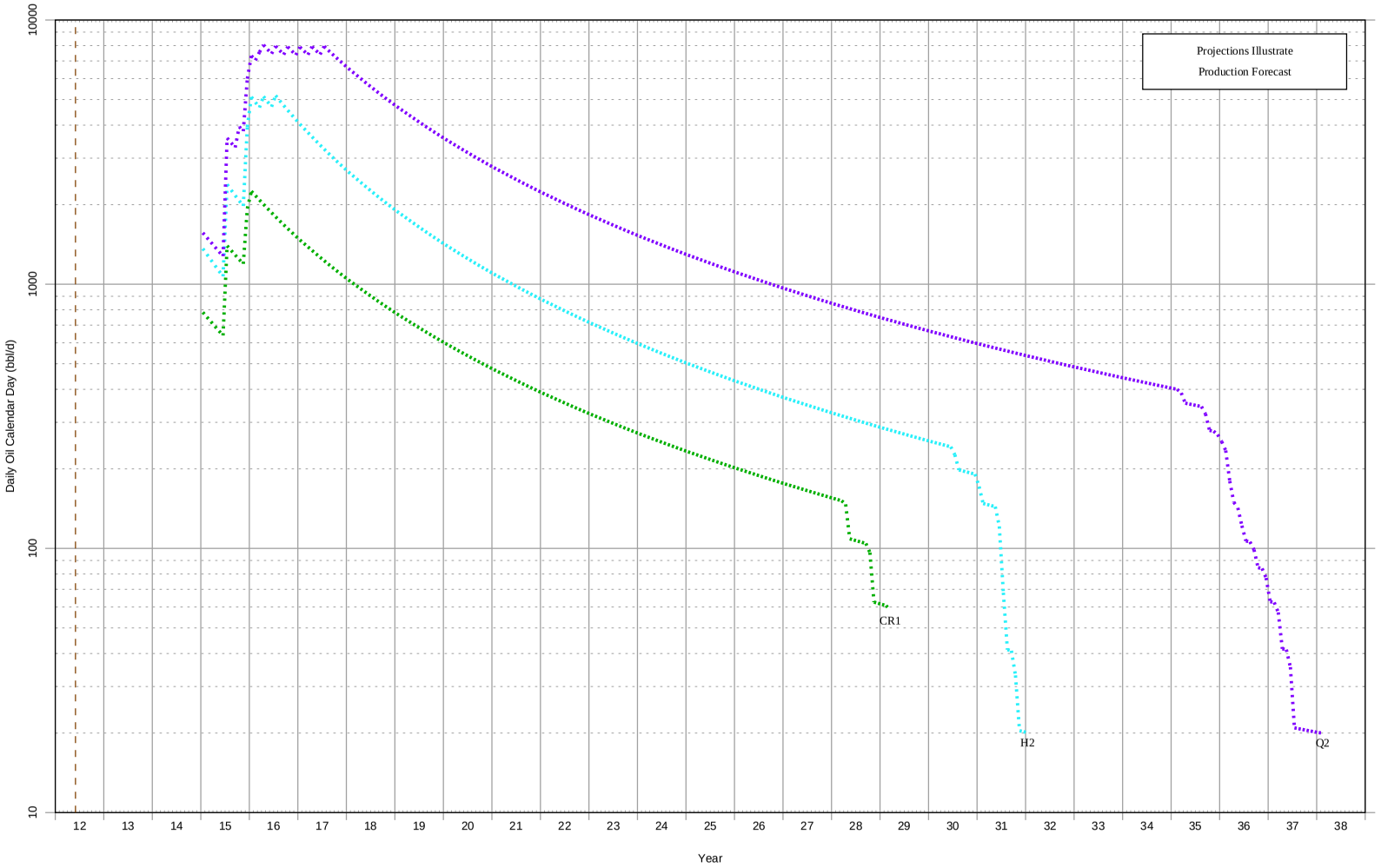


Figure 1. Stratigraphic cross section showing bypassed pay at Maku-2, and wet zones between the two wells.

Historical and Forecast Production
Maku - Total Property

Property : Maku



Total Reserves Summary @ 2012/06/01

Reserves Classification		Reserves (Mbbl) Ultimate	Cum Production	Remaining
P + P UDev	H2(R)	7394	0	7394
PPP UDev	Q2(R)	16837	0	16837
Low Estimate ...	CR1(R)	3044	0	3044

Average Production Rates (Last 12 months ending 2012/06/01)

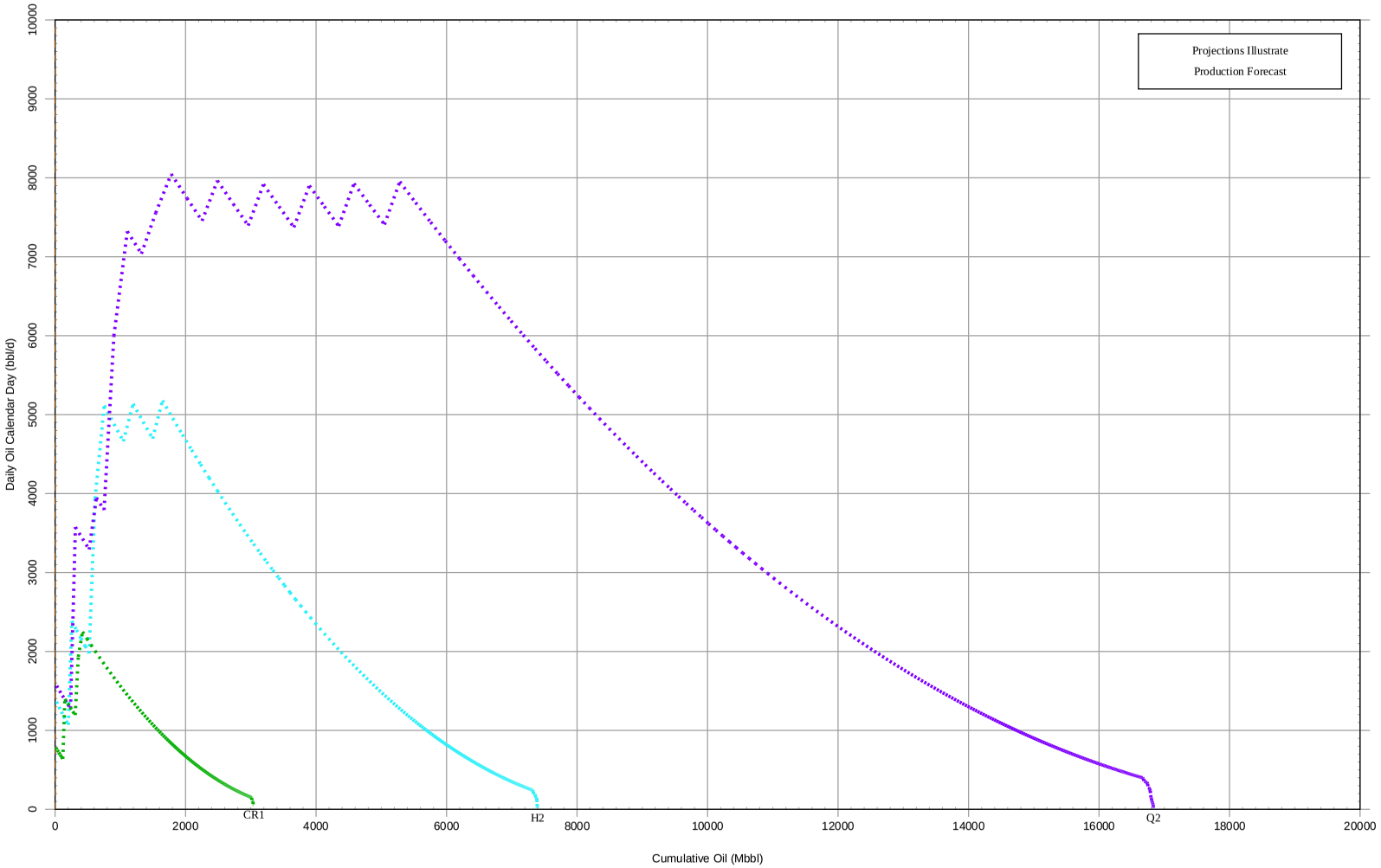
Gas :	0.0 Mcf/d	0.0 Mcf/cd	WGR :	0.0 bbl/MMcf
Oil :	0.0 bbl/d	0.0 bbl/cd	GOR :	0.0 scf/bbl
On Prod :	0.0 days		WC :	0.0 %

Cumulative Production

Oil :	0.0 Mbbl	Gas :	0.0 MMcf	Water :	0.0 Mbbl

Historical and Forecast Production
Maku - Total Property

Property : Maku



Total Reserves Summary @ 2012/06/01

Reserves Classification		Reserves (Mbbl) Ultimate	Cum Production	Remaining
P + P UDev	H2(R)	7394	0	7394
PPP UDev	Q2(R)	16837	0	16837
Low Estimate ...	CR1(R)	3044	0	3044

Average Production Rates (Last 12 months ending 2012/06/01)

Gas :	0.0 Mcf/d	0.0 Mcf/cd	WGR :	0.0 bbl/MMcf
Oil :	0.0 bbl/d	0.0 bbl/cd	GOR :	0.0 scf/bbl
On Prod :	0.0 days		WC :	0.0 %

Cumulative Production

Oil :	0.0 Mbbl	Gas :	0.0 MMcf	Water :	0.0 Mbbl

Last Month of Data: Alta.: 2012-11 Sask.: 2012-11 B.C.: 2012-11 Man.: 2012-10

Well List and Production Summary

#	Well Location	Regulatory Field Pool	Current Status	RigRel yr-mm	Production Dates First yr-mm	Last yr-mm	Inj yr-mm	Last Quarter Production Statistics Prod Days	Oil bbl/d	Gas Mcf/d	GOR scf/bbl	WGR bbl/MMcf	WC %	Cumulative Production Oil Mbbl	Gas MMcf	Water Mbbl
1	MAKU-1			1985-03				0	0	0				0	0	0
2	MAKU-2			1986-04				0	0	0				0	0	0
	Total								**0**	**0**				**0**	**0**	**0**

Table 2

Company: **Griffiths Energy International Inc.**
Property: **Maku**
Currency: **$US Dollars**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Gross Lease Reserves Summary

Entity Description	Reserve Class	Methodology	Oil (Mbbl) Initial Recoverable	Oil (Mbbl) Cumulative Production	Oil (Mbbl) Reserves	Non-Associated Gas (MMcf) Initial Recoverable	Non-Associated Gas (MMcf) Cumulative Production	Non-Associated Gas (MMcf) Raw Gas	Non-Associated Gas (MMcf) Reserves	Other Gross Lease Reserves Sol'n Gas MMcf	Other Gross Lease Reserves Cond Mbbl	Other Gross Lease Reserves LPG Mbbl	Other Gross Lease Reserves Sulphur Mlt
Proved Plus Probable Undeveloped													
Maku-03	H2	Dec,Vol	672	0	667 *	0	0	0	0	0	0	0	0
Maku-04	H2	Dec,Vol	672	0	667 *	0	0	0	0	0	0	0	0
Maku-05	H2	Dec,Vol	672	0	663 *	0	0	0	0	0	0	0	0
Maku-06	H2	Dec,Vol	672	0	663 *	0	0	0	0	0	0	0	0
Maku-07	H2	Dec,Vol	672	0	659 *	0	0	0	0	0	0	0	0
Maku-08	H2	Dec,Vol	672	0	659 *	0	0	0	0	0	0	0	0
Maku-09	H2	Dec,Vol	672	0	658 *	0	0	0	0	0	0	0	0
Maku-10	H2	Dec	672	0	659 *	0	0	0	0	0	0	0	0
Maku-11	H2	Dec	672	0	658 *	0	0	0	0	0	0	0	0
Maku-12	H2	Dec	672	0	656 *	0	0	0	0	0	0	0	0
Maku-13	H2	Dec	673	0	654 *	0	0	0	0	0	0	0	0
Total: Proved Plus Probable Undeveloped			**7,394**	**0**	**7,262 ***	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
PPP Undeveloped													
Maku-03	Q2	Dec,Vol	935	0	903 *	0	0	0	0	0	0	0	0
Maku-04	Q2	Dec,Vol	935	0	903 *	0	0	0	0	0	0	0	0
Maku-05	Q2	Dec,Vol	935	0	898 *	0	0	0	0	0	0	0	0
Maku-06	Q2	Dec,Vol	935	0	898 *	0	0	0	0	0	0	0	0
Maku-07	Q2	Dec,Vol	935	0	893 *	0	0	0	0	0	0	0	0
Maku-08	Q2	Dec,Vol	935	0	893 *	0	0	0	0	0	0	0	0
Maku-09	Q2	Dec,Vol	935	0	892 *	0	0	0	0	0	0	0	0
Maku-10	Q2	Dec	935	0	893 *	0	0	0	0	0	0	0	0
Maku-11	Q2	Dec	935	0	892 *	0	0	0	0	0	0	0	0
Maku-12	Q2	Dec	935	0	889 *	0	0	0	0	0	0	0	0
Maku-13	Q2	Dec	935	0	887 *	0	0	0	0	0	0	0	0
Maku-14	Q2	Dec	935	0	898 *	0	0	0	0	0	0	0	0
Maku-15	Q2	Dec	935	0	895 *	0	0	0	0	0	0	0	0
Maku-16	Q2	Dec	935	0	890 *	0	0	0	0	0	0	0	0
Maku-17	Q2	Dec	935	0	884 *	0	0	0	0	0	0	0	0
Maku-18	Q2	Dec	935	0	880 *	0	0	0	0	0	0	0	0
Maku-19	Q2	Dec	935	0	877 *	0	0	0	0	0	0	0	0
Maku-20	Q2	Dec	951	0	886 *	0	0	0	0	0	0	0	0
Total: PPP Undeveloped			**16,838**	**0**	**16,053 ***	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Low Estimate Contingent Resources													
Maku-03	CR1	Dec,Vol	435	0	435 *	0	0	0	0	0	0	0	0
Maku-04	CR1	Dec,Vol	435	0	435 *	0	0	0	0	0	0	0	0
Maku-05	CR1	Dec,Vol	435	0	431 *	0	0	0	0	0	0	0	0
Maku-06	CR1	Dec,Vol	435	0	431 *	0	0	0	0	0	0	0	0
Maku-07	CR1	Dec,Vol	435	0	428 *	0	0	0	0	0	0	0	0
Maku-08	CR1	Dec,Vol	435	0	428 *	0	0	0	0	0	0	0	0
Maku-09	CR1	Dec,Vol	432	0	425 *	0	0	0	0	0	0	0	0
Total: Low Estimate Contingent Resources			**3,044**	**0**	**3,011 ***	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Table 2

Notes

1. [*] Remaining reserves are less than the estimate due to economic limit.

Table 2.1
Oil Reservoir Parameters
Maku
Effective Date: December 31, 2012

	Description	Area (acres)	Net Pay (feet)	GRV (acreft)	Ngross	NRV (acreft)	Porosity	Water Satur'n	Formation Volume Factor	Original Oil-In-Place (mstb)	Recovery Factor	Original Recoverable Reserves (mstb)	Cumulative Oil Prod'n to 12-12-31 (mstb)	Remaining Reserves (mstb)
Maku	P90	1,055	21.5	36,117	0.6270	22,645	22.2%	36.0%	1.230	20,293				
Maku	P02	4,190	29.8	348,081	0.3590	124,961	22.3%	45.0%	1.230	96,669				
Maku	Low Estimate Contingent Resources									20,293	15.0%	3,044	0	3,044
Maku	Proved plus Probable Undeveloped Reserves									36,969	20.0%	7,394	0	7,394
Maku	PPP Undeveloped Reserves									67,349	25.0%	16,837	0	16,837

Table 3

Company: **Griffiths Energy International Inc.**
Property: **Maku**
Currency: **$US Dollars**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Gross Lease Daily Oil Production

Entity Description	Reserve Class	Year (bbl/d) 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Totals (Mbbl) Subtotal	Remainder	Total
Proved Plus Probable Undeveloped																
Maku-03	H2	0	0	532	327	220	159	120	94	75	62	52	44	614	52	667
Maku-04	H2	0	0	532	327	220	159	120	94	75	62	52	44	614	52	667
Maku-05	H2	0	0	304	410	265	185	137	106	84	68	56	48	607	56	663
Maku-06	H2	0	0	304	410	265	185	137	106	84	68	56	48	607	56	663
Maku-07	H2	0	0	58	509	314	214	155	117	92	74	61	51	600	59	659
Maku-08	H2	0	0	58	509	314	214	155	117	92	74	61	51	600	59	659
Maku-09	H2	0	0	0	533	326	220	159	120	94	75	62	52	598	60	658
Maku-10	H2	0	0	58	509	314	214	155	117	92	74	61	51	600	59	659
Maku-11	H2	0	0	0	533	326	220	159	120	94	75	62	52	598	60	658
Maku-12	H2	0	0	0	426	364	241	171	128	99	79	65	54	594	62	656
Maku-13	H2	0	0	0	304	410	265	186	138	106	84	68	57	590	64	654
Total: Proved Plus Probable Undeveloped		**0**	**0**	**1,846**	**4,797**	**3,336**	**2,275**	**1,652**	**1,258**	**985**	**794**	**654**	**550**	**6,624**	**638**	**7,262**
PPP Undeveloped																
Maku-03	Q2	0	0	633	416	293	218	168	134	109	91	76	66	804	99	903
Maku-04	Q2	0	0	633	416	293	218	168	134	109	91	76	66	804	99	903
Maku-05	Q2	0	0	356	507	345	251	190	150	120	99	83	71	793	105	898
Maku-06	Q2	0	0	356	507	345	251	190	150	120	99	83	71	793	105	898
Maku-07	Q2	0	0	66	610	402	285	213	165	131	107	89	76	783	110	893
Maku-08	Q2	0	0	66	610	402	285	213	165	131	107	89	76	783	110	893
Maku-09	Q2	0	0	0	635	415	293	218	169	134	109	91	77	781	112	892
Maku-10	Q2	0	0	66	610	402	285	213	165	131	107	89	76	783	110	893
Maku-11	Q2	0	0	0	635	415	293	218	169	134	109	91	77	781	112	892
Maku-12	Q2	0	0	0	503	457	317	233	179	141	115	95	80	774	115	889
Maku-13	Q2	0	0	0	356	506	346	251	191	149	120	99	83	767	119	887
Maku-14	Q2	0	0	356	507	345	251	190	150	120	99	83	71	793	105	898
Maku-15	Q2	0	0	189	566	378	271	203	159	127	104	87	74	787	108	895
Maku-16	Q2	0	0	0	549	442	309	228	176	139	113	93	79	776	114	890
Maku-17	Q2	0	0	0	189	564	378	271	204	158	127	104	87	760	123	884
Maku-18	Q2	0	0	0	0	633	415	293	218	168	134	109	91	753	128	880
Maku-19	Q2	0	0	0	0	503	457	317	234	179	141	115	95	745	132	877
Maku-20	Q2	0	0	0	0	357	510	350	255	194	153	123	102	746	141	886
Total: PPP Undeveloped		**0**	**0**	**2,723**	**7,617**	**7,495**	**5,630**	**4,128**	**3,168**	**2,497**	**2,025**	**1,676**	**1,413**	**14,005**	**2,047**	**16,053**
Low Estimate Contingent Resources																
Maku-03	CR1	0	0	317	209	148	110	85	68	55	46	39	33	405	30	435
Maku-04	CR1	0	0	317	209	148	110	85	68	55	46	39	33	405	30	435
Maku-05	CR1	0	0	178	255	174	126	96	76	61	50	42	36	399	31	431
Maku-06	CR1	0	0	178	255	174	126	96	76	61	50	42	36	399	31	431
Maku-07	CR1	0	0	33	306	202	144	107	84	67	54	45	38	394	33	428
Maku-08	CR1	0	0	33	306	202	144	107	84	67	54	45	38	394	33	428
Maku-09	CR1	0	0	0	318	208	147	109	85	67	55	45	38	391	33	425
Total: Low Estimate Contingent Resources		**0**	**0**	**1,058**	**1,857**	**1,254**	**907**	**686**	**539**	**433**	**356**	**298**	**253**	**2,789**	**222**	**3,011**

Table 3.1

Company: **Griffiths Energy International Inc.**
Property: **Maku**
Currency: **$US Dollars**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Company Daily Oil Production

Entity Description	Reserve Class	Year (bbl/d) 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Totals (Mbbl) Subtotal	Remainder	Total
Proved Plus Probable Undeveloped																
Maku-03	H2	0	0	254	156	105	76	57	45	36	29	21	17	291	24	314
Maku-04	H2	0	0	254	156	105	76	57	45	36	29	21	17	291	24	314
Maku-05	H2	0	0	145	196	126	88	65	50	40	32	23	19	287	25	312
Maku-06	H2	0	0	145	196	126	88	65	50	40	32	23	19	287	25	312
Maku-07	H2	0	0	28	243	150	102	74	56	44	35	24	20	283	27	310
Maku-08	H2	0	0	28	243	150	102	74	56	44	35	24	20	283	27	310
Maku-09	H2	0	0	0	254	155	105	76	57	45	36	25	21	282	27	309
Maku-10	H2	0	0	28	243	150	102	74	56	44	35	24	20	283	27	310
Maku-11	H2	0	0	0	254	155	105	76	57	45	36	25	21	282	27	309
Maku-12	H2	0	0	0	203	174	115	82	61	47	38	26	21	280	28	308
Maku-13	H2	0	0	0	145	195	127	89	66	50	40	27	22	278	29	307
Total: Proved Plus Probable Undeveloped		**0**	**0**	**881**	**2,290**	**1,592**	**1,086**	**789**	**600**	**470**	**379**	**262**	**218**	**3,127**	**288**	**3,415**
PPP Undeveloped																
Maku-03	Q2	0	0	302	199	140	104	72	43	36	31	27	25	357	43	400
Maku-04	Q2	0	0	302	199	140	104	72	43	36	31	27	25	357	43	400
Maku-05	Q2	0	0	170	242	165	120	82	48	40	34	30	27	349	46	395
Maku-06	Q2	0	0	170	242	165	120	82	48	40	34	30	27	349	46	395
Maku-07	Q2	0	0	32	291	192	136	91	53	44	37	32	28	342	48	390
Maku-08	Q2	0	0	32	291	192	136	91	53	44	37	32	28	342	48	390
Maku-09	Q2	0	0	0	303	198	140	93	54	44	38	33	29	340	49	389
Maku-10	Q2	0	0	32	291	192	136	91	53	44	37	32	28	342	48	390
Maku-11	Q2	0	0	0	303	198	140	93	54	44	38	33	29	340	49	389
Maku-12	Q2	0	0	0	240	218	152	100	57	47	39	34	30	335	50	385
Maku-13	Q2	0	0	0	170	242	165	108	61	50	42	36	31	330	52	382
Maku-14	Q2	0	0	170	242	165	120	82	48	40	34	30	27	349	46	395
Maku-15	Q2	0	0	90	270	180	129	87	51	42	36	31	28	345	47	392
Maku-16	Q2	0	0	0	262	211	147	98	56	46	39	34	30	337	50	386
Maku-17	Q2	0	0	0	90	269	180	116	65	53	44	37	33	324	54	378
Maku-18	Q2	0	0	0	0	302	198	126	70	56	46	39	34	318	56	374
Maku-19	Q2	0	0	0	0	240	218	136	75	59	49	41	36	312	58	369
Maku-20	Q2	0	0	0	0	170	243	150	82	64	53	44	38	308	61	369
Total: PPP Undeveloped		**0**	**0**	**1,300**	**3,636**	**3,578**	**2,687**	**1,772**	**1,012**	**828**	**698**	**602**	**530**	**6,074**	**892**	**6,966**
Low Estimate Contingent Resources																
Maku-03	CR1	0	0	151	100	70	52	41	32	26	22	19	16	193	14	208
Maku-04	CR1	0	0	151	100	70	52	41	32	26	22	19	16	193	14	208
Maku-05	CR1	0	0	85	122	83	60	46	36	29	24	20	17	191	15	206
Maku-06	CR1	0	0	85	122	83	60	46	36	29	24	20	17	191	15	206
Maku-07	CR1	0	0	16	146	96	69	51	40	32	26	22	18	188	16	204
Maku-08	CR1	0	0	16	146	96	69	51	40	32	26	22	18	188	16	204
Maku-09	CR1	0	0	0	152	99	70	52	40	32	26	22	18	187	16	203
Total: Low Estimate Contingent Resources		**0**	**0**	**505**	**886**	**599**	**433**	**328**	**257**	**206**	**170**	**142**	**121**	**1,331**	**108**	**1,439**

Table 4

Company: **Griffiths Energy International Inc.** Effective Date: **31-Dec-12**

Property: **Maku**

Economic Parameters

A) Price Forecasts and By-Product Data

GLJ (2013-01)

Oil Reference: 95% of BRENTUS

Transport Costs

Low Estimate Contingent Resources	$22.08/bbl
Proved plus Probable Undeveloped	$14.35/bbl
Proved plus Probable plus Possible Undeveloped	$11.49/bbl

Transport Costs are $6.50/bbl for export pipeline plus ITA tarriff

B) Operating Costs (2013 Dollars)

Well Costs: $10,000 / well / momth
Variable Costs $3.00 / bbl

Fixed Operating Costs and G&A

	Facility Operating Costs			G&A Costs		
Year	Proved M$	Proved+ Probable M$	Proved+ Probable+ Possible M$	Proved M$	Proved+ Probable M$	Proved+ Probable+ Possible M$
2013	0	0	0	1,500	3,750	7,500
2014	0	0	0	1,000	2,000	5,000
2015	1,500	3,000	7,500	1,000	2,000	5,000
2016	1,500	3,000	7,500	1,000	2,000	5,000
2017	1,500	3,000	7,500	500	1,000	2,500
2018	1,500	3,000	7,500	500	1,000	2,500
2019	1,500	3,000	7,500	250	500	1,250
2020+	1,500	3,000	7,500	250	500	1,250

All values are in 2012 dollars

C) Abandonment Costs (2013 Dollars)

	M$
Proved Undeveloped	$ 1,400
Proved plus Probable Undeveloped	$ 3,400
Proved plus Probable plus Possible Undeveloped	$ 5,400

Abandonment costs are scheduled on a unit of production basis.

Table 4.1

Company: **Griffiths Energy International Inc.** Effective Date: **31-Dec-12**
Property: **Maku**

Economic Parameters

D) Capital Costs

Capital Summary (2013 Dollars)

Year	Well/Area	RC	Development Description	Gross Lease Capital Expenditures: Development M$	Tangible M$	Plant & Gath. M$	Total M$	Company Total M$	Capital Interest %
	Low Estimate Contingent Resources								
2013	Maku			0	0	12,211	12,211	8,141	66.67
2014	Maku			0	0	24,422	24,422	16,281	66.67
	Well Capital			20,800	0	0	20,800	13,867	66.67
2015	Well Capital			41,600	0	0	41,600	27,733	66.67
2016	Well Capital			10,400	0	0	10,400	6,933	66.67
	Total: Low Estimate Contingent Resources			**72,800**	**0**	**36,633**	**109,433**	**72,955**	**66.67**
	Proved Plus Probable Undeveloped								
2013	Maku			0	0	25,263	25,263	16,842	66.67
2014	Maku			0	0	50,527	50,527	33,685	66.67
	Well Capital			31,800	0	0	31,800	21,200	66.67
2015	Well Capital			63,000	0	0	63,000	42,000	66.67
2016	Well Capital			52,600	0	0	52,600	35,067	66.67
	Total: Proved Plus Probable Undeveloped			**147,400**	**0**	**75,790**	**223,190**	**148,793**	**66.67**
	PPP Undeveloped								
2013	Maku			0	0	43,463	43,463	28,975	66.67
2014	Maku			0	0	86,925	86,925	57,950	66.67
	Well Capital			47,700	0	0	47,700	31,800	66.67
2015	Well Capital			78,900	0	0	78,900	52,600	66.67
2016	Well Capital			78,900	0	0	78,900	52,600	66.67
2017	Well Capital			31,200	0	0	31,200	20,800	66.67
	Total: PPP Undeveloped			**236,700**	**0**	**130,388**	**367,088**	**244,725**	**66.67**

Table 4.2
Griffiths Energy International Inc.
Maku Property
Capital Cost Breakdown
by Reserves Class

	Amounts (M$)		
Category, (well counts**)**	**CR1**	**2P**	**3P**
Oil Wells, (7/11/18**)**	72,800	114,400	187,200
Injector/Service Wells, (0/6/9**)**	-	33,000	49,500
Facilities & Pipelines	36,633	75,790	130,388
Totals	**109,433**	**223,190**	**367,088**

Company: **Griffiths Energy International Inc.**
Property: **Maku**
Currency: **$US Dollars**

Reserve Class: **Proved Plus Probable**
Development Class: **Undeveloped**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production				
Year	Gross Oil Wells	Gross Daily bbl/d	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	0	0	0	0	0	0.00
2014	0	0	0	0	0	0.00
2015	7	1,846	881	322	322	83.03
2016	11	4,797	2,290	836	836	83.03
2017	11	3,336	1,592	581	581	80.65
2018	11	2,275	1,086	396	396	80.65
2019	11	1,652	789	288	288	81.93
2020	11	1,258	600	219	219	83.86
2021	11	985	470	172	172	85.83
2022	11	794	379	138	138	87.82
2023	11	654	262	96	96	89.87
2024	11	550	218	80	80	91.95
Sub.				3,127	3,127	83.04
Rem.				288	288	97.93
Tot.				**3,415**	**3,415**	**84.30**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	0	0	0	0	0	0	0	0	0	0	0	0	2,501	0	2,501
2014	0	0	0	0	0	0	0	0	0	0	0	0	1,701	0	1,701
2015	26,709	0	0	26,709	0	26,709	0	0	0	0	0	26,709	5,384	0	5,384
2016	69,387	0	0	69,387	0	69,387	0	0	0	0	0	69,387	8,074	0	8,074
2017	46,875	0	0	46,875	0	46,875	0	0	0	0	0	46,875	6,540	0	6,540
2018	31,964	0	0	31,964	0	31,964	0	0	0	0	0	31,964	5,933	0	5,933
2019	23,581	0	0	23,581	0	23,581	0	0	0	0	0	23,581	5,071	0	5,071
2020	18,376	0	0	18,376	0	18,376	0	0	0	0	0	18,376	4,841	0	4,841
2021	14,729	0	0	14,729	0	14,729	0	0	0	0	0	14,729	4,705	0	4,705
2022	12,155	0	0	12,155	0	12,155	0	0	0	0	0	12,155	4,633	0	4,633
2023	8,606	0	0	8,606	0	8,606	0	0	0	0	0	8,606	4,601	0	4,601
2024	7,319	0	0	7,319	0	7,319	0	0	0	0	0	7,319	4,598	0	4,598
Sub.	259,700	0	0	259,700	0	259,700	0	0	0	0	0	259,700	58,581	0	58,581
Rem.	28,223	0	0	28,223	0	28,223	0	0	0	0	0	28,223	22,678	0	22,678
Tot.	**287,923**	**0**	**0**	**287,923**	**0**	**287,923**	**0**	**0**	**0**	**0**	**0**	**287,923**	**81,259**	**0**	**81,259**
Disc	166,251	0	0	166,251	0	166,251	0	0	0	0	0	166,251	39,719	0	39,719

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	**Net Prod'n Revenue** M$	Other Income M$	**Aband. Costs** M$	**Oper. Income** M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	-2,501	-1,333	0	-3,834	0	16,842	0	16,842	-20,676	-20,676	-19,714
2014	0	0	0	-1,701	0	0	-1,701	21,624	34,358	0	55,982	-57,683	-78,360	-69,713
2015	0	0	0	21,326	0	224	21,102	43,697	0	0	43,697	-22,595	-100,955	-87,518
2016	0	0	0	61,313	0	593	60,720	37,213	0	0	37,213	23,507	-77,448	-70,679
2017	0	0	0	40,335	0	421	39,914	0	0	0	0	39,914	-37,534	-44,686
2018	0	0	0	26,030	0	293	25,738	0	0	0	0	25,738	-11,797	-29,448
2019	0	0	0	18,510	0	217	18,293	0	0	0	0	18,293	6,497	-19,603
2020	0	0	0	13,534	0	168	13,366	0	0	0	0	13,366	19,863	-13,063
2021	0	0	0	10,024	0	135	9,889	0	0	0	0	9,889	29,752	-8,664
2022	0	0	0	7,522	0	111	7,411	0	0	0	0	7,411	37,163	-5,668
2023	0	0	0	4,005	0	93	3,912	0	0	0	0	3,912	41,075	-4,230
2024	0	0	0	2,721	0	80	2,641	0	0	0	0	2,641	43,716	-3,347
Sub.	0	0	0	201,118	-1,333	2,334	197,451	102,534	51,201	0	153,734	43,716	43,716	-3,347
Rem.	0	0	0	5,545	0	196	5,349	0	0	0	0	5,349	49,066	-1,880
Tot.	**0**	**0**	**0**	**206,664**	**-1,333**	**2,530**	**202,800**	**102,534**	**51,201**	**0**	**153,734**	**49,066**	**49,066**	**-1,880**
Disc	0	0	0	126,532	-1,271	1,468	123,793	79,833	45,840	0	125,673	-1,880	-1,880	-1,880

SUMMARY OF RESERVES

		Remaining Reserves at Jan 01, 2013					Oil Equivalents			Reserve Life Indic. (yr)		
Product	Units	Gross	Working Interest	Roy/NPI Interest	Total Company	Net	Oil Eq. Factor	Company Mboe	% of Total	Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	7,262	3,415	0	3,415	3,415	1.000	3,415	100	17.0	10.6	4.9
Total: Oil Eq.	Mboe	7,262	3,415	0	3,415	3,415	1.000	3,415	100	17.0	10.6	4.9

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	0.00	0.00	0.00	0.00	0.00	0.00	0.00	287,923	100	166,251	100
Total: Oil Eq.	$/boe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	287,923	100	166,251	100

INTEREST AND NET PRESENT VALUE SUMMARY

Revenue Interests and Burdens (%)		
Entity Name	Initial	Average
Working Interest	0.0000	46.9692
Capital Interest	66.6667	66.6667
Royalty Interest	0.0000	0.0000
Crown Royalty	0.0000	0.0000
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000

	Net Present Value Before Income Tax				
Disc. Rate %	Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/boe
0.0	206,664	202,800	153,734	49,066	14.37
5.0	159,858	156,661	138,518	18,143	5.31
8.0	138,594	135,691	130,560	5,131	1.50
10.0	126,532	123,793	125,673	-1,880	-0.55
12.0	115,866	113,271	121,089	-7,818	-2.29
15.0	102,052	99,643	114,728	-15,085	-4.42
20.0	83,601	81,438	105,322	-23,884	-6.99

Evaluator: Herchen, Leonard L.
Run Date: January 21, 2013 15:30:28

Company: **Griffiths Energy International Inc.**
Property: **Maku**
Currency: **$US Dollars**

Reserve Class: **PPP**
Development Class: **Undeveloped**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production				
Year	Gross Oil Wells	Gross Daily bbl/d	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	0	0	0	0	0	0.00
2014	0	0	0	0	0	0.00
2015	9	2,723	1,300	475	475	85.88
2016	15	7,617	3,636	1,327	1,327	85.88
2017	18	7,495	3,578	1,306	1,306	83.51
2018	18	5,630	2,687	981	981	83.51
2019	18	4,128	1,772	647	647	84.79
2020	18	3,168	1,012	369	369	86.72
2021	18	2,497	828	302	302	88.69
2022	18	2,025	698	255	255	90.68
2023	18	1,676	602	220	220	92.73
2024	18	1,413	530	193	193	94.81
Sub.				6,074	6,074	85.80
Rem.				892	892	102.50
Tot.				**6,966**	**6,966**	**87.94**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After Process.	Net Revenue After Royalty	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	M$	M$	Fixed M$	Variable M$	Total M$
2013	0	0	0	0	0	0	0	0	0	0	0	0	5,001	0	5,001
2014	0	0	0	0	0	0	0	0	0	0	0	0	3,401	0	3,401
2015	40,753	0	0	40,753	0	40,753	0	0	0	0	0	40,753	10,905	0	10,905
2016	113,973	0	0	113,973	0	113,973	0	0	0	0	0	113,973	15,225	0	15,225
2017	109,047	0	0	109,047	0	109,047	0	0	0	0	0	109,047	14,134	0	14,134
2018	81,912	0	0	81,912	0	81,912	0	0	0	0	0	81,912	13,400	0	13,400
2019	54,830	0	0	54,830	0	54,830	0	0	0	0	0	54,830	11,584	0	11,584
2020	32,017	0	0	32,017	0	32,017	0	0	0	0	0	32,017	11,011	0	11,011
2021	26,791	0	0	26,791	0	26,791	0	0	0	0	0	26,791	10,658	0	10,658
2022	23,106	0	0	23,106	0	23,106	0	0	0	0	0	23,106	10,459	0	10,459
2023	20,379	0	0	20,379	0	20,379	0	0	0	0	0	20,379	10,357	0	10,357
2024	18,342	0	0	18,342	0	18,342	0	0	0	0	0	18,342	10,326	0	10,326
Sub.	521,150	0	0	521,150	0	521,150	0	0	0	0	0	521,150	126,461	0	126,461
Rem.	91,408	0	0	91,408	0	91,408	0	0	0	0	0	91,408	69,693	0	69,693
Tot.	**612,558**	**0**	**0**	**612,558**	**0**	**612,558**	**0**	**0**	**0**	**0**	**0**	**612,558**	**196,153**	**0**	**196,153**
Disc	335,411	0	0	335,411	0	335,411	0	0	0	0	0	335,411	88,614	0	88,614

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	**Net Prod'n Revenue** M$	Other Income M$	**Aband. Costs** M$	**Oper. Income** M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	-5,001	-1,333	0	-6,334	0	28,975	0	28,975	-35,309	-35,309	-33,666
2014	0	0	0	-3,401	0	0	-3,401	32,436	59,109	0	91,545	-94,946	-130,255	-115,964
2015	0	0	0	29,848	0	238	29,610	54,725	0	0	54,725	-25,115	-155,370	-135,754
2016	0	0	0	98,748	0	678	98,070	55,820	0	0	55,820	42,250	-113,120	-105,488
2017	0	0	0	94,913	0	681	94,233	22,515	0	0	22,515	71,718	-41,402	-58,783
2018	0	0	0	68,512	0	522	67,991	0	0	0	0	67,991	26,589	-18,531
2019	0	0	0	43,246	0	390	42,856	0	0	0	0	42,856	69,445	4,534
2020	0	0	0	21,007	0	305	20,701	0	0	0	0	20,701	90,146	14,663
2021	0	0	0	16,133	0	245	15,888	0	0	0	0	15,888	106,034	21,730
2022	0	0	0	12,647	0	203	12,444	0	0	0	0	12,444	118,477	26,761
2023	0	0	0	10,022	0	171	9,851	0	0	0	0	9,851	128,328	30,383
2024	0	0	0	8,015	0	147	7,868	0	0	0	0	7,868	136,196	33,012
Sub.	0	0	0	394,689	-1,333	3,581	389,776	165,495	88,084	0	253,579	136,196	136,196	33,012
Rem.	0	0	0	21,715	0	499	21,216	0	0	0	0	21,216	157,412	38,560
Tot.	**0**	**0**	**0**	**416,404**	**-1,333**	**4,080**	**410,991**	**165,495**	**88,084**	**0**	**253,579**	**157,412**	**157,412**	**38,560**
Disc	0	0	0	246,797	-1,271	2,218	243,308	125,886	78,862	0	204,748	38,560	38,560	38,560

SUMMARY OF RESERVES

		Remaining Reserves at Jan 01, 2013					Oil Equivalents			Reserve Life Indic. (yr)		
Product	Units	Gross	Working Interest	Roy/NPI Interest	Total Company	Net	Oil Eq. Factor	Company Mboe	% of Total	Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	16,053	6,966	0	6,966	6,966	1.000	6,966	100	19.0	14.7	5.4
Total: Oil Eq.	Mboe	16,053	6,966	0	6,966	6,966	1.000	6,966	100	19.0	14.7	5.4

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	0.00	0.00	0.00	0.00	0.00	0.00	0.00	612,558	100	335,411	100
Total: Oil Eq.	$/boe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	612,558	100	335,411	100

INTEREST AND NET PRESENT VALUE SUMMARY

Revenue Interests and Burdens (%)		
Entity Name	Initial	Average
Working Interest	0.0000	43.2934
Capital Interest	66.6667	66.6667
Royalty Interest	0.0000	0.0000
Crown Royalty	0.0000	0.0000
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000

	Net Present Value Before Income Tax				
Disc. Rate %	Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/boe
0.0	416,404	410,991	253,579	157,412	22.60
5.0	316,369	312,118	226,936	85,183	12.23
8.0	271,818	268,059	213,155	54,904	7.88
10.0	246,797	243,308	204,748	38,560	5.54
12.0	224,825	221,568	196,899	24,669	3.54
15.0	196,582	193,619	186,067	7,552	1.08
20.0	159,250	156,666	170,184	-13,518	-1.94

Evaluator: Herchen, Leonard L.
Run Date: January 21, 2013 15:30:47

Company: **Griffiths Energy International Inc.**
Property: **Maku**
Currency: **$US Dollars**

Reserve Class: **Contingent Resources**
Development Class: **Low Estimate**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production				
Year	Gross Oil Wells	Gross Daily bbl/d	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	0	0	0	0	0	0.00
2014	0	0	0	0	0	0.00
2015	6	1,058	505	184	184	75.29
2016	7	1,857	886	324	324	75.28
2017	7	1,254	599	219	219	72.91
2018	7	907	433	158	158	72.91
2019	7	686	328	120	120	74.19
2020	7	539	257	94	94	76.12
2021	7	433	206	75	75	78.09
2022	7	356	170	62	62	80.08
2023	7	298	142	52	52	82.13
2024	7	253	121	44	44	84.21
Sub.				1,331	1,331	75.52
Rem.				108	108	88.70
Tot.				**1,439**	**1,439**	**76.51**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens														
	Working Interest				Royalty Interest	Company Interest	Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After Process.	Net Revenue After Royalty	Operating Expenses		
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	M$	M$	Fixed M$	Variable M$	Total M$
2013	0	0	0	0	0	0	0	0	0	0	0	0	1,001	0	1,001
2014	0	0	0	0	0	0	0	0	0	0	0	0	681	0	681
2015	13,873	0	0	13,873	0	13,873	0	0	0	0	0	13,873	2,704	0	2,704
2016	24,355	0	0	24,355	0	24,355	0	0	0	0	0	24,355	3,639	0	3,639
2017	15,932	0	0	15,932	0	15,932	0	0	0	0	0	15,932	3,040	0	3,040
2018	11,519	0	0	11,519	0	11,519	0	0	0	0	0	11,519	2,821	0	2,821
2019	8,873	0	0	8,873	0	8,873	0	0	0	0	0	8,873	2,509	0	2,509
2020	7,150	0	0	7,150	0	7,150	0	0	0	0	0	7,150	2,436	0	2,436
2021	5,885	0	0	5,885	0	5,885	0	0	0	0	0	5,885	2,393	0	2,393
2022	4,963	0	0	4,963	0	4,963	0	0	0	0	0	4,963	2,374	0	2,374
2023	4,259	0	0	4,259	0	4,259	0	0	0	0	0	4,259	2,370	0	2,370
2024	3,718	0	0	3,718	0	3,718	0	0	0	0	0	3,718	2,377	0	2,377
Sub.	100,528	0	0	100,528	0	100,528	0	0	0	0	0	100,528	28,343	0	28,343
Rem.	9,603	0	0	9,603	0	9,603	0	0	0	0	0	9,603	7,849	0	7,849
Tot.	**110,131**	**0**	**0**	**110,131**	**0**	**110,131**	**0**	**0**	**0**	**0**	**0**	**110,131**	**36,193**	**0**	**36,193**
Disc	63,919	0	0	63,919	0	63,919	0	0	0	0	0	63,919	18,307	0	18,307

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	**Net Prod'n Revenue** M$	Other Income M$	**Aband. Costs** M$	**Oper. Income** M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	-1,001	-1,333	0	-2,334	0	8,141	0	8,141	-10,475	-10,475	-9,987
2014	0	0	0	-681	0	0	-681	14,144	16,607	0	30,751	-31,432	-41,907	-37,232
2015	0	0	0	11,170	0	129	11,041	28,854	0	0	28,854	-17,813	-59,719	-51,268
2016	0	0	0	20,716	0	230	20,486	7,358	0	0	7,358	13,128	-46,591	-41,864
2017	0	0	0	12,892	0	159	12,733	0	0	0	0	12,733	-33,858	-33,572
2018	0	0	0	8,698	0	117	8,581	0	0	0	0	8,581	-25,277	-28,492
2019	0	0	0	6,365	0	90	6,274	0	0	0	0	6,274	-19,003	-25,115
2020	0	0	0	4,715	0	72	4,643	0	0	0	0	4,643	-14,361	-22,843
2021	0	0	0	3,492	0	59	3,433	0	0	0	0	3,433	-10,927	-21,316
2022	0	0	0	2,589	0	50	2,539	0	0	0	0	2,539	-8,388	-20,289
2023	0	0	0	1,889	0	42	1,847	0	0	0	0	1,847	-6,541	-19,610
2024	0	0	0	1,341	0	37	1,304	0	0	0	0	1,304	-5,237	-19,175
Sub.	0	0	0	72,184	-1,333	985	69,866	50,355	24,747	0	75,103	-5,237	-5,237	-19,175
Rem.	0	0	0	1,754	0	52	1,702	0	0	0	0	1,702	-3,535	-18,695
Tot.	**0**	**0**	**0**	**73,938**	**-1,333**	**1,037**	**71,568**	**50,355**	**24,747**	**0**	**75,103**	**-3,535**	**-3,535**	**-18,695**
Disc	0	0	0	45,612	-1,271	612	43,728	40,267	22,156	0	62,423	-18,695	-18,695	-18,695

SUMMARY OF RESERVES

		Remaining Reserves at Jan 01, 2013					Oil Equivalents			Reserve Life Indic. (yr)		
Product	Units	Gross	Working Interest	Roy/NPI Interest	Total Company	Net	Oil Eq. Factor	Company Mboe	% of Total	Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	3,011	1,439	0	1,439	1,439	1.000	1,439	100	16.0	7.8	5.0
Total: Oil Eq.	Mboe	3,011	1,439	0	1,439	1,439	1.000	1,439	100	16.0	7.8	5.0

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	0.00	0.00	0.00	0.00	0.00	0.00	0.00	110,131	100	63,919	100
Total: Oil Eq.	$/boe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	110,131	100	63,919	100

INTEREST AND NET PRESENT VALUE SUMMARY

Revenue Interests and Burdens (%)		
Entity Name	Initial	Average
Working Interest	0.0000	47.8243
Capital Interest	66.6667	66.6667
Royalty Interest	0.0000	0.0000
Crown Royalty	0.0000	0.0000
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000

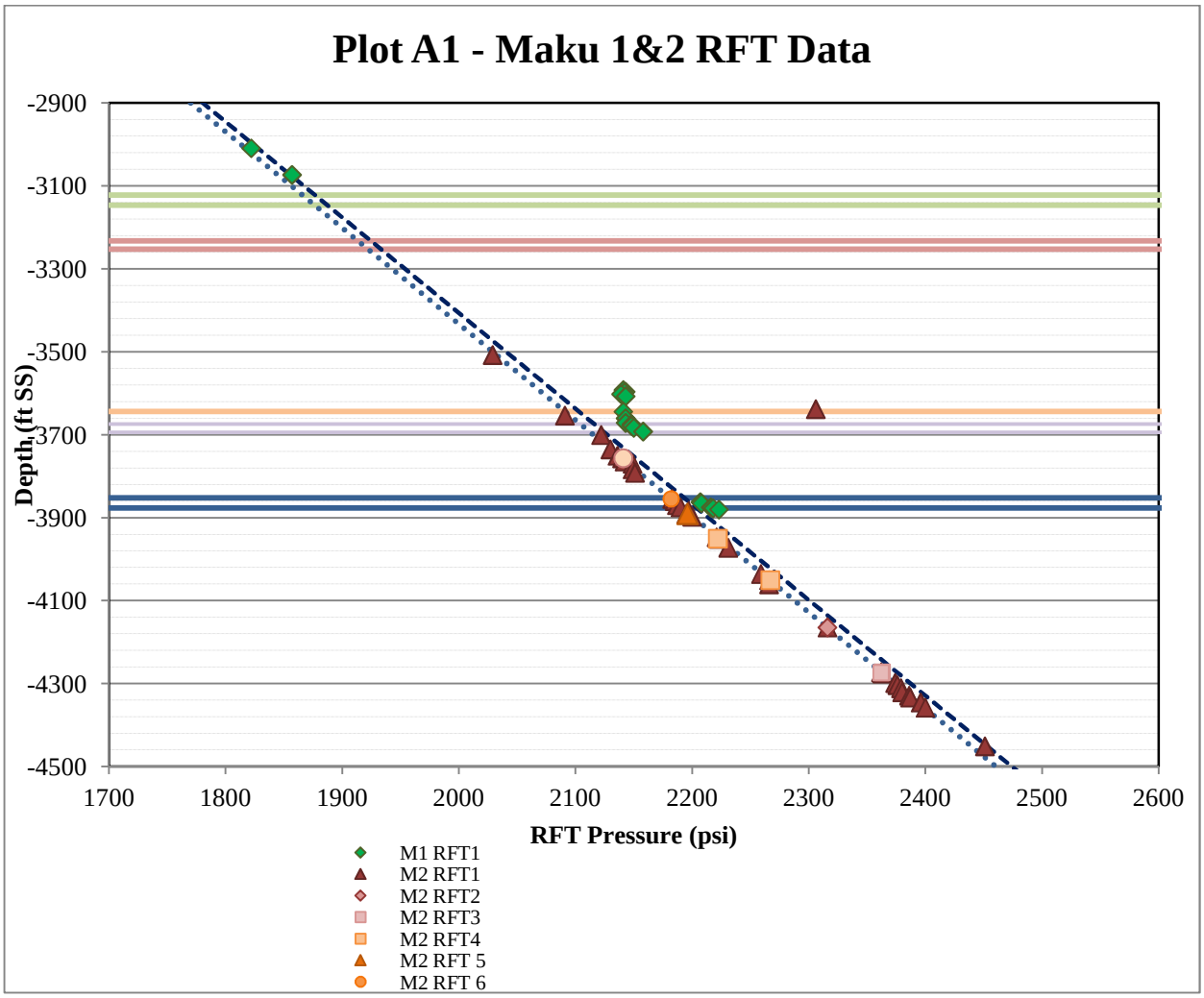
	Net Present Value Before Income Tax				
Disc. Rate %	Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/boe
0.0	73,938	71,568	75,103	-3,534.8	-2.46
5.0	57,396	55,310	68,268	-12,958.1	-9.00
8.0	49,878	47,921	64,655	-16,734.6	-11.63
10.0	45,612	43,728	62,423	-18,695.2	-12.99
12.0	41,838	40,019	60,319	-20,299.9	-14.10
15.0	36,947	35,214	57,382	-22,168.5	-15.40
20.0	30,406	28,790	53,003	-24,212.9	-16.82

Evaluator: Herchen, Leonard L.
Run Date: January 21, 2013 15:30:55

MAKU – RFT Summary

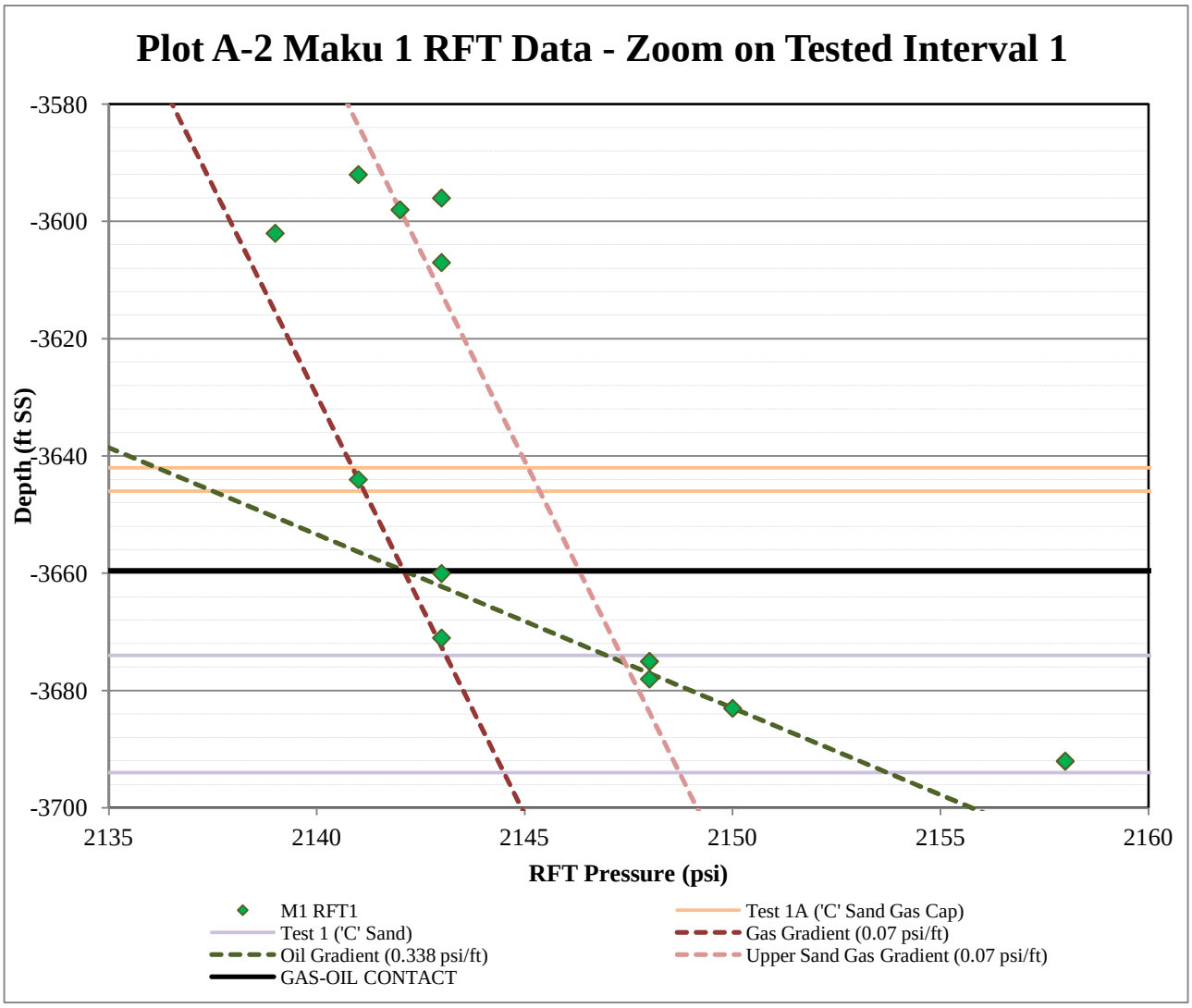
Plot A1 – All RFT data points

- Green data points = Maku-1
- Red/Orange data points = Maku-2
- Tested intervals between colored lines:
  - Orange = Gas Cap in Maku-1 – C Sand
  - Purple = Tested oil zone in Maku-1 – C Sand
  - Blue = Tested water zone in Maku-2 – C Sand



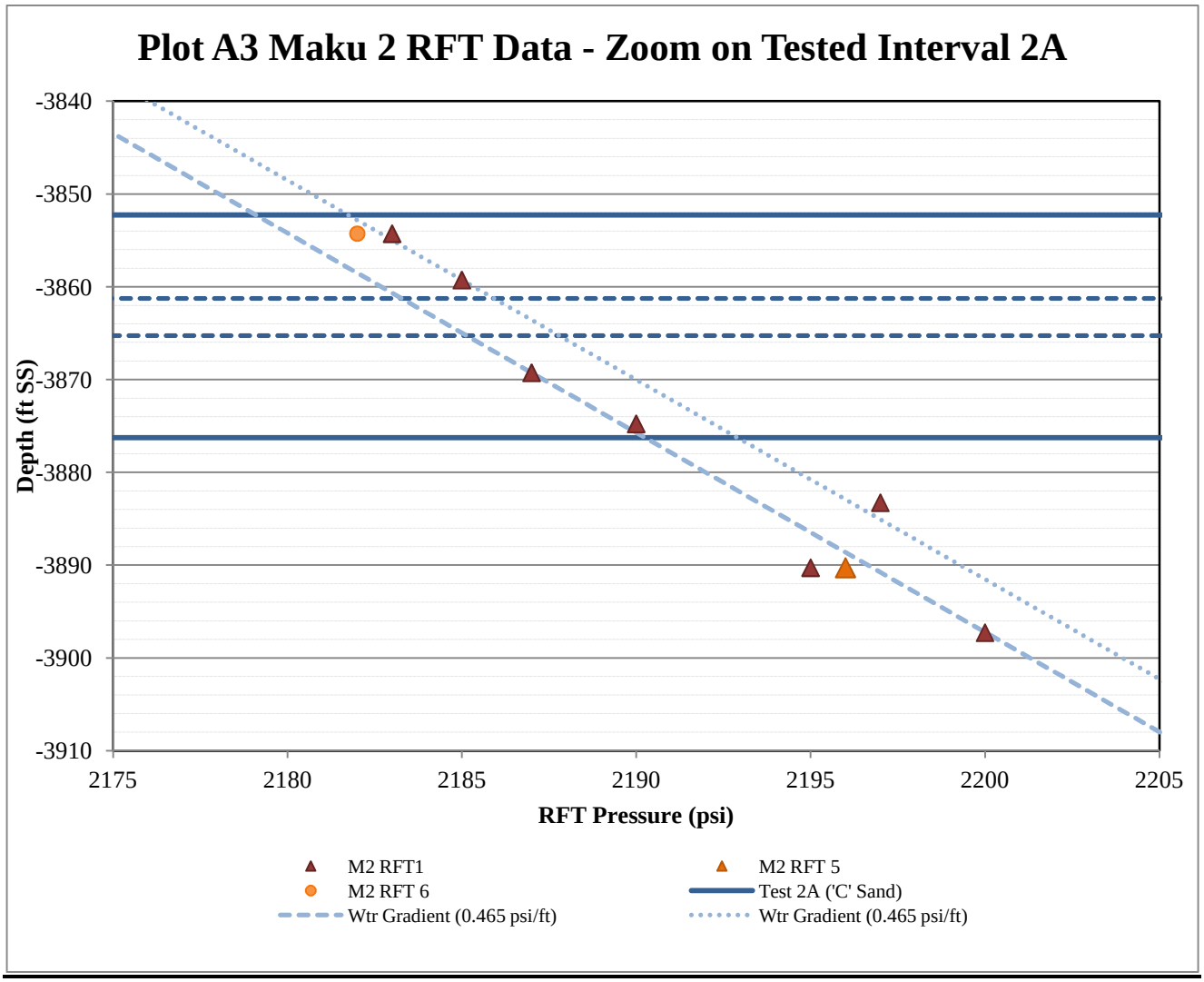
Plot A2 – Zoom in on Maku-1 "C" Sand data

- Gas-oil contact (GOC) located at ~ -3660 ft (-1115.6 m) (+/- 2-5 ft).
- Attempted to use the last measured pressure point in the 'C' sand to locate an oil-water contact (OWC) but this resulted in a contact within the tested oil leg. Thus concluded there is not a water contact at Maku-1 (which is in agreement with log interpretation).

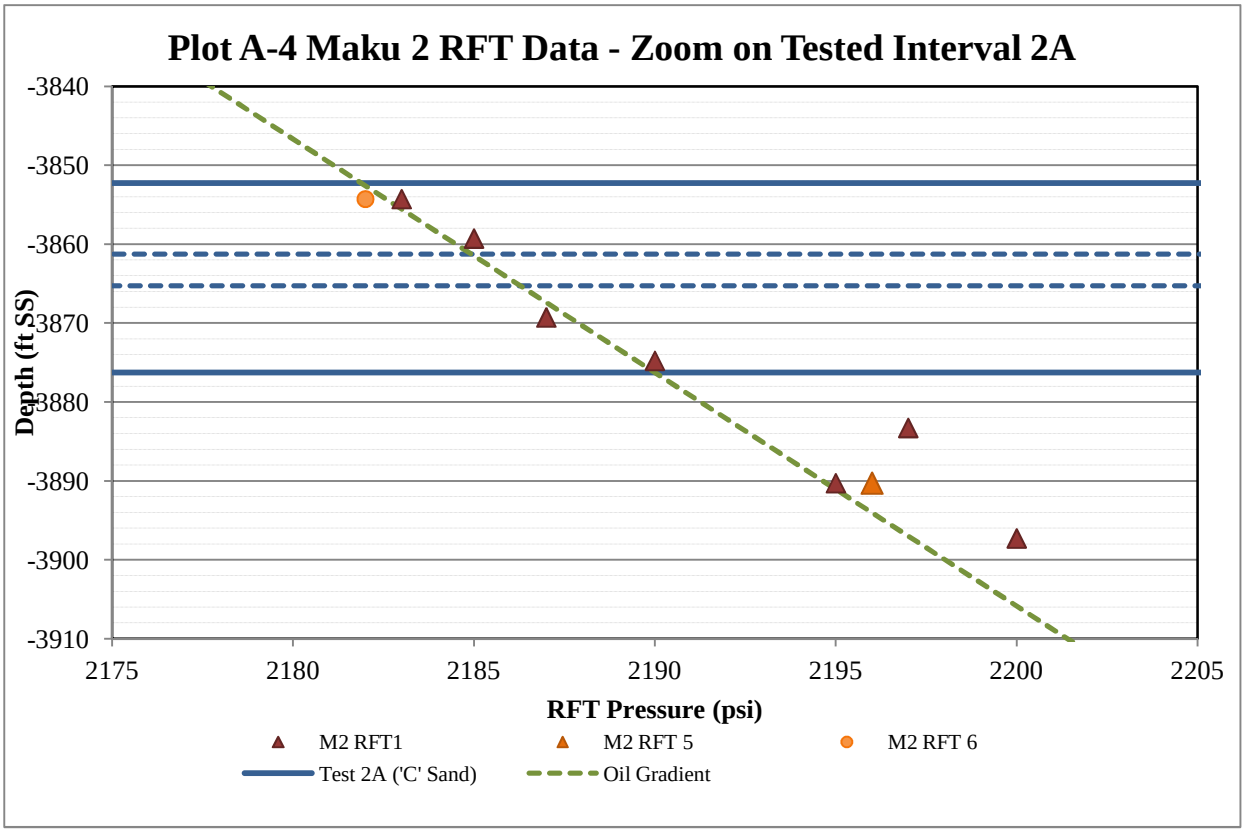


Plots A3 and A4 – Zoom in on Maku-2 "C" Sand data

- The plot below shows a good fit using a water gradient of 0.465 psi/ft but assumes the two completed intervals are not in communication and are two separate water zones:



- Could also fit the data in the two completed intervals using an oil gradient of 0.338 psi/ft, assuming one continuous zone:

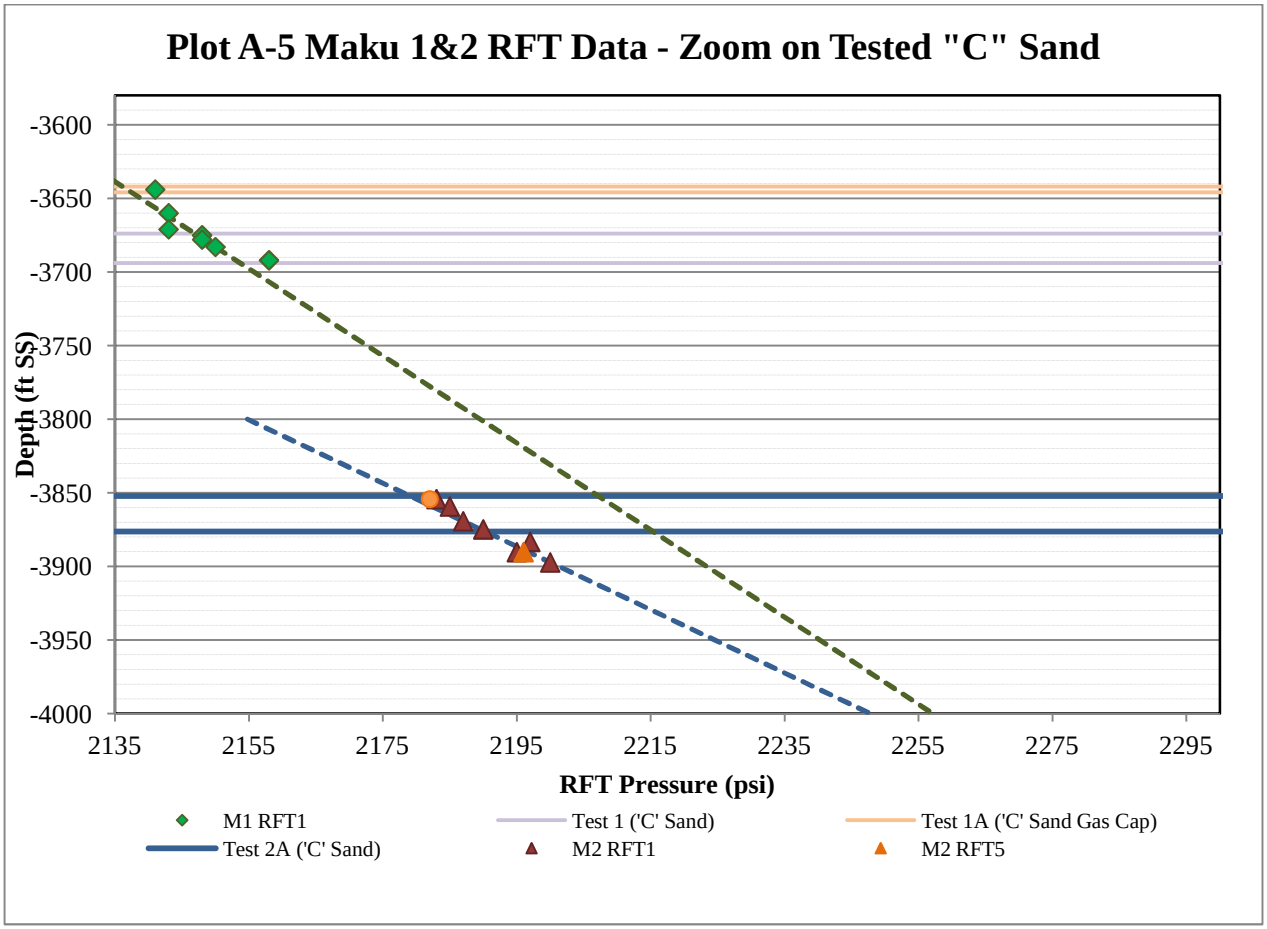


- Thus the RFT data over the water tested interval in Maku-2 does not rule out the possibility of oil. However, additional data (logs, fluid recovery, gas detection during drilling etc.) result in the conclusion that Maku-2 is in fact wet in the tested intervals.

Plot A5 – Zoom in on Maku-1 & 2 "C" Sand data

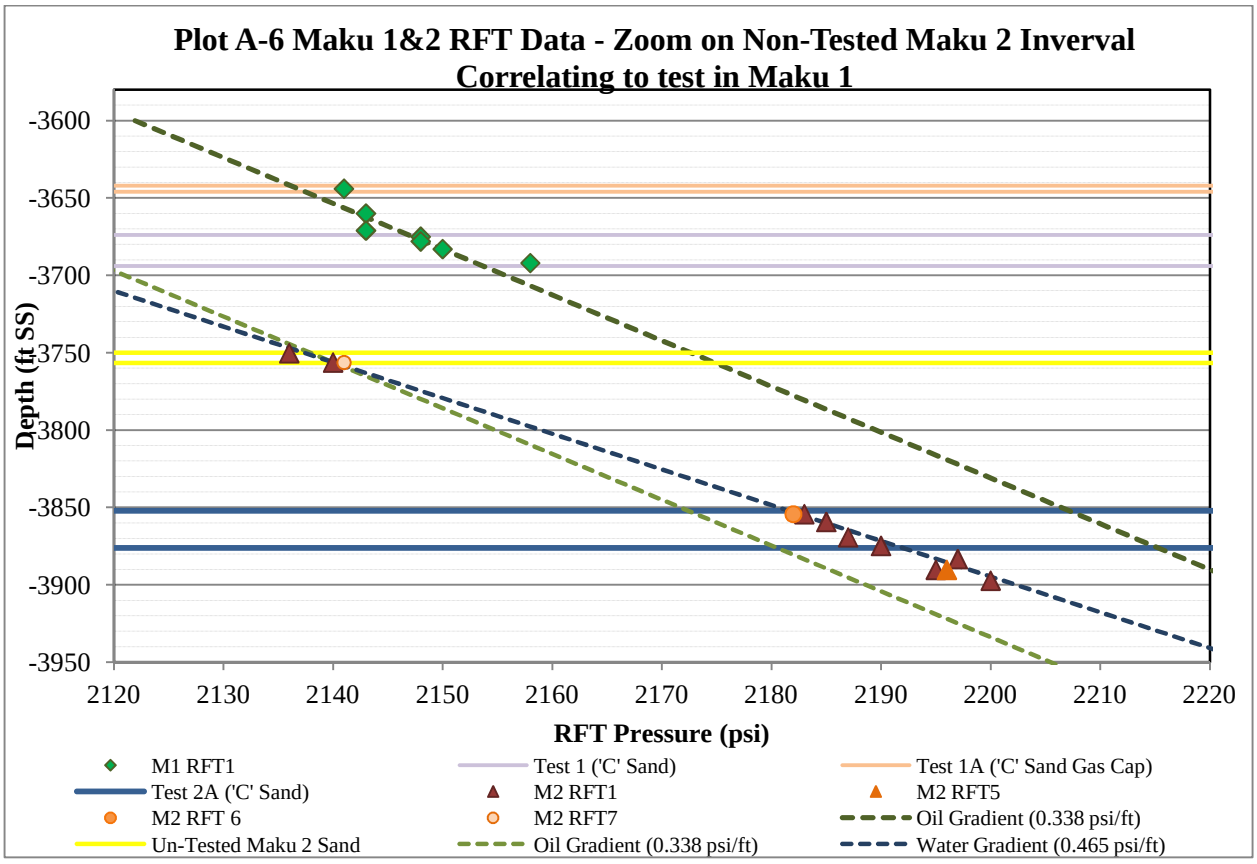
- Lastly the Maku-1 & 2 RFT data over the tested interval was plotted simultaneously. The data below indicates that the "C" sand intervals in the two wells are not in communication. For Maku-2 to have tested the water leg connected to Maku-1, the pressure points would have had to fall to the right of the extrapolated oil gradient in Maku-2. Furthermore, If there was in fact oil in Maku-2, the data from Maku-2 would have fallen on the green oil gradient line as well.
- The implied OWC from the data below would be the intersection of the green oil gradient line with the blue water gradient line which would be way below the actual water tested zone.
- Thus based on RFT data alone, one would conclude the 'C' sands in Maku-1 & 2 are not in communication. However, assumptions were required in this analysis such as:

- Assumed pressure measurements were recorded in psig for both wells (test notes indicate “psi” only).
- Assumed the depths recorded were measured from KB.
- Assumed recorders were properly calibrated and were accurate and consistent between wells.
- Assumed all depths were TVD for both wells. Maku-2 has low deviation angle at the C sand interval. Maku-1 did have a sidetrack but RFT tests 1-3 were taken prior to the successful sidetrack – assumed that the original hole was not deviated. There could be very slight deviation at the ‘C’ sand intervals in Maku-1 and 2 but this is likely minimal.



Plot A6 – Zoom in on Maku-1 Tested Sand and Correlated Sand in Maku-2 (Not Tested)

- Log analysis identified the sand that could be correlated to the interval that tested oil in Maku-1 as 4914.7-4996.7 ft (actual oil pay more like 4973.8-4980.3 ft). RFT data from Maku-2 over this interval is highlighted in yellow:



- Thus it appears that RFT data is indicating the two are not in communication. However, the quality of the data is uncertain and there are not many data points to go on. Plus this analysis is limited by the following assumptions:
  - Assumed pressure measurements were recorded in psig for both wells (test notes indicate “psi” only).
  - Assumed the depths recorded were measured from KB.
  - Assumed recorders were properly calibrated and were accurate and consistent between wells.
  - Assumed all depths were TVD for both wells. Maku-2 has low deviation angle at the C sand interval. Maku-1 did have a sidetrack but RFT tests 1-3 were taken prior to the successful sidetrack – assumed that the original hole was not deviated. There could be very slight deviation at the ‘C’ sand intervals in Maku-1 and 2 but this is likely minimal.

GRIFFITHS ENERGY INTERNATIONAL INC.

MANGARA

Effective December 31, 2012

Prepared by
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The analysis of this property as reported herein was conducted within the context of an evaluation of a distinct group of properties in aggregate. Extraction and use of this analysis outside this context may not be appropriate without supplementary due diligence.

MANGARA

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Company: **Griffiths Energy International Inc.**
Property: **Mangara**
Currency: **$US Dollars**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Summary of Reserves and Values

	Proved Undeveloped	Proved Plus Probable Undeveloped	PPP Undeveloped
MARKETABLE RESERVES			
Light/Medium Oil (Mbbl)			
Gross Lease	11,257	32,667	84,221
Total Company Interest	5,386	13,448	29,227
Net After Royalty	5,386	13,448	29,227
Oil Equivalent (Mbbl)			
Gross Lease	11,257	32,667	84,221
Total Company Interest	5,386	13,448	29,227
Net After Royalty	5,386	13,448	29,227
BEFORE TAX PRESENT VALUE (M$)			
0%	333,763	756,897	1,566,193
5%	289,621	629,389	1,172,291
8%	267,882	570,335	1,015,037
10%	254,984	536,388	930,891
12%	243,191	506,032	859,193
15%	227,307	466,133	769,691
20%	204,831	411,498	655,090
FIRST 6 YEARS BEFORE TAX CASH FLOW (M$)			
2013	64,177	80,570	91,867
2014	48,113	130,896	183,109
2015	71,180	136,510	229,361
2016	55,342	115,901	145,357
2017	37,350	86,395	130,865
2018	29,286	50,244	124,964

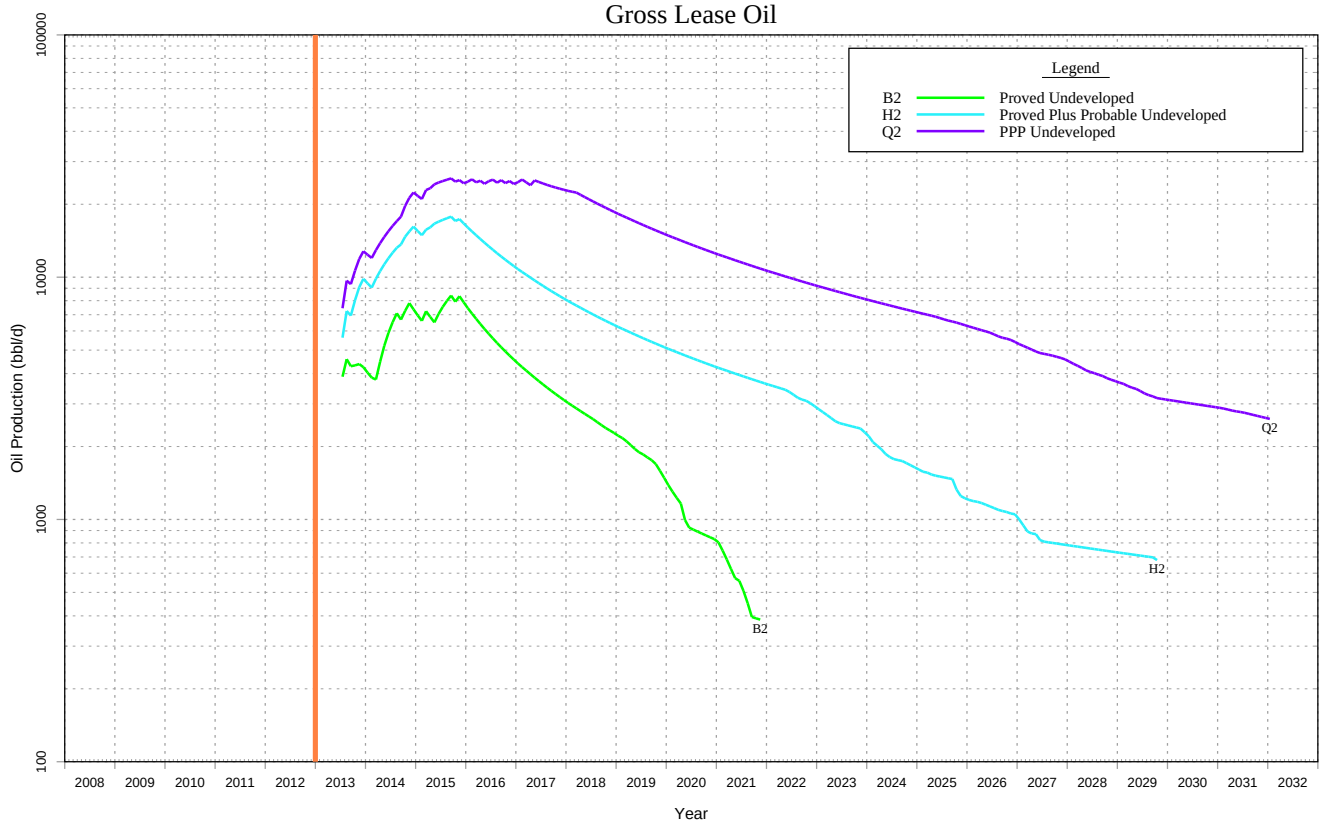
BOE Factors: HVY OIL 1.0 | COND 1.0 | RES GAS 6.0 | SLN GAS 6.0 | PROPANE 1.0 | BUTANE 1.0 | ETHANE 1.0 | SULPHUR 0.0

Run Date: January 21, 2013 12:54:02

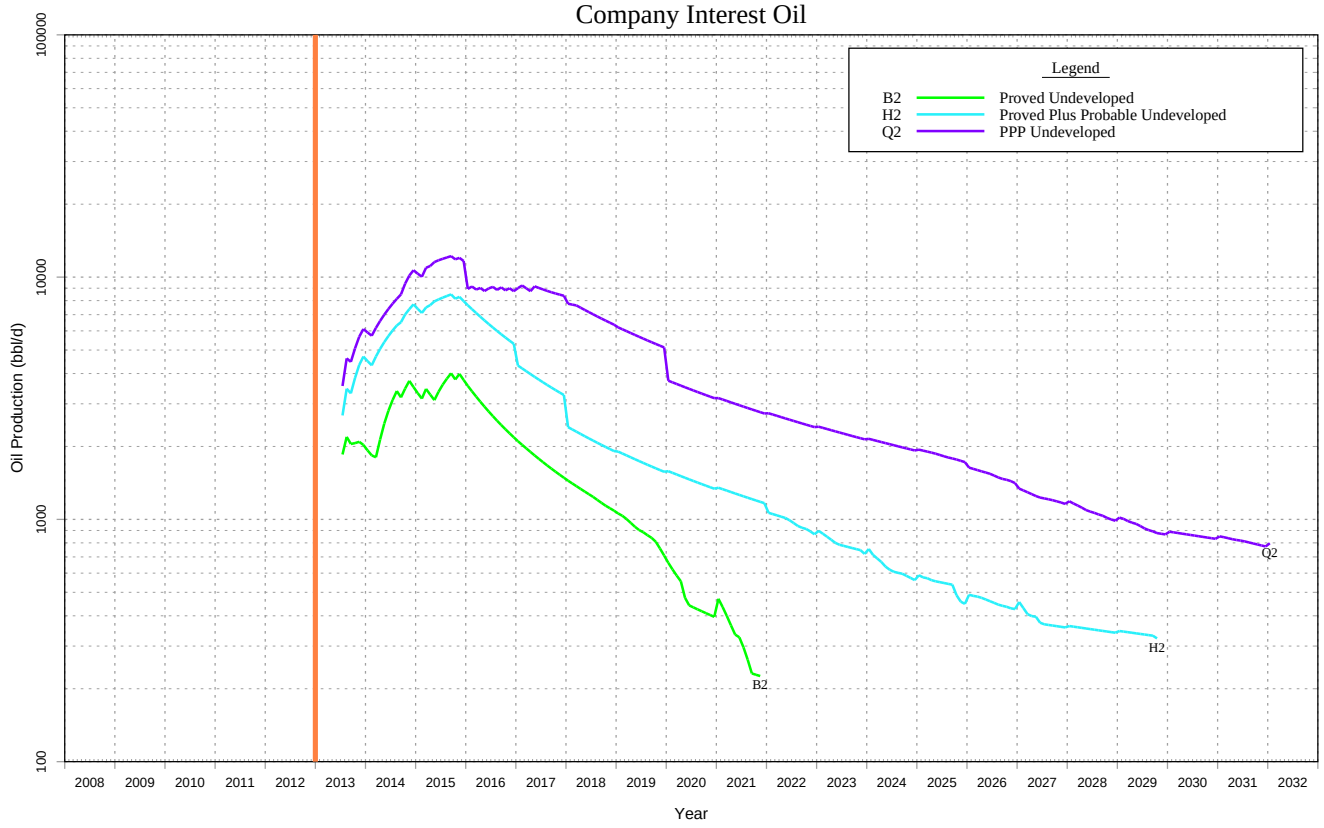
Historical and Forecast Production

Company: **Griffiths Energy International Inc.**
Property: **Mangara**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Gross Lease Oil



Company Interest Oil



*Note: Historical company interest production is based on current interests in the evaluated reserves entities applied to reported actual gross lease production. Consequently, company actuals may differ from the history shown due to changes in ownership.

Gross Lease Oil
1132107 / Jan 21, 2013

Company: **Griffiths Energy International Inc.**
Property: **Mangara**
Currency: **$US Dollars**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Daily Production, Reserves and Present Value Summary

Entity Description	Reserve Class	2013 Gross Lease Production				2013 Company Interest Production				Gross Lease Reserves					Company Interest Reserves					Before Tax 10% Dcf Present Value M$
		Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	
Proved Undeveloped																				
Drilling Capital	B2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-189,220
Glencore Carry	B2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	216,426
M-04/C1b	B2	0	34	0	34	0	16	0	16	0	118	0	0	118	0	57	0	0	57	2,855
M-04/C2	B2	0	401	0	401	0	192	0	192	0	558	0	0	558	0	266	0	0	266	16,272
M-04/C3	B2	0	33	0	33	0	16	0	16	0	86	0	0	86	0	41	0	0	41	2,325
M-04/E	B2	0	93	0	93	0	44	0	44	0	243	0	0	243	0	117	0	0	117	6,223
M-05/C1b	B2	0	34	0	34	0	16	0	16	0	118	0	0	118	0	57	0	0	57	2,852
M-05/C2	B2	0	401	0	401	0	192	0	192	0	558	0	0	558	0	266	0	0	266	16,272
M-05/C3	B2	0	33	0	33	0	16	0	16	0	86	0	0	86	0	41	0	0	41	2,325
M-05/E	B2	0	93	0	93	0	44	0	44	0	243	0	0	243	0	117	0	0	117	6,223
M-06/C1b	B2	0	34	0	34	0	16	0	16	0	118	0	0	118	0	57	0	0	57	2,852
M-06/C2	B2	0	401	0	401	0	192	0	192	0	558	0	0	558	0	266	0	0	266	16,272
M-06/C3	B2	0	33	0	33	0	16	0	16	0	86	0	0	86	0	41	0	0	41	2,330
M-06/E	B2	0	93	0	93	0	44	0	44	0	243	0	0	243	0	117	0	0	117	6,223
M-07/C2	B2	0	346	0	346	0	165	0	165	0	558	0	0	558	0	266	0	0	266	16,125
M-08/C1a	B2	0	4	0	4	0	2	0	2	0	22	0	0	22	0	10	0	0	10	584
M-08/C1b	B2	0	10	0	10	0	5	0	5	0	63	0	0	63	0	30	0	0	30	1,508
M-08/C3	B2	0	12	0	12	0	6	0	6	0	63	0	0	63	0	30	0	0	30	1,689
M-08/E	B2	0	48	0	48	0	23	0	23	0	240	0	0	240	0	115	0	0	115	5,997
M-09/C1a	B2	0	2	0	2	0	1	0	1	0	22	0	0	22	0	10	0	0	10	577
M-09/C1b	B2	0	7	0	7	0	3	0	3	0	63	0	0	63	0	30	0	0	30	1,486
M-09/C3	B2	0	8	0	8	0	4	0	4	0	63	0	0	63	0	30	0	0	30	1,671
M-09/E	B2	0	32	0	32	0	16	0	16	0	239	0	0	239	0	115	0	0	115	5,917
M-10/C1a	B2	0	1	0	1	0	1	0	1	0	22	0	0	22	0	10	0	0	10	571
M-10/C1b	B2	0	3	0	3	0	2	0	2	0	63	0	0	63	0	30	0	0	30	1,465
M-10/C3	B2	0	4	0	4	0	2	0	2	0	63	0	0	63	0	30	0	0	30	1,652
M-11/C1a	B2	0	0	0	0	0	0	0	0	0	22	0	0	22	0	10	0	0	10	555
M-11/C1b	B2	0	0	0	0	0	0	0	0	0	61	0	0	61	0	30	0	0	30	1,406
M-11/C3	B2	0	0	0	0	0	0	0	0	0	63	0	0	63	0	30	0	0	30	1,603
M-12/C2	B2	0	0	0	0	0	0	0	0	0	438	0	0	438	0	209	0	0	209	12,171
M-13/C1a	B2	0	0	0	0	0	0	0	0	0	22	0	0	22	0	10	0	0	10	543
M-13/C1b	B2	0	0	0	0	0	0	0	0	0	61	0	0	61	0	29	0	0	29	1,368
M-13/C2	B2	0	0	0	0	0	0	0	0	0	438	0	0	438	0	209	0	0	209	12,081
M-13/C3	B2	0	0	0	0	0	0	0	0	0	63	0	0	63	0	30	0	0	30	1,572
M-14/C1a	B2	0	0	0	0	0	0	0	0	0	22	0	0	22	0	10	0	0	10	537
M-14/C1b	B2	0	0	0	0	0	0	0	0	0	60	0	0	60	0	29	0	0	29	1,348
M-14/C2	B2	0	0	0	0	0	0	0	0	0	438	0	0	438	0	209	0	0	209	11,977
M-14/C3	B2	0	0	0	0	0	0	0	0	0	63	0	0	63	0	30	0	0	30	1,556
M-15/C1a	B2	0	0	0	0	0	0	0	0	0	22	0	0	22	0	10	0	0	10	531
M-15/C1b	B2	0	0	0	0	0	0	0	0	0	60	0	0	60	0	29	0	0	29	1,328
M-15/C2	B2	0	0	0	0	0	0	0	0	0	438	0	0	438	0	209	0	0	209	11,869
M-15/C3	B2	0	0	0	0	0	0	0	0	0	63	0	0	63	0	30	0	0	30	1,540
M-16/C1a	B2	0	0	0	0	0	0	0	0	0	22	0	0	22	0	10	0	0	10	525
M-16/C1b	B2	0	0	0	0	0	0	0	0	0	59	0	0	59	0	29	0	0	29	1,308

Daily Production, Reserves and Present Value Summary

Entity Description	Reserve Class	2013 Gross Lease Production Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	2013 Company Interest Production Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	Gross Lease Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Company Interest Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Before Tax 10% Dcf Present Value M$
Proved Undeveloped (Cont.)																				
M-16/C2	B2	0	0	0	0	0	0	0	0	0	438	0	0	438	0	209	0	0	209	11,751
M-16/C3	B2	0	0	0	0	0	0	0	0	0	63	0	0	63	0	30	0	0	30	1,522
M-18/C2	B2	0	0	0	0	0	0	0	0	0	557	0	0	557	0	267	0	0	267	14,066
M-19/C2	B2	0	0	0	0	0	0	0	0	0	555	0	0	555	0	266	0	0	266	13,881
M-21/C2	B2	0	0	0	0	0	0	0	0	0	545	0	0	545	0	261	0	0	261	13,153
M-24/C2	B2	0	0	0	0	0	0	0	0	0	438	0	0	438	0	209	0	0	209	10,529
M-25/C2	B2	0	0	0	0	0	0	0	0	0	438	0	0	438	0	209	0	0	209	10,404
M-26/C2	B2	0	0	0	0	0	0	0	0	0	438	0	0	438	0	210	0	0	210	10,268
M-27/C2	B2	0	0	0	0	0	0	0	0	0	438	0	0	438	0	210	0	0	210	10,124
M-28/C2	B2	0	0	0	0	0	0	0	0	0	438	0	0	438	0	210	0	0	210	9,812
Other Revenue and Expenses	B2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-63,818
Total: Proved Undeveloped		**0**	**2,161**	**0**	**2,161**	**0**	**1,031**	**0**	**1,031**	**0**	**11,257**	**0**	**0**	**11,257**	**0**	**5,386**	**0**	**0**	**5,386**	**254,984**
Proved Plus Probable Undeveloped																				
Drilling Capital	H2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-291,354
Glencore Carry	H2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	224,699
M-04/C1a	H2	0	10	0	10	0	5	0	5	0	54	0	0	54	0	21	0	0	21	1,030
M-04/C1b	H2	0	62	0	62	0	29	0	29	0	424	0	0	424	0	167	0	0	167	6,494
M-04/C2	H2	0	600	0	600	0	286	0	286	0	1,185	0	0	1,185	0	511	0	0	511	29,883
M-04/C3	H2	0	60	0	60	0	29	0	29	0	298	0	0	298	0	120	0	0	120	5,267
M-04/E	H2	0	120	0	120	0	57	0	57	0	542	0	0	542	0	220	0	0	220	9,931
M-05/C1a	H2	0	10	0	10	0	5	0	5	0	54	0	0	54	0	21	0	0	21	1,030
M-05/C1b	H2	0	62	0	62	0	29	0	29	0	424	0	0	424	0	167	0	0	167	6,494
M-05/C2	H2	0	600	0	600	0	286	0	286	0	1,185	0	0	1,185	0	511	0	0	511	29,883
M-05/C3	H2	0	60	0	60	0	29	0	29	0	298	0	0	298	0	120	0	0	120	5,267
M-05/E	H2	0	120	0	120	0	57	0	57	0	542	0	0	542	0	220	0	0	220	9,931
M-06/C1a	H2	0	10	0	10	0	5	0	5	0	54	0	0	54	0	21	0	0	21	1,030
M-06/C1b	H2	0	62	0	62	0	29	0	29	0	424	0	0	424	0	167	0	0	167	6,494
M-06/C2	H2	0	600	0	600	0	286	0	286	0	1,185	0	0	1,185	0	511	0	0	511	29,883
M-06/C3	H2	0	60	0	60	0	29	0	29	0	298	0	0	298	0	120	0	0	120	5,267
M-06/E	H2	0	120	0	120	0	57	0	57	0	542	0	0	542	0	220	0	0	220	9,931
M-07/C1a	H2	0	8	0	8	0	4	0	4	0	54	0	0	54	0	21	0	0	21	1,016
M-07/C1b	H2	0	51	0	51	0	25	0	25	0	423	0	0	423	0	167	0	0	167	6,405
M-07/C2	H2	0	512	0	512	0	244	0	244	0	1,185	0	0	1,185	0	510	0	0	510	29,603
M-07/C3	H2	0	50	0	50	0	24	0	24	0	297	0	0	297	0	120	0	0	120	5,201
M-07/E	H2	0	100	0	100	0	48	0	48	0	541	0	0	541	0	219	0	0	219	9,808
M-08/C1a	H2	0	5	0	5	0	2	0	2	0	63	0	0	63	0	24	0	0	24	1,044
M-08/C1b	H2	0	12	0	12	0	6	0	6	0	166	0	0	166	0	65	0	0	65	2,470
M-08/C2	H2	0	229	0	229	0	109	0	109	0	710	0	0	710	0	312	0	0	312	18,798
M-08/C3	H2	0	24	0	24	0	12	0	12	0	173	0	0	173	0	70	0	0	70	3,617
M-08/E	H2	0	61	0	61	0	29	0	29	0	539	0	0	539	0	217	0	0	217	9,562
M-09/C1a	H2	0	3	0	3	0	2	0	2	0	63	0	0	63	0	24	0	0	24	1,030
M-09/C1b	H2	0	8	0	8	0	4	0	4	0	165	0	0	165	0	65	0	0	65	2,434
M-09/C2	H2	0	157	0	157	0	75	0	75	0	710	0	0	710	0	311	0	0	311	18,605
M-09/C3	H2	0	16	0	16	0	8	0	8	0	173	0	0	173	0	69	0	0	69	3,571
M-09/E	H2	0	41	0	41	0	20	0	20	0	538	0	0	538	0	216	0	0	216	9,435

Daily Production, Reserves and Present Value Summary

Entity Description	Reserve Class	2013 Gross Lease Production Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	2013 Company Interest Production Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	Gross Lease Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Company Interest Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Before Tax 10% Dcf Present Value M$
Proved Plus Probable Undeveloped (Cont.)																				
M-10/C1a	H2	0	2	0	2	0	1	0	1	0	63	0	0	63	0	24	0	0	24	1,015
M-10/C1b	H2	0	4	0	4	0	2	0	2	0	165	0	0	165	0	64	0	0	64	2,400
M-10/C2	H2	0	82	0	82	0	39	0	39	0	710	0	0	710	0	310	0	0	310	18,410
M-10/C3	H2	0	8	0	8	0	4	0	4	0	173	0	0	173	0	69	0	0	69	3,525
M-11/C1a	H2	0	0	0	0	0	0	0	0	0	63	0	0	63	0	23	0	0	23	973
M-11/C1b	H2	0	0	0	0	0	0	0	0	0	163	0	0	163	0	63	0	0	63	2,298
M-11/C2	H2	0	0	0	0	0	0	0	0	0	710	0	0	710	0	307	0	0	307	17,871
M-11/C3	H2	0	0	0	0	0	0	0	0	0	173	0	0	173	0	68	0	0	68	3,394
M-12/C1a	H2	0	0	0	0	0	0	0	0	0	63	0	0	63	0	23	0	0	23	959
M-12/C1b	H2	0	0	0	0	0	0	0	0	0	163	0	0	163	0	63	0	0	63	2,264
M-12/C2	H2	0	0	0	0	0	0	0	0	0	710	0	0	710	0	306	0	0	306	17,689
M-12/C3	H2	0	0	0	0	0	0	0	0	0	173	0	0	173	0	68	0	0	68	3,348
M-13/C1a	H2	0	0	0	0	0	0	0	0	0	63	0	0	63	0	23	0	0	23	945
M-13/C1b	H2	0	0	0	0	0	0	0	0	0	162	0	0	162	0	63	0	0	63	2,230
M-13/C2	H2	0	0	0	0	0	0	0	0	0	710	0	0	710	0	305	0	0	305	17,506
M-13/C3	H2	0	0	0	0	0	0	0	0	0	173	0	0	173	0	68	0	0	68	3,304
M-14/C1a	H2	0	0	0	0	0	0	0	0	0	63	0	0	63	0	23	0	0	23	930
M-14/C1b	H2	0	0	0	0	0	0	0	0	0	162	0	0	162	0	63	0	0	63	2,195
M-14/C2	H2	0	0	0	0	0	0	0	0	0	710	0	0	710	0	304	0	0	304	17,309
M-14/C3	H2	0	0	0	0	0	0	0	0	0	173	0	0	173	0	68	0	0	68	3,258
M-15/C1a	H2	0	0	0	0	0	0	0	0	0	63	0	0	63	0	23	0	0	23	916
M-15/C1b	H2	0	0	0	0	0	0	0	0	0	161	0	0	161	0	62	0	0	62	2,161
M-15/C2	H2	0	0	0	0	0	0	0	0	0	710	0	0	710	0	303	0	0	303	17,111
M-15/C3	H2	0	0	0	0	0	0	0	0	0	173	0	0	173	0	67	0	0	67	3,212
M-16/C1a	H2	0	0	0	0	0	0	0	0	0	63	0	0	63	0	23	0	0	23	904
M-16/C1b	H2	0	0	0	0	0	0	0	0	0	161	0	0	161	0	62	0	0	62	2,130
M-16/C2	H2	0	0	0	0	0	0	0	0	0	710	0	0	710	0	302	0	0	302	16,898
M-16/C3	H2	0	0	0	0	0	0	0	0	0	175	0	0	175	0	68	0	0	68	3,177
M-17/C2	H2	0	0	0	0	0	0	0	0	0	710	0	0	710	0	301	0	0	301	16,677
M-18/C1b	H2	0	0	0	0	0	0	0	0	0	405	0	0	405	0	155	0	0	155	5,181
M-18/C2	H2	0	0	0	0	0	0	0	0	0	1,185	0	0	1,185	0	490	0	0	490	25,279
M-18/C3	H2	0	0	0	0	0	0	0	0	0	289	0	0	289	0	112	0	0	112	4,257
M-19/C2	H2	0	0	0	0	0	0	0	0	0	1,185	0	0	1,185	0	489	0	0	489	24,902
M-20/C2	H2	0	0	0	0	0	0	0	0	0	1,185	0	0	1,185	0	487	0	0	487	24,523
M-21/C2	H2	0	0	0	0	0	0	0	0	0	1,185	0	0	1,185	0	481	0	0	481	23,497
M-22/C2	H2	0	0	0	0	0	0	0	0	0	710	0	0	710	0	292	0	0	292	15,111
M-23/C2	H2	0	0	0	0	0	0	0	0	0	710	0	0	710	0	290	0	0	290	14,895
M-23/E	H2	0	0	0	0	0	0	0	0	0	516	0	0	516	0	197	0	0	197	7,137
M-24/C2	H2	0	0	0	0	0	0	0	0	0	710	0	0	710	0	289	0	0	289	14,662
M-25/C2	H2	0	0	0	0	0	0	0	0	0	710	0	0	710	0	287	0	0	287	14,426
M-26/C2	H2	0	0	0	0	0	0	0	0	0	710	0	0	710	0	286	0	0	286	14,173
M-27/C2	H2	0	0	0	0	0	0	0	0	0	710	0	0	710	0	284	0	0	284	13,908
M-28/C2	H2	0	0	0	0	0	0	0	0	0	674	0	0	674	0	268	0	0	268	12,914
Other Revenue and Expenses	H2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-77,243
Total: Proved Plus Probable Undeveloped		**0**	**3,930**	**0**	**3,930**	**0**	**1,876**	**0**	**1,876**	**0**	**32,667**	**0**	**0**	**32,667**	**0**	**13,448**	**0**	**0**	**13,448**	**536,388**

Daily Production, Reserves and Present Value Summary

Entity Description	Reserve Class	2013 Gross Lease Production Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	2013 Company Interest Production Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	Gross Lease Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Company Interest Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Before Tax 10% Dcf Present Value M$
PPP Undeveloped																				
Drilling Capital	Q2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-473,469
Glencore Carry	Q2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	225,821
M-04/C1a	Q2	0	12	0	12	0	6	0	6	0	136	0	0	136	0	45	0	0	45	1,568
M-04/C1b	Q2	0	99	0	99	0	47	0	47	0	921	0	0	921	0	319	0	0	319	10,922
M-04/C2	Q2	0	802	0	802	0	383	0	383	0	2,107	0	0	2,107	0	822	0	0	822	45,406
M-04/C3	Q2	0	97	0	97	0	46	0	46	0	603	0	0	603	0	212	0	0	212	8,920
M-04/E	Q2	0	145	0	145	0	69	0	69	0	871	0	0	871	0	311	0	0	311	12,839
M-05/C1a	Q2	0	12	0	12	0	6	0	6	0	136	0	0	136	0	45	0	0	45	1,568
M-05/C1b	Q2	0	99	0	99	0	47	0	47	0	921	0	0	921	0	319	0	0	319	10,922
M-05/C2	Q2	0	802	0	802	0	383	0	383	0	2,107	0	0	2,107	0	822	0	0	822	45,406
M-05/C3	Q2	0	97	0	97	0	46	0	46	0	603	0	0	603	0	212	0	0	212	8,920
M-05/E	Q2	0	145	0	145	0	69	0	69	0	871	0	0	871	0	311	0	0	311	12,839
M-06/C1a	Q2	0	12	0	12	0	6	0	6	0	136	0	0	136	0	45	0	0	45	1,568
M-06/C1b	Q2	0	99	0	99	0	47	0	47	0	921	0	0	921	0	319	0	0	319	10,922
M-06/C2	Q2	0	802	0	802	0	383	0	383	0	2,107	0	0	2,107	0	822	0	0	822	45,406
M-06/C3	Q2	0	97	0	97	0	46	0	46	0	603	0	0	603	0	212	0	0	212	8,920
M-06/E	Q2	0	145	0	145	0	69	0	69	0	871	0	0	871	0	311	0	0	311	12,839
M-07/C1a	Q2	0	10	0	10	0	5	0	5	0	136	0	0	136	0	45	0	0	45	1,549
M-07/C1b	Q2	0	82	0	82	0	39	0	39	0	920	0	0	920	0	317	0	0	317	10,793
M-07/C2	Q2	0	680	0	680	0	325	0	325	0	2,107	0	0	2,107	0	819	0	0	819	45,002
M-07/C3	Q2	0	81	0	81	0	39	0	39	0	603	0	0	603	0	212	0	0	212	8,821
M-07/E	Q2	0	121	0	121	0	58	0	58	0	870	0	0	870	0	310	0	0	310	12,697
M-08/C1a	Q2	0	6	0	6	0	3	0	3	0	100	0	0	100	0	33	0	0	33	1,385
M-08/C1b	Q2	0	15	0	15	0	7	0	7	0	268	0	0	268	0	92	0	0	92	3,121
M-08/C2	Q2	0	258	0	258	0	123	0	123	0	1,089	0	0	1,089	0	435	0	0	435	25,016
M-08/C3	Q2	0	31	0	31	0	15	0	15	0	213	0	0	213	0	80	0	0	80	4,302
M-08/E	Q2	0	74	0	74	0	35	0	35	0	869	0	0	869	0	308	0	0	308	12,412
M-09/C1a	Q2	0	4	0	4	0	2	0	2	0	100	0	0	100	0	33	0	0	33	1,367
M-09/C1b	Q2	0	10	0	10	0	5	0	5	0	268	0	0	268	0	92	0	0	92	3,083
M-09/C2	Q2	0	175	0	175	0	84	0	84	0	1,089	0	0	1,089	0	433	0	0	433	24,778
M-09/C3	Q2	0	20	0	20	0	10	0	10	0	213	0	0	213	0	79	0	0	79	4,253
M-09/E	Q2	0	49	0	49	0	24	0	24	0	868	0	0	868	0	307	0	0	307	12,265
M-10/C1a	Q2	0	2	0	2	0	1	0	1	0	100	0	0	100	0	33	0	0	33	1,351
M-10/C1b	Q2	0	5	0	5	0	2	0	2	0	268	0	0	268	0	92	0	0	92	3,045
M-10/C2	Q2	0	91	0	91	0	44	0	44	0	1,089	0	0	1,089	0	431	0	0	431	24,542
M-10/C3	Q2	0	11	0	11	0	5	0	5	0	213	0	0	213	0	79	0	0	79	4,205
M-11/C1a	Q2	0	0	0	0	0	0	0	0	0	100	0	0	100	0	32	0	0	32	1,299
M-11/C1b	Q2	0	0	0	0	0	0	0	0	0	267	0	0	267	0	91	0	0	91	2,929
M-11/C2	Q2	0	0	0	0	0	0	0	0	0	1,089	0	0	1,089	0	425	0	0	425	23,770
M-11/C3	Q2	0	0	0	0	0	0	0	0	0	213	0	0	213	0	78	0	0	78	4,055
M-12/C1a	Q2	0	0	0	0	0	0	0	0	0	100	0	0	100	0	32	0	0	32	1,281
M-12/C1b	Q2	0	0	0	0	0	0	0	0	0	267	0	0	267	0	90	0	0	90	2,888
M-12/C2	Q2	0	0	0	0	0	0	0	0	0	1,089	0	0	1,089	0	422	0	0	422	23,484
M-12/C3	Q2	0	0	0	0	0	0	0	0	0	213	0	0	213	0	77	0	0	77	4,001
M-13/C1a	Q2	0	0	0	0	0	0	0	0	0	100	0	0	100	0	32	0	0	32	1,263
M-13/C1b	Q2	0	0	0	0	0	0	0	0	0	266	0	0	266	0	90	0	0	90	2,848
M-13/C2	Q2	0	0	0	0	0	0	0	0	0	1,089	0	0	1,089	0	420	0	0	420	23,198

Daily Production, Reserves and Present Value Summary

Entity Description	Reserve Class	2013 Gross Lease Production Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	2013 Company Interest Production Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	Gross Lease Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Company Interest Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Before Tax 10% Dcf Present Value M$
PPP Undeveloped (Cont.)																				
M-13/C3	Q2	0	0	0	0	0	0	0	0	0	213	0	0	213	0	77	0	0	77	3,948
M-14/C1a	Q2	0	0	0	0	0	0	0	0	0	100	0	0	100	0	32	0	0	32	1,245
M-14/C1b	Q2	0	0	0	0	0	0	0	0	0	266	0	0	266	0	89	0	0	89	2,807
M-14/C2	Q2	0	0	0	0	0	0	0	0	0	1,089	0	0	1,089	0	418	0	0	418	22,893
M-14/C3	Q2	0	0	0	0	0	0	0	0	0	213	0	0	213	0	77	0	0	77	3,892
M-15/C1a	Q2	0	0	0	0	0	0	0	0	0	100	0	0	100	0	32	0	0	32	1,227
M-15/C1b	Q2	0	0	0	0	0	0	0	0	0	266	0	0	266	0	89	0	0	89	2,767
M-15/C2	Q2	0	0	0	0	0	0	0	0	0	1,089	0	0	1,089	0	415	0	0	415	22,588
M-15/C3	Q2	0	0	0	0	0	0	0	0	0	213	0	0	213	0	76	0	0	76	3,836
M-16/C1a	Q2	0	0	0	0	0	0	0	0	0	100	0	0	100	0	32	0	0	32	1,209
M-16/C1b	Q2	0	0	0	0	0	0	0	0	0	265	0	0	265	0	89	0	0	89	2,725
M-16/C2	Q2	0	0	0	0	0	0	0	0	0	1,089	0	0	1,089	0	413	0	0	413	22,263
M-16/C3	Q2	0	0	0	0	0	0	0	0	0	213	0	0	213	0	76	0	0	76	3,778
M-17/C1a	Q2	0	0	0	0	0	0	0	0	0	100	0	0	100	0	32	0	0	32	1,190
M-17/C1b	Q2	0	0	0	0	0	0	0	0	0	265	0	0	265	0	88	0	0	88	2,683
M-17/C2	Q2	0	0	0	0	0	0	0	0	0	1,089	0	0	1,089	0	410	0	0	410	21,927
M-17/C3	Q2	0	0	0	0	0	0	0	0	0	213	0	0	213	0	75	0	0	75	3,719
M-18/C1a	Q2	0	0	0	0	0	0	0	0	0	136	0	0	136	0	43	0	0	43	1,280
M-18/C1b	Q2	0	0	0	0	0	0	0	0	0	904	0	0	904	0	301	0	0	301	8,916
M-18/C2	Q2	0	0	0	0	0	0	0	0	0	2,107	0	0	2,107	0	766	0	0	766	38,038
M-18/C3	Q2	0	0	0	0	0	0	0	0	0	603	0	0	603	0	202	0	0	202	7,313
M-18/E	Q2	0	0	0	0	0	0	0	0	0	861	0	0	861	0	292	0	0	292	10,532
M-19/C1a	Q2	0	0	0	0	0	0	0	0	0	136	0	0	136	0	43	0	0	43	1,260
M-19/C1b	Q2	0	0	0	0	0	0	0	0	0	903	0	0	903	0	299	0	0	299	8,772
M-19/C2	Q2	0	0	0	0	0	0	0	0	0	2,107	0	0	2,107	0	761	0	0	761	37,407
M-19/C3	Q2	0	0	0	0	0	0	0	0	0	603	0	0	603	0	201	0	0	201	7,193
M-20/C2	Q2	0	0	0	0	0	0	0	0	0	2,107	0	0	2,107	0	756	0	0	756	36,777
M-21/C1a	Q2	0	0	0	0	0	0	0	0	0	135	0	0	135	0	42	0	0	42	1,182
M-21/C1b	Q2	0	0	0	0	0	0	0	0	0	895	0	0	895	0	293	0	0	293	8,211
M-21/C2	Q2	0	0	0	0	0	0	0	0	0	2,107	0	0	2,107	0	741	0	0	741	34,972
M-21/C3	Q2	0	0	0	0	0	0	0	0	0	599	0	0	599	0	197	0	0	197	6,719
M-21/E	Q2	0	0	0	0	0	0	0	0	0	857	0	0	857	0	285	0	0	285	9,698
M-22/C2	Q2	0	0	0	0	0	0	0	0	0	1,089	0	0	1,089	0	390	0	0	390	19,491
M-23/C1a	Q2	0	0	0	0	0	0	0	0	0	100	0	0	100	0	31	0	0	31	1,047
M-23/C1b	Q2	0	0	0	0	0	0	0	0	0	262	0	0	262	0	85	0	0	85	2,357
M-23/C2	Q2	0	0	0	0	0	0	0	0	0	1,089	0	0	1,089	0	386	0	0	386	19,135
M-23/C3	Q2	0	0	0	0	0	0	0	0	0	213	0	0	213	0	71	0	0	71	3,248
M-23/E	Q2	0	0	0	0	0	0	0	0	0	856	0	0	856	0	282	0	0	282	9,368
M-24/C1b	Q2	0	0	0	0	0	0	0	0	0	262	0	0	262	0	85	0	0	85	2,315
M-24/C2	Q2	0	0	0	0	0	0	0	0	0	1,089	0	0	1,089	0	383	0	0	383	18,753
M-25/C2	Q2	0	0	0	0	0	0	0	0	0	1,089	0	0	1,089	0	379	0	0	379	18,370
M-26/C2	Q2	0	0	0	0	0	0	0	0	0	1,089	0	0	1,089	0	375	0	0	375	17,959
M-27/C2	Q2	0	0	0	0	0	0	0	0	0	1,089	0	0	1,089	0	371	0	0	371	17,532
M-28/C2	Q2	0	0	0	0	0	0	0	0	0	1,089	0	0	1,089	0	363	0	0	363	16,640
M-29/C2	Q2	0	0	0	0	0	0	0	0	0	1,089	0	0	1,089	0	354	0	0	354	15,674
M-30/C1a	Q2	0	0	0	0	0	0	0	0	0	100	0	0	100	0	30	0	0	30	891
M-30/C1b	Q2	0	0	0	0	0	0	0	0	0	259	0	0	259	0	82	0	0	82	1,998

Daily Production, Reserves and Present Value Summary

Entity Description	Reserve Class	2013 Gross Lease Production Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	2013 Company Interest Production Gas Mcf/d	Oil bbl/d	NGL bbl/d	Oil Eq. boe/d	Gross Lease Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Company Interest Reserves Gas MMcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	Oil Eq. Mboe	Before Tax 10% Dcf Present Value M$
PPP Undeveloped (Cont.)																				
M-30/C2	Q2	0	0	0	0	0	0	0	0	0	1,089	0	0	1,089	0	353	0	0	353	15,514
M-30/C3	Q2	0	0	0	0	0	0	0	0	0	213	0	0	213	0	66	0	0	66	2,695
M-31/C2	Q2	0	0	0	0	0	0	0	0	0	1,089	0	0	1,089	0	352	0	0	352	15,192
M-32/C1a	Q2	0	0	0	0	0	0	0	0	0	100	0	0	100	0	29	0	0	29	848
M-32/C1b	Q2	0	0	0	0	0	0	0	0	0	258	0	0	258	0	81	0	0	81	1,901
M-32/C2	Q2	0	0	0	0	0	0	0	0	0	1,089	0	0	1,089	0	350	0	0	350	14,842
M-32/C3	Q2	0	0	0	0	0	0	0	0	0	213	0	0	213	0	66	0	0	66	2,569
M-33/C2	Q2	0	0	0	0	0	0	0	0	0	1,089	0	0	1,089	0	349	0	0	349	14,662
M-34/C1a	Q2	0	0	0	0	0	0	0	0	0	100	0	0	100	0	29	0	0	29	815
M-34/C1b	Q2	0	0	0	0	0	0	0	0	0	257	0	0	257	0	81	0	0	81	1,826
M-34/C2	Q2	0	0	0	0	0	0	0	0	0	1,089	0	0	1,089	0	347	0	0	347	14,271
M-34/C3	Q2	0	0	0	0	0	0	0	0	0	213	0	0	213	0	65	0	0	65	2,467
M-35/C1a	Q2	0	0	0	0	0	0	0	0	0	100	0	0	100	0	29	0	0	29	792
M-35/C1b	Q2	0	0	0	0	0	0	0	0	0	256	0	0	256	0	80	0	0	80	1,775
M-35/C2	Q2	0	0	0	0	0	0	0	0	0	1,089	0	0	1,089	0	345	0	0	345	13,860
M-36/C2	Q2	0	0	0	0	0	0	0	0	0	1,089	0	0	1,089	0	343	0	0	343	13,418
M-37/C1a	Q2	0	0	0	0	0	0	0	0	0	100	0	0	100	0	29	0	0	29	760
M-37/C1b	Q2	0	0	0	0	0	0	0	0	0	247	0	0	247	0	77	0	0	77	1,675
M-37/C2	Q2	0	0	0	0	0	0	0	0	0	1,061	0	0	1,061	0	333	0	0	333	13,036
M-37/C3	Q2	0	0	0	0	0	0	0	0	0	197	0	0	197	0	60	0	0	60	2,195
M-38/C2	Q2	0	0	0	0	0	0	0	0	0	2,125	0	0	2,125	0	656	0	0	656	22,774
M-39/E	Q2	0	0	0	0	0	0	0	0	0	837	0	0	837	0	257	0	0	257	6,351
M-40/E	Q2	0	0	0	0	0	0	0	0	0	836	0	0	836	0	257	0	0	257	6,263
M-41/E	Q2	0	0	0	0	0	0	0	0	0	835	0	0	835	0	256	0	0	256	6,171
M-42/E	Q2	0	0	0	0	0	0	0	0	0	834	0	0	834	0	255	0	0	255	6,078
M-43/E	Q2	0	0	0	0	0	0	0	0	0	833	0	0	833	0	254	0	0	254	5,986
M-44/E	Q2	0	0	0	0	0	0	0	0	0	833	0	0	833	0	253	0	0	253	5,891
M-45/E	Q2	0	0	0	0	0	0	0	0	0	832	0	0	832	0	253	0	0	253	5,797
M-46/E	Q2	0	0	0	0	0	0	0	0	0	831	0	0	831	0	252	0	0	252	5,699
M-47/E	Q2	0	0	0	0	0	0	0	0	0	830	0	0	830	0	251	0	0	251	5,629
M-48/E	Q2	0	0	0	0	0	0	0	0	0	856	0	0	856	0	259	0	0	259	5,675
Other Revenue and Expenses	Q2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-80,599
Total: PPP Undeveloped		**0**	**5,191**	**0**	**5,191**	**0**	**2,478**	**0**	**2,478**	**0**	**84,221**	**0**	**0**	**84,221**	**0**	**29,227**	**0**	**0**	**29,227**	**930,891**

BOE Factors: HVY OIL 1.0 RES GAS 6.0 PROPANE 1.0 ETHANE 1.0
COND 1.0 SLN GAS 6.0 BUTANE 1.0 SULPHUR 0.0

GENERAL

The Mangara Field is located 350 kilometres south of N'Djamena in the DOB Block of the Republic of Chad as shown on Map 1. The field is subject to the Mangara/Badila Production Sharing Contract (PSC) which covers an area of 2,744 square kilometres in the Doba Basin.

Griffiths Energy International Inc. (Griffiths) originally held a 75 percent participating interest in the PSC. This evaluation includes the terms of a farm-in agreement (Glencore Farm-in) between Griffiths and Glencore International AG (Glencore). The Glencore Farm-in assigns one-third of Griffiths' interest in the PSC to Glencore. In exchange, Glencore has agreed to carry a maximum of 330,747 M$ of Griffiths' capital (including recovery of costs sunk as of the effective date). The interests evaluated herein are Griffiths' net interest after the Glencore Farm-in.

Esso Exploration and Production Chad Inc. (Esso), the previous operator of the block, discovered the Mangara Field with the drilling of the Mangara-1 well in January 1978. The well encountered hydrocarbon accumulations in the Lower Cretaceous. A total of nine drillstem tests (DSTs) were run in the well over five separate reservoir layers (C1b, C2, C3/D05, D and E1a). The C2 reservoir interval tested oil to surface on DST No. 5 at a maximum rate of 1875 bbl/d of 38 °API oil. The C1b, C3/D05 and E1a reservoirs also recovered oil, but at a lesser rate than the C2 reservoir.

Appraisal wells Mangara-2 and Mangara-3 were drilled in 2003 and 2006. Interpretation of the production logging tool (PLT) during a commingled production test in the well Mangara-2 indicated oil flow of 700 bbl/d from the C1a, C1b, C2 and C3/D05 reservoirs, with 86 percent of the flow originating from the C2 reservoir. These same intervals were recompleted and retested in 2012. The commingled test indicated an oil flow rate of 800 bbl/d. At Mangara-3, two tests were performed over the C2 interval. The lower C2 was completed and tested during DST No. 1. After completion the lower C2 did not flow to surface and recovered a fluid that was described in the testing report as "formation water" upon swabbing. The interval was subsequently fracture stimulated. After the stimulation, the well did not flow to surface and the oil cut did not increase when swabbed. The upper part of the C2 was tested in DST No. 2. The second test also failed to flow to surface. Recovery on swabbing consisted of drilling and completion fluids; a result of well killing and disposal operations performed at the end of DST No. 1. DST No. 2 is not considered to be a valid test of the zone.

In this report, the fault block containing the Mangara-1 well is referred to as the Mangara-1 Block and the fault block containing the Mangara-2 and 3 wells is referred to as the Mangara-2/3 Block. For the E1a reservoir, Mangara-1 and 3 are in the same fault block, which is referred to as the Mangara-1/3 Block.

Development of the Mangara Field has begun with oil production scheduled to commence in July 2013. The planned development includes drilling new wells, installing production facilities and constructing a 95 kilometre oil pipeline to the sales terminal at Badila. An additional 16 kilometre pipeline is required to connect Badila to the existing TOTCO pipeline at kilometre 50.

All values and costs presented in this report are in U.S. dollars.

GEOLOGY

The Griffiths PSCs are on blocks within two geologic basins in Chad, the Doba and Doseo Basins. These basins are separated by an area termed the Borogop uplift which is a large inversion anticlinal trend and is part of the Central African Rift trend, a continental plate boundary crossing through Chad from the Sudan to Cameroon.

The Doba and Doseo Basins were formed as rift basins in the Early Cretaceous (84-144 Ma). The Doba Basin formed as a series of northwest - southwest trending half grabens. The Doseo Basin formed as a large asymmetrical basin with a northwest - southeast oriented rift faulted relay series. The Borogop uplift is the steeply lifted basin edge fault zone which separates the basins.

Geologic sedimentation occurred during the Aptian through Conician when the two basins underwent a thermal sag phase which provided accommodation space for sediments. It is noteworthy that thermal events also include a phase of sill intrusion dating to 97-100 Ma. Sills have been found and sampled along the northern flank of the Doseo Basin.

The Cretaceous provides the multiple reservoirs which have been tested in the two basins. The Cretaceous E interval consists of sediments sourced by axial transport from the east. Sediments drained generally to the west towards Doba and probably ultimately exited the Doba Basin through the Yola arm of the Benue trough and then onto the south to the Benue forming the proto Niger Delta. The top of the E sequence is bounded by the D Sequence Boundary (DSB) and is generally a very good high amplitude seismic marker. The Cretaceous D sequence is a continuation of the same non-marine fluvial and deltaic lacustrine facies as observed in the E sequence. The Cretaceous C zone overlies the D sequence and is also composed of fluvial, lacustrine, and deltaic sediments.

The traps evaluated for this work were all four way closed structure, whilst source rocks are provided by the prevalent lacustrine sediments deposited throughout both basins.

GEOPHYSICS

Griffiths acquired approximately 147 square kilometers of vibroseis 3D in the Spring of 2012. The interpretation was first audited and then reinterpreted by GLJ. Data quality was excellent over the entire 3D. Horizon ties were established from the three existing wells on the Mangara structures.

Depth maps were prepared on the C2, D3, and E1 sands. Only a single average velocity was used to convert to depth for each sand, and these velocities were determined from the Mangara–1 well. The velocities used were:

C2	2698 m/sec
D3	2732 m/sec
E1	2756 m/sec.

The depths were calculated assuming a 500 metre seismic datum.

PRODUCTION TESTS AND FLUID ANALYSES

Well Test Results

DST and production test data are summarized in Table 1. The following pertinent information has been extracted from the test data:

C1a Reservoir

The C1a reservoir was not tested independently. It was interpreted to have contributed 3 percent of the flow during the production test on Mangara-2, producing approximately 21 bbl/d. The permeability of the interval was estimated to be 2.2 md. The flow capacity of this reservoir was estimated to be 15 to 25 bopd at 75 percent drawdown.

C1b Reservoir

DST No. 1 and DST No. 6 at Mangara-1 indicated reservoir permeability of approximately 6.8 and 1.1 md, respectively, in the C1b reservoir. The C1b reservoir was also interpreted to have contributed 4 percent of the flow during the production test on Mangara-2; approximately 28 bbl/d. The permeability of the interval was estimated to be 1.4 md in the Mangara-2 Block. The flow capacity of this reservoir was estimated to be 70 to 200 bopd at 75 percent drawdown from the block containing the Mangara-1 well and 40 to 60 bopd from the block containing the Mangara-2 well.

C2 Reservoir

Pressure transient analysis of build-up data from both wells Mangara-1 and 2 indicate reservoir permeability of approximately 15 md in the C2 reservoir. This suggests that the layer has relatively consistent properties over the structure.

DST No. 1 at well Mangara-3 tested a fluid described as “formation water”, indicating a potential oil-water contact (OWC) at an elevation above -1684 metres. DST No. 2 tested interval -1665.7 to -1677.6 metres which was interpreted to cover the oil bearing part of the C2 reservoir and was inconclusive as it recovered completion fluids that were injected into the DST No. 1 interval.

In the proved case, Mangara-3 DST No. 1 was considered to be a valid test of the zone, indicating a possible high water saturation. Assigned reserves were limited to a nine spacing unit area around Mangara-2, which excludes the volumes in the vicinity of Mangara-3. In the proved plus probable and proved plus probable plus possible case, this test was given less weight and mapped gross rock volumes were not limited to areas adjacent to Mangara-2.

The flow capacity of this reservoir was estimated to be 1000 to 1800 bopd from the block containing Mangara-1 and 900 to 1100 bopd from the block containing Mangara-2.

C3 Reservoir

DST No. 4A at Mangara-1 indicates reservoir permeability of approximately 0.3 md in the C3 reservoir. The C3 reservoir was also interpreted to have contributed 7 percent of the flow during the production test on Mangara-2; approximately 49 bbl/d. The permeability of the interval was estimated to be 2.1 md. The flow capacity of this reservoir was estimated to be 70 to 200 bopd at 75 percent drawdown from the block containing Mangara-1 and 50 to 125 bopd from the block containing Mangara-2.

E1a Reservoir

DST No. 2A at Mangara-1 indicates reservoir permeability of approximately 6.3 md in the E1a reservoir. The flow capacity of this reservoir was estimated to be 200 to 300 bopd at 75 percent drawdown. A production test of the E1a reservoir in Mangara-2 yielded no oil to surface. Subsequent pressure measurements in Mangara-2 indicated a fluid column of approximately 80 percent water and 20 percent oil in the well.

Initial Reservoir Conditions and Fluid Properties

The initial reservoir conditions and fluid properties used in this study are summarized as follows:

Parameter	Units	C1a	C1b	C2	C3	E1a
Reservoir Pressure	psia	2750	2762	2911	2965	3490
Reservoir Temperature	°R	628	628	636	640	656
Oil Gravity	°API	37	39	38	38	39
Solution GOR	scf/bbl	700	700	690	700	915
Formation Volume Factor	rbbl/stb	1.38	1.38	1.38	1.38	1.50

VOLUMETRIC ANALYSIS

The oil initially-in-place (OIIP) for the Mangara Field has been determined by volumetric analysis using deterministic methods. The following is a discussion of the methodology and input parameters.

Petrophysical Analysis

GLJ Petroleum Consultants (GLJ) conducted a review of petrophysical analysis by Griffiths. This showed it to be broadly similar to earlier studies undertaken by Esso, RPS Group and Ryder Scott. It was decided to define a range of rock properties for the key reservoir units by utilizing a range of low, most likely and high case cut-offs. For the Mangara Field GLJ used "most likely" cutoffs of 7 percent porosity and a 60 percent water saturation to define wellbore parameters. Low case and high case parameters were also determined by applying different cutoffs.

Mapping

GLJ interpreted the new 3D data to provide depth maps for the C1a, C1b, C2, C3 and E1a reservoirs for the calculation of gross rock volumes (GRV) for the assignment of reserves to the most significant reservoir units.

Oil-Water Contacts

Areal extents in the GLJ analysis are generally governed by the following:

- Proved GRV was limited by lowest known oil (LKO). In this case GLJ has used lowest tested oil as the logs were not always reliable for picking OWC.
- Proved plus probable plus possible GRV was taken to either the interpreted OWC or the trap closure.
- Proved plus probable GRV was taken to either the interpreted OWC or halfway between LKO and the trap closure.

Deviations from the above are explained in the following sections for each reservoir.

C1a Reservoir

This reservoir was not tested independently. The zone was part of the comingled test at Mangara-2 and it was reported that 3 percent of the flow was from the C1a. The C1a was not tested in the Mangara-1 Block. Proved reserves were included for the Mangara 2/3 Block based on the PLT test. Proved reserves were not included in the Mangara-1 Block pending demonstration of commercial rates.

In the Mangara-1 and Mangara-2/3 Blocks, closure was mapped at -1564 metres. This depth was used to establish the proved plus probable plus possible GRV. The lowest tested interval was -1546.6 metres in the Mangara-2 well, which was used to establish the proved GRV in Block 2/3. GLJ used a depth of -1554.4 metres in the Mangara-1 and the Mangara 2/3 Blocks to define the proved plus probable GRV. These elevations are illustrated on the depth structure map included as Map 2.

C1b Reservoir

In the Mangara-1 Block, oil was tested and logged down to -1570.3 metres and the closure was mapped at -1614 metres. The proved plus probable GRV in the Mangara-1 Block was taken halfway between LKO and closure at -1592 metres.

In the Mangara-2/3 Block, oil was tested down to -1596.2 metres based on the LKO from testing. The proved plus probable plus possible contact was based on the mapped spill at -1614 metres. The proved plus probable GRV was taken halfway between LKO and closure at -1605 metres. These elevations are illustrated on Map 3.

C2 Reservoir

In the Mangara-1 Block, oil was tested down to -1662.7 metres in DST No. 5 which establishes the LKO and the proved GRV. The closure was estimated to be -1693.4 metres and was used for the proved plus probable plus possible GRV. The proved plus probable GRV in the Mangara-1 Block was taken halfway between LKO and closure at -1678 metres.

In the Mangara-2/3 Block, oil was tested down to -1692.4 metres in the Mangara-2 flow test. This establishes the LKO at -1692.4 metres. In Mangara-3 the interval -1684 to -1693.2 metres tested water on DST No. 1. This establishes the highest known water (HKW) at -1684 metres. GLJ has picked the OWC at -1688.7 metres, halfway between the LKO and the HKW. Proved and proved

plus possible GRV were determined using -1688.7 metres. GLJ has limited the proved GRV assignment to an area equivalent to nine spacing units around the Mangara-2 well. The proved plus probable plus possible GRV was determined using a closure at -1693.4 metres.

These elevations are illustrated on the depth structure map included as Map 4.

C3 Reservoir

In the Mangara-1 Block, oil was tested and logged down to -1708.4 metres and the closure was mapped at -1754 metres. The proved plus probable GRV in the Mangara-1 Block was taken to -1731.2 metres, which is halfway between LKO and closure.

In the Mangara-2/3 Block, oil was tested down to -1743.6 metres which was used to define the LKO. The proved plus probable GRV was based on the LKO on logs at -1748.8 metres and the proved plus probable plus possible GRV was based on the mapped spill at -1754.0 metres.

These elevations are illustrated on the depth structure map included as Map 5.

E1a Reservoir

In the Mangara-1/3 Block, oil was tested and logged down to -2083.0 metres and the closure was mapped at -2135.0 metres. The proved plus probable GRV was taken at -2109.0 metres which is halfway between LKO and closure. These elevations are illustrated on the depth structure map included as Map 6.

A summary of wellbore petrophysics for the existing three Mangara wells is included as Table 2. Total volumetric inputs for the individual zones in each of the blocks are presented as Table 2.1.

RESERVES AND DEVELOPMENT FORECAST

Griffiths plans to commingle the production from each of the reservoir layers where they are found to be productive. It is expected that the reservoirs will produce under some degree of natural water drive; however, Griffiths currently intends to inject water to supplement the water drive in all of the intervals.

Due to the degree of permeability variation between the reservoir layers, it is expected that the C2 reservoir will be effectively waterflooded, as will to a lesser extent the C1a, C1b, C3 and E1a reservoirs. Due to the permeability variation, it is expected that an injection well injecting water into all zones simultaneously would not effectively deliver water to the C1a, C1b and C3 intervals. Separate injection wells will be needed for the C2 and E1a intervals and the C1a, C1b and C3 intervals. Proved waterflood recovery factors have not been included for the C1a, C1b or C3 intervals at this time, as it is uncertain if they will be effectively flooded.

The following recovery factors have been assigned to each reservoir in this evaluation:

Reservoir	Depletion Mechanism	Recovery Factors		
		1P	2P	3P
C1a	Primary/Waterflood	6%	12%	15%
C1b	Primary/Waterflood	6%	12%	15%
C2	Waterflood	15%	22%	30%
C3	Primary/Waterflood	6%	12%	15%
E1a	Waterflood	9%	12%	15%

The gross lease oil reserves are presented in Table 2.2.

Development of the Mangara Field has commenced as of the effective date of the report, with first oil forecast for July 2013. The following wells are scheduled to be drilled in this evaluation:

Well Type	1P	2P	3P
Oil Production	21	25	45
Water Injection	15	34	60
Water Source	4	6	12

Gross lease and company interest production forecasts for each well are presented in Tables 3 and 3.1.

ECONOMIC ANALYSIS

A summary of economic parameters used in this evaluation, including product pricing, operating expenses and capital costs is provided in Tables 4 and 4.1. Economic parameters are described in the following sections.

Production Sharing Contract

- Oil production is subject to a 14.25 percent royalty.
- Inland transportation agreement (ITA) tariffs are included as a deduction from oil price.

The cost oil recovery ceiling is 70 percent of the gross revenue after deduction of the royalty. Bonuses are not cost recoverable. The following items can be claimed for cost recovery:

- Capital and operating costs.
- General and administrative costs.
- Abandonment fund.

The Glencore Farm-in agreement provides for an assignment of one-third of Griffiths' interest in Chad, including the Chari East-Doseo Block to Glencore. In exchange, Glencore has agreed to carry up to $330,764 M$ of development capital associated with the Badila and Mangara Fields. Consequently, cash flows presented herein represent Griffiths remaining interest, and include the terms of the Glencore Farm-in agreement. The interests presented here assume an assignment of one-third of Griffiths' original participation to Glencore. Chad's participation is expected to occur through the Société des Hydrocarbures du Tchad (SHT), the state oil company of Chad. That is, the evaluated interest assumes participation as follows:

Griffiths Energy International Inc.	50%
Glencore International AG	25%
SHT	25%

As defined within the PSC, the Republic of Chad's costs are carried proportionately by Griffiths and Glencore. This 25 percent carry of SHT's costs are included as cost recoverable amounts to Griffiths and Glencore. Interest on the 25 percent carry of SHT costs was scheduled.

Gathering and abandonment costs are scheduled from the effective date as all of these expenses are cost recoverable.

The profits remaining after cost recovery are split between the Contractors and the Government in accordance with the following sharing arrangement:

R Factor	Contractors Share
≤ 2.25	60%
>2.25 & ≤ 3.00	50%
> 3.00	40%

R-Factor = (cost oil + profit oil – operating cost – abandonment cost)/capital cost

The capital recovery associated with the Glencore carry is scheduled as "Other Income" for recovery of sunk costs and as a negative capital amount for future income. The recovery of carried capital is scheduled as follows:

		Glencore Carry Amount ($M)			
Year	**Description**	**1P**	**2P**	**3P**	**Scheduled As**
2012	Sunk Prior to June 30, 2012	24,258	24,258	24,258	Other Income
2012	Sunk costs July 1 to Dec 31, 2012	78,896	78,896	78,896	Other Income
2013	2013 Capital (Mangara)	44,523	53,273	55,447	Capital
2014	2014 Capital (Mangara)	40,917	53,818	53,635	Capital
2015	2015 Capital (Mangara)	50,959	36,680	35,674	Capital
2016	2016 Capital (Mangara)	0	0	0	Capital
	Total	239,552	246,925	247,910	

*Note, all values are in dollars of the day

Note: Values are in dollars of the day (escalated)

Glencore carry amounts do not affect the cost oil recovery calculation.

Capital and Operating Costs

Well operating costs have been estimated at $10,000 per well month. Variable costs for oil were estimated at $3.00/bbl. Fixed operating costs include a component for G&A costs, as well as facilities operating costs. The G&A costs were scheduled since they can be recovered as cost oil. G&A costs were scheduled from the effective date of the analysis. Facility operating costs were scheduled from first production. G&A costs were scaled to production and reserves volumes. Operating cost parameters are presented in Table 4.

Capital requirements for injection and source wells were estimated at 7,700 and 3,500 M$ per well, respectively. Production well capital requirements were estimated to decrease with time to

allow for efficiencies to be realized. Wells drilled to the C sands level are forecast to decrease from a maximum capital amount of 9,754 M$ to a final amount of 7,803 M$. Similarly the wells drilled to the E sand level are forecast to decrease from a maximum capital amount of 14,710 $M to a reduced amount of 9,403 $M. The increased costs of the E sand wells are due to the increased depth. Capital estimates for the production wells were supplied by Griffiths.

Capital was also included for the construction of facilities. Griffiths supplied the capital estimate for the proved plus probable plus possible scenario. These capital costs were then scaled based on peak rate to estimate the capital requirements for the proved and proved plus probable scenarios. Remaining capital costs at the effective date range from 131,666 M$ in the proved case to 158,065 M$ in the proved plus probable plus possible case. A capital amount of 152,785 M$ was used in the proved plus probable case.

Commodity Prices

Oil prices were estimated to be 95 percent of Brent prices, less a $6.50 per barrel transportation fee for the Cameroon to Chad export pipeline less the ITA tariff. The ITA tariff varies for each reserves class. Details on the ITA tariff at Badila and Mangara are presented in the ITA Badila-Mangara report.

Solution gas is considered unmarketable and it was assumed all solution gas would be flared and/or used as fuel.

Economic forecasts for each of the reserves categories have been included in the Economic Forecasts section of this report.

Other Economic Considerations

This report does not address the following issues:

- Non-reserves well abandonment, wellsite reclamation and facility abandonment/salvage including possible environmental concerns.
- Potential processing income.
- The current condition of field, gathering and processing facilities, i.e. an inspection was not carried out.

PSC Parameters - Mangara

Griffiths Energy International Inc (Griffiths) has entered into a Production Sharing Contract with the Republic of Chad.
Key parameters in the economic model* are as follows:

		Griffiths	Glencore	Chad	Comment
Participation		50.00%	25.00%	25.00%	Assumes Chad exercises right to back in for 25% participation
Carry		16.67%	8.33%		Griffiths and Glencore carry 25% of total capital, operating and abandonment costs
Lease Expiry		Dec-36			10 year extension permitted and included in 2P and 3P cases
Oil Royalty		14.25%			Deducted from lease revenue, prior to cost oil and profit oil calculation
Gas Royalty		5%			Deducted from lease revenue, prior to cost oil and profit oil calculation

Allocation of Profit Oil

R Factor		**Griffiths**	**Glencore**	**SHT**	**Chad**	
Profit Oil Share	$R \leq 2.25$	30%	15%	15%	40%	
Profit Oil Share	$2.25 < R \leq 3.00$	25%	13%	13%	50%	
Profit Oil Share	$R > 3$	20%	10%	10%	60%	
Numerator						Contractor Revenue less Cumulative Operating costs and Cumulative Abandonment Costs
Denominator						Contractor Capital and Recovered Exploration Costs

Abandonment Costs	UOP		Abandonment costs recovered on a Unit of Production Basis.
Bonus	0		No remaining Bonus payable. Bonuses not cost recoverable

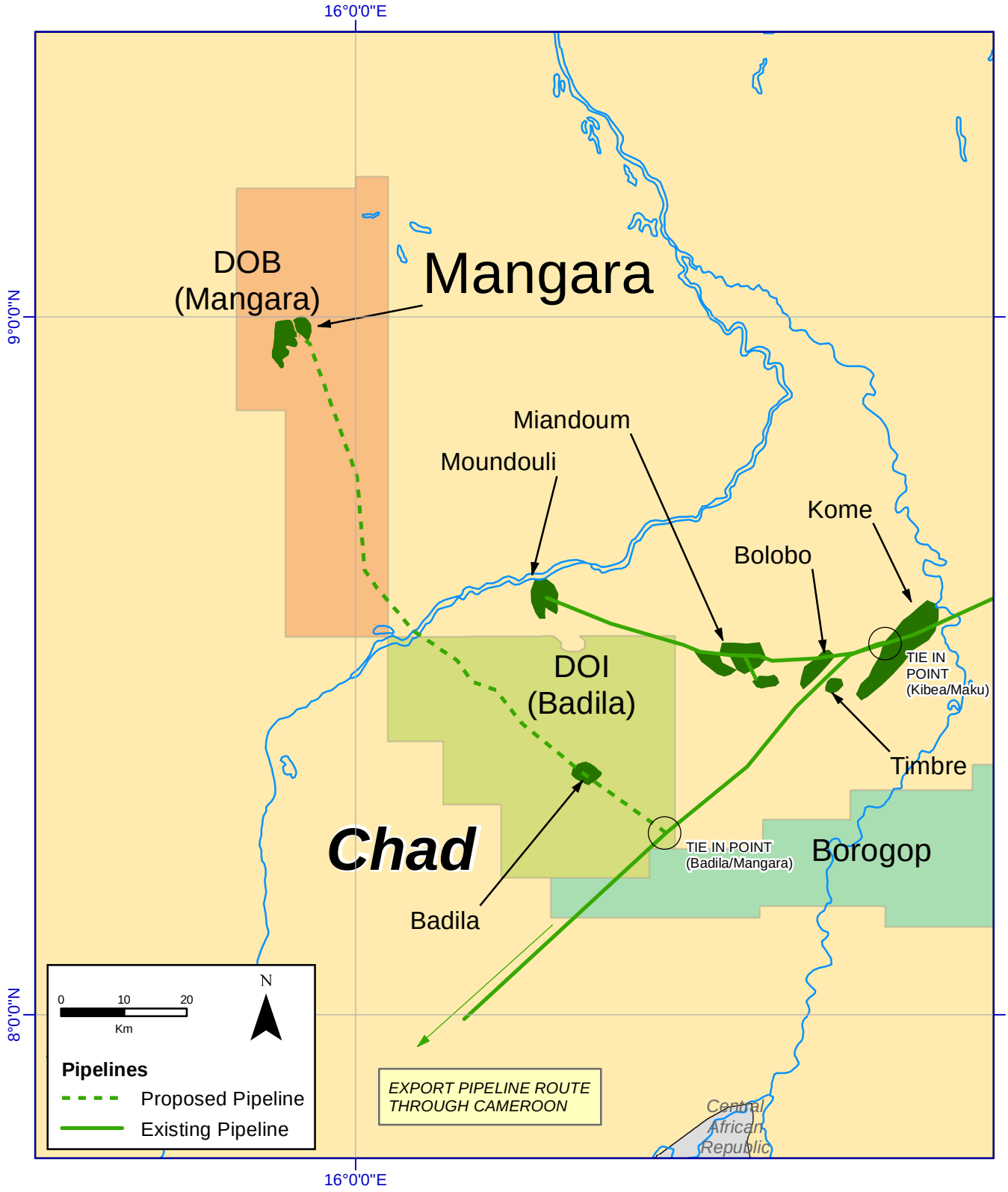
Opening Balances of Recoverable Costs			
Exploration	$	12,367,292	Provided by Griffiths
Capital Costs	$	191,736,282	Sunk capital costs to effective date
G & A Costs	$	29,775,293	Sunk G & A costs to effective date
Total	$	233,878,867	

*The economic model used in this report assumes that the proposed transaction with Glencore International AG will occur
SHT is the *Société des Hydrocarbures du Tchad* , the state oil company of Chad.

Map 1
Land Map
Mangara

Company: Griffiths Energy International Inc.
Property: Mangara

Effective Date: December 31, 2012
Scale: 1:900,000 s1132107/manm01



Map 1a

Exclusive Exploitation Authorization Map

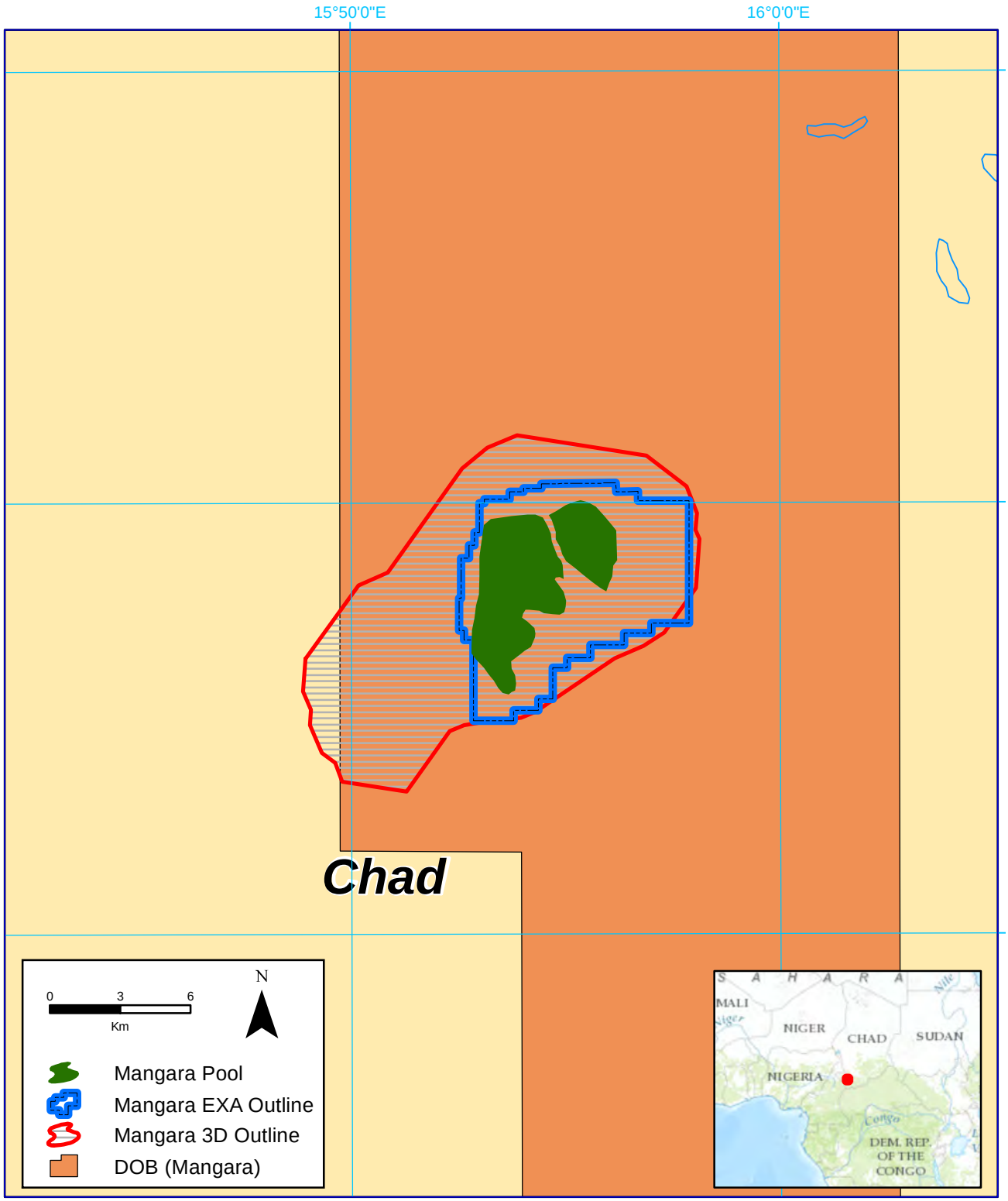
Mangara

Company: Griffiths Energy International Inc.

Property: Mangara

Effective Date: December 31, 2012

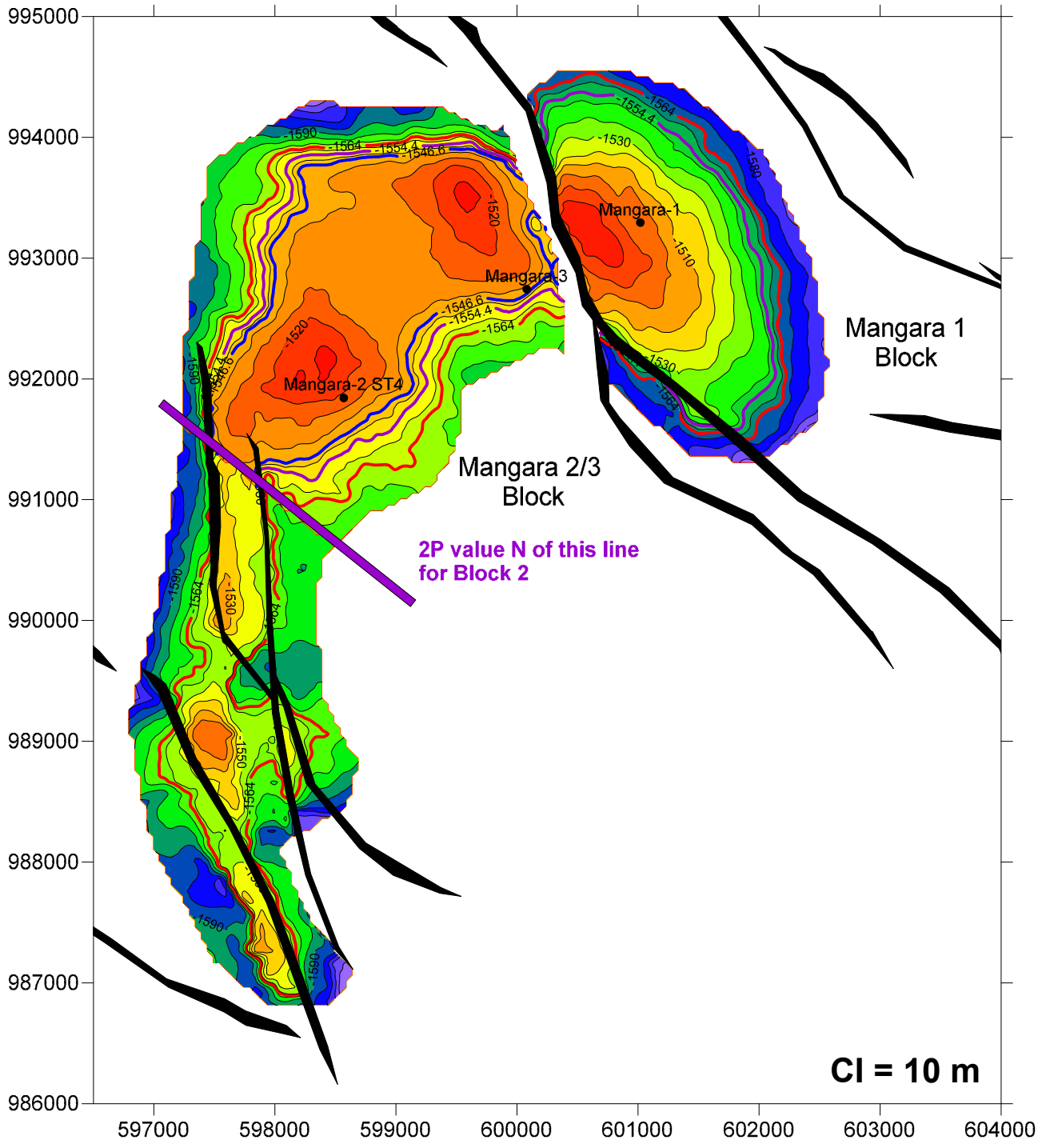
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Map 2
Mangara Field
Depth Structure Map (metres)
C1a Sand

Company: Griffiths Energy International Inc.
Property: Mangara

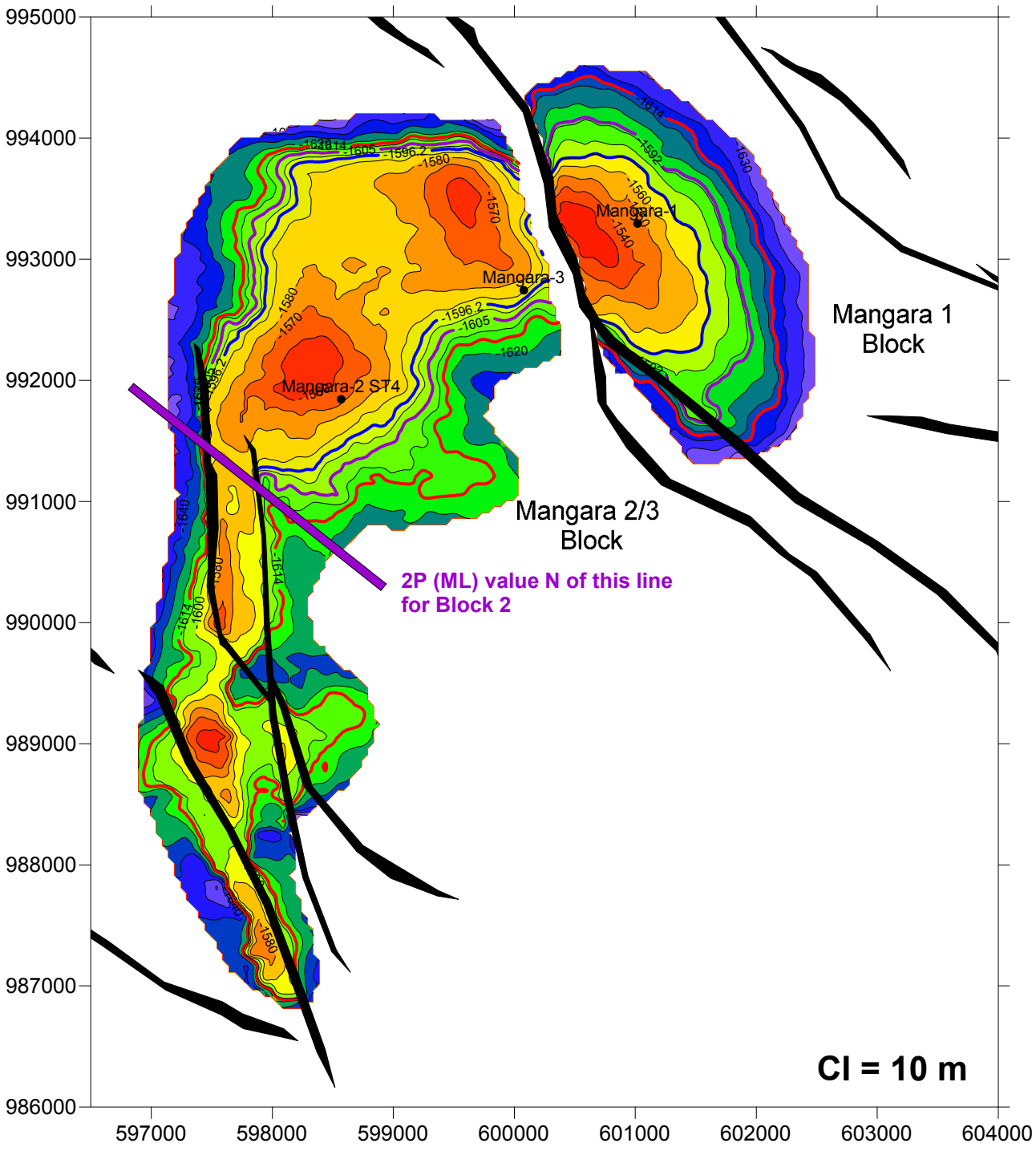
Effective Date: December 31, 2012
Scale: 1:50,000 s1132107



Map 3
Mangara Field
Depth Structure Map (metres)
C1b Sand

Company: Griffiths Energy International Inc.
Property: Mangara

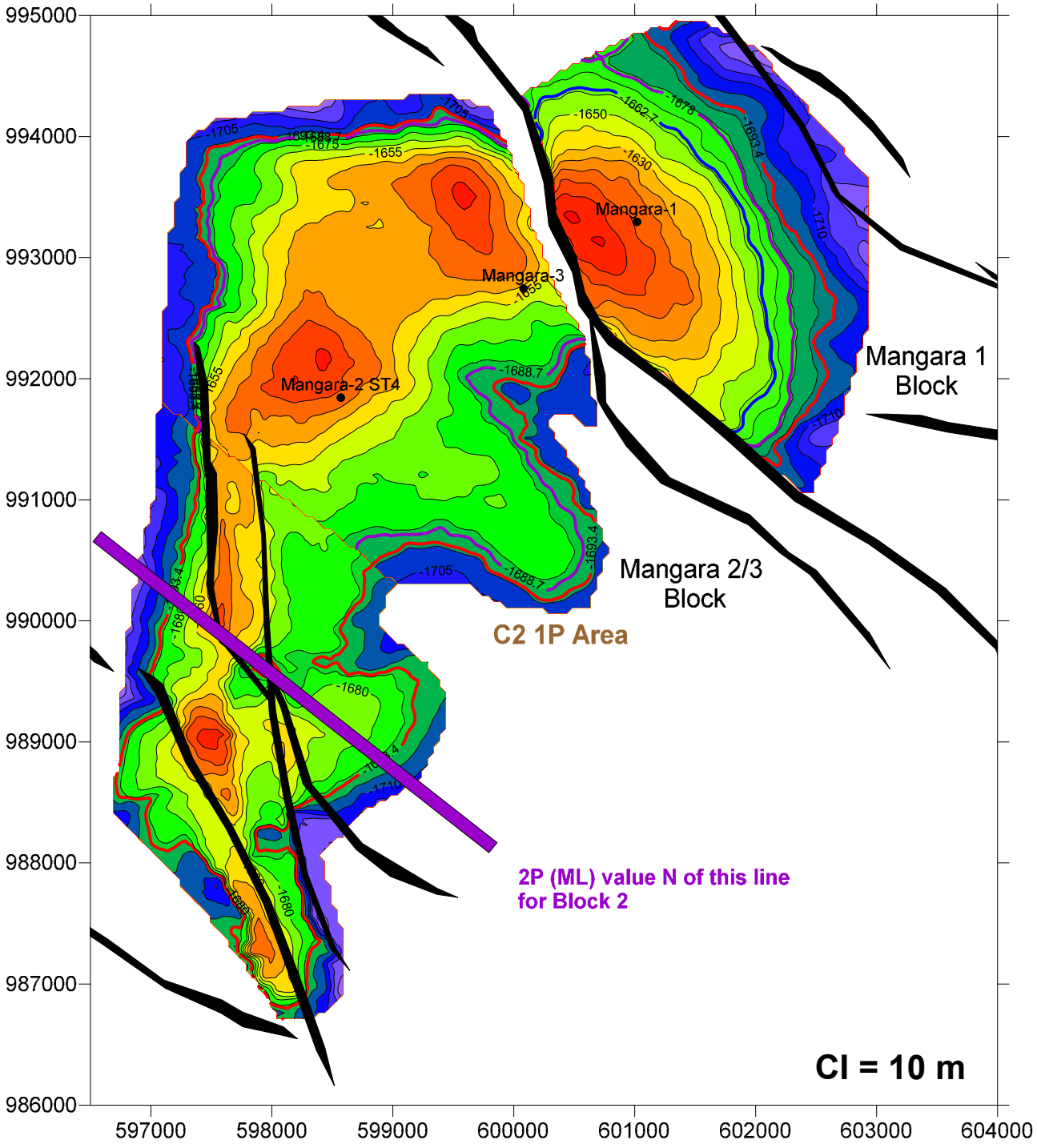
Effective Date: December 31, 2012
Scale: 1:50,000 s1132107



Map 4
Mangara Field
Depth Structure Map (metres)
C2 Sand

Company: Griffiths Energy International Inc.
Property: Mangara

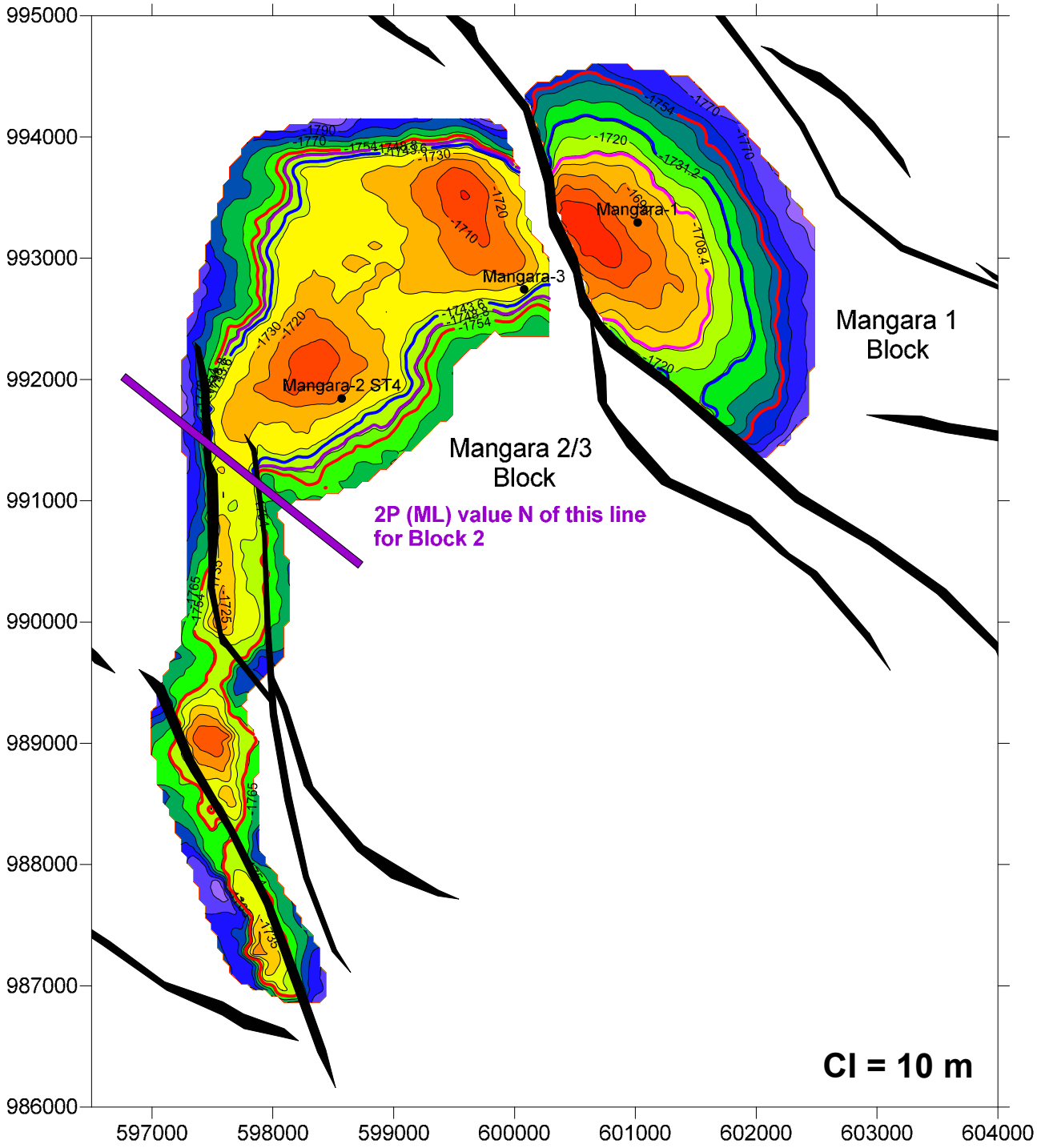
Effective Date: December 31, 2012
Scale: 1:50,000 s1132107



Map 5
Mangara Field
Depth Structure Map (metres)
C3 Sand

Company: Griffiths Energy International Inc.
Property: Mangara

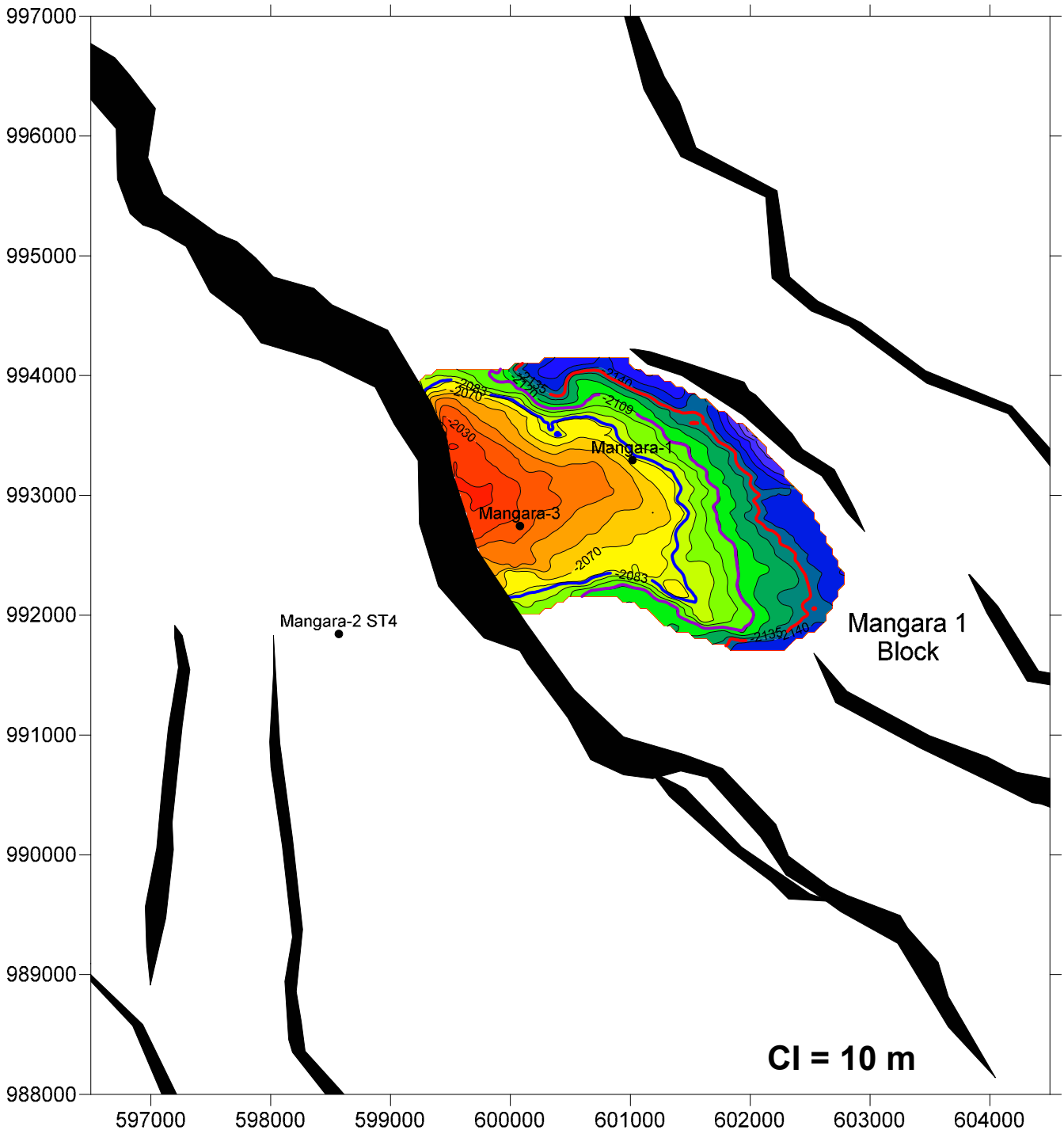
Effective Date: December 31, 2012
Scale: 1:50,000 s1132107



Map 6
Mangara Field
Depth Structure Map (metres)
E1a Sand

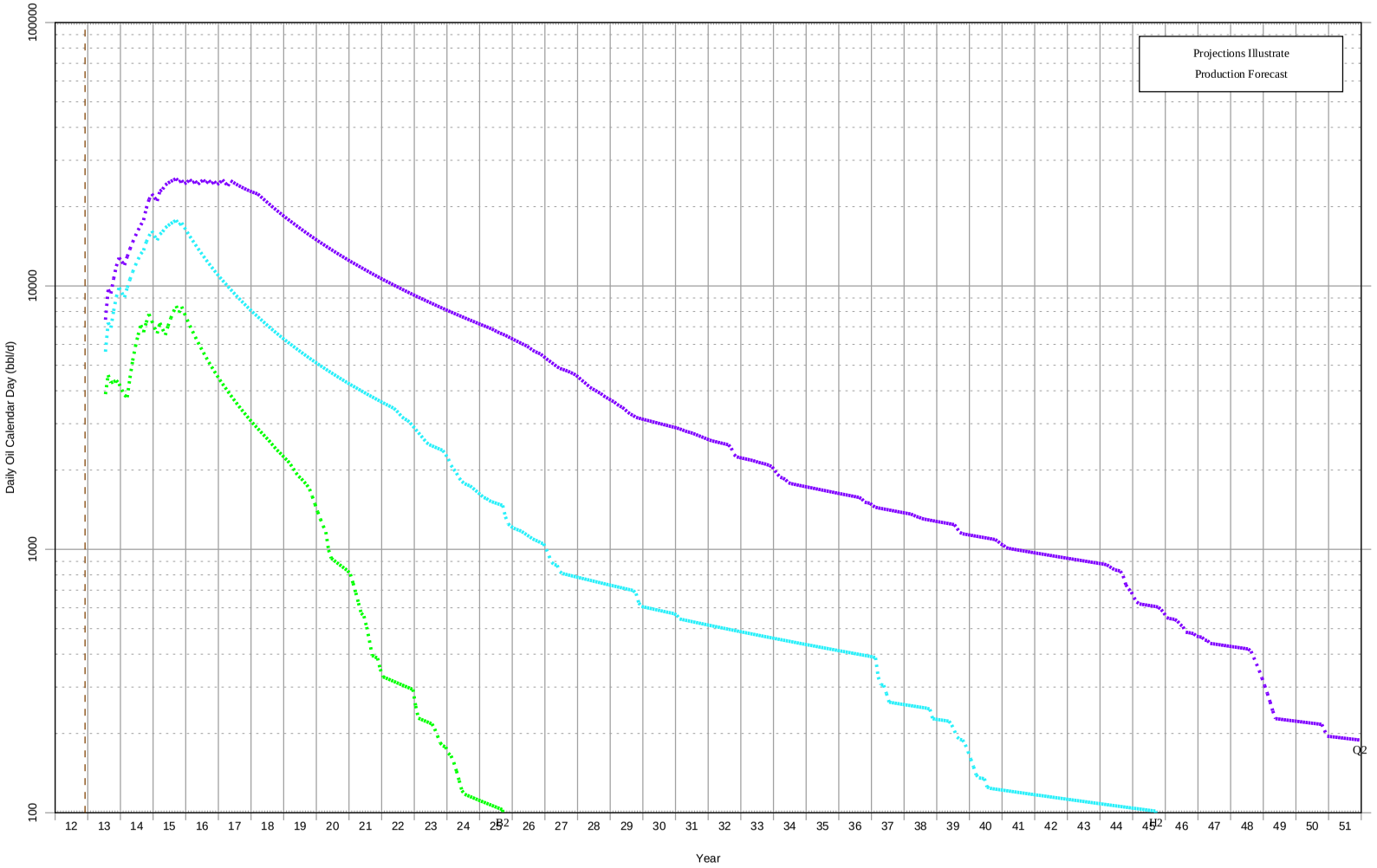
Company: Griffiths Energy International Inc.
Property: Mangara

Effective Date: December 31, 2012
Scale: 1:50,000 s1132107



Historical and Forecast Production
Mangara - Total Property

Property : Mangara



Total Reserves Summary @ 2012/12/01

Reserves Classification		Reserves (Mbbl) Ultimate	Cum Production	Remaining
Pv UDev	B2(R)	11610	0	11610
P + P UDev	H2(R)	34462	0	34462
PPP UDev	Q2(R)	86345	0	86345

Average Production Rates (Last 12 months ending 2012/12/01)

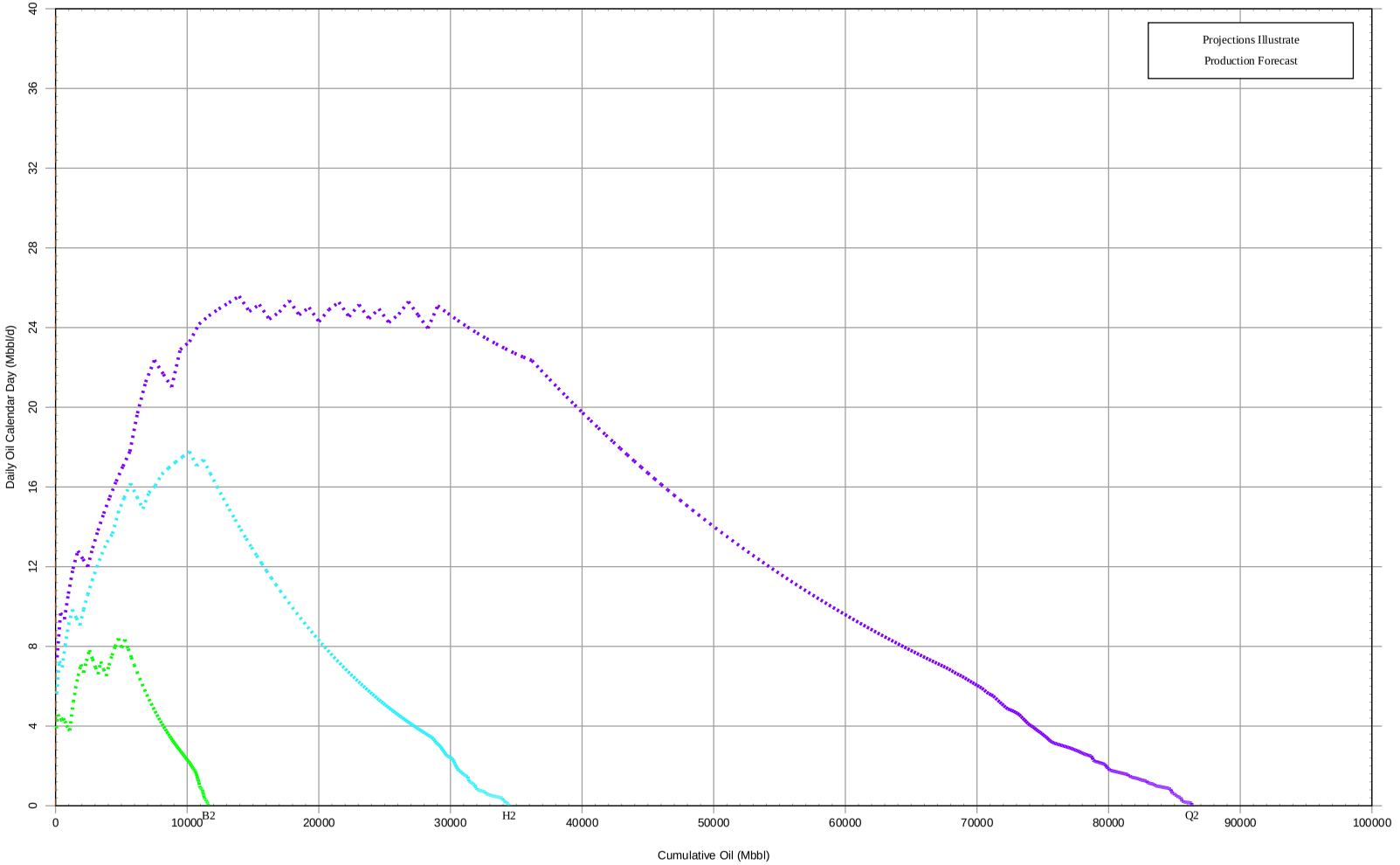
Gas :	0.0 Mcf/d	0.0 Mcf/cd	WGR :	0.0 bbl/MMcf
Oil :	0.0 bbl/d	0.0 bbl/cd	GOR :	0.0 scf/bbl
On Prod :	0.0 days		WC :	0.0 %

Cumulative Production

Oil :	0.0 Mbbl	Gas :	0.0 MMcf	Water :	0.0 Mbbl

Historical and Forecast Production
Mangara - Total Property

Property : Mangara



Total Reserves Summary @ 2012/12/01

Reserves Classification		Reserves (Mbbl) Ultimate	Cum Production	Remaining
Pv UDev	B2(R)	11610	0	11610
P + P UDev	H2(R)	34462	0	34462
PPP UDev	Q2(R)	86345	0	86345

Average Production Rates (Last 12 months ending 2012/12/01)

Gas :	0.0 Mcf/d	0.0 Mcf/cd	WGR :	0.0 bbl/MMcf
Oil :	0.0 bbl/d	0.0 bbl/cd	GOR :	0.0 scf/bbl
On Prod :	0.0 days		WC :	0.0 %

Cumulative Production

Oil :	0.0 Mbbl	Gas :	0.0 MMcf	Water :	0.0 Mbbl

TABLE 1
MANGARA FIELD
SUMMARY OF TEST DATA

Well	Source	Zone	KB Elev m	Test Interval mKB Top	Test Interval mKB Base	Test Interval Elev. mTVD Top	Test Interval Elev. mTVD Base	Gauge Depth Measured mKB	Gauge Depth Elevation m	Flow Period	Flow Time minutes	Flowing Pressure Initial psia	Flowing Pressure Final psia	Buildup Time minutes	Buildup Pressure psia	kh md-ft	k md	Skin	Fluid Recovery Water Cushion bbl	Fluid Recovery Mud bbl	Fluid Recovery Oil bbl	Fluid Recovery Oil Gravity °API	Fluid Recovery Formation Water bbl	Comment
Mangara 1	DST 1	C1b	395.0	1934.5	1957.0	-1539.5	-1562.0	1927.8	-1532.8	1st	124.0	838	1751	176.0	2410.2	460	6.8	5.1	20.0	4.0	52.0	37.1	0.0	Valid test, no formation water
	DST 2	E1a	395.0	2471.0	2488.0	-2076.0	-2093.0	2468.0	-2073.0	1st	138.0			149.0					1.8	0.0	0.0	0.0	0.0	Test misrun, hydrospring mandrel plugged on opening
	DST 2A	E1a	395.0	2471.0	2487.5	-2076.0	-2092.5	2362.7	-1967.7	1st	10.0	741	1038	62.0	3282.0	130	6.3	14.5	8.5	16.0	50.0	39.0	0.0	Valid test.
			395.0	2471.0	2487.5	-2076.0	-2092.5	2362.7	-1967.7	2nd	212.0	1073	1819	27.0	3210.0									
			395.0	2471.0	2487.5	-2076.0	-2092.5	2362.7	-1967.7	3rd	71.0	1784	1950	696.0	3307.0									
			395.0	2471.0	2487.5	-2076.0	-2092.5	2362.7	-1967.7	4th	189.0	1983	2308	292.0	3303.0									
	DST 3	D	395.0	2344.0	2352.0	-1949.0	-1957.0	2315.7	-1920.7	1st	4.0	538	675	107.0	1874.0	2-4	0.015	-1.9	7.1	2.9	0.0	0.0	0.0	Valid test, very low k, no trace of oil, gas or fm wtr
			395.0	2344.0	2352.0	-1949.0	-1957.0	2315.7	-1920.7	2nd	42.0	681	726	30.0	1465.0									
			395.0	2344.0	2352.0	-1949.0	-1957.0	2315.7	-1920.7	3rd	34.0	737	769	31.0	1346.0									
			395.0	2344.0	2352.0	-1949.0	-1957.0	2315.7	-1920.7	4th	32.0	769	782	94.0	1450.0									
	DST 3A	D	395.0	2344.0	2352.0	-1949.0	-1957.0	2327.6	-1932.6	1st	75.0	618	658	131.0	1783.0	0.24	0.01		6.8	1.6	0.0	0.0	0.0	Valid test, very low k, no trace of oil, gas or fm wtr
			395.0	2344.0	2352.0	-1949.0	-1957.0	2327.6	-1932.6	2nd	30.0	671	692	none	none									
	DST 4	C3/D05	395.0	2090.0	2103.4	-1695.0	-1708.4	2080.0	-1685.0	1st	9.0	1427	1738	70.0	2564.0	87	1.4	-3.5	7.1	3.0	10.0	39.0	12.5	Not a valid test of the zone. Test to water sands below.
			395.0	2090.0	2103.4	-1695.0	-1708.4	2080.0	-1685.0	2nd	378.0	1485	1708	83.0	2269.0									
	DST 4A	C3/D05	395.0	2093.4	2102.5	-1698.4	-1707.5	2071.9	-1676.9	1st	300.0	825	1344	68.0	2730.0	19	0.3	5.5	14.0	3.5	17.3	38.2	2.2	Valid test, water is likely mud filtrate
			395.0	2093.4	2102.5	-1698.4	-1707.5	2071.9	-1676.9	2nd	380.0	1373	1419	482.0	2844.0									
	DST 5	C2	395.0	2027.0	2057.0	-1632.0	-1662.0	2022.0	-1627.0	1st	9.0	1624	1777	65.0	2845.0	1685	15.7	3.5				38.4	0.0	Valid test, OTS max 1875 bpd, GOR 690 scf/bbl
			395.0	2027.0	2057.0	-1632.0	-1662.0	2022.0	-1627.0	2nd	579.0	1750	2093	790.0	2806.0									
			395.0	2027.0	2057.0	-1632.0	-1662.0	2022.0	-1627.0	3rd	455.0	1702	2226	112.0	2772.0									
	DST 6	C1b	395.0	1940.0	1969.5	-1545.0	-1574.5	1937.0	-1542.0	1st	9.0	664	765	64.0	2750.0	72	1.1	5.3				38.7		Valid test, OTS 46 bpd, Gas tstm
			395.0	1940.0	1969.5	-1545.0	-1574.5	1937.0	-1542.0	2nd	260.0	859	1342	668.0	2579.0									
			395.0	1940.0	1969.5	-1545.0	-1574.5	1937.0	-1542.0	3rd	596.0	1419	1714	100.0	2295.0									
Mangara 2	Prod Test	E1a	399.6	2610.3	2660.3	-2210.7	-2260.7																	No OTS, fluid column 80% fm water, 20% oil
	Prod Test	C1a	399.6	1923.6	2142.4	-1524.0	-1742.8								2895.0	32.1	2.2	6.1				36-37		Commingled test, oil rate ~700 bpd, 700 scf/bbl, 3%
		C1b														42.8	1.4	6.1						C1a, 4% C1b, 86% C2 & 7% C3/D05 from PLT log.
		C2														920.2	15.1	6.1						Total test kh split between zones based on contribution to
		C3/D05														74.9	2.1	6.1						flow.
	Prod Test	C1a	399.6	1935.7	2142.2	-1536.1	-1742.6								2904.0	312.5/851.3	1.8/4.8	5.4				37-38		Commingled test, tested at ~800 bpd before being
		C1b																						stepped down to ~513 bopd and ~330 bopd. GOR of
		C2																						1135 scf/bbl. Modelled as two region composite
		C3/D05																						reservoir.
Mangara 3	DST 1	C2 Lwr	406.9	2090.9	2100.1	-1684.0	-1693.2	2090.9	-1684.0						2895.0	560	7.0	-3.7				33-35		Fracture stimulate, Swabbed 700 bpd, 95-98% water
	DST 2	C2 Uppr	406.9	2072.6	2084.5	-1665.7	-1677.6	2030.4	-1623.5						N/A									Swabbed 650 bpd, 98-100% water, fluid may have been
																								the injectants disposed of in DST 1

TABLE 2
MANGARA
SUMMARY OF PETROPHYSICAL ANALYSIS

					Proved			Proved plus Probable			Proved plus Probable plus Possible		
Well	Datum (m)	Top MD, m	Base MD, m	Gross Thickness tvd, m	Net Oil m	Phi	Sw	Net Oil m	Phi	Sw	Net Oil m	Phi	Sw
C1a Reservoir													
M-1	395.0	1890.4	1908.7	18.3	1.4	10.6%	49%	2.2	9.7%	50%	3.9	9.3%	52%
M-2 ST4	399.9	1923.0	1944.6	21.6	4.1	16.2%	42%	4.5	15.5%	42%	5.8	15.4%	45%
M-3	406.9	1950.1	1968.4	18.3	0.0	0.0%	0%	0.0	0.0%	0%	0.0	0.0%	0%
Averages:				**19.4**	**1.8**	**14.7%**	**43.2%**	**2.2**	**13.6%**	**43.6%**	**3.2**	**12.9%**	**47.0%**
Net/Gross:					**0.095**			**0.115**			**0.166**		
C1b Reservoir													
M-1	395.0	1942.8	1965.4	22.6	12.30	13.09%	31.90%	20.70	12%	32.20%	22.10	12%	32.6%
M-2 ST4	399.9	1967.8	1996.1	28.3	8.23	18.20%	37.20%	9.07	17%	37.20%	10.44	17%	39.1%
M-3	406.9	1995.5	2024.2	28.7	3.58	21.86%	29.60%	4.42	19%	30.20%	5.26	18%	32.0%
Averages:				**26.5**	**8.0**	**16.1%**	**33.5%**	**11.4**	**14.5%**	**33.4%**	**12.6**	**14.0%**	**34.6%**
Net/Gross:					**0.303**			**0.430**			**0.475**		
C2 Reservoir													
M-1	395.0	1996.4	2057.7	61.3	28.00	14.33%	27.70%	32.50	14%	28.90%	34.50	14%	30.2%
M-2 ST4	399.9	2029.1	2087.9	58.8	17.07	16.19%	32.30%	18.59	16%	31.90%	20.27	15%	32.9%
M-3	406.9	2055.3	2114.1	58.8	25.98	19.08%	43.40%	26.75	19%	43.40%	30.33	19%	45.0%
Averages:				**59.6**	**23.7**	**16.5%**	**35.4%**	**25.9**	**15.9%**	**35.5%**	**28.4**	**15.9%**	**37.1%**
Net/Gross:					**0.397**			**0.435**			**0.476**		
C3 Reservoir													
M-1	395.0	2078.4	2123.5	45.1	16.40	15.4%	41.70%	19.00	15.2%	42.70%	22.40	15.4%	45.0%
M-2 ST4	399.9	2121.1	2171.1	50.0	17.15	12.7%	39.70%	21.95	12.0%	39.40%	25.60	11.7%	41.2%
M-3	406.9	2142.4	2176.9	34.4	10.13	15.0%	42.90%	11.05	14.5%	42.70%	12.12	14.2%	43.8%
Averages:				**43.2**	**14.6**	**14.3%**	**41.3%**	**17.3**	**13.7%**	**41.5%**	**20.0**	**13.6%**	**43.3%**
Net/Gross:					**0.337**			**0.401**			**0.464**		
E1a Reservoir													
M-1	395.0	2471.0	2478.9	7.9	5.70	12.8%	34.00%	6.30	12.4%	34.10%	6.50	12.2%	34.3%
M-2 ST4	399.9	2612.3	2619.2	6.9	wet	wet	wet	wet	wet	wet	wet	wet	wet
M-3	406.9	2442.1	2449.1	7.0	3.81	13.9%	46.30%	4.04	13.6%	46.50%	4.88	13.0%	48.0%
Averages:				**7.3**	**4.8**	**13.2%**	**39.2%**	**5.2**	**12.8%**	**39.2%**	**5.7**	**12.6%**	**40.4%**
Net/Gross:					**0.654**			**0.711**			**0.783**		

Notes

Proved Case = Phi>8%, Sw<55%, Vsh <50%

Proved + Probable Case = Phi>7%, Sw<55%, Vsh <75%

Proved + Probable + Possible Case = Phi>6%, Sw<60%, Vsh 100%

TABLE 2.1
MANGARA
OIL RESERVOIR PARAMETERS

Block 1	Porosity %			Water Saturation %			Gross Rock Volume acre-ft			Area acres			Net Pay ft			Form. Volume	Original Oil-in-Place Mbbl			Recovey Factor %			Ultimate Reserves Mbbl		
Zone	Proved	P+P	3P	Proved	P+P	3P	Proved	P+P	3P	Proved	P+P	3P	Proved	P+P	3P	Factor	Proved	P+P	3P	Proved	P+P	3P	Proved	P+P	3P
C1a	0%	10%	9%	0%	50%	52%	0	54725	119995	0	588	963	0.0	11.2	26.2	1.38	0	1791	6324	0	12	15	0	215	949
C1b	13%	12%	12%	32%	32%	33%	23838	58594	114821	355	613	931	36.6	87.7	120.9	1.38	6516	24602	51163	6	12	15	391	2952	7675
C2	14%	14%	14%	28%	29%	30%	97901	145379	204420	820	1031	1264	54.6	74.7	91.1	1.38	26004	43117	63225	15	22	30	3901	9486	18967
C3	15%	15%	15%	42%	43%	45%	23471	60258	118792	359	614	923	23.8	41.3	64.0	1.38	4312	12421	28317	6	12	15	259	1491	4248
E1a	13%	13%	13%	39%	39%	40%	59775	127744	378597	633	916	2717	60.2	96.6	106.3	1.50	15830	35632	112196	9	12	15	1425	4276	16829
																	52662	**117563**	**261224**				**5975**	**18419**	**48667**

Block 2	Porosity %			Water Saturation %			Gross Rock Volume acre-ft			Area acres			Net Pay ft			Form. Volume	Original Oil-in-Place Mbbl			Recovey Factor %			Ultimate Reserves Mbbl		
Zone	Proved	P+P	3P	Proved	P+P	3P	Proved	P+P	3P	Proved	P+P	3P	Proved	P+P	3P	Factor	Proved	P+P	3P	Proved	P+P	3P	Proved	P+P	3P
C1a	16%	16%	15%	42%	42%	45%	52756	82068	155217	1047	1224	2043	5.2	7.6	11.0	1.38	2870	4687	10717	6	12	15	172	562	1608
C1b	19%	18%	17%	35%	35%	37%	65508	100760	184631	1118	1310	2312	12.1	18.2	22.0	1.38	9622	15779	30764	6	12	15	577	1894	4615
C2	18%	18%	17%	39%	39%	41%	130719	237806	378453	1323	2178	3727	36.2	42.0	43.7	1.38	29175	54764	94237	15	22	30	4376	12048	28271
C3	14%	13%	13%	41%	41%	42%	57778	77001	116160	1064	1173	1677	17.5	25.7	31.0	1.38	8418	12969	21126	6	12	15	505	1556	3169
E1a	0%	0%	0%	0%	0%	0%	0	0	0	0	0	0	0.0	0.0	0.0	1.50	0	0	0	0	0	0	0	0	0
																	50086	**88200**	**156844**				**5631**	**16060**	**37662**
																Mangara Total:	**102748**	**205763**	**418069**				**11606**	**34480**	**86330**

Table 2.2

Company: **Griffiths Energy International Inc.**
Property: **Mangara**
Currency: **$US Dollars**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Gross Lease Reserves Summary

Entity Description	Reserve Class	Methodology	Oil (Mbbl) Initial Recoverable	Oil (Mbbl) Cumulative Production	Oil (Mbbl) Reserves	Non-Associated Gas (MMcf) Initial Recoverable	Non-Associated Gas (MMcf) Cumulative Production	Non-Associated Gas (MMcf) Raw Gas	Non-Associated Gas (MMcf) Reserves	Other Gross Lease Reserves Sol'n Gas MMcf	Other Gross Lease Reserves Cond Mbbl	Other Gross Lease Reserves LPG Mbbl	Other Gross Lease Reserves Sulphur Mlt
Proved Undeveloped													
M-04/C1b	B2	Vol	131	0	118 *	0	0	0	0	0	0	0	0
M-04/C2	B2	Vol	558	0	558	0	0	0	0	0	0	0	0
M-04/C3	B2	Vol	86	0	86	0	0	0	0	0	0	0	0
M-04/E	B2	Vol	285	0	243 *	0	0	0	0	0	0	0	0
M-05/C1b	B2	Vol	130	0	118 *	0	0	0	0	0	0	0	0
M-05/C2	B2	Vol	558	0	558	0	0	0	0	0	0	0	0
M-05/C3	B2	Vol	86	0	86	0	0	0	0	0	0	0	0
M-05/E	B2	Vol	285	0	243 *	0	0	0	0	0	0	0	0
M-06/C1b	B2	Vol	130	0	118 *	0	0	0	0	0	0	0	0
M-06/C2	B2	Vol	558	0	558	0	0	0	0	0	0	0	0
M-06/C3	B2	Vol	86	0	86	0	0	0	0	0	0	0	0
M-06/E	B2	Vol	285	0	243 *	0	0	0	0	0	0	0	0
M-07/C2	B2	Vol	558	0	558	0	0	0	0	0	0	0	0
M-08/C1a	B2	Vol	22	0	22 *	0	0	0	0	0	0	0	0
M-08/C1b	B2	Vol	72	0	63 *	0	0	0	0	0	0	0	0
M-08/C3	B2	Vol	63	0	63	0	0	0	0	0	0	0	0
M-08/E	B2	Vol	285	0	240 *	0	0	0	0	0	0	0	0
M-09/C1a	B2	Vol	22	0	22 *	0	0	0	0	0	0	0	0
M-09/C1b	B2	Vol	72	0	63 *	0	0	0	0	0	0	0	0
M-09/C3	B2	Vol	63	0	63	0	0	0	0	0	0	0	0
M-09/E	B2	Vol	285	0	239 *	0	0	0	0	0	0	0	0
M-10/C1a	B2	Vol	22	0	22 *	0	0	0	0	0	0	0	0
M-10/C1b	B2	Vol	72	0	63 *	0	0	0	0	0	0	0	0
M-10/C3	B2	Vol	63	0	63	0	0	0	0	0	0	0	0
M-11/C1a	B2	Vol	22	0	22 *	0	0	0	0	0	0	0	0
M-11/C1b	B2	Vol	72	0	61 *	0	0	0	0	0	0	0	0
M-11/C3	B2	Vol	63	0	63	0	0	0	0	0	0	0	0
M-12/C2	B2	Vol	438	0	438	0	0	0	0	0	0	0	0
M-13/C1a	B2	Vol	22	0	22 *	0	0	0	0	0	0	0	0
M-13/C1b	B2	Vol	72	0	61 *	0	0	0	0	0	0	0	0
M-13/C2	B2	Vol	438	0	438	0	0	0	0	0	0	0	0
M-13/C3	B2	Vol	63	0	63	0	0	0	0	0	0	0	0
M-14/C1a	B2	Vol	22	0	22 *	0	0	0	0	0	0	0	0
M-14/C1b	B2	Vol	72	0	60 *	0	0	0	0	0	0	0	0
M-14/C2	B2	Vol	438	0	438	0	0	0	0	0	0	0	0
M-14/C3	B2	Vol	63	0	63	0	0	0	0	0	0	0	0
M-15/C1a	B2	Vol	22	0	22 *	0	0	0	0	0	0	0	0
M-15/C1b	B2	Vol	72	0	60 *	0	0	0	0	0	0	0	0
M-15/C2	B2	Vol	438	0	438	0	0	0	0	0	0	0	0
M-15/C3	B2	Vol	63	0	63	0	0	0	0	0	0	0	0
M-16/C1a	B2	Vol	22	0	22 *	0	0	0	0	0	0	0	0
M-16/C1b	B2	Vol	72	0	59 *	0	0	0	0	0	0	0	0
M-16/C2	B2	Vol	438	0	438	0	0	0	0	0	0	0	0
M-16/C3	B2	Vol	63	0	63	0	0	0	0	0	0	0	0
M-18/C2	B2	Vol	558	0	557 *	0	0	0	0	0	0	0	0
M-19/C2	B2	Vol	558	0	555 *	0	0	0	0	0	0	0	0
M-21/C2	B2	Vol	554	0	545 *	0	0	0	0	0	0	0	0

Gross Lease Reserves Summary

Entity Description	Reserve Class	Methodology	Oil (Mbbl) Initial Recoverable	Oil (Mbbl) Cumulative Production	Oil (Mbbl) Reserves	Non-Associated Gas (MMcf) Initial Recoverable	Non-Associated Gas (MMcf) Cumulative Production	Non-Associated Gas (MMcf) Raw Gas	Non-Associated Gas (MMcf) Reserves	Other Gross Lease Reserves Sol'n Gas MMcf	Other Gross Lease Reserves Cond Mbbl	Other Gross Lease Reserves LPG Mbbl	Other Gross Lease Reserves Sulphur Mlt
Proved Undeveloped (Cont.)													
M-24/C2	B2	Vol	438	0	438	0	0	0	0	0	0	0	0
M-25/C2	B2	Vol	438	0	438	0	0	0	0	0	0	0	0
M-26/C2	B2	Vol	438	0	438	0	0	0	0	0	0	0	0
M-27/C2	B2	Vol	438	0	438	0	0	0	0	0	0	0	0
M-28/C2	B2	Vol	438	0	438	0	0	0	0	0	0	0	0
Total: Proved Undeveloped			**11,611**	**0**	**11,257***	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Proved Plus Probable Undeveloped													
M-04/C1a	H2	Vol	54	0	54	0	0	0	0	0	0	0	0
M-04/C1b	H2	Vol	590	0	424*	0	0	0	0	0	0	0	0
M-04/C2	H2	Vol	1,185	0	1,185	0	0	0	0	0	0	0	0
M-04/C3	H2	Vol	298	0	298	0	0	0	0	0	0	0	0
M-04/E	H2	Vol	611	0	542*	0	0	0	0	0	0	0	0
M-05/C1a	H2	Vol	54	0	54	0	0	0	0	0	0	0	0
M-05/C1b	H2	Vol	590	0	424*	0	0	0	0	0	0	0	0
M-05/C2	H2	Vol	1,185	0	1,185	0	0	0	0	0	0	0	0
M-05/C3	H2	Vol	298	0	298	0	0	0	0	0	0	0	0
M-05/E	H2	Vol	611	0	542*	0	0	0	0	0	0	0	0
M-06/C1a	H2	Vol	54	0	54	0	0	0	0	0	0	0	0
M-06/C1b	H2	Vol	590	0	424*	0	0	0	0	0	0	0	0
M-06/C2	H2	Vol	1,185	0	1,185	0	0	0	0	0	0	0	0
M-06/C3	H2	Vol	298	0	298	0	0	0	0	0	0	0	0
M-06/E	H2	Vol	611	0	542*	0	0	0	0	0	0	0	0
M-07/C1a	H2	Vol	54	0	54	0	0	0	0	0	0	0	0
M-07/C1b	H2	Vol	590	0	423*	0	0	0	0	0	0	0	0
M-07/C2	H2	Vol	1,185	0	1,185	0	0	0	0	0	0	0	0
M-07/C3	H2	Vol	298	0	297*	0	0	0	0	0	0	0	0
M-07/E	H2	Vol	611	0	541*	0	0	0	0	0	0	0	0
M-08/C1a	H2	Vol	63	0	63	0	0	0	0	0	0	0	0
M-08/C1b	H2	Vol	210	0	166*	0	0	0	0	0	0	0	0
M-08/C2	H2	Vol	710	0	710	0	0	0	0	0	0	0	0
M-08/C3	H2	Vol	173	0	173	0	0	0	0	0	0	0	0
M-08/E	H2	Vol	611	0	539*	0	0	0	0	0	0	0	0
M-09/C1a	H2	Vol	63	0	63	0	0	0	0	0	0	0	0
M-09/C1b	H2	Vol	210	0	165*	0	0	0	0	0	0	0	0
M-09/C2	H2	Vol	710	0	710	0	0	0	0	0	0	0	0
M-09/C3	H2	Vol	173	0	173	0	0	0	0	0	0	0	0
M-09/E	H2	Vol	611	0	538*	0	0	0	0	0	0	0	0
M-10/C1a	H2	Vol	63	0	63	0	0	0	0	0	0	0	0
M-10/C1b	H2	Vol	210	0	165*	0	0	0	0	0	0	0	0
M-10/C2	H2	Vol	710	0	710	0	0	0	0	0	0	0	0
M-10/C3	H2	Vol	173	0	173	0	0	0	0	0	0	0	0
M-11/C1a	H2	Vol	63	0	63	0	0	0	0	0	0	0	0
M-11/C1b	H2	Vol	210	0	163*	0	0	0	0	0	0	0	0
M-11/C2	H2	Vol	710	0	710	0	0	0	0	0	0	0	0
M-11/C3	H2	Vol	173	0	173	0	0	0	0	0	0	0	0
M-12/C1a	H2	Vol	63	0	63	0	0	0	0	0	0	0	0
M-12/C1b	H2	Vol	210	0	163*	0	0	0	0	0	0	0	0
M-12/C2	H2	Vol	710	0	710	0	0	0	0	0	0	0	0
M-12/C3	H2	Vol	173	0	173	0	0	0	0	0	0	0	0

Gross Lease Reserves Summary

Entity Description	Reserve Class	Methodology	Oil (Mbbl) Initial Recoverable	Oil (Mbbl) Cumulative Production	Oil (Mbbl) Reserves	Non-Associated Gas (MMcf) Initial Recoverable	Non-Associated Gas (MMcf) Cumulative Production	Non-Associated Gas (MMcf) Raw Gas	Non-Associated Gas (MMcf) Reserves	Other Gross Lease Reserves Sol'n Gas MMcf	Other Gross Lease Reserves Cond Mbbl	Other Gross Lease Reserves LPG Mbbl	Other Gross Lease Reserves Sulphur Mlt
Proved Plus Probable Undeveloped (Cont.)													
M-13/C1a	H2	Vol	63	0	63	0	0	0	0	0	0	0	0
M-13/C1b	H2	Vol	210	0	162 *	0	0	0	0	0	0	0	0
M-13/C2	H2	Vol	710	0	710	0	0	0	0	0	0	0	0
M-13/C3	H2	Vol	173	0	173	0	0	0	0	0	0	0	0
M-14/C1a	H2	Vol	63	0	63	0	0	0	0	0	0	0	0
M-14/C1b	H2	Vol	210	0	162 *	0	0	0	0	0	0	0	0
M-14/C2	H2	Vol	710	0	710	0	0	0	0	0	0	0	0
M-14/C3	H2	Vol	173	0	173	0	0	0	0	0	0	0	0
M-15/C1a	H2	Vol	63	0	63	0	0	0	0	0	0	0	0
M-15/C1b	H2	Vol	210	0	161 *	0	0	0	0	0	0	0	0
M-15/C2	H2	Vol	710	0	710	0	0	0	0	0	0	0	0
M-15/C3	H2	Vol	173	0	173	0	0	0	0	0	0	0	0
M-16/C1a	H2	Vol	63	0	63	0	0	0	0	0	0	0	0
M-16/C1b	H2	Vol	212	0	161 *	0	0	0	0	0	0	0	0
M-16/C2	H2	Vol	710	0	710	0	0	0	0	0	0	0	0
M-16/C3	H2	Vol	175	0	175	0	0	0	0	0	0	0	0
M-17/C2	H2	Vol	710	0	710	0	0	0	0	0	0	0	0
M-18/C1b	H2	Vol	590	0	405 *	0	0	0	0	0	0	0	0
M-18/C2	H2	Vol	1,185	0	1,185	0	0	0	0	0	0	0	0
M-18/C3	H2	Vol	298	0	289 *	0	0	0	0	0	0	0	0
M-19/C2	H2	Vol	1,185	0	1,185	0	0	0	0	0	0	0	0
M-20/C2	H2	Vol	1,185	0	1,185	0	0	0	0	0	0	0	0
M-21/C2	H2	Vol	1,185	0	1,185	0	0	0	0	0	0	0	0
M-22/C2	H2	Vol	710	0	710	0	0	0	0	0	0	0	0
M-23/C2	H2	Vol	710	0	710	0	0	0	0	0	0	0	0
M-23/E	H2	Vol	607	0	516 *	0	0	0	0	0	0	0	0
M-24/C2	H2	Vol	710	0	710	0	0	0	0	0	0	0	0
M-25/C2	H2	Vol	710	0	710	0	0	0	0	0	0	0	0
M-26/C2	H2	Vol	710	0	710	0	0	0	0	0	0	0	0
M-27/C2	H2	Vol	710	0	710	0	0	0	0	0	0	0	0
M-28/C2	H2	Vol	674	0	674	0	0	0	0	0	0	0	0
Total: Proved Plus Probable Undeveloped			**34,462**	**0**	**32,667 ***	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
PPP Undeveloped													
M-04/C1a	Q2	Vol	136	0	136	0	0	0	0	0	0	0	0
M-04/C1b	Q2	Vol	1,098	0	921 *	0	0	0	0	0	0	0	0
M-04/C2	Q2	Vol	2,107	0	2,107	0	0	0	0	0	0	0	0
M-04/C3	Q2	Vol	603	0	603	0	0	0	0	0	0	0	0
M-04/E	Q2	Vol	883	0	871 *	0	0	0	0	0	0	0	0
M-05/C1a	Q2	Vol	136	0	136	0	0	0	0	0	0	0	0
M-05/C1b	Q2	Vol	1,098	0	921 *	0	0	0	0	0	0	0	0
M-05/C2	Q2	Vol	2,107	0	2,107	0	0	0	0	0	0	0	0
M-05/C3	Q2	Vol	603	0	603	0	0	0	0	0	0	0	0
M-05/E	Q2	Vol	883	0	871 *	0	0	0	0	0	0	0	0
M-06/C1a	Q2	Vol	136	0	136	0	0	0	0	0	0	0	0
M-06/C1b	Q2	Vol	1,098	0	921 *	0	0	0	0	0	0	0	0
M-06/C2	Q2	Vol	2,107	0	2,107	0	0	0	0	0	0	0	0
M-06/C3	Q2	Vol	603	0	603	0	0	0	0	0	0	0	0
M-06/E	Q2	Vol	883	0	871 *	0	0	0	0	0	0	0	0
M-07/C1a	Q2	Vol	136	0	136	0	0	0	0	0	0	0	0

Gross Lease Reserves Summary

Entity Description	Reserve Class	Methodology	Oil (Mbbl) Initial Recoverable	Oil (Mbbl) Cumulative Production	Oil (Mbbl) Reserves	Non-Associated Gas (MMcf) Initial Recoverable	Non-Associated Gas (MMcf) Cumulative Production	Non-Associated Gas (MMcf) Raw Gas	Non-Associated Gas (MMcf) Reserves	Other Gross Lease Reserves Sol'n Gas MMcf	Other Gross Lease Reserves Cond Mbbl	Other Gross Lease Reserves LPG Mbbl	Other Gross Lease Reserves Sulphur Mlt
PPP Undeveloped (Cont.)													
M-07/C1b	Q2	Vol	1,098	0	920 *	0	0	0	0	0	0	0	0
M-07/C2	Q2	Vol	2,107	0	2,107	0	0	0	0	0	0	0	0
M-07/C3	Q2	Vol	603	0	603	0	0	0	0	0	0	0	0
M-07/E	Q2	Vol	883	0	870 *	0	0	0	0	0	0	0	0
M-08/C1a	Q2	Vol	100	0	100	0	0	0	0	0	0	0	0
M-08/C1b	Q2	Vol	273	0	268 *	0	0	0	0	0	0	0	0
M-08/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-08/C3	Q2	Vol	213	0	213	0	0	0	0	0	0	0	0
M-08/E	Q2	Vol	883	0	869 *	0	0	0	0	0	0	0	0
M-09/C1a	Q2	Vol	100	0	100	0	0	0	0	0	0	0	0
M-09/C1b	Q2	Vol	273	0	268 *	0	0	0	0	0	0	0	0
M-09/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-09/C3	Q2	Vol	213	0	213	0	0	0	0	0	0	0	0
M-09/E	Q2	Vol	883	0	868 *	0	0	0	0	0	0	0	0
M-10/C1a	Q2	Vol	100	0	100	0	0	0	0	0	0	0	0
M-10/C1b	Q2	Vol	273	0	268 *	0	0	0	0	0	0	0	0
M-10/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-10/C3	Q2	Vol	213	0	213	0	0	0	0	0	0	0	0
M-11/C1a	Q2	Vol	100	0	100	0	0	0	0	0	0	0	0
M-11/C1b	Q2	Vol	273	0	267 *	0	0	0	0	0	0	0	0
M-11/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-11/C3	Q2	Vol	213	0	213	0	0	0	0	0	0	0	0
M-12/C1a	Q2	Vol	100	0	100	0	0	0	0	0	0	0	0
M-12/C1b	Q2	Vol	273	0	267 *	0	0	0	0	0	0	0	0
M-12/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-12/C3	Q2	Vol	213	0	213	0	0	0	0	0	0	0	0
M-13/C1a	Q2	Vol	100	0	100	0	0	0	0	0	0	0	0
M-13/C1b	Q2	Vol	273	0	266 *	0	0	0	0	0	0	0	0
M-13/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-13/C3	Q2	Vol	213	0	213	0	0	0	0	0	0	0	0
M-14/C1a	Q2	Vol	100	0	100	0	0	0	0	0	0	0	0
M-14/C1b	Q2	Vol	273	0	266 *	0	0	0	0	0	0	0	0
M-14/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-14/C3	Q2	Vol	213	0	213	0	0	0	0	0	0	0	0
M-15/C1a	Q2	Vol	100	0	100	0	0	0	0	0	0	0	0
M-15/C1b	Q2	Vol	273	0	266 *	0	0	0	0	0	0	0	0
M-15/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-15/C3	Q2	Vol	213	0	213	0	0	0	0	0	0	0	0
M-16/C1a	Q2	Vol	100	0	100	0	0	0	0	0	0	0	0
M-16/C1b	Q2	Vol	273	0	265 *	0	0	0	0	0	0	0	0
M-16/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-16/C3	Q2	Vol	213	0	213	0	0	0	0	0	0	0	0
M-17/C1a	Q2	Vol	100	0	100	0	0	0	0	0	0	0	0
M-17/C1b	Q2	Vol	273	0	265 *	0	0	0	0	0	0	0	0
M-17/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-17/C3	Q2	Vol	213	0	213	0	0	0	0	0	0	0	0
M-18/C1a	Q2	Vol	136	0	136	0	0	0	0	0	0	0	0
M-18/C1b	Q2	Vol	1,098	0	904 *	0	0	0	0	0	0	0	0
M-18/C2	Q2	Vol	2,107	0	2,107	0	0	0	0	0	0	0	0
M-18/C3	Q2	Vol	603	0	603	0	0	0	0	0	0	0	0
M-18/E	Q2	Vol	883	0	861 *	0	0	0	0	0	0	0	0

Gross Lease Reserves Summary

Entity Description	Reserve Class	Methodology	Oil (Mbbl) Initial Recoverable	Oil (Mbbl) Cumulative Production	Oil (Mbbl) Reserves	Non-Associated Gas (MMcf) Initial Recoverable	Non-Associated Gas (MMcf) Cumulative Production	Non-Associated Gas (MMcf) Raw Gas	Non-Associated Gas (MMcf) Reserves	Other Gross Lease Reserves Sol'n Gas MMcf	Other Gross Lease Reserves Cond Mbbl	Other Gross Lease Reserves LPG Mbbl	Other Gross Lease Reserves Sulphur Mlt
PPP Undeveloped (Cont.)													
M-19/C1a	Q2	Vol	136	0	136	0	0	0	0	0	0	0	0
M-19/C1b	Q2	Vol	1,098	0	903 *	0	0	0	0	0	0	0	0
M-19/C2	Q2	Vol	2,107	0	2,107	0	0	0	0	0	0	0	0
M-19/C3	Q2	Vol	603	0	603	0	0	0	0	0	0	0	0
M-20/C2	Q2	Vol	2,107	0	2,107	0	0	0	0	0	0	0	0
M-21/C1a	Q2	Vol	135	0	135	0	0	0	0	0	0	0	0
M-21/C1b	Q2	Vol	1,090	0	895 *	0	0	0	0	0	0	0	0
M-21/C2	Q2	Vol	2,107	0	2,107	0	0	0	0	0	0	0	0
M-21/C3	Q2	Vol	599	0	599	0	0	0	0	0	0	0	0
M-21/E	Q2	Vol	883	0	857 *	0	0	0	0	0	0	0	0
M-22/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-23/C1a	Q2	Vol	100	0	100	0	0	0	0	0	0	0	0
M-23/C1b	Q2	Vol	273	0	262 *	0	0	0	0	0	0	0	0
M-23/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-23/C3	Q2	Vol	213	0	213	0	0	0	0	0	0	0	0
M-23/E	Q2	Vol	883	0	856 *	0	0	0	0	0	0	0	0
M-24/C1b	Q2	Vol	273	0	262 *	0	0	0	0	0	0	0	0
M-24/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-25/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-26/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-27/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-28/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-29/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-30/C1a	Q2	Vol	100	0	100	0	0	0	0	0	0	0	0
M-30/C1b	Q2	Vol	273	0	259 *	0	0	0	0	0	0	0	0
M-30/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-30/C3	Q2	Vol	213	0	213	0	0	0	0	0	0	0	0
M-31/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-32/C1a	Q2	Vol	100	0	100	0	0	0	0	0	0	0	0
M-32/C1b	Q2	Vol	273	0	258 *	0	0	0	0	0	0	0	0
M-32/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-32/C3	Q2	Vol	213	0	213	0	0	0	0	0	0	0	0
M-33/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-34/C1a	Q2	Vol	100	0	100	0	0	0	0	0	0	0	0
M-34/C1b	Q2	Vol	273	0	257 *	0	0	0	0	0	0	0	0
M-34/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-34/C3	Q2	Vol	213	0	213	0	0	0	0	0	0	0	0
M-35/C1a	Q2	Vol	100	0	100	0	0	0	0	0	0	0	0
M-35/C1b	Q2	Vol	273	0	256 *	0	0	0	0	0	0	0	0
M-35/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-36/C2	Q2	Vol	1,089	0	1,089	0	0	0	0	0	0	0	0
M-37/C1a	Q2	Vol	100	0	100	0	0	0	0	0	0	0	0
M-37/C1b	Q2	Vol	259	0	247 *	0	0	0	0	0	0	0	0
M-37/C2	Q2	Vol	1,061	0	1,061	0	0	0	0	0	0	0	0
M-37/C3	Q2	Vol	197	0	197	0	0	0	0	0	0	0	0
M-38/C2	Q2	Vol	2,126	0	2,125	0	0	0	0	0	0	0	0
M-39/E	Q2	Vol	883	0	837 *	0	0	0	0	0	0	0	0
M-40/E	Q2	Vol	883	0	836 *	0	0	0	0	0	0	0	0
M-41/E	Q2	Vol	883	0	835 *	0	0	0	0	0	0	0	0
M-42/E	Q2	Vol	883	0	834 *	0	0	0	0	0	0	0	0
M-43/E	Q2	Vol	883	0	833 *	0	0	0	0	0	0	0	0

Gross Lease Reserves Summary

Entity Description	Reserve Class	Methodology	Oil (Mbbl) Initial Recoverable	Oil (Mbbl) Cumulative Production	Oil (Mbbl) Reserves	Non-Associated Gas (MMcf) Initial Recoverable	Non-Associated Gas (MMcf) Cumulative Production	Non-Associated Gas (MMcf) Raw Gas	Non-Associated Gas (MMcf) Reserves	Other Gross Lease Reserves Sol'n Gas MMcf	Other Gross Lease Reserves Cond Mbbl	Other Gross Lease Reserves LPG Mbbl	Other Gross Lease Reserves Sulphur Mlt
PPP Undeveloped (Cont.)													
M-44/E	Q2	Vol	883	0	833 *	0	0	0	0	0	0	0	0
M-45/E	Q2	Vol	883	0	832 *	0	0	0	0	0	0	0	0
M-46/E	Q2	Vol	883	0	831 *	0	0	0	0	0	0	0	0
M-47/E	Q2	Vol	883	0	830 *	0	0	0	0	0	0	0	0
M-48/E	Q2	Vol	925	0	856 *	0	0	0	0	0	0	0	0
Total: PPP Undeveloped			**86,343**	**0**	**84,221 ***	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Notes

1. [*] Remaining reserves are less than the estimate due to economic limit.

Table 3

Company: **Griffiths Energy International Inc.**
Property: **Mangara**
Currency: **$US Dollars**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Gross Lease Daily Oil Production

Entity Description	Reserve Class	Year (bbl/d)												Totals (Mbbl)		
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Subtotal	Remainder	Total
Proved Undeveloped																
M-04/C1b	B2	34	59	50	43	38	33	29	26	12	0	0	0	118	0	118
M-04/C2	B2	401	451	250	159	109	80	61	17	0	0	0	0	558	0	558
M-04/C3	B2	33	54	43	35	29	25	17	0	0	0	0	0	86	0	86
M-04/E	B2	93	145	110	86	69	57	48	40	17	0	0	0	243	0	243
M-05/C1b	B2	34	59	50	43	38	33	29	26	12	0	0	0	118	0	118
M-05/C2	B2	401	451	250	159	109	80	61	17	0	0	0	0	558	0	558
M-05/C3	B2	33	54	43	35	29	25	17	0	0	0	0	0	86	0	86
M-05/E	B2	93	145	110	86	69	57	48	40	17	0	0	0	243	0	243
M-06/C1b	B2	34	59	50	43	38	33	29	26	12	0	0	0	118	0	118
M-06/C2	B2	401	451	250	159	109	80	61	17	0	0	0	0	558	0	558
M-06/C3	B2	33	54	43	35	29	25	17	0	0	0	0	0	86	0	86
M-06/E	B2	93	145	110	86	69	57	48	40	17	0	0	0	243	0	243
M-07/C2	B2	346	479	261	164	113	82	63	22	0	0	0	0	558	0	558
M-08/C1a	B2	4	14	13	12	11	6	0	0	0	0	0	0	22	0	22
M-08/C1b	B2	10	35	29	25	21	18	16	14	6	0	0	0	63	0	63
M-08/C3	B2	12	43	36	30	26	22	4	0	0	0	0	0	63	0	63
M-08/E	B2	48	157	118	92	73	60	50	42	18	0	0	0	240	0	240
M-09/C1a	B2	2	14	13	12	11	7	0	0	0	0	0	0	22	0	22
M-09/C1b	B2	7	35	29	25	21	18	16	14	6	0	0	0	63	0	63
M-09/C3	B2	8	44	36	30	26	22	6	0	0	0	0	0	63	0	63
M-09/E	B2	32	161	120	93	74	61	50	43	18	0	0	0	239	0	239
M-10/C1a	B2	1	14	13	12	11	8	0	0	0	0	0	0	22	0	22
M-10/C1b	B2	3	36	30	25	22	19	16	14	6	0	0	0	63	0	63
M-10/C3	B2	4	44	37	31	26	23	8	0	0	0	0	0	63	0	63
M-11/C1a	B2	0	12	13	12	11	10	0	0	0	0	0	0	22	0	22
M-11/C1b	B2	0	31	31	26	22	19	17	15	7	0	0	0	61	0	61
M-11/C3	B2	0	38	38	32	27	23	13	0	0	0	0	0	63	0	63
M-12/C2	B2	0	474	314	174	111	77	51	0	0	0	0	0	438	0	438
M-13/C1a	B2	0	10	13	12	11	11	2	0	0	0	0	0	22	0	22
M-13/C1b	B2	0	25	32	27	23	20	17	15	7	0	0	0	61	0	61
M-13/C2	B2	0	436	332	182	114	79	57	0	0	0	0	0	438	0	438
M-13/C3	B2	0	31	40	33	28	24	17	0	0	0	0	0	63	0	63
M-14/C1a	B2	0	9	14	12	11	11	2	0	0	0	0	0	22	0	22
M-14/C1b	B2	0	22	33	27	23	20	17	15	7	0	0	0	60	0	60
M-14/C2	B2	0	395	353	190	119	81	59	3	0	0	0	0	438	0	438
M-14/C3	B2	0	28	40	34	28	24	18	0	0	0	0	0	63	0	63
M-15/C1a	B2	0	7	14	13	12	11	3	0	0	0	0	0	22	0	22
M-15/C1b	B2	0	19	33	28	24	20	18	16	7	0	0	0	60	0	60
M-15/C2	B2	0	352	375	199	123	83	60	8	0	0	0	0	438	0	438
M-15/C3	B2	0	24	41	34	29	25	20	0	0	0	0	0	63	0	63
M-16/C1a	B2	0	6	14	13	12	11	4	0	0	0	0	0	22	0	22
M-16/C1b	B2	0	16	34	28	24	21	18	16	7	0	0	0	59	0	59
M-16/C2	B2	0	304	400	208	127	86	62	12	0	0	0	0	438	0	438
M-16/C3	B2	0	20	42	35	29	25	22	1	0	0	0	0	63	0	63
M-18/C2	B2	0	223	542	286	176	119	86	65	27	0	0	0	557	0	557
M-19/C2	B2	0	154	579	300	182	123	89	67	27	0	0	0	555	0	555
M-21/C2	B2	0	0	587	362	210	138	97	72	28	0	0	0	545	0	545

Gross Lease Daily Oil Production

Entity Description	Reserve Class	Year (bbl/d) 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Totals (Mbbl) Subtotal	Remainder	Total
Proved Undeveloped (Cont.)																
M-24/C2	B2	0	0	395	354	190	119	81	59	3	0	0	0	438	0	438
M-25/C2	B2	0	0	352	376	198	123	83	61	8	0	0	0	438	0	438
M-26/C2	B2	0	0	304	401	208	127	86	62	12	0	0	0	438	0	438
M-27/C2	B2	0	0	252	429	218	132	89	64	17	0	0	0	438	0	438
M-28/C2	B2	0	0	137	493	240	142	94	67	26	0	0	0	438	0	438
Total: Proved Undeveloped		**2,161**	**5,844**	**7,445**	**5,841**	**3,700**	**2,631**	**1,877**	**1,019**	**323**	**0**	**0**	**0**	**11,257**	**0**	**11,257**
Proved Plus Probable Undeveloped																
M-04/C1a	H2	10	19	17	16	15	14	13	12	12	11	10	0	54	0	54
M-04/C1b	H2	62	114	105	97	89	82	76	71	66	62	58	55	342	82	424
M-04/C2	H2	600	780	489	336	244	186	146	118	97	81	69	60	1,171	15	1,185
M-04/C3	H2	60	105	89	77	67	59	52	46	42	37	34	31	255	43	298
M-04/E	H2	120	204	170	144	123	106	93	82	73	65	58	53	471	72	542
M-05/C1a	H2	10	19	17	16	15	14	13	12	12	11	10	0	54	0	54
M-05/C1b	H2	62	114	105	97	89	82	76	71	66	62	58	55	342	82	424
M-05/C2	H2	600	780	489	336	244	186	146	118	97	81	69	60	1,171	15	1,185
M-05/C3	H2	60	105	89	77	67	59	52	46	42	37	34	31	255	43	298
M-05/E	H2	120	204	170	144	123	106	93	82	73	65	58	53	471	72	542
M-06/C1a	H2	10	19	17	16	15	14	13	12	12	11	10	0	54	0	54
M-06/C1b	H2	62	114	105	97	89	82	76	71	66	62	58	55	342	82	424
M-06/C2	H2	600	780	489	336	244	186	146	118	97	81	69	60	1,171	15	1,185
M-06/C3	H2	60	105	89	77	67	59	52	46	42	37	34	31	255	43	298
M-06/E	H2	120	204	170	144	123	106	93	82	73	65	58	53	471	72	542
M-07/C1a	H2	8	19	17	16	15	14	13	12	12	11	10	0	54	0	54
M-07/C1b	H2	51	115	105	97	90	83	77	72	67	63	59	55	341	82	423
M-07/C2	H2	512	816	507	346	250	190	149	120	99	83	70	60	1,169	16	1,185
M-07/C3	H2	50	106	90	78	68	59	52	47	42	38	34	31	254	43	297
M-07/E	H2	100	208	172	146	124	107	94	83	73	65	59	53	469	72	541
M-08/C1a	H2	5	19	18	17	16	15	14	13	13	12	11	11	59	3	63
M-08/C1b	H2	12	47	43	39	36	33	31	29	27	25	23	22	133	32	166
M-08/C2	H2	229	606	351	230	161	120	92	74	60	23	0	0	710	0	710
M-08/C3	H2	24	85	69	58	48	41	36	31	28	24	22	7	173	0	173
M-08/E	H2	61	215	178	150	127	110	96	84	75	67	60	54	466	73	539
M-09/C1a	H2	3	19	18	17	16	15	14	13	13	12	11	11	59	4	63
M-09/C1b	H2	8	47	43	39	36	33	31	29	27	25	23	22	133	32	165
M-09/C2	H2	157	640	366	237	166	123	94	75	61	28	0	0	710	0	710
M-09/C3	H2	16	86	70	58	49	42	36	32	28	25	22	9	173	0	173
M-09/E	H2	41	218	180	152	129	111	97	85	75	67	60	55	464	74	538
M-10/C1a	H2	2	19	18	17	16	15	14	13	13	12	11	11	59	4	63
M-10/C1b	H2	4	47	43	40	36	34	31	29	27	25	23	22	132	33	165
M-10/C2	H2	82	675	381	245	170	125	96	76	62	32	0	0	710	0	710
M-10/C3	H2	8	88	71	59	50	42	37	32	28	25	22	10	173	0	173
M-11/C1a	H2	0	16	18	17	16	15	14	14	13	12	11	11	58	5	63
M-11/C1b	H2	0	40	44	41	37	34	32	29	27	25	24	22	130	33	163
M-11/C2	H2	0	628	432	271	185	135	102	81	65	46	0	0	710	0	710
M-11/C3	H2	0	76	75	62	52	44	38	33	29	26	23	16	173	0	173
M-12/C1a	H2	0	15	18	17	16	15	14	14	13	12	12	11	57	5	63
M-12/C1b	H2	0	36	45	41	37	34	32	30	27	26	24	22	129	33	163
M-12/C2	H2	0	579	452	281	191	138	105	82	66	51	0	0	710	0	710
M-12/C3	H2	0	69	76	63	53	45	38	34	29	26	23	18	173	0	173

Gross Lease Daily Oil Production

Entity Description	Reserve Class	Year (bbl/d) 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Totals (Mbbl) Subtotal	Remainder	Total
Proved Plus Probable Undeveloped (Cont.)																
M-13/C1a	H2	0	13	18	17	16	15	14	14	13	12	12	11	57	5	63
M-13/C1b	H2	0	33	45	41	38	35	32	30	28	26	24	23	129	33	162
M-13/C2	H2	0	529	473	291	196	142	107	84	67	55	1	0	710	0	710
M-13/C3	H2	0	62	78	64	53	45	39	34	30	26	23	19	173	0	173
M-14/C1a	H2	0	11	19	17	16	15	15	14	13	12	12	11	57	6	63
M-14/C1b	H2	0	29	45	41	38	35	32	30	28	26	24	23	128	34	162
M-14/C2	H2	0	475	496	302	202	145	109	86	68	56	6	0	710	0	710
M-14/C3	H2	0	55	79	65	54	46	39	34	30	26	24	21	173	0	173
M-15/C1a	H2	0	10	19	18	16	15	15	14	13	12	12	11	56	6	63
M-15/C1b	H2	0	25	46	42	38	35	32	30	28	26	24	23	127	34	161
M-15/C2	H2	0	420	520	313	208	149	112	87	70	57	10	0	710	0	710
M-15/C3	H2	0	48	80	66	55	47	40	35	30	27	24	21	172	1	173
M-16/C1a	H2	0	8	19	18	17	16	15	14	13	12	12	11	56	7	63
M-16/C1b	H2	0	21	46	42	39	36	33	31	28	26	25	23	127	34	161
M-16/C2	H2	0	359	547	326	215	153	114	89	71	58	14	0	710	0	710
M-16/C3	H2	0	40	82	67	56	47	41	35	31	27	24	22	173	2	175
M-17/C2	H2	0	295	576	339	222	157	117	91	72	59	19	0	710	0	710
M-18/C1b	H2	0	31	117	107	98	91	84	78	72	68	63	59	317	88	405
M-18/C2	H2	0	324	895	546	366	263	198	155	124	102	85	72	1,143	42	1,185
M-18/C3	H2	0	31	110	93	80	69	61	54	48	43	38	35	241	48	289
M-19/C2	H2	0	221	939	567	378	270	203	158	126	103	86	73	1,141	44	1,185
M-20/C2	H2	0	115	986	588	389	277	207	161	129	105	87	74	1,139	46	1,185
M-21/C2	H2	0	0	908	660	427	300	222	171	136	110	91	77	1,132	53	1,185
M-22/C2	H2	0	0	579	453	280	191	138	105	82	66	51	0	710	0	710
M-23/C2	H2	0	0	529	474	290	196	142	107	84	67	55	1	710	0	710
M-23/E	H2	0	0	156	198	164	139	119	103	90	80	71	63	432	84	516
M-24/C2	H2	0	0	475	497	301	202	145	110	85	68	56	6	710	0	710
M-25/C2	H2	0	0	420	521	312	208	149	112	87	70	57	10	710	0	710
M-26/C2	H2	0	0	359	548	324	215	153	115	89	71	58	14	710	0	710
M-27/C2	H2	0	0	295	577	337	222	157	117	91	72	59	19	710	0	710
M-28/C2	H2	0	0	156	628	351	224	156	115	88	69	56	4	674	0	674
Total: Proved Plus Probable Undeveloped		**3,930**	**12,356**	**16,625**	**13,372**	**9,381**	**7,115**	**5,661**	**4,669**	**3,925**	**3,295**	**2,531**	**1,856**	**30,921**	**1,745**	**32,667**
PPP Undeveloped																
M-04/C1a	Q2	12	24	23	22	21	20	19	18	17	17	16	15	82	54	136
M-04/C1b	Q2	99	183	168	155	143	133	123	115	107	101	94	89	552	370	921
M-04/C2	Q2	802	1,144	784	572	434	341	275	227	190	161	139	121	1,895	212	2,107
M-04/C3	Q2	97	171	147	129	113	100	89	80	72	66	60	55	430	173	603
M-04/E	Q2	145	252	214	185	160	141	125	111	100	90	81	74	612	259	871
M-05/C1a	Q2	12	24	23	22	21	20	19	18	17	17	16	15	82	54	136
M-05/C1b	Q2	99	183	168	155	143	133	123	115	107	101	94	89	552	370	921
M-05/C2	Q2	802	1,144	784	572	434	341	275	227	190	161	139	121	1,895	212	2,107
M-05/C3	Q2	97	171	147	129	113	100	89	80	72	66	60	55	430	173	603
M-05/E	Q2	145	252	214	185	160	141	125	111	100	90	81	74	612	259	871
M-06/C1a	Q2	12	24	23	22	21	20	19	18	17	17	16	15	82	54	136
M-06/C1b	Q2	99	183	168	155	143	133	123	115	107	101	94	89	552	370	921
M-06/C2	Q2	802	1,144	784	572	434	341	275	227	190	161	139	121	1,895	212	2,107
M-06/C3	Q2	97	171	147	129	113	100	89	80	72	66	60	55	430	173	603
M-06/E	Q2	145	252	214	185	160	141	125	111	100	90	81	74	612	259	871
M-07/C1a	Q2	10	24	23	22	21	20	19	18	17	17	16	16	81	54	136

Gross Lease Daily Oil Production

Entity Description	Reserve Class	Year (bbl/d) 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Totals (Mbbl) Subtotal	Remainder	Total
PPP Undeveloped (Cont.)																
M-07/C1b	Q2	82	184	169	156	144	134	124	116	108	101	95	90	549	371	920
M-07/C2	Q2	680	1,186	807	587	443	348	280	231	193	164	141	123	1,891	215	2,107
M-07/C3	Q2	81	173	149	130	114	101	90	81	73	66	60	55	429	175	603
M-07/E	Q2	121	256	217	187	162	142	126	112	100	91	82	75	610	260	870
M-08/C1a	Q2	6	24	22	21	20	19	18	17	16	15	14	14	75	26	100
M-08/C1b	Q2	15	56	51	47	43	40	37	34	32	30	28	26	161	108	268
M-08/C2	Q2	258	752	488	343	253	195	155	126	104	88	75	65	1,060	29	1,089
M-08/C3	Q2	31	104	83	68	57	48	41	36	31	28	25	22	210	3	213
M-08/E	Q2	74	263	223	192	166	145	128	115	102	92	83	76	606	263	869
M-09/C1a	Q2	4	24	22	21	20	19	18	17	16	15	14	14	74	26	100
M-09/C1b	Q2	10	56	52	47	44	40	37	35	32	30	28	26	160	108	268
M-09/C2	Q2	175	784	505	353	259	199	158	128	106	89	76	66	1,058	31	1,089
M-09/C3	Q2	20	106	85	70	58	49	42	36	32	28	25	22	209	4	213
M-09/E	Q2	49	267	226	194	168	147	130	116	103	93	84	77	604	265	868
M-10/C1a	Q2	2	24	23	21	20	19	18	17	16	15	14	14	74	26	100
M-10/C1b	Q2	5	57	52	48	44	40	37	35	32	30	28	27	159	109	268
M-10/C2	Q2	91	817	521	363	266	203	161	131	108	90	77	67	1,056	33	1,089
M-10/C3	Q2	11	108	86	71	59	49	42	37	32	28	25	22	208	4	213
M-11/C1a	Q2	0	20	23	22	20	19	18	17	16	15	15	14	73	28	100
M-11/C1b	Q2	0	48	53	49	45	41	38	36	33	31	29	27	157	110	267
M-11/C2	Q2	0	742	577	394	285	216	170	137	113	94	80	69	1,051	39	1,089
M-11/C3	Q2	0	95	91	74	61	52	44	38	33	29	26	23	206	6	213
M-12/C1a	Q2	0	18	23	22	20	19	18	17	16	15	15	14	72	28	100
M-12/C1b	Q2	0	44	53	49	45	42	38	36	33	31	29	27	156	111	267
M-12/C2	Q2	0	680	598	406	293	221	173	140	114	96	81	70	1,049	41	1,089
M-12/C3	Q2	0	86	93	75	62	52	45	38	33	29	26	23	206	7	213
M-13/C1a	Q2	0	16	23	22	20	19	18	17	16	15	15	14	72	29	100
M-13/C1b	Q2	0	39	54	49	45	42	39	36	33	31	29	27	155	111	266
M-13/C2	Q2	0	618	620	418	300	226	177	142	116	97	82	71	1,047	43	1,089
M-13/C3	Q2	0	77	95	77	63	53	45	39	34	30	26	23	205	7	213
M-14/C1a	Q2	0	14	23	22	21	19	18	17	16	15	15	14	71	29	100
M-14/C1b	Q2	0	34	54	50	46	42	39	36	34	31	29	27	154	112	266
M-14/C2	Q2	0	551	644	432	308	231	180	145	118	98	83	72	1,045	45	1,089
M-14/C3	Q2	0	68	97	78	64	54	46	39	34	30	27	24	204	8	213
M-15/C1a	Q2	0	12	23	22	21	19	18	17	16	16	15	14	71	29	100
M-15/C1b	Q2	0	30	55	50	46	42	39	36	34	31	29	28	154	112	266
M-15/C2	Q2	0	484	668	445	316	236	184	147	120	100	84	73	1,043	47	1,089
M-15/C3	Q2	0	59	98	79	65	54	46	40	35	30	27	24	204	9	213
M-16/C1a	Q2	0	10	24	22	21	20	18	17	16	16	15	14	71	30	100
M-16/C1b	Q2	0	25	55	51	46	43	39	37	34	32	30	28	153	113	265
M-16/C2	Q2	0	411	695	459	324	242	187	150	122	101	86	73	1,040	49	1,089
M-16/C3	Q2	0	50	100	81	66	55	47	40	35	31	27	24	203	10	213
M-17/C1a	Q2	0	8	24	22	21	20	19	18	17	16	15	14	70	30	100
M-17/C1b	Q2	0	20	56	51	47	43	40	37	34	32	30	28	152	113	265
M-17/C2	Q2	0	335	723	474	333	248	191	153	124	103	87	74	1,038	51	1,089
M-17/C3	Q2	0	40	102	82	67	56	48	41	35	31	27	24	202	10	213
M-18/C1a	Q2	0	6	24	23	22	21	20	19	18	18	17	16	75	61	136
M-18/C1b	Q2	0	50	187	172	158	146	135	126	117	109	102	96	511	393	904
M-18/C2	Q2	0	426	1,275	859	615	463	361	290	237	198	168	145	1,838	268	2,107
M-18/C3	Q2	0	49	178	153	133	117	103	92	82	74	67	61	405	198	603
M-18/E	Q2	0	74	263	223	191	166	145	129	114	102	92	84	578	283	861

Gross Lease Daily Oil Production

Entity Description	Reserve Class	Year (bbl/d) 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Totals (Mbbl) Subtotal	Remainder	Total
PPP Undeveloped (Cont.)																
M-19/C1a	Q2	0	4	24	23	22	21	20	19	18	18	17	16	74	62	136
M-19/C1b	Q2	0	33	188	173	159	147	136	127	118	110	103	97	508	395	903
M-19/C2	Q2	0	288	1,324	885	631	474	369	296	241	201	170	146	1,834	272	2,107
M-19/C3	Q2	0	33	180	155	134	118	104	93	83	75	68	62	403	200	603
M-20/C2	Q2	0	150	1,374	913	647	484	376	301	245	204	173	148	1,830	276	2,107
M-21/C1a	Q2	0	0	21	23	22	21	20	20	19	18	17	17	72	63	135
M-21/C1b	Q2	0	0	161	178	163	151	139	130	120	112	105	98	495	399	895
M-21/C2	Q2	0	0	1,239	1,002	700	518	399	317	257	213	180	154	1,818	289	2,107
M-21/C3	Q2	0	0	157	163	140	123	108	96	86	77	70	63	395	204	599
M-21/E	Q2	0	0	234	239	203	176	153	135	120	107	96	87	566	291	857
M-22/C2	Q2	0	0	680	600	405	293	221	174	139	114	96	81	1,023	66	1,089
M-23/C1a	Q2	0	0	16	23	22	20	19	18	17	16	15	15	67	34	100
M-23/C1b	Q2	0	0	39	54	49	45	42	39	36	33	31	29	145	117	262
M-23/C2	Q2	0	0	618	622	417	300	226	177	142	116	97	82	1,021	69	1,089
M-23/C3	Q2	0	0	77	95	76	63	53	45	39	34	30	26	197	16	213
M-23/E	Q2	0	0	190	246	209	180	157	138	122	109	98	89	561	295	856
M-24/C1b	Q2	0	0	34	54	50	46	42	39	36	34	31	29	144	118	262
M-24/C2	Q2	0	0	551	645	430	308	231	181	144	118	98	84	1,018	71	1,089
M-25/C2	Q2	0	0	484	670	443	316	236	184	147	120	100	85	1,016	73	1,089
M-26/C2	Q2	0	0	411	696	458	324	242	188	149	122	101	86	1,014	76	1,089
M-27/C2	Q2	0	0	335	725	472	333	248	192	152	124	103	87	1,011	78	1,089
M-28/C2	Q2	0	0	175	786	504	352	259	200	158	128	106	89	1,006	83	1,089
M-29/C2	Q2	0	0	0	855	539	372	272	208	164	132	109	92	1,001	88	1,089
M-30/C1a	Q2	0	0	0	22	23	21	20	19	18	17	16	15	63	38	100
M-30/C1b	Q2	0	0	0	53	53	48	44	41	38	35	33	31	137	122	259
M-30/C2	Q2	0	0	0	797	558	383	279	213	167	135	111	93	999	91	1,089
M-30/C3	Q2	0	0	0	103	90	73	60	51	43	38	33	29	189	23	213
M-31/C2	Q2	0	0	0	680	598	405	293	222	173	139	114	96	993	96	1,089
M-32/C1a	Q2	0	0	0	14	23	22	21	19	18	17	16	16	61	39	100
M-32/C1b	Q2	0	0	0	34	54	50	46	42	39	36	34	31	134	124	258
M-32/C2	Q2	0	0	0	551	644	431	308	232	180	144	118	99	988	101	1,089
M-32/C3	Q2	0	0	0	68	97	78	64	54	46	39	34	30	186	26	213
M-33/C2	Q2	0	0	0	484	668	444	316	237	184	147	120	100	985	104	1,089
M-34/C1a	Q2	0	0	0	8	24	22	21	20	19	18	17	16	60	41	100
M-34/C1b	Q2	0	0	0	20	56	51	47	43	40	37	34	32	131	126	257
M-34/C2	Q2	0	0	0	335	723	473	334	248	191	152	124	103	980	110	1,089
M-34/C3	Q2	0	0	0	40	102	82	67	56	48	41	35	31	183	29	213
M-35/C1a	Q2	0	0	0	4	24	22	21	20	19	18	17	16	59	42	100
M-35/C1b	Q2	0	0	0	10	56	52	47	44	40	37	35	32	129	127	256
M-35/C2	Q2	0	0	0	175	784	505	352	260	199	158	128	106	974	116	1,089
M-36/C2	Q2	0	0	0	0	853	540	372	273	208	164	132	110	968	122	1,089
M-37/C1a	Q2	0	0	0	0	22	23	21	20	19	18	17	16	57	43	100
M-37/C1b	Q2	0	0	0	0	52	52	48	44	40	37	34	32	124	123	247
M-37/C2	Q2	0	0	0	0	791	551	375	273	206	162	130	107	947	114	1,061
M-37/C3	Q2	0	0	0	0	101	88	70	58	48	41	35	30	172	25	197
M-38/C2	Q2	0	0	0	0	1,030	1,073	745	549	420	332	269	223	1,694	432	2,125
M-39/E	Q2	0	0	0	0	167	248	212	183	159	139	123	110	490	347	837
M-40/E	Q2	0	0	0	0	145	252	214	185	160	141	125	111	486	349	836
M-41/E	Q2	0	0	0	0	121	256	217	187	162	142	126	112	483	352	835
M-42/E	Q2	0	0	0	0	97	259	220	190	164	144	127	113	480	354	834
M-43/E	Q2	0	0	0	0	74	263	223	192	166	145	128	115	477	357	833

Gross Lease Daily Oil Production

Entity Description	Reserve Class	Year (bbl/d)												Totals (Mbbl)		
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Subtotal	Remainder	Total
PPP Undeveloped (Cont.)																
M-44/E	Q2	0	0	0	0	49	267	226	194	168	147	130	116	473	359	833
M-45/E	Q2	0	0	0	0	25	271	229	197	170	149	131	117	470	362	832
M-46/E	Q2	0	0	0	0	0	275	232	199	172	150	132	118	467	364	831
M-47/E	Q2	0	0	0	0	0	253	235	202	174	152	134	119	463	367	830
M-48/E	Q2	0	0	0	0	0	234	241	207	180	157	139	124	468	388	856
Total: PPP Undeveloped		**5,191**	**16,335**	**23,998**	**24,861**	**24,166**	**20,749**	**16,597**	**13,704**	**11,527**	**9,904**	**8,633**	**7,633**	**66,904**	**17,317**	**84,221**

Table 3.1

Company: **Griffiths Energy International Inc.**
Property: **Mangara**
Currency: **$US Dollars**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Company Daily Oil Production

Entity Description	Reserve Class	Year (bbl/d) 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Totals (Mbbl) Subtotal	Remainder	Total
Proved Undeveloped																
M-04/C1b	B2	16	28	24	21	18	16	14	12	7	0	0	0	57	0	57
M-04/C2	B2	192	216	119	76	52	38	29	8	0	0	0	0	266	0	266
M-04/C3	B2	16	26	21	17	14	12	8	0	0	0	0	0	41	0	41
M-04/E	B2	44	69	52	41	33	27	23	19	10	0	0	0	117	0	117
M-05/C1b	B2	16	28	24	21	18	16	14	12	7	0	0	0	57	0	57
M-05/C2	B2	192	216	119	76	52	38	29	8	0	0	0	0	266	0	266
M-05/C3	B2	16	26	21	17	14	12	8	0	0	0	0	0	41	0	41
M-05/E	B2	44	69	52	41	33	27	23	19	10	0	0	0	117	0	117
M-06/C1b	B2	16	28	24	21	18	16	14	12	7	0	0	0	57	0	57
M-06/C2	B2	192	216	119	76	52	38	29	8	0	0	0	0	266	0	266
M-06/C3	B2	16	26	21	17	14	12	8	0	0	0	0	0	41	0	41
M-06/E	B2	44	69	52	41	33	27	23	19	10	0	0	0	117	0	117
M-07/C2	B2	165	229	125	78	54	39	30	10	0	0	0	0	266	0	266
M-08/C1a	B2	2	7	6	6	5	3	0	0	0	0	0	0	10	0	10
M-08/C1b	B2	5	17	14	12	10	9	8	7	4	0	0	0	30	0	30
M-08/C3	B2	6	21	17	14	12	11	2	0	0	0	0	0	30	0	30
M-08/E	B2	23	75	56	44	35	28	24	20	11	0	0	0	115	0	115
M-09/C1a	B2	1	7	6	6	5	3	0	0	0	0	0	0	10	0	10
M-09/C1b	B2	3	17	14	12	10	9	8	7	4	0	0	0	30	0	30
M-09/C3	B2	4	21	17	15	12	11	3	0	0	0	0	0	30	0	30
M-09/E	B2	16	77	57	45	35	29	24	20	11	0	0	0	115	0	115
M-10/C1a	B2	1	7	6	6	5	4	0	0	0	0	0	0	10	0	10
M-10/C1b	B2	2	17	14	12	10	9	8	7	4	0	0	0	30	0	30
M-10/C3	B2	2	21	18	15	13	11	4	0	0	0	0	0	30	0	30
M-11/C1a	B2	0	6	6	6	5	5	0	0	0	0	0	0	10	0	10
M-11/C1b	B2	0	15	15	13	11	9	8	7	4	0	0	0	30	0	30
M-11/C3	B2	0	18	18	15	13	11	6	0	0	0	0	0	30	0	30
M-12/C2	B2	0	226	150	83	53	37	25	0	0	0	0	0	209	0	209
M-13/C1a	B2	0	5	6	6	5	5	1	0	0	0	0	0	10	0	10
M-13/C1b	B2	0	12	15	13	11	9	8	7	4	0	0	0	29	0	29
M-13/C2	B2	0	208	158	87	55	38	27	0	0	0	0	0	209	0	209
M-13/C3	B2	0	15	19	16	13	11	8	0	0	0	0	0	30	0	30
M-14/C1a	B2	0	4	6	6	5	5	1	0	0	0	0	0	10	0	10
M-14/C1b	B2	0	11	16	13	11	10	8	7	4	0	0	0	29	0	29
M-14/C2	B2	0	189	168	91	57	39	28	2	0	0	0	0	209	0	209
M-14/C3	B2	0	13	19	16	14	12	9	0	0	0	0	0	30	0	30
M-15/C1a	B2	0	4	7	6	6	5	2	0	0	0	0	0	10	0	10
M-15/C1b	B2	0	9	16	13	11	10	8	7	4	0	0	0	29	0	29
M-15/C2	B2	0	168	179	95	59	40	29	4	0	0	0	0	209	0	209
M-15/C3	B2	0	11	20	16	14	12	10	0	0	0	0	0	30	0	30
M-16/C1a	B2	0	3	7	6	6	5	2	0	0	0	0	0	10	0	10
M-16/C1b	B2	0	8	16	13	11	10	9	7	4	0	0	0	29	0	29
M-16/C2	B2	0	145	191	99	61	41	30	6	0	0	0	0	209	0	209
M-16/C3	B2	0	10	20	17	14	12	10	0	0	0	0	0	30	0	30
M-18/C2	B2	0	107	259	136	84	57	41	31	16	0	0	0	267	0	267
M-19/C2	B2	0	74	276	143	87	59	42	32	16	0	0	0	266	0	266
M-21/C2	B2	0	0	280	173	100	66	46	35	16	0	0	0	261	0	261

Company Daily Oil Production

Entity Description	Reserve Class	Year (bbl/d) 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Totals (Mbbl) Subtotal	Remainder	Total
Proved Undeveloped (Cont.)																
M-24/C2	B2	0	0	189	169	91	57	39	28	2	0	0	0	209	0	209
M-25/C2	B2	0	0	168	179	95	59	40	29	4	0	0	0	209	0	209
M-26/C2	B2	0	0	145	191	99	61	41	30	7	0	0	0	210	0	210
M-27/C2	B2	0	0	121	205	104	63	42	30	10	0	0	0	210	0	210
M-28/C2	B2	0	0	66	235	115	68	45	32	15	0	0	0	210	0	210
Total: Proved Undeveloped		**1,031**	**2,789**	**3,554**	**2,788**	**1,766**	**1,256**	**896**	**487**	**189**	**0**	**0**	**0**	**5,386**	**0**	**5,386**
Proved Plus Probable Undeveloped																
M-04/C1a	H2	5	9	8	8	6	4	4	4	4	3	3	0	21	0	21
M-04/C1b	H2	29	55	50	46	36	25	23	22	21	18	18	19	132	35	167
M-04/C2	H2	286	372	233	160	98	56	45	37	31	24	22	20	506	5	511
M-04/C3	H2	29	50	43	37	27	18	16	15	13	11	11	11	102	18	120
M-04/E	H2	57	98	81	69	49	32	28	26	23	19	18	18	189	31	220
M-05/C1a	H2	5	9	8	8	6	4	4	4	4	3	3	0	21	0	21
M-05/C1b	H2	29	55	50	46	36	25	23	22	21	18	18	19	132	35	167
M-05/C2	H2	286	372	233	160	98	56	45	37	31	24	22	20	506	5	511
M-05/C3	H2	29	50	43	37	27	18	16	15	13	11	11	11	102	18	120
M-05/E	H2	57	98	81	69	49	32	28	26	23	19	18	18	189	31	220
M-06/C1a	H2	5	9	8	8	6	4	4	4	4	3	3	0	21	0	21
M-06/C1b	H2	29	55	50	46	36	25	23	22	21	18	18	19	132	35	167
M-06/C2	H2	286	372	233	160	98	56	45	37	31	24	22	20	506	5	511
M-06/C3	H2	29	50	43	37	27	18	16	15	13	11	11	11	102	18	120
M-06/E	H2	57	98	81	69	49	32	28	26	23	19	18	18	189	31	220
M-07/C1a	H2	4	9	8	8	6	4	4	4	4	3	3	0	21	0	21
M-07/C1b	H2	25	55	50	46	36	25	24	22	21	18	18	19	131	35	167
M-07/C2	H2	244	390	242	165	100	57	46	38	32	24	22	21	504	6	510
M-07/C3	H2	24	51	43	37	27	18	16	15	13	11	11	11	101	18	120
M-07/E	H2	48	99	82	70	50	32	29	26	23	19	18	18	188	31	219
M-08/C1a	H2	2	9	9	8	6	4	4	4	4	4	4	4	23	1	24
M-08/C1b	H2	6	22	20	19	14	10	9	9	8	7	7	7	51	14	65
M-08/C2	H2	109	289	168	110	64	36	28	23	19	7	0	0	312	0	312
M-08/C3	H2	12	40	33	27	19	12	11	10	9	7	7	2	70	0	70
M-08/E	H2	29	102	85	71	51	33	29	26	24	20	19	19	186	31	217
M-09/C1a	H2	2	9	9	8	6	4	4	4	4	4	4	4	22	1	24
M-09/C1b	H2	4	22	20	19	14	10	9	9	9	7	7	7	51	14	65
M-09/C2	H2	75	305	175	113	66	37	29	23	19	8	0	0	311	0	311
M-09/C3	H2	8	41	34	28	20	13	11	10	9	7	7	3	69	0	69
M-09/E	H2	20	104	86	73	52	34	30	27	24	20	19	19	185	32	216
M-10/C1a	H2	1	9	9	8	6	5	4	4	4	4	4	4	22	1	24
M-10/C1b	H2	2	23	21	19	15	10	9	9	9	7	7	8	50	14	64
M-10/C2	H2	39	322	182	117	68	38	29	24	20	10	0	0	310	0	310
M-10/C3	H2	4	42	34	28	20	13	11	10	9	7	7	4	69	0	69
M-11/C1a	H2	0	8	9	8	6	5	4	4	4	4	4	4	22	2	23
M-11/C1b	H2	0	19	21	19	15	10	10	9	9	8	7	8	49	14	63
M-11/C2	H2	0	300	206	129	74	41	31	25	21	14	0	0	307	0	307
M-11/C3	H2	0	36	36	30	21	13	12	10	9	8	7	5	68	0	68
M-12/C1a	H2	0	7	9	8	6	5	4	4	4	4	4	4	21	2	23
M-12/C1b	H2	0	17	21	19	15	10	10	9	9	8	8	8	49	14	63
M-12/C2	H2	0	277	216	134	76	42	32	26	21	15	0	0	306	0	306
M-12/C3	H2	0	33	36	30	21	13	12	10	9	8	7	6	68	0	68

Company Daily Oil Production

Entity Description	Reserve Class	Year (bbl/d) 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Totals (Mbbl) Subtotal	Remainder	Total
Proved Plus Probable Undeveloped (Cont.)																
M-13/C1a	H2	0	6	9	8	7	5	4	4	4	4	4	4	21	2	23
M-13/C1b	H2	0	16	21	20	15	10	10	9	9	8	8	8	49	14	63
M-13/C2	H2	0	253	226	139	78	43	33	26	21	16	0	0	305	0	305
M-13/C3	H2	0	30	37	31	21	14	12	11	9	8	7	7	68	0	68
M-14/C1a	H2	0	5	9	8	7	5	4	4	4	4	4	4	21	2	23
M-14/C1b	H2	0	14	22	20	15	11	10	9	9	8	8	8	48	14	63
M-14/C2	H2	0	227	237	144	81	44	33	27	22	17	2	0	304	0	304
M-14/C3	H2	0	26	38	31	22	14	12	11	10	8	7	7	68	0	68
M-15/C1a	H2	0	5	9	8	7	5	4	4	4	4	4	4	21	2	23
M-15/C1b	H2	0	12	22	20	15	11	10	9	9	8	8	8	48	14	62
M-15/C2	H2	0	200	248	150	83	45	34	27	22	17	3	0	303	0	303
M-15/C3	H2	0	23	38	32	22	14	12	11	10	8	7	7	67	0	67
M-16/C1a	H2	0	4	9	8	7	5	4	4	4	4	4	4	21	3	23
M-16/C1b	H2	0	10	22	20	15	11	10	10	9	8	8	8	47	15	62
M-16/C2	H2	0	171	261	155	86	46	35	28	23	17	4	0	302	0	302
M-16/C3	H2	0	19	39	32	22	14	12	11	10	8	8	7	67	1	68
M-17/C2	H2	0	141	275	162	89	47	36	28	23	17	6	0	301	0	301
M-18/C1b	H2	0	15	56	51	39	27	26	24	23	20	20	20	117	38	155
M-18/C2	H2	0	155	427	261	146	79	61	48	40	30	27	25	474	16	490
M-18/C3	H2	0	15	52	44	32	21	19	17	15	13	12	12	92	20	112
M-19/C2	H2	0	106	448	271	151	81	62	49	40	31	27	25	471	17	489
M-20/C2	H2	0	55	471	281	155	84	63	50	41	31	28	25	469	18	487
M-21/C2	H2	0	0	433	315	171	90	68	54	43	33	29	26	461	21	481
M-22/C2	H2	0	0	277	216	112	57	42	33	26	20	16	0	292	0	292
M-23/C2	H2	0	0	253	226	116	59	43	33	27	20	17	0	290	0	290
M-23/E	H2	0	0	75	95	66	42	36	32	29	24	22	22	161	36	197
M-24/C2	H2	0	0	227	237	120	61	44	34	27	20	18	2	289	0	289
M-25/C2	H2	0	0	200	249	125	63	46	35	28	21	18	3	287	0	287
M-26/C2	H2	0	0	171	262	130	65	47	36	28	21	18	5	286	0	286
M-27/C2	H2	0	0	141	275	135	67	48	37	29	21	19	6	284	0	284
M-28/C2	H2	0	0	75	300	140	68	48	36	28	20	18	1	268	0	268
Total: Proved Plus Probable Undeveloped		**1,876**	**5,898**	**7,936**	**6,383**	**3,749**	**2,144**	**1,730**	**1,459**	**1,255**	**974**	**796**	**636**	**12,715**	**734**	**13,448**
PPP Undeveloped																
M-04/C1a	Q2	6	11	11	8	8	7	6	5	4	4	4	4	29	16	45
M-04/C1b	Q2	47	87	80	56	52	45	42	29	27	26	25	24	198	121	319
M-04/C2	Q2	383	546	374	206	158	117	93	57	48	42	37	32	764	58	822
M-04/C3	Q2	46	82	70	46	41	34	30	20	18	17	16	15	159	53	212
M-04/E	Q2	69	120	102	67	59	48	42	28	25	23	21	20	228	83	311
M-05/C1a	Q2	6	11	11	8	8	7	6	5	4	4	4	4	29	16	45
M-05/C1b	Q2	47	87	80	56	52	45	42	29	27	26	25	24	198	121	319
M-05/C2	Q2	383	546	374	206	158	117	93	57	48	42	37	32	764	58	822
M-05/C3	Q2	46	82	70	46	41	34	30	20	18	17	16	15	159	53	212
M-05/E	Q2	69	120	102	67	59	48	42	28	25	23	21	20	228	83	311
M-06/C1a	Q2	6	11	11	8	8	7	6	5	4	4	4	4	29	16	45
M-06/C1b	Q2	47	87	80	56	52	45	42	29	27	26	25	24	198	121	319
M-06/C2	Q2	383	546	374	206	158	117	93	57	48	42	37	32	764	58	822
M-06/C3	Q2	46	82	70	46	41	34	30	20	18	17	16	15	159	53	212
M-06/E	Q2	69	120	102	67	59	48	42	28	25	23	21	20	228	83	311
M-07/C1a	Q2	5	11	11	8	8	7	6	5	4	4	4	4	28	16	45

Company Daily Oil Production

Entity Description	Reserve Class	Year (bbl/d) 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Totals (Mbbl) Subtotal	Remainder	Total
PPP Undeveloped (Cont.)																
M-07/C1b	Q2	39	88	81	56	53	46	42	29	28	26	25	24	196	121	317
M-07/C2	Q2	325	566	385	212	162	119	95	58	49	42	37	33	760	59	819
M-07/C3	Q2	39	83	71	47	42	35	31	20	19	17	16	15	158	53	212
M-07/E	Q2	58	122	104	68	59	49	43	28	26	23	22	20	227	84	310
M-08/C1a	Q2	3	11	11	8	7	6	6	4	4	4	4	4	26	7	33
M-08/C1b	Q2	7	27	24	17	16	14	13	9	8	8	7	7	57	35	92
M-08/C2	Q2	123	359	233	124	92	67	53	32	27	23	20	17	427	8	435
M-08/C3	Q2	15	50	40	25	21	16	14	9	8	7	6	6	79	1	80
M-08/E	Q2	35	126	106	69	61	50	44	29	26	24	22	20	223	85	308
M-09/C1a	Q2	2	11	11	8	7	6	6	4	4	4	4	4	26	7	33
M-09/C1b	Q2	5	27	25	17	16	14	13	9	8	8	7	7	57	35	92
M-09/C2	Q2	84	374	241	127	95	68	54	32	27	23	20	18	424	8	433
M-09/C3	Q2	10	51	41	25	21	17	14	9	8	7	7	6	79	1	79
M-09/E	Q2	24	127	108	70	61	50	44	29	26	24	22	20	221	85	307
M-10/C1a	Q2	1	11	11	8	7	6	6	4	4	4	4	4	26	7	33
M-10/C1b	Q2	2	27	25	17	16	14	13	9	8	8	7	7	56	36	92
M-10/C2	Q2	44	390	249	131	97	70	55	33	27	23	20	18	422	9	431
M-10/C3	Q2	5	52	41	26	21	17	14	9	8	7	7	6	78	1	79
M-11/C1a	Q2	0	10	11	8	7	7	6	4	4	4	4	4	25	7	32
M-11/C1b	Q2	0	23	25	18	16	14	13	9	8	8	8	7	55	36	91
M-11/C2	Q2	0	354	276	142	104	74	58	35	29	24	21	18	414	10	425
M-11/C3	Q2	0	45	44	27	22	18	15	10	8	8	7	6	76	2	78
M-12/C1a	Q2	0	9	11	8	7	7	6	4	4	4	4	4	25	8	32
M-12/C1b	Q2	0	21	26	18	16	14	13	9	8	8	8	7	54	36	90
M-12/C2	Q2	0	325	286	147	107	76	59	35	29	25	21	19	412	11	422
M-12/C3	Q2	0	41	44	27	23	18	15	10	9	8	7	6	76	2	77
M-13/C1a	Q2	0	8	11	8	7	7	6	4	4	4	4	4	24	8	32
M-13/C1b	Q2	0	19	26	18	17	14	13	9	9	8	8	7	54	36	90
M-13/C2	Q2	0	295	296	151	110	77	60	36	30	25	22	19	409	11	420
M-13/C3	Q2	0	37	45	28	23	18	15	10	9	8	7	6	75	2	77
M-14/C1a	Q2	0	7	11	8	8	7	6	4	4	4	4	4	24	8	32
M-14/C1b	Q2	0	16	26	18	17	14	13	9	9	8	8	7	53	36	89
M-14/C2	Q2	0	263	307	156	112	79	61	36	30	26	22	19	406	12	418
M-14/C3	Q2	0	33	46	28	23	18	16	10	9	8	7	6	74	2	77
M-15/C1a	Q2	0	6	11	8	8	7	6	4	4	4	4	4	24	8	32
M-15/C1b	Q2	0	14	26	18	17	14	13	9	9	8	8	7	53	37	89
M-15/C2	Q2	0	231	319	160	115	81	62	37	31	26	22	19	403	12	415
M-15/C3	Q2	0	28	47	29	24	19	16	10	9	8	7	6	74	2	76
M-16/C1a	Q2	0	5	11	8	8	7	6	4	4	4	4	4	24	8	32
M-16/C1b	Q2	0	12	26	18	17	15	13	9	9	8	8	7	52	37	89
M-16/C2	Q2	0	196	332	166	118	83	64	38	31	26	23	20	400	13	413
M-16/C3	Q2	0	24	48	29	24	19	16	10	9	8	7	6	73	3	76
M-17/C1a	Q2	0	4	11	8	8	7	6	4	4	4	4	4	23	8	32
M-17/C1b	Q2	0	9	27	18	17	15	13	9	9	8	8	7	51	37	88
M-17/C2	Q2	0	160	345	171	122	85	65	38	32	27	23	20	397	14	410
M-17/C3	Q2	0	19	49	30	25	19	16	10	9	8	7	7	72	3	75
M-18/C1a	Q2	0	3	12	8	8	7	7	5	5	5	4	4	25	19	43
M-18/C1b	Q2	0	24	89	62	58	50	46	32	30	28	27	26	172	129	301
M-18/C2	Q2	0	203	608	310	224	158	123	73	61	51	44	39	692	74	766
M-18/C3	Q2	0	24	85	55	48	40	35	23	21	19	18	16	140	62	202
M-18/E	Q2	0	35	126	81	70	57	49	32	29	27	24	22	201	91	292

Company Daily Oil Production

Entity Description	Reserve Class	Year (bbl/d) 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Totals (Mbbl) Subtotal	Remainder	Total
PPP Undeveloped (Cont.)																
M-19/C1a	Q2	0	2	12	8	8	7	7	5	5	5	4	4	24	19	43
M-19/C1b	Q2	0	16	90	63	58	50	46	32	30	29	27	26	170	129	299
M-19/C2	Q2	0	138	632	319	230	162	125	74	62	52	45	39	686	76	761
M-19/C3	Q2	0	16	86	56	49	40	35	23	21	19	18	17	139	62	201
M-20/C2	Q2	0	71	656	329	236	166	128	76	63	53	45	40	680	77	756
M-21/C1a	Q2	0	0	10	8	8	7	7	5	5	5	5	4	23	19	42
M-21/C1b	Q2	0	0	77	64	60	51	47	33	31	29	28	26	163	130	293
M-21/C2	Q2	0	0	591	362	256	177	135	80	66	55	47	41	661	81	741
M-21/C3	Q2	0	0	75	59	51	42	37	24	22	20	18	17	133	64	197
M-21/E	Q2	0	0	111	86	74	60	52	34	31	28	25	23	192	93	285
M-22/C2	Q2	0	0	325	216	148	100	75	44	36	30	25	22	372	17	390
M-23/C1a	Q2	0	0	8	8	8	7	7	5	4	4	4	4	21	9	31
M-23/C1b	Q2	0	0	19	19	18	15	14	10	9	9	8	8	47	38	85
M-23/C2	Q2	0	0	295	224	152	103	77	45	36	30	26	22	368	18	386
M-23/C3	Q2	0	0	37	34	28	22	18	11	10	9	8	7	67	4	71
M-23/E	Q2	0	0	91	89	76	62	53	35	31	28	26	24	188	95	282
M-24/C1b	Q2	0	0	16	20	18	16	14	10	9	9	8	8	47	38	85
M-24/C2	Q2	0	0	263	233	157	105	79	45	37	31	26	22	364	19	383
M-25/C2	Q2	0	0	231	242	162	108	80	46	37	31	26	23	360	19	379
M-26/C2	Q2	0	0	196	251	167	111	82	47	38	32	27	23	356	20	375
M-27/C2	Q2	0	0	160	261	172	114	84	48	39	32	27	23	351	21	371
M-28/C2	Q2	0	0	84	283	184	120	88	50	40	33	28	24	341	22	363
M-29/C2	Q2	0	0	0	308	197	127	92	52	42	34	29	25	331	23	354
M-30/C1a	Q2	0	0	0	8	8	7	7	5	5	4	4	4	19	10	30
M-30/C1b	Q2	0	0	0	19	19	17	15	10	10	9	9	8	42	40	82
M-30/C2	Q2	0	0	0	288	204	131	95	54	43	35	29	25	329	24	353
M-30/C3	Q2	0	0	0	37	33	25	21	13	11	10	9	8	60	6	66
M-31/C2	Q2	0	0	0	245	218	139	99	56	44	36	30	26	326	25	352
M-32/C1a	Q2	0	0	0	5	9	7	7	5	5	4	4	4	18	11	29
M-32/C1b	Q2	0	0	0	12	20	17	16	11	10	9	9	8	41	40	81
M-32/C2	Q2	0	0	0	199	235	147	105	58	46	37	31	26	323	27	350
M-32/C3	Q2	0	0	0	25	35	27	22	14	12	10	9	8	59	7	66
M-33/C2	Q2	0	0	0	175	244	152	107	60	47	38	32	27	321	27	349
M-34/C1a	Q2	0	0	0	3	9	8	7	5	5	5	4	4	18	11	29
M-34/C1b	Q2	0	0	0	7	20	17	16	11	10	10	9	9	40	41	81
M-34/C2	Q2	0	0	0	121	264	162	113	62	49	39	33	28	318	29	347
M-34/C3	Q2	0	0	0	14	37	28	23	14	12	11	9	8	57	8	65
M-35/C1a	Q2	0	0	0	1	9	8	7	5	5	5	4	4	18	12	29
M-35/C1b	Q2	0	0	0	4	21	18	16	11	10	10	9	9	39	41	80
M-35/C2	Q2	0	0	0	63	286	173	120	65	51	41	34	28	314	31	345
M-36/C2	Q2	0	0	0	0	311	185	126	69	53	42	35	29	310	32	343
M-37/C1a	Q2	0	0	0	0	8	8	7	5	5	5	4	4	17	12	29
M-37/C1b	Q2	0	0	0	0	19	18	16	11	10	10	9	9	37	40	77
M-37/C2	Q2	0	0	0	0	289	188	127	69	53	42	34	29	303	30	333
M-37/C3	Q2	0	0	0	0	37	30	24	15	12	11	9	8	53	7	60
M-38/C2	Q2	0	0	0	0	376	367	253	138	107	86	71	60	532	124	656
M-39/E	Q2	0	0	0	0	61	85	72	46	41	36	32	29	147	111	257
M-40/E	Q2	0	0	0	0	53	86	73	47	41	36	33	30	145	111	257
M-41/E	Q2	0	0	0	0	44	87	74	47	41	37	33	30	144	112	256
M-42/E	Q2	0	0	0	0	36	89	75	48	42	37	33	30	142	113	255
M-43/E	Q2	0	0	0	0	27	90	76	48	42	38	34	31	141	114	254

Company Daily Oil Production

Entity Description	Reserve Class	Year (bbl/d) 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Totals (Mbbl) Subtotal	Remainder	Total
PPP Undeveloped (Cont.)																
M-44/E	Q2	0	0	0	0	18	91	77	49	43	38	34	31	139	114	253
M-45/E	Q2	0	0	0	0	9	93	78	49	43	39	34	31	137	115	253
M-46/E	Q2	0	0	0	0	0	94	79	50	44	39	35	32	136	116	252
M-47/E	Q2	0	0	0	0	0	87	80	51	44	39	35	32	134	117	251
M-48/E	Q2	0	0	0	0	0	80	82	52	46	41	37	33	135	124	259
Total: PPP Undeveloped		**2,478**	**7,797**	**11,455**	**8,968**	**8,823**	**7,095**	**5,637**	**3,448**	**2,943**	**2,567**	**2,272**	**2,041**	**23,917**	**5,311**	**29,227**

Table 4

Company: **Griffiths Energy International Inc.** Effective Date: **31-Dec-12**
Property: **Mangara**

Economic Parameters

A) Price Forecasts and By-Product Data

GLJ (2013-01)

Oil Reference: 95% of BRENTUS

Transport Costs:

Proved Undeveloped	$8.20 / bbl
Proved plus Probable Undeveloped	$7.52 / bbl
Proved plus Probable plus Possible Undeveloped	$7.22 / bbl

B) Operating Costs (2013 Dollars)

Well Costs: $10,000 / well / month
Variable Costs $3.00 / bbl

Fixed Operating Costs and G&A

	Facility Operating Costs			G&A Costs		
Year	Proved M$	Proved+ Probable M$	Proved+ Probable+ Possible M$	Proved M$	Proved+ Probable M$	Proved+ Probable+ Possible M$
2013	3,750	5,000	5,000	1,750	7,000	17,500
2014	7,500	10,000	10,000	1,500	6,000	15,000
2015	7,500	10,000	10,000	750	3,000	7,500
2016	7,500	10,000	10,000	750	3,000	7,500
2017	7,500	10,000	10,000	750	3,000	7,500
2018	7,500	10,000	10,000	750	3,000	7,500
2019	7,500	10,000	10,000	375	1,500	3,750
2020+	7,500	10,000	10,000	375	1,500	3,750

C) Abandonment Costs (2013 Dollars)

	M$
Proved Undeveloped	7,200
Proved plus Probable Undeveloped	11,800
Proved plus Probable plus Possible Undeveloped	21,000

Abandonment costs are scheduled on a unit of production basis.

Table 4.1

Company: **Griffiths Energy International Inc.** Effective Date: **31-Dec-12**
Property: **Mangara**

Economic Parameters

D) Capital Costs

Capital Summary (2013 Dollars)

Year	Well/Area	Development Description	Gross Lease Capital Expenditures: Development	Tangible	Plant & Gath.	Total $	Company Total M$	Capital Interest %
	Proved Undeveloped							
2013	Drilling Capital	Well Capital	78,421	0	0	78,421	52,281	66.67
	Glencore Carry		-44,523	0	0	-44,523	-44,523	100
	Mangara	Pipeline & Facilities	0	0	89,731	89,731	59,821	66.67
2014	Drilling Capital	Well Capital	92,862	0	0	92,862	61,908	66.67
	Glencore Carry		-40,115	0	0	-40,115	-40,115	100
	Mangara	Pipeline & Facilities	0	0	11,505	11,505	7,670	66.67
2015	Drilling Capital	Well Capital	116,955	0	0	116,955	77,970	66.67
	Glencore Carry		-48,980	0	0	-48,980	-48,980	100
2016	Drilling Capital	Well Capital	31,524	0	0	31,524	21,016	66.67
2017	Drilling Capital	Well Capital	10,088	0	0	10,088	6,725	66.67
	Total: Proved Undeveloped		**196,232**	**0**	**101,236**	**297,468**	**153,773**	**51.7**
	Proved Plus Probable Undeveloped							
2013	Drilling Capital	Well Capital	80,421	0	0	80,421	53,614	66.67
	Glencore Carry		-53,273	0	0	-53,273	-53,273	100
	Mangara	Pipeline & Facilities	0	0	110,850	110,850	73,900	66.67
2014	Drilling Capital	Well Capital	126,379	0	0	126,379	84,252	66.67
	Glencore Carry		-52,763	0	0	-52,763	-52,763	100
	Mangara	Pipeline & Facilities	0	0	11,505	11,505	7,670	66.67
2015	Drilling Capital	Well Capital	194,869	0	0	194,869	129,913	66.67
	Glencore Carry		-35,256	0	0	-35,256	-35,256	100
2016	Drilling Capital	Well Capital	99,631	0	0	99,631	66,421	66.67
2017	Drilling Capital	Well Capital	18,614	0	0	18,614	12,409	66.67
	Total: Proved Plus Probable Undeveloped		**378,623**	**0**	**122,355**	**500,978**	**286,888**	**57.3**
	PPP Undeveloped							
2013	Drilling Capital	Well Capital	80,421	0	0	80,421	53,614	66.67
	Glencore Carry		-55,447	0	0	-55,447	-55,447	100
	Mangara	Pipeline & Facilities	0	0	116,130	116,130	77,420	66.67
2014	Drilling Capital	Well Capital	128,996	0	0	128,996	85,997	66.67
	Glencore Carry		-52,583	0	0	-52,583	-52,583	100
	Mangara	Pipeline & Facilities	0	0	11,505	11,505	7,670	66.67
2015	Drilling Capital	Well Capital	215,246	0	0	215,246	143,498	66.67
	Glencore Carry		-34,289	0	0	-34,289	-34,289	100
2016	Drilling Capital	Well Capital	160,823	0	0	160,823	107,215	66.67
2017	Drilling Capital	Well Capital	159,161	0	0	159,161	106,108	66.67
2018	Drilling Capital	Well Capital	91,527	0	0	91,527	61,018	66.67
2019	Drilling Capital	Well Capital	80,409	0	0	80,409	53,606	66.67
	Total: PPP Undeveloped		**774,264**	**0**	**127,635**	**901,899**	**553,827**	**61.4**

Company: **Griffiths Energy International Inc.**
Property: **Mangara**
Currency: **$US Dollars**

Reserve Class: **Proved**
Development Class: **Undeveloped**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

	Light/Medium Oil Production					
Year	Gross Oil Wells	Gross Daily bbl/d	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	7	2,161	1,031	376	376	91.55
2014	15	5,844	2,789	1,018	1,018	89.18
2015	21	7,445	3,554	1,297	1,297	89.17
2016	21	5,841	2,788	1,018	1,018	89.18
2017	21	3,700	1,766	645	645	86.80
2018	21	2,631	1,256	458	458	86.80
2019	21	1,877	896	327	327	88.08
2020	20	1,019	487	178	178	90.01
2021	13	323	189	69	69	91.98
Tot.				**5,386**	**5,386**	**88.85**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	34,463	0	0	34,463	0	34,463	0	0	0	0	0	34,463	5,524	0	5,524
2014	90,793	0	0	90,793	0	90,793	0	0	0	0	0	90,793	11,695	0	11,695
2015	115,676	0	0	115,676	0	115,676	0	0	0	0	0	115,676	13,125	0	13,125
2016	90,758	0	0	90,758	0	90,758	0	0	0	0	0	90,758	12,145	0	12,145
2017	55,950	0	0	55,950	0	55,950	0	0	0	0	0	55,950	10,695	0	10,695
2018	39,788	0	0	39,788	0	39,788	0	0	0	0	0	39,788	10,048	0	10,048
2019	28,804	0	0	28,804	0	28,804	0	0	0	0	0	28,804	9,347	0	9,347
2020	15,984	0	0	15,984	0	15,984	0	0	0	0	0	15,984	8,723	0	8,723
2021	6,342	0	0	6,342	0	6,342	0	0	0	0	0	6,342	4,196	0	4,196
Tot.	**478,559**	**0**	**0**	**478,559**	**0**	**478,559**	**0**	**0**	**0**	**0**	**0**	**478,559**	**85,498**	**0**	**85,498**
Disc	353,859	0	0	353,859	0	353,859	0	0	0	0	0	353,859	58,525	0	58,525

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	Net Prod'n Revenue M$	Other Income M$	Aband. Costs M$	Oper. Income M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	28,938	103,154	338	131,755	7,758	59,821	0	67,578	64,177	64,177	61,190
2014	0	0	0	79,098	0	932	78,166	22,229	7,824	0	30,053	48,113	112,290	102,894
2015	0	0	0	102,551	0	1,211	101,340	30,161	0	0	30,161	71,180	183,469	158,982
2016	0	0	0	78,613	0	969	77,644	22,303	0	0	22,303	55,342	238,811	198,626
2017	0	0	0	45,255	0	626	44,629	7,280	0	0	7,280	37,350	276,161	222,949
2018	0	0	0	29,741	0	454	29,286	0	0	0	0	29,286	305,447	240,288
2019	0	0	0	19,456	0	330	19,126	0	0	0	0	19,126	324,573	250,581
2020	0	0	0	7,261	0	183	7,078	0	0	0	0	7,078	331,651	254,044
2021	0	0	0	2,146	0	34	2,112	0	0	0	0	2,112	333,763	254,984
Tot.	**0**	**0**	**0**	**393,060**	**103,154**	**5,077**	**491,137**	**89,730**	**67,644**	**0**	**157,374**	**333,763**	**333,763**	**254,984**
Disc	0	0	0	295,334	98,353	3,737	389,950	71,148	63,818	0	134,966	254,984	254,984	254,984

SUMMARY OF RESERVES

		Remaining Reserves at Jan 01, 2013					Oil Equivalents			Reserve Life Indic. (yr)		
Product	Units	Gross	Working Interest	Roy/NPI Interest	Total Company	Net	Oil Eq. Factor	Company Mboe	% of Total	Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	11,257	5,386	0	5,386	5,386	1.000	5,386	100	9.0	14.3	3.0
Total: Oil Eq.	Mboe	11,257	5,386	0	5,386	5,386	1.000	5,386	100	9.0	14.3	3.0

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	85.00	6.55	91.55	0.00	14.68	0.00	76.87	478,559	100	353,859	100
Total: Oil Eq.	$/boe	85.00	6.55	91.55	0.00	14.68	0.00	76.87	478,559	100	353,859	100

INTEREST AND NET PRESENT VALUE SUMMARY

Revenue Interests and Burdens (%)		
Entity Name	Initial	Average
Working Interest	47.7342	47.8504
Capital Interest	54.6622	51.7234
Royalty Interest	0.0000	0.0000
Crown Royalty	0.0000	0.0000
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000

	Net Present Value Before Income Tax				
Disc. Rate	Prod'n Revenue	Operating Income	Capital Invest.	**Cash Flow**	
%	M$	M$	M$	M$	$/boe
0.0	393,060	491,137	157,374	333,763	61.97
5.0	338,502	434,846	145,225	289,621	53.77
8.0	311,448	406,752	138,870	267,882	49.74
10.0	295,334	389,950	134,966	254,984	47.34
12.0	280,558	374,491	131,301	243,191	45.15
15.0	260,594	353,515	126,208	227,307	42.20
20.0	232,217	323,490	118,659	204,831	38.03

Evaluator: Herchen, Leonard L.
Run Date: January 21, 2013 12:50:56

Company: **Griffiths Energy International Inc.**
Property: **Mangara**
Currency: **$US Dollars**

Reserve Class: **Proved Plus Probable**
Development Class: **Undeveloped**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

	Light/Medium Oil Production					
Year	Gross Oil Wells	Gross Daily bbl/d	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	7	3,930	1,876	685	685	92.23
2014	17	12,356	5,898	2,153	2,153	89.85
2015	25	16,625	7,936	2,897	2,897	89.86
2016	25	13,372	6,383	2,330	2,330	89.85
2017	25	9,381	3,749	1,368	1,368	87.48
2018	25	7,115	2,144	783	783	87.48
2019	25	5,661	1,730	631	631	88.76
2020	25	4,669	1,459	532	532	90.69
2021	25	3,925	1,255	458	458	92.66
2022	25	3,295	974	355	355	94.65
2023	25	2,531	796	291	291	96.70
2024	23	1,856	636	232	232	98.78
Sub.				12,715	12,715	90.12
Rem.				734	734	104.65
Tot.				**13,448**	**13,448**	**90.91**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After Process.	Net Revenue After Royalty	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	M$	M$	Fixed M$	Variable M$	Total M$
2013	63,160	0	0	63,160	0	63,160	0	0	0	0	0	63,160	11,150	0	11,150
2014	193,437	0	0	193,437	0	193,437	0	0	0	0	0	193,437	21,467	0	21,467
2015	260,267	0	0	260,267	0	260,267	0	0	0	0	0	260,267	23,724	0	23,724
2016	209,339	0	0	209,339	0	209,339	0	0	0	0	0	209,339	21,678	0	21,678
2017	119,697	0	0	119,697	0	119,697	0	0	0	0	0	119,697	18,959	0	18,959
2018	68,459	0	0	68,459	0	68,459	0	0	0	0	0	68,459	17,511	0	17,511
2019	56,043	0	0	56,043	0	56,043	0	0	0	0	0	56,043	15,540	0	15,540
2020	48,284	0	0	48,284	0	48,284	0	0	0	0	0	48,284	15,019	0	15,019
2021	42,453	0	0	42,453	0	42,453	0	0	0	0	0	42,453	14,683	0	14,683
2022	33,640	0	0	33,640	0	33,640	0	0	0	0	0	33,640	14,427	0	14,427
2023	28,091	0	0	28,091	0	28,091	0	0	0	0	0	28,091	14,035	0	14,035
2024	22,919	0	0	22,919	0	22,919	0	0	0	0	0	22,919	13,505	0	13,505
Sub.	1,145,790	0	0	1,145,790	0	1,145,790	0	0	0	0	0	1,145,790	201,699	0	201,699
Rem.	76,785	0	0	76,785	0	76,785	0	0	0	0	0	76,785	61,980	0	61,980
Tot.	**1,222,575**	**0**	**0**	**1,222,575**	**0**	**1,222,575**	**0**	**0**	**0**	**0**	**0**	**1,222,575**	**263,679**	**0**	**263,679**
Disc	825,618	0	0	825,618	0	825,618	0	0	0	0	0	825,618	139,733	0	139,733

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	**Net Prod'n Revenue** M$	Other Income M$	**Aband. Costs** M$	**Oper. Income** M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	52,010	103,154	353	154,811	341	73,900	0	74,241	80,570	80,570	76,821
2014	0	0	0	171,969	0	1,131	170,839	32,119	7,824	0	39,943	130,896	211,466	190,279
2015	0	0	0	236,543	0	1,552	234,991	98,481	0	0	98,481	136,510	347,975	297,846
2016	0	0	0	187,661	0	1,273	186,388	70,486	0	0	70,486	115,901	463,877	380,872
2017	0	0	0	100,739	0	911	99,828	13,432	0	0	13,432	86,395	550,272	437,135
2018	0	0	0	50,948	0	705	50,244	0	0	0	0	50,244	600,516	466,881
2019	0	0	0	40,503	0	572	39,931	0	0	0	0	39,931	640,447	488,372
2020	0	0	0	33,265	0	481	32,784	0	0	0	0	32,784	673,231	504,413
2021	0	0	0	27,769	0	413	27,357	0	0	0	0	27,357	700,588	516,581
2022	0	0	0	19,213	0	353	18,860	0	0	0	0	18,860	719,447	524,207
2023	0	0	0	14,056	0	277	13,779	0	0	0	0	13,779	733,227	529,272
2024	0	0	0	9,414	0	207	9,206	0	0	0	0	9,206	742,433	532,349
Sub.	0	0	0	944,091	103,154	8,227	1,039,017	214,860	81,724	0	296,584	742,433	742,433	532,349
Rem.	0	0	0	14,805	0	342	14,464	0	0	0	0	14,464	756,897	536,388
Tot.	**0**	**0**	**0**	**958,896**	**103,154**	**8,569**	**1,053,481**	**214,860**	**81,724**	**0**	**296,584**	**756,897**	**756,897**	**536,388**
Disc	0	0	0	685,886	98,353	5,600	778,639	165,008	77,243	0	242,251	536,388	536,388	536,388

SUMMARY OF RESERVES

		Remaining Reserves at Jan 01, 2013					Oil Equivalents			Reserve Life Indic. (yr)		
Product	Units	Gross	Working Interest	Roy/NPI Interest	Total Company	Net	Oil Eq. Factor	Company Mboe	% of Total	Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	32,667	13,448	0	13,448	13,448	1.000	13,448	100	17.0	19.6	3.4
Total: Oil Eq.	Mboe	32,667	13,448	0	13,448	13,448	1.000	13,448	100	17.0	19.6	3.4

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	85.00	7.23	92.23	0.00	16.28	0.00	75.95	1,222,575	100	825,618	100
Total: Oil Eq.	$/boe	85.00	7.23	92.23	0.00	16.28	0.00	75.95	1,222,575	100	825,618	100

INTEREST AND NET PRESENT VALUE SUMMARY

Revenue Interests and Burdens (%)		
Entity Name	Initial	Average
Working Interest	47.7342	41.1507
Capital Interest	53.7986	57.3928
Royalty Interest	0.0000	0.0000
Crown Royalty	0.0000	0.0000
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000

	Net Present Value Before Income Tax				
Disc. Rate %	Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/boe
0.0	958,896	1,053,481	296,584	756,897	56.28
5.0	802,497	896,344	266,955	629,389	46.80
8.0	728,729	821,949	251,614	570,335	42.41
10.0	685,886	778,639	242,251	536,388	39.89
12.0	647,280	739,539	233,507	506,032	37.63
15.0	596,091	687,571	221,438	466,133	34.66
20.0	525,115	615,238	203,740	411,498	30.60

Evaluator: Herchen, Leonard L.
Run Date: January 21, 2013 12:52:06

Company: **Griffiths Energy International Inc.**
Property: **Mangara**
Currency: **$US Dollars**

Reserve Class: **PPP**
Development Class: **Undeveloped**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Economic Forecast

PRODUCTION FORECAST

		Light/Medium Oil Production				
Year	Gross Oil Wells	Gross Daily bbl/d	Company Daily bbl/d	Company Yearly Mbbl	Net Yearly Mbbl	Price $/bbl
2013	7	5,191	2,478	904	904	92.53
2014	17	16,335	7,797	2,846	2,846	90.16
2015	25	23,998	11,455	4,181	4,181	90.15
2016	32	24,861	8,968	3,273	3,273	90.15
2017	42	24,166	8,823	3,220	3,220	87.78
2018	45	20,749	7,095	2,590	2,590	87.78
2019	45	16,597	5,637	2,057	2,057	89.06
2020	45	13,704	3,448	1,259	1,259	90.99
2021	45	11,527	2,943	1,074	1,074	92.96
2022	45	9,904	2,567	937	937	94.95
2023	45	8,633	2,272	829	829	97.00
2024	45	7,633	2,041	745	745	99.08
Sub.				23,917	23,917	90.45
Rem.				5,311	5,311	116.38
Tot.				**29,227**	**29,227**	**95.16**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens						Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After	Net Revenue After	Operating Expenses		
	Working Interest				Royalty Interest	Company Interest									
Year	Oil M$	Gas M$	NGL+Sul M$	Total M$	Total M$	Total M$	Crown M$	Other M$	Crown M$	Other M$	Process. M$	Royalty M$	Fixed M$	Variable M$	Total M$
2013	83,688	0	0	83,688	0	83,688	0	0	0	0	0	83,688	19,070	0	19,070
2014	256,585	0	0	256,585	0	256,585	0	0	0	0	0	256,585	30,550	0	30,550
2015	376,955	0	0	376,955	0	376,955	0	0	0	0	0	376,955	32,445	0	32,445
2016	295,107	0	0	295,107	0	295,107	0	0	0	0	0	295,107	34,357	0	34,357
2017	282,681	0	0	282,681	0	282,681	0	0	0	0	0	282,681	35,361	0	35,361
2018	227,314	0	0	227,314	0	227,314	0	0	0	0	0	227,314	33,579	0	33,579
2019	183,240	0	0	183,240	0	183,240	0	0	0	0	0	183,240	28,021	0	28,021
2020	114,520	0	0	114,520	0	114,520	0	0	0	0	0	114,520	26,156	0	26,156
2021	99,870	0	0	99,870	0	99,870	0	0	0	0	0	99,870	24,817	0	24,817
2022	88,972	0	0	88,972	0	88,972	0	0	0	0	0	88,972	23,898	0	23,898
2023	80,452	0	0	80,452	0	80,452	0	0	0	0	0	80,452	23,245	0	23,245
2024	73,794	0	0	73,794	0	73,794	0	0	0	0	0	73,794	22,802	0	22,802
Sub.	2,163,178	0	0	2,163,178	0	2,163,178	0	0	0	0	0	2,163,178	334,303	0	334,303
Rem.	618,023	0	0	618,023	0	618,023	0	0	0	0	0	618,023	380,103	0	380,103
Tot.	**2,781,201**	**0**	**0**	**2,781,201**	**0**	**2,781,201**	**0**	**0**	**0**	**0**	**0**	**2,781,201**	**714,406**	**0**	**714,406**
Disc	1,527,777	0	0	1,527,777	0	1,527,777	0	0	0	0	0	1,527,777	260,266	0	260,266

								Net Capital Investment				Before Tax Cash Flow		
Year	Mineral Tax M$	Capital Tax M$	NPI Burden M$	**Net Prod'n Revenue** M$	Other Income M$	**Aband. Costs** M$	**Oper. Income** M$	Dev. M$	Plant M$	Tang. M$	Total M$	Annual M$	Cum. M$	10.0% Dcf M$
2013	0	0	0	64,618	103,154	318	167,454	-1,833	77,420	0	75,587	91,867	91,867	87,592
2014	0	0	0	226,035	0	1,020	225,015	34,082	7,824	0	41,906	183,109	274,976	246,308
2015	0	0	0	344,510	0	1,528	342,982	113,621	0	0	113,621	229,361	504,337	427,041
2016	0	0	0	260,749	0	1,615	259,135	113,778	0	0	113,778	145,357	649,694	531,168
2017	0	0	0	247,320	0	1,601	245,719	114,854	0	0	114,854	130,865	780,559	616,390
2018	0	0	0	193,735	0	1,402	192,333	67,369	0	0	67,369	124,964	905,523	690,372
2019	0	0	0	155,218	0	1,144	154,074	60,369	0	0	60,369	93,705	999,228	740,805
2020	0	0	0	88,363	0	964	87,400	0	0	0	0	87,400	1,086,628	783,568
2021	0	0	0	75,053	0	827	74,226	0	0	0	0	74,226	1,160,854	816,583
2022	0	0	0	65,074	0	724	64,350	0	0	0	0	64,350	1,225,204	842,604
2023	0	0	0	57,207	0	644	56,563	0	0	0	0	56,563	1,281,767	863,396
2024	0	0	0	50,992	0	581	50,411	0	0	0	0	50,411	1,332,178	880,243
Sub.	0	0	0	1,828,875	103,154	12,368	1,919,661	502,239	85,244	0	587,483	1,332,178	1,332,178	880,243
Rem.	0	0	0	237,920	0	3,905	234,015	0	0	0	0	234,015	1,566,193	930,891
Tot.	**0**	**0**	**0**	**2,066,795**	**103,154**	**16,273**	**2,153,676**	**502,239**	**85,244**	**0**	**587,483**	**1,566,193**	**1,566,193**	**930,891**
Disc	0	0	0	1,267,511	98,353	8,373	1,357,491	346,001	80,599	0	426,600	930,891	930,891	930,891

SUMMARY OF RESERVES

		Remaining Reserves at Jan 01, 2013					Oil Equivalents			Reserve Life Indic. (yr)		
Product	Units	Gross	Working Interest	Roy/NPI Interest	Total Company	Net	Oil Eq. Factor	Company Mboe	% of Total	Reserve Life	Life Index	Half Life
Light/Med Oil	Mbbl	84,221	29,227	0	29,227	29,227	1.000	29,227	100	31.0	32.3	5.1
Total: Oil Eq.	Mboe	84,221	29,227	0	29,227	29,227	1.000	29,227	100	31.0	32.3	5.1

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Light/Med Oil	$/bbl	85.00	7.53	92.53	0.00	21.09	0.00	71.44	2,781,201	100	1,527,777	100
Total: Oil Eq.	$/boe	85.00	7.53	92.53	0.00	21.09	0.00	71.44	2,781,201	100	1,527,777	100

INTEREST AND NET PRESENT VALUE SUMMARY

Revenue Interests and Burdens (%)		
Entity Name	Initial	Average
Working Interest	47.7342	34.5613
Capital Interest	53.5683	61.6067
Royalty Interest	0.0000	0.0000
Crown Royalty	0.0000	0.0000
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000

	Net Present Value Before Income Tax				
Disc. Rate %	Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/boe
0.0	2,066,795	2,153,676	587,483	1,566,193	53.59
5.0	1,579,739	1,669,185	496,894	1,172,291	40.11
8.0	1,377,796	1,467,713	452,676	1,015,037	34.73
10.0	1,267,511	1,357,491	426,600	930,891	31.85
12.0	1,172,168	1,262,074	402,881	859,193	29.40
15.0	1,051,232	1,140,840	371,149	769,691	26.33
20.0	893,043	981,840	326,749	655,090	22.41

Evaluator: Herchen, Leonard L.
Run Date: January 21, 2013 12:54:02

GRIFFITHS ENERGY INTERNATIONAL INC.

PROSPECTIVE RESOURCE EVALUATION
REPUBLIC OF CHAD

SUMMARY

Effective December 31, 2012

1132107

PROSPECTIVE RESOURCE EVALUATION

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GLJ Petroleum Consultants

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President & CEO
Jodi L. Anhorn, M.Sc., P. Eng.
Executive Vice President & COO

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John H. Stilling, P. Eng.
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James H. Willmon, P. Eng.

February 28, 2013

Project 1132107

Board of Directors
Griffiths Energy International Inc.
2100, 555 – 4th Avenue SW
Calgary, Alberta T2P 3E7

RBC Europe Limited
Riverbank House
2 Swan Lane
London, United Kingdom
EC4R 3BF

Re: Griffiths Energy International Inc.
Competent Persons Report - Prospects
Republic of Chad
Effective December 31, 2012

GLJ Petroleum Consultants Ltd. (GLJ) has completed an independent prospective resources assessment and evaluation of the oil prospects and leads of Griffiths Energy International Inc. (the "Company") located in the Republic of Chad. The effective date of this evaluation is December 31, 2012. The Company holds its interest in Chad through Production Sharing Contracts.

The prospective resources and undiscovered petroleum initially-in-place (UPIIP) reported in this report are evaluated at the gross lease (100 percent) level. Company interest volumes were not calculated. The terms of a farm-in agreement (Glencore Farm-in) between the Company and Glencore International AG, yet to close, do not affect the gross lease estimate of UPIIP or prospective resources. The Glencore Farm-in provides for the Company to sell a one-third interest in its interests and liabilities in Chad, in exchange for Glencore Energy International (Glencore) carrying sunk and future costs of the Company, to a maximum of $330,747,000. The evaluated interest is net of the transfer of a one-third interest to Glencore and accounts for the capital costs carried by Glencore.

This report has been prepared for the Company for the purpose of business and other financial requirements including filing a prospectus in connection with admission of the Company's common shares to the premium listing segment of the Official List of the Financial Conduct Authority. This evaluation has been prepared in accordance with resource and reserves definitions, standards and guidelines contained in the Petroleum Resources Management System (PRMS) of the Society of Petroleum Engineers (SPE). This report is in accordance with the requirements of the European Securities and Markets Authority as presented in paragraphs 131 to 133 (i) published in March 2011 and the Prospectus Rules of the Financial Conduct Authority of the United Kingdom.

GLJ Petroleum Consultants

We note that GLJ's evaluation of prospective oil resources was prepared including an adjustment for minimum economic field size. Solution gas is currently not considered marketable, therefore no prospective volumes for solution gas have been included.

There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

Yours very truly,

GLJ PETROLEUM CONSULTANTS LTD.



Leonard L. Herchen, P. Eng.
Vice President

LLH/jem
Attachments

INDEPENDENT PETROLEUM CONSULTANTS' CONSENT

The undersigned firm of Independent Petroleum Consultants of Calgary, Alberta, Canada has prepared an independent evaluation of the **Griffiths Energy International Inc.'s** (the "Company") Chadian oil resources and hereby gives consent to the use of its name and to the said estimates. The effective date of the evaluation is **December 31, 2012.**

In the course of the evaluation, the Company provided GLJ Petroleum Consultants Ltd. personnel with basic information which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. The Company has provided a representation letter confirming that all information provided to GLJ Petroleum Consultants Ltd. is correct and complete to the best of its knowledge.. In conducting the evaluation, nothing came to GLJ Petroleum Consultants Ltd.'s attention that would suggest that information provided by the Company was not complete and accurate. GLJ Petroleum Consultants Ltd. reserves the right to review all calculations referred to or included in this report and to revise the estimates in light of erroneous data supplied or information existing but not made available which becomes known subsequent to the preparation of this report.

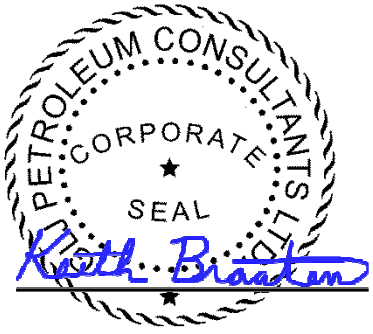
The accuracy of any reserves, resources and production estimate is a function of the quality and quantity of available data and of engineering interpretation and judgment. While resources presented herein are considered reasonable, the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward.

PERMIT TO PRACTICE
GLJ PETROLEUM CONSULTANTS LTD.

Signature: _____

Date: January 29, 2013

PERMIT NUMBER: P 2066
The Association of Professional Engineers
and Geoscientists of Alberta



GENERAL

GLJ Petroleum Consultants Ltd. (GLJ) has evaluated a total of 83 prospects located in the Republic of Chad, within lands currently held by Griffiths Energy International Inc. (Griffiths). The Griffiths' Production Sharing Contracts (PSCs) include blocks within two geologic basins in Chad, the Doba and Doseo Basins. These basins are separated by an area termed the Borogop uplift which is a large inversion anticlinal trend and is part of the Central African Rift trend, a continental plate boundary crossing through Chad from the Sudan to Cameroon. The majority of the prospects and leads are structural anomalies identified on 2D seismic lines expected to be prospective in one or more of the Cretaceous C, D and E Sands. The effective date of the evaluation is December 31, 2012. Map 1 presents the prospects identified by Griffiths, those evaluated by GLJ and the relevant blocks in Chad.

The Cretaceous provides multiple reservoirs which have been tested in the two basins. The Cretaceous E interval consists of sediments sourced by axial transport from the east. Sediments drained generally to the west towards Doba and probably ultimately exited the Doba Basin through the Yola Arm of the Benue trough and then south towards the Benue forming the proto Niger Delta. The top of the E Sequence is bounded by the D Sequence Boundary (DSB) and is generally a very good high amplitude seismic marker. The Cretaceous D Sequence is a continuation of the same non-marine fluvial and deltaic lacustrine facies as observed in the E Sequence. The Cretaceous C Sequence overlies the D Sequence and is also composed of fluvial, lacustrine, and deltaic sediments. However, in some cases, stratigraphic opportunities and basement anomalies have been identified.

Griffiths has inherited a large 2D seismic database; in the order of 17,000 linear kilometres of data. In general the data has been acquired so that the majority of lines over a prospect are dip lines. A recent 3D seismic program was acquired in the Mangara Area and results of that 3D was incorporated in this analysis where possible.

Griffiths has discoveries at four fields (Mangara, Badila, Kibea and Maku) that were considered important geological analogies for a significant number of the evaluated prospects.

The evaluation was initiated in May 2012 and completed by January 2013. Estimates of prospective resources were generally prepared using well information, engineering, geophysical and geological information provided by Griffiths and available as of December 31, 2012. Pertinent interest and offset well data such as drillstem tests, workovers, pressure surveys,

production tests, etc., were provided by Griffiths or were obtained from other operators, public records or GLJ non-confidential files.

In addition, Griffiths provided land and fiscal parameters, and high level capital and operating cost expectations. Griffiths has confirmed that, to the best of its knowledge, all information provided to GLJ is correct and complete as of the effective date.

This evaluation has been prepared in accordance with resource and reserves definitions, procedures, and standards contained in the Society of Petroleum Engineering's Petroleum Resources Management System (PRMS). The definitions are presented in the Resource and Reserves Definitions section of this report.

All prospective resource evaluations imply a set of commodity price assumptions. In this case, GLJ used its January 1, 2013 price forecast. It is presented in the Product Price and Market Forecasts section of this report.

GEOPHYSICS

This is a general review of the prospects that have been identified on the lands acquired by Griffiths. It deals with factors that GLJ deem to be important in the assessment of a prospect, but it does not analyze specific prospects.

The area is covered with an extensive grid of seismic data, approximately 17,000 linear kilometres in total. The density of seismic lines is variable and has been acquired to assess areas that were considered to be prospective. To this end, the seismic crews revisited some areas and shot infill lines in order to more accurately map the structures. Some of the prospects interpreted have a relatively tight grid: 1 kilometre by 1.5 kilometre line spacing, whereas other areas have grids that are 4 kilometre by 4 kilometre. The quality of the data appears to be determined more by the vintage of the acquisition rather than the area of the acquisition. There are many examples of data within the same area with one set being relatively poor in quality and a contiguous set being fairly good quality.

The seismic headers to which GLJ has access have little information as to the acquisition and processing of the data contained in them; therefore, GLJ is not aware of the processing sequence used or the year the data was acquired. It has been assumed that data has been improved in time by the modification of the acquisition parameters and by improvements in processing techniques. Ranges of amplitude spectrums on various data sets have been measured; they range from 10 to 26 Hz, with a dominant frequency of approximately 19 Hz, to a high of 14 to 54 Hz, with a dominant frequency of approximately 35 Hz. The relatively low frequency data tends to be of an older vintage; it can be used in time and depth mapping but is not as useful for stratigraphic work. The relatively narrow bandwidth for some of the data is a result of the method of acquisition, with areally large shot and receiver arrays being employed in order to cancel shot generated noise. These large arrays discriminate against the higher frequencies resulting in the data having a low dominant frequency. If detailed stratigraphic work is undertaken in a specific area then the low frequency data should be omitted from the analysis.

The Esso exploration effort and the current Griffiths work has concentrated largely on the identification and analysis of mapped structures. GLJ has not had access to the Esso seismic work but it is presumed that the structural prospects identified are similar to those worked on by Griffiths. There are some stratigraphic plays that Griffiths has done some mapping and analysis. These are considered more conceptual at present and would rank latter in the drilling cycle. Prior to drilling one of the stratigraphic plays some semi-regional mapping of the depositional history

and variations in isopachs should be undertaken. This would entail integrating seismic mapping with geological concepts. The creation of a depositional model would help in the understanding of the basin and lend support to a drilling location. To a large extent this has not been undertaken, presumably because of time constraints.

GLJ was supplied with a number of prospects, some of which were ranked as being more prospective. GLJ was supplied with the interpreted seismic data, usually with a single key event identified and mapped; quite often this event was the top of the Lower Cretaceous, or the C Flooding Surface (CFS). If the prospect was contiguous to an existing well, the seismic-to-well ties were checked at the well and the correlation to the area under study made. If no well existed near a prospect being analyzed then either a jump correlation or a long distance correlation was made. For some of the most isolated prospects this proved difficult. The velocity used in depth conversion was obtained at the nearest well. If the prospect was of low relief (i.e. limited time differences across the structure) a single velocity was used in the depth conversion. If the structure had significant two-way time (TWT) relief to mapped closure then an acceleration factor was calculated and employed. The formula used was $V_z=V_o+KZ$, where V_z is the velocity at the mapped event, V_o is the initial velocity, with 1500 m/sec being used, K is the acceleration factor in m/sec/sec and Z is the depth at the event. The effect of applying the acceleration factor is to slightly depress the outer limits of the structure, and reducing the volumetrics.

In the Doseo Block there is an area of volcanic activity, where numerous sills are present. These sills have been identified by the strong seismic amplitude associated with them. Most are parallel bedding but some can be seen to be cross-bedding. Work in areas around the world has shown that the thermal alteration associated with the sills is confined to a limited distance. Therefore the area where the sills occur can be considered prospective. Some of the structures in this area are high amplitude, with large fault displacements at the Base Tertiary event and with faulting interpreted to the surface. The integrity of many of the traps in this area is questioned because of the perceived lack of a vertical seal. On the eastern side of the Mahimi prospect there is a seismically dead zone within the core of the structure. This could be the result of diapiric action, within an early Cretaceous shale or a dike penetrating into the section. In either case the potential reservoir draping over the high will have been reduced.

GEOLOGY

Regional Setting

The Griffiths PSCs are on blocks within two geologic basins in Chad, the Doba and Doseo Basins (Map 1). These basins are separated by an area termed the Borogop Uplift which is a large inversion anticlinal trend, and which is part of the Central African Rift trend, a continental plate boundary crossing through Chad from the Sudan to Cameroon.

The Doba and Doseo Basins were formed as rift basins in the Early Cretaceous (84-144 Ma). The Doba Basin formed as a series of northwest to southwest trending half grabens. The Doseo Basin formed as a large asymmetrical basin with a northwest to southeast oriented rift faulted relay series. The Borogop Uplift is the steeply lifted basin edge fault zone, which separates the basins.

Geologic sedimentation occurred during the Aptian through Conician when the two basins underwent a thermal sag phase, which provided accommodation space for sediments. It is noteworthy that thermal events also include a phase of sill intrusion dating 97-100 Ma. Sills have been found and sampled along the northern flank of the Doseo Basin.

The Cretaceous provides the multiple reservoirs, which have been tested in the two basins. The Cretaceous E interval consists of sediments sourced by axial transport from the east. Sediments drained generally to the west towards the Doba and probably ultimately exited the Doba Basin through the Yola arm of the Benue Trough and then onto the south to the Benue forming the proto Niger Delta. The top of the E Sequence is bounded by the D Sequence Boundary (DSB) and is generally a very good high amplitude seismic marker. The Cretaceous D Sequence is a continuation of the same non-marine fluvial and deltaic lacustrine facies as observed in the E Sequence. The Cretaceous C zone overlies the D Sequence and is also composed of fluvial, lacustrine, and deltaic sediments. Stratigraphic opportunities and basement anomalies have been identified as well.

Most of the traps evaluated for prospective resources consisted of both four-way closures and three-way dip closures with fault seal. Source rocks are provided by the prevalent lacustrine sediments deposited throughout both basins. Stratigraphic traps have also been evaluated in three prospects as well as two conceptual plays in structurally high basement.

PROSPECTIVE RESOURCES

Low, best and high estimate prospective resources have been assigned to 83 prospects using a probabilistic analysis. The following is a discussion of the methodology and geological and engineering input parameters utilized in the probabilistic models. A summary of input parameters used in the models are included in Appendices A through H, and presented as Table 1 for each prospect (i.e. Appendix A – Tables A.1.1 through A.1.6).

Methodology Overview

Two different methods were used to evaluate the prospects: the Primary Method and the Analogy Method. The two methods were utilized to manage the evaluation resources available to complete the project by assessing approximately 90 percent of the total unrisked prospective resources in a detailed manner. The Primary Method required a complete review and evaluation of the seismic data, geological mapping and probabilistic analysis for the individual prospects; whereas with the Analogy Method, GLJ audited Griffiths' maps and modified some P10, P50, and P90 areas to be consistent with our practices for determining the spill point.

Primary Method

The Primary Method workflow evolved from the start of the project to its current finalized form. A series of parts define this workflow as follows: analogy selection from four discovered fields to evaluate the number of sand packages present in a particular zone, parameters from analogous wells to provide inputs for the stochastic model, depth mapping to determine area-volume data, geological risking, and finally the probabilistic analysis, which includes running a Monte Carlo simulation on all input parameters to calculate the undiscovered petroleum initially-in-place (UPIIP) and risked and unrisked prospective resources at the P90, P50 and P10 certainty levels.

The number of potential sand packages and prospective reservoirs present were based on GLJ's analysis of the Mangara, Badila, Maku and Kibea Fields also referred to as the analog pools for the DOB, DOI and Chari East Doseo Blocks, respectively. For prospects in and around the DOH Block, the N'Donambo-1 and Damalla-1 wells were used to determine the number of potential prospective sand packages. For prospects not directly related to or in close proximity to one of the four analogous fields, an average of C, D, and E Sands from both the Doba and Doseo Basins was used with consideration for depositional environment similarities. These prospects include Ouham C to I, Mahimi, Sahr, and Emok.

GLJ's petrophysical analysis evaluated the interpreted data provided by Griffiths. Using GLJ established cutoffs and Griffiths formation tops, the porosity, water saturation, and net-to-gross ratio for a given sand package was determined. These data form part of the inputs into the probabilistic analysis.

Depth maps were generated for each prospect and area-volume data were extracted from each prospect for input into the stochastic model.

Geologic risk is often evaluated though a combination of eight essential geological parameters. It is based on the existence of a hydrocarbon accumulation of any size. The following is a brief description of the geological parameters assessed in risking prospects:

Source Rock – There must a rock that contains kerogen or organic matter that will generate hydrocarbons under the correct temperatures.

Thermal History – The source rock must have been buried to depths that are sufficient to heat the kerogen to the point of producing hydrocarbons.

Migration – There must be a migration path to permit the hydrocarbons to move away from the source rock.

Reservoir Rock – There must be a porous rock that could contain the hydrocarbons, and eventually permit them to be produced at commercial rates.

Seal – This reservoir rock must be capped by a tight rock (top seal) to prevent the hydrocarbons from migrating up section. In some cases, a fault plane may form part of the lateral trapping mechanism. This fault must be sealed in order to prevent hydrocarbons from escaping out of the trap. The risk that such faults are not sealing must be considered.

Trap – In the case of structure traps, the reservoir rock must exist in a configuration that prevents the lateral migration of hydrocarbons. This can be formed by either dip closure, by sealing faults, or by a combination of the two.

Timing – All of the above must occur in the correct sequence. The hydrocarbons must be expelled after the creation of the migration paths, the reservoir rock and the seals.

Preservation – The hydrocarbons must be preserved from destruction. This can occur due to the introduction of bacteria that can biodegrade the oil into an unrecoverable substance such as bitumen, or thermal cracking that can reduce liquid hydrocarbons into pyrobitumen. The introduction of acid gases such as CO_2 or N_2 must be considered.

In some regions of more mature basins, some of these risks can be removed (i.e. the existence of source rocks, the correct thermal history). However, in true wildcat exploration all of these parameters must be considered and sometimes can be combined. For example, Source Rock, Thermal History and Migration can be grouped together and called 'Hydrocarbon Charge'. In this evaluation, GLJ has combined four geological parameters as play or dependent risks: Source

Rock, Maturity, Migration, and Timing. With occasional exceptions, the following three geological parameters were considered statistically independent risks: Seal, Reservoir, Rock and Trap. However, all prospects in the DOB and DOI Blocks as well as Bepara have seal as a play risk and therefore were not considered statistically independent. A probability is assigned to each of these geological parameters. The product of all of these parameters provides the exploration risk, or the geological risk (Pg); that is, the chance of finding any hydrocarbons. Geological risking is presented in Appendices A through H, as Table 2 for each prospect.

Lastly, GLJ uses @Risk software by Palisade Decision Tools to run the Monte Carlo simulation that provides a resulting probability distribution for UPIIP and unrisked prospective resources from which the P10, P50, and P90 outcomes for any given prospect are calculated. Input variables can be defined individually using various statistical distributions, which can be truncated at high and low ends to avoid extreme and unrealistic data points. The geological input variables include gross thickness, maximum hydrocarbon column, percent fill, reservoir coverage, net-to-gross ratio, porosity, oil saturation, and geological risk. Engineering inputs include initial oil formation volume factor and recovery factor. The hydrocarbon column is the only value not entered as a distribution as it is calculated from the depth structure mapping as the vertical section from the crest of a structure to its spill point. Refer to Appendices A through H to review input parameters, distribution type and truncation values, which are included as Table 1 and separated for each prospect.

Analogy Method

Analogy Method prospects were evaluated in the Chari East Doseo, DOB, DOH, and DOI Blocks using the depth structure maps provided by Griffiths. P10 and P90 areas were examined visually on the maps to determine if the interpretation was reasonable. If P10 and P90 areas were determined to be consistent with GLJ methodologies, a GLJ/Griffiths ratio of 1.0 was applied to the areas supplied by Griffiths. If the spill point was deemed inconsistent with GLJ methodologies, GLJ/Griffiths factors were determined for the P90, P50 and P10 areas. GLJ/Griffiths ratios were determined by a combination of both visual inspection of Griffiths' depth structure mapping, and by applying average GLJ/Griffiths ratios from nearby prospects that GLJ evaluated in detail within the same block. Geological risk was assigned by use of analogs within the same block that exhibited similar geologic controls.

To define distributions for UPIIP and unrisked prospective resources for prospects evaluated using the analogy method, results from prospects that were fully evaluated by GLJ were utilized. From those prospects, the ratios for UPIIP and unrisked prospective resources per unit area were

calculated at the P90, P50 and P10 certainties. The areal assignments for each prospect were then multiplied by the average ratio for their respective block to obtain distribution inputs at the P90, P50 and P10 certainties. In certain instances, these ratios were adjusted to account for the sand intervals being targeted and/or whether a nearby prospect was considered to be directly analogous.

Following this, the inputs for unrisked UPIIP and prospective resources were utilized in a lognormal distribution and truncated at the P01 and P99 certainties. A Monte Carlo simulation was then run for a total of 10,000 iterations, from which the P90, P50 and P10 realizations were calculated.

Input parameters for each prospect evaluated using the Analogy Method are included in Appendices A through F, and presented as Table 3.

DOB Prospects (Mangara Related)

Mangara related prospects are located in the Doba Basin. The prospects identified in Figure 1 below were evaluated as the Primary Method. Also noted in Figure 1 are the zones evaluated per prospect, each of the hydrocarbon columns associated with these zones, the trap type, and the map number. Refer to Appendix A, Table A.3 for the Analogy Method evaluated prospects, which include: Lore, Mankola, and Sourma East. The hydrocarbon columns were determined from seismic mapping based on the assessment of spill point for each structural closure. In some cases, a hydrocarbon column for one particular sand horizon was used in the probabilistic analysis of the subsequent sands as indicated below with an asterix (*). The number of potential sand packages present in all of these Mangara related prospects were determined from the three Mangara wells drilled in the Mangara Field. Gross thicknesses were also determined as an average of the correlated sand packages. The C Sand succession consists of three sand packages where Griffiths' C1a and C1b Sequence are combined as one in GLJ's analysis. The D Sand succession consists of three packages and the E and succession has two sand packages that have bookable reservoirs.

Prospect Name	Zone Evaluated	Maximum HC Column (m)	Trap Type	Map Number
Dono	C	30.3	A fault bounded three-way structural closure.	2
	D	25.4		3
	E	25.4		3*

Prospect Name	Zone Evaluated	Maximum HC Column (m)	Trap Type	Map Number
Krim	C	77.8	A fault bounded three-way closure, smaller in areal extent than Mangara but at approximately the same time and depth.	4
	D	68.1		5
	E	88.5		6
Langue Lead	C	11.8	Possible anticline with four-way closure. Too few seismic lines available to define closure.	7*
	D	11.8		7
	E	11.8		7
Sourma	C	37.7	An anticline with four-way closure at the C and D levels. E Sand pinches out against basement high.	8
	D	10.7		9
	E	81.5		10
Togoro East	C	58.3	A fault bounded three-way closure.	11
	D	62.0		12
	E	62.0		12*
Togoro West	C	54.6	A three-way dip closure, with a northwest plunge and a fault truncation to the east and south.	13
	D	64.0		14
	E	64.0		14*

Figure 1: DOB Block Prospects (Mangara Related)

DOI Prospects (Badila Related)

Badila related prospects are also located within the Doba Basin. The prospects identified in Figure 2 below were evaluated as the Primary Method. Also noted in Figure 2 are the zones evaluated per prospect, each of the hydrocarbon columns associated with these zones, the trap type, and the map number. Refer to Appendix B, Table B.3 for the Analogy Method prospects evaluated, which include: Badila Deep, Badila East, Badila South, Bebann, Bodjama North, and Mankou. The hydrocarbon columns were determined from seismic mapping based on the assessment of spill point for each structural closure. In some cases, a hydrocarbon column for one particular sand horizon was used in the probabilistic analysis of the subsequent sands as indicated below with an asterix (*). The number of potential sand packages present in these Badila-related prospects was determined from the Badila-1 well in the Badila Field. Gross thicknesses for each of the sands were also determined on the Badila-1 well. The C Sand succession consists of four sand packages. The D Sand succession consists of nine packages and the E Sand succession has two sand packages that have bookable reservoirs.

Prospect Name	Zone Evaluated	Maximum HC Column (m)	Trap Type	Map Number
Bitanda	D	155.9	A four-way structural closure, with a northeast plunge and a basement truncation to the southwest.	15
	E	140.9		16

Prospect Name	Zone Evaluated	Maximum HC Column (m)	Trap Type	Map Number
Bodjama	C	13.0	An anticline with four-way closure.	17
	D	18.4		18
	E	18.7		19
Maikoro	D	15.7	A possible three-way closure with a fault truncation to the southwest. Seismic coverage is poor.	20
Manlia Northeast	C	22.9	A possible anticline with four-way closure. Seismic coverage is poor.	21
	D	42.3		22
Manlia Southwest	E	48.4	A possible anticline with four-way closure. Seismic coverage is poor.	23
Maybor	C	19.2	A three-way dip closure at the D and E levels with a fault truncation to the west and south, respectively.	24
	D	55.5		25
	E	170.5		26
Ngebe	C	113.0	A three-way dip closure, with a north plunge and a fault truncation to the west, east, and south.	27
	D	82.4		28
	E	89.7		29

Figure 2: DOI Block Prospects (Badila Related)

Again the most significant differences between GLJ and Griffiths work are based on seismic interpretation and spill point selection. Specifically at Bitanda however, GLJ has not assigned any prospective resources to the C Sand because GLJ has interpreted it as having no closure. In addition, GLJ has only assigned D Sands at Maikoro for the same reason. Regarding the Manlia prospect, GLJ has divided the prospect into two because one well would not penetrate both closures in all three horizons.

DOH Prospects (N'Donambo, Damalla Related)

The DOH prospects are located in the Doba Basin. The prospects identified in Figure 3 below were evaluated as the Primary Method. Also noted in Figure 3 are the zones evaluated per prospect, each of the hydrocarbon columns associated with these zones, the trap type, and the map number. Refer to Appendix C, Table C.3 for the Analogy Method evaluated prospects, which include: Bekondijo and Beongo. The hydrocarbon columns were determined from seismic mapping based on the assessment of spill point for each structural closure. In some cases, a hydrocarbon column for one particular sand horizon was used in the probabilistic analysis of the subsequent sands as indicated below with an asterix (*). The number of potential sand packages present in the DOH prospects were determined from the Damalla-1 well for the M, A, and B Sand series and the N'Donambo-1 well for the C and D Sand series. Gross thicknesses for each of the sands were also determined from these two wells. The M Sand succession consists of three sand

packages, the A Sand has two, the B Sand has three, the C Sand has four and the D Sand succession has two sand packages that have bookable reservoirs.

Prospect Name	Zone Evaluated	Maximum HC Column (m)	Trap Type	Map Number
Bedaya	C	44.2	A possible three-way closure with a fault truncation to the north. Seismic is sparse.	30*
	D	44.2		30
Bessama	C	7.8	A possible three-way closure with a fault truncation to the northeast. Seismic is sparse.	31*
	D	7.8		31
Beyara	A	90.1	A possible three-way closure with a fault truncation to the northeast. Seismic is sparse.	32*
	M	90.1		32
	B	90.1		32
Damalla	A	112.9	A faulted anticline at the A, M, and B levels. A three-way closure with a fault truncation to the northeast for the C and D Sands.	33*
	M	112.9		33
	B	115.9		34
	C	146.6		35
	D	171.1		36
Damalla East	A	173.8	A three-way closure with a fault truncation to the south at the A, M, B, C and D levels.	37*
	M	173.8		37
	B	241.8		38
	C	261.1		39
	D	228.1		40
Damalla Southeast	A	112.9	A faulted anticline at all levels.	41*
	M	112.9		41
	B	115.9		42
	C	136.2		43
	D	171.1		44
Derguigui	C	32.7	A possible anticline with four-way closure. Seismic is sparse.	45*
	D	32.7		45
N’Donambo	A	130.4	A faulted anticline with four-way closure.	46
	B	130.4		46
	C	130.4		46
	D	130.4		46*
Yei North	A	23.5	A possible anticline with four-way closure. Seismic is sparse.	47*
	M	23.5		47
	B	23.5		47
Yei South	C	16.3	A possible anticline with four-way closure. Seismic is sparse.	48*
	D	16.3		48

Figure 3: DOH Block Prospects (N'Donambo-Damalla Related)

These prospects contain the largest number of potential sands evaluated in this analysis. A total of fourteen sands were run in the Monte Carlo simulation for each of these prospects.

The Damalla-1 and N'Donambo-1 wells are important data points from the DOH prospect analysis. These two wells were drilled near the top of the structures they define and were abandoned. For the Damalla-1 well, no well report exists, however, an Esso summary report states the well was drilled off structure. The N'Donambo-1 well did have some oil shows but the deliverability is questionable.

The Yei prospect was separated in two as the closures for all five horizons did not stack. The Yei North prospect consists of the M, A, and B successions and the Yei South prospect includes the C and D series of sands.

Chari East Doseo Prospects

The prospects located in the Chari East Doseo Block span a large area and in some cases do not have analog pools in close proximity. Therefore an average across the entire Doseo Basin has been used for the C, D and E Sand successions.

The prospects identified in Figure 4 below were evaluated as the Primary Method. Also noted in Figure 4 are the zones evaluated per prospect, each of the hydrocarbon columns associated with these zones, the trap type, and the map number. Refer to Appendix D, Table D.3 for the Analogy Method evaluated prospects, which include: Bahr, Bangono, Bouna, Chari G, Dokolo A and B, Gondey, Goro, Hori, Kou, Mahimi B and D, Sahr, Tega East A and B and Tega South. The hydrocarbon columns were determined from seismic mapping based on the assessment of spill point for each structural closure. In some cases, a hydrocarbon column for one particular sand horizon was used in the probabilistic analysis of the subsequent sands as indicated below with an asterix (*). The number of potential sand packages present in this grouping of prospects were determined from an average number of sands in the C, D, and E Sequences collected from Kibea-1, Sako North-1, Maku-1 and Maku-2, and Tega-1. Gross thicknesses were also determined as an average of the correlated sand packages from these wells. Thus, the C Sand succession consists of four sand packages, the D Sand succession consists of three packages and the E Sand succession also has three sand packages that have bookable reservoirs.

Prospect Name	Zone Evaluated	Maximum HC Column (m)	Trap Type	Map Number
Baouda East	C	70.7	An anticline with four-way closure.	56*
	D			56
	E			56
Baouda West	C	61.4	An anticline with four-way closure.	56
	D			56
	E			56
Emok	C	438.8	A three-way dip closure with four fault truncations trending west to east, to the north of the prospect.	57
Mahimi	C	366.2	An anticline with four-way closure.	58
	D	249.0		59
	E	365.5		60
Maku	D	194.2	A faulted anticline with four-way closure.	61
	E	193.7		62
Maku NE	C	112.8	The structure is on the same structural trend as Maku and is separated by a structurally low, unfaulted area. An anticline with four-way closure defines the trap.	63 a*
	D	112.8		63 b
	E	112.8		63 c
Maku SW	C	260.5	The structure is on the same structural trend as Maku and is separated by a structurally low, unfaulted area. An anticline with four-way closure defines the trap.	64 a*
	D	260.5		64 b
	E	260.5		64 c
Ouham C	C	51.1	A four-way closed anticline.	65*
	D	51.1		65
	E	51.1		65
Ouham D	D	56.4	A four-way closed anticline.	65
	E	56.4		65
Ouham F	C	72.2	A four-way closed anticline.	65
	D	72.2		65
	E	72.2		65
Ouham G	C	19.1	A four-way closed anticline.	65
	D	19.1		65
	E	19.1		65

Prospect Name	Zone Evaluated	Maximum HC Column (m)	Trap Type	Map Number
Ouham I	C	100.1	A four-way closed anticline.	65
	D	100.1		65
	E	100.1		65
Ouham I West	C	46.8	A four-way closed anticline.	65
	D	46.8		65
	E	46.8		65
Sahr	C	216.0	A faulted anticline with four-way closure.	66*
	D	216.0		66
	E	216.0		66
Sako North	C	45.0	An anticline with four-way closure.	67
	D	45.2		68
	E	113.0		69
Sako North B	C	52.3	An inversion anticline with three-way dip closure and fault bounded to the northeast.	70
	D	51.8		71
	E	45.8		72
Sako SE	C	301.5	An anticline with four-way closure.	73*
	D	301.5		73
	E	301.5		73
Tega East A Tega Northeast Tega East A and Tega Northeast	C	104.1	An anticline with four-way closure.	74
	D	100.7		75
	E	35.0		76

Figure 4: Chari East Doseo Block Prospects

GLJ has not assigned prospective resource numbers to the Ouham J prospect, instead have replaced it with the Ouham I West prospect. The Ouham prospects are very close to surface and all but the Ouham I prospect are overlain by a fault envelope which likely breaches any potential seals for the C, D, and E Sands. The Sahr prospect also has faults which come to surface, likely resulting in breached seals and trap failure. The geologic risk for the Sahr and Ouham prospects reflects these factors.

The Sako North-1 well was drilled at Griffiths' Sako North prospect and penetrated the C and D Sands. GLJ has assigned prospective resources updip of that well for the C and D Sands and assigned resources to the entire structure for the E Sands as they were not penetrated by the Sako North-1 well. This accounts for the major variances in prospective resource volumes between GLJ and Griffiths. For the Sako North B prospect the selection of the spill point for the C, D, and E Sands is the largest difference. At the Sako Southeast prospect, GLJ's seismic mapping depicts

a significantly larger volume than Griffiths. The hydrocarbon column is three times larger, which likely accounts for some of the dissimilarity in resource volumes.

The resource assignments for the Tega prospects have used the Tega-1 well as a control point for these prospects. The Tega East A prospect has been assigned C and E Sands, whereas the Tega Northeast prospect has been assigned D and E Sands. This is based on Griffiths' interpretation of proximity of the C Sands to sediment source and the presence of turbidites in the D and E Sands.

Chari East Doseo Prospects (Kibea-Sako Related)

Kibea and Sako related prospects are located in the Chari East Doseo Basin. The prospects identified in Figure 5 below were evaluated as the Primary Method. Also noted in Figure 5 are the zones evaluated per prospect, each of the hydrocarbon columns associated with these zones, the trap type, and the map number. Refer to Appendix E, Table E.3 for the Analogy Method evaluated prospects, which include: Baouda Northeast, Baouda Northwest, Beche C, Kibea North, and Sako South. The hydrocarbon columns were determined from seismic mapping based on the assessment of spill point for each structural closure. The number of potential sand packages that are present in these Beche prospects and the gross thicknesses of these sands were determined from the Kibea-1 well. The C Sand succession consists of five sand packages, the D Sand succession consists of two packages and the E Sand succession has six sand packages that have bookable reservoirs.

Prospect Name	Zone Evaluated	Maximum HC Column (m)	Trap Type	Map Number
Beche	C	140.0	A three-way dip closure whose axis trends northeast to southwest, with a southwest plunge and a fault truncation to the north and northeast.	50
	D	236.0		51
	E	247.2		52
Beche B	C	242.0	A three-way dip closure with a fault truncation to the north.	53
	D	437.7		54
	E	373.7		55

Figure 5: Chari East Doseo Block Prospects (Kibea-Sako Related)

There are no significant differences in seismic mapping and spill point selection as seen in other blocks.

Borogop Prospects

The Bepara prospect is located within the Borogop Block (Map 49). It has been evaluated for C and D Sands only. To determine the potential bookable reservoirs, an average between Badila-1

and N'Donambo-1 was used since these are the two closest analogous wells. Four C Sand packages and six D Sand packages have been run in the stochastic model.

The depth structure map reveals a maximum hydrocarbon column of 158.3 metres and the trap type is a faulted anticline. GLJ interprets the fault as penetrating the surface, which increases the geological risk due to the potential for trap and seal failure.

Refer to Appendix F, Table F.3 for the Analogy Method evaluated prospects, which include: Bouna and Kou.

Stratigraphic Plays

Three stratigraphic play-types have been evaluated in this analysis (Figure 6). They are regarded as conceptual play-types because there are no analogies currently discovered in the Doba and Doseo Basins.

The Daba prospect is defined by up-dip and lateral pinch-outs of turbidite sandstones. The targeted Lower Cretaceous reservoir possibly consists of mass gravity transport sandstones relying heavily on facies changes for trapping configurations and seal. GLJ's greatest concern includes the lack of well data to tie and correlate seismic horizons across the Doseo Basin at this depth.

The Koumogo prospect has both a stratigraphic and structural component consisting of a four-way closure potentially enhanced by levee channel complexes, and slope and basin fans. It has been assessed by way of low, most likely and high case scenarios. The low case considers only the four-way structural closure as possible. The most likely case suggests a thick sand lobe and a four-way structural closure as prominent. The high case considers only a stratigraphic component that combines two lobes, which likely consist of a levee channel complex and slope or basin fans. As with many stratigraphic traps, the up-dip sealing potential of the facies change and the presence of reservoir sand within the levee complex are critical to the accumulation of hydrocarbons.

The Mainon prospect targets Lower Cretaceous C Sands of deltaic origin. The secondary shoreface anomaly target has not been evaluated. The size of the deltaic complex has been defined by a seismic anomaly that extends approximately 30 kilometres in length and about 2 to 3 kilometres in width. The development of reservoir sand and the sealing potential of up-dip shales are of primary importance to the development of a hydrocarbon accumulation.

Prospect Name	Zone Evaluated	Maximum HC Column (m)	Trap Type	Map Number
Daba	Lower Cretaceous		Updip and lateral pinchouts of sandstones.	77
Koumogo	Lower Cretaceous	56.5 56.5 56.5	Structural and stratigraphic trap at most likely case includes thick sand succession and four-way closure.	78 79 80
Mainon	Lower Cretaceous		Prograding delta anomaly as depicted on seismic.	81

Figure 6: Stratigraphic Plays

These stratigraphic plays are relatively high risk from a geological perspective, however, if successful, they can define depositional fairways of significant importance within the Doseo Basin.

Basement Plays

Two basement play concepts have been evaluated in the DOI Block, Badila West and Bendo Bindo (Figure 7). There are no current discovered analogies within the Doba Basin, however, there are global examples of basement-related discoveries in Venezuela, North Africa, USA, Yemen, Vietnam, and Indonesia. The Badila West prospect possibly resembles the Cuu Long Basin in Vietnam and the Bendo Bindo prospect likely resembles the "granite wash" plays along the Kansas Uplift and the Armadillo Arch in the USA.

The Badila West prospect relies on the development of primary and secondary porosity, and connectivity of fracture networks to define viability within the basement granite. The Badila-1 and Bao-1 wells were drilled to basement. The cuttings descriptions only tagged about 50 metres of the granite and do not reveal any information about porosity or fracturing. Regarding source rocks, it was assumed that the lacustrine sediments are adequate source rocks for the granite provided they are in contact with it or a migration pathway is present. The shales present within the C, D, and E successions would likely form adequate seals for any hydrocarbon accumulations within the granite to be contained.

The reservoir of the Bendo Bindo prospect likely resides in a clastic apron eroded from structurally high basement granite whereby weathering and mechanical reworking of the granite forms the favourable reservoir. Source and seal are provided by the lacustrine shales overlying the granite.

Prospect Name	Zone Evaluated	Maximum HC Column (m)	Trap Type	Map Number
Badila West	Basement	346.3	Thrust associated, fracture-dominated basement high.	82
Bendo Bindo	Basement	155.7	"Granite wash" – reservoir in clastic apron eroded from basement high. A three-way closure against fault.	82

Figure 7: Basement Plays

These basement plays require a significant amount of data to better define the porosity, fracturing, and presence of hydrocarbons within the granitic lithology.

Analogy Method Prospects

Refer to Figure 8 for a summary of the Analogy Method prospects evaluated, their location, their closest field analogy, whether their area was modified at one or more inputs, and their map number. GLJ did not map each individual prospect but has audited the mapping provided by Griffiths as described in the Methodology Overview section. The maps in this report have been modified from Griffiths' original presentations. The modifications revolve around annotations only. The structures and closures shown have not been changed on the maps and reflect Griffiths' interpretations.

Prospect Name	Block	Closest Field Analogy	GLJ Modified Area	Map Number
Badila Deep	DOI	Badila	No	83
Badila East	DOI	Badila	Yes	84 a, b
Badila South	DOI	Badila	Yes	85 a, b
Bahr	Chari East Doseo	Kibea	No	86
Bangono	Chari East Doseo		No	87
Baouda Northeast	Chari East Doseo	Kibea	Yes	88
Baouda Northwest	Chari East Doseo	Kibea	No	89
Bebann	DOI	Badila	Yes	90
Beche C	Chari East Doseo	Kibea	Yes	91 a, b, c
Bekondijo	DOH	N'Donambo	Yes	92
Beongo	DOH	N'Donambo	Yes	93 a, b
Bodjama North	DOI	Badila	No	94 a, b, c
Bouna	Borogop		No	95
Chari G	Chari East Doseo		No	96
Dokolo A	Chari East Doseo		Yes	97
Dokolo B	Chari East Doseo		Yes	97
Gondey	Chari East Doseo		Yes	98
Goro	Chari East Doseo		Yes	99
Hori	Chari East Doseo		Yes	100
Kibea North	Chari East Doseo	Kibea	No	101 a, b, c

Prospect Name	Block	Closest Field Analogy	GLJ Modified Area	Map Number
Kou	Borogop		No	102
Lore	DOB	Mangara	No	103
Mahimi B	Chari East Doseo	Maku	No	104
Mahimi D	Chari East Doseo	Maku	No	104
Mankola	DOB	Mangara	No	105
Mankou	DOI	Badila	No	106 a, b
Sako South	Chari East Doseo	Kibea	No	107
Sourma East	DOB	Mangara	Yes	108 a, b
Tega East A	Chari East Doseo	Maku	Yes	109
Tega East B	Chari East Doseo	Maku	No	109
Tega South	Chari East Doseo	Maku	No	109

Figure 8: Analogy Method Prospects

A brief explanation of differences in specific prospects is described below for the various blocks.

Where spill points for analogy method prospects were generally determined to be consistent with the method in which GLJ would have evaluated these prospects, a GLJ/Griffiths ratio of 1.00 was applied.

In some cases, there were significant differences in how GLJ would evaluate spill points. For example in the Chari East Doseo Block, the P10 area for the Hori prospect was determined to be too large and a GLJ/Griffiths ratio of 0.70 was determined by visual inspection. The P50 and P90 ratios were also adjusted accordingly to provide consistency in the distribution, 0.60 and 0.50 respectively. The P10 area for the Gondey prospect was also determined to be too large by incorporating two anticline structures, and was reduced using a GLJ/Griffiths ratio of 0.40. P50 and P90 areas for the Hori prospect remained unchanged. The area for the Baouda Northeast prospect was reduced by 60 percent to account for the block boundary, and the inability of one well to likely drain the northern portion of the closure. In the Beche C prospect, the P10 area was reduced by 20 percent, and P50 by 10 percent as they were deemed too large. The P90 area was left unchanged. Only the P10 area in the Dokolo A prospect was reduced by 10 percent to account for the slight inaccuracy of the spill point outline on the southeastern edge of the closure. In the Goro prospect, the P10 and the P50 areas were modified to a GLJ/Griffiths ratio of 0.50 and 0.75, respectively to account for the lack of closure at the Griffiths defined structure contour. In the Tega East A prospect, the P10 area was reduced by 50 percent to incorporate one structural closure.

In the DOH Block, the P10 area for Beongo prospect was determined to be too large as it incorporated at least two separate structures as well as the area beyond what has been interpreted as a sealing fault. A 15 percent reduction to the P10 area was therefore applied, while P50 and

P90 areas were adjusted to be consistent with the reduced P10 area. A ratio of 0.80 was applied to the P10 area for the Bekondijo prospect as it did not show closure on any particular structure contour. The P50 area was subsequently adjusted to 0.90, and the P90 area was left unchanged.

The Lore and Mankola prospects, located in the DOB Block, were both consistent with GLJ's methodologies and left unchanged. The P10 area for Sourma East prospect, however, was determined to be too large, and the GLJ/ Griffiths ratio of 0.40 was applied. P50 and P90 areas were left unchanged.

In the DOI Block, the P10 area for the Badila East prospect did not follow structure contours, therefore a GLJ/Griffiths ratio of 0.50 was determined by visual inspection. The P90 area was left unchanged and the P50 area was reduced to 0.75 of Griffiths' value. The C and E horizons at the Bodjama North prospect were deemed non-prospective as the C horizon is downdip from the Bodjama spill point and there is no significant closure on the E horizon. Mapping for the D horizon was consistent with GLJ's methodology and the areas were left unchanged. At the Badila South prospect, only the P10 area associated with the prospect well location was evaluated. The current interpretation shows little to no displacement along the fault that the secondary P10 area closes on. A GLJ/ Griffiths factor of 0.65 was applied to the single P10 area. A ratio of 0.80 was applied to the P50 area, and the P90 area was left unchanged. The Bebann prospect areas were reduced significantly to a GLJ/Griffiths ratio of 0.20 for the three distributions. In GLJ's view, this prospect should be separated into three individual ones to better define a volume where a prospective resource assignment can be made. Only the central closure was evaluated.

Engineering Inputs – Primary Method

Oil Formation Volume Factor

For each iteration of the Monte Carlo simulation, the oil formation volume factor was calculated independently for each formation utilizing the Standing correlation, which uses values for initial reservoir pressure, reservoir temperature, bubble point pressure, API gravity, initial gas-oil-ratio (GOR), and gas specific gravity. Possible values for API gravity, initial pressure and temperature GOR, gas gravity were probabilistically modeled based on observed oil properties and expected prospect depth.

Initial Reservoir Pressure and Temperature

Pressure and temperature gradients were estimated utilizing measured data points from tested wells across both the Doba and Doseo Basins. The average gradients from these data points were found to be 0.433 psi/ft and 0.0133 °R/ft for pressure and temperature, respectively. An average surface temperature of 541 °R was assumed. Utilizing these gradients an average reservoir pressure and temperature was estimated at the mid-point of the formation as defined from GLJ's depth structure mapping and the iterative value for hydrocarbon column.

Bubble Point Pressure

This probabilistic analysis has incorporated varying levels of saturation for the prospective reservoirs. The bubble point pressure has been varied using a uniform distribution that ranges between 60 and 100 percent of the initial reservoir pressure. This distribution has been directly correlated with the API gravity.

API Gravity

The API gravity has been modeled based on measured data points from production tests across both basins. A normal distribution with a mean value of 34 °API and a standard deviation of 4.5 °API, truncated for reasonableness. API gravity was statistically correlated within sands of each individual prospect.

Initial Gas-Oil Ratio and Gas Specific Gravity

The initial GOR has been calculated using the Vasquez-Beggs correlation, which uses the reservoir temperature, API gravity, bubble point pressure and gas specific gravity, which was assumed to be 0.7.

Recovery Factor

The recovery factor has been modeled using a lognormal distribution with inputs of 10, 25 and 45 percent for the P90, P_{mean} and P10 cases respectively. This distribution was truncated at 5 and 50 percent and captures the range for primary and secondary recovery.

Minimum Economic Field Size (MEFS)

As discussed within the PRMS and associated guidelines, the probability of an accumulation being sufficiently large to be of commercial size can be included in the estimate of prospective resources. GLJ has chosen to present the prospective resources for each prospect after adjustment for minimum economic field size.

The minimum economic field size was estimated at 1.5 MMstb of recoverable oil. This estimate was derived assuming a small field development tied-in to a regional pipeline such as the Badila/Mangara/TOTCO pipeline currently under construction or the Kome-Kibea-Maku pipeline currently under evaluation by the Company. Volumetric and economic analysis was conducted to determine the probability of discovering the minimum commercial size ($P_c = P_{mefs} * P_g$). This risk is included in order to arrive at an estimate of the chance of success.

All evaluations for prospective resources carry within them an implied commodity price forecast. This evaluation assumes the commodity price forecast of GLJ effective October 1, 2012.

Table 1 summarizes the UPIIP and prospective resources subsequent to adjustment for minimum economic field size. Tables 2.1, 2.2 and 2.3 summarize subtotals by selected block. GLJ notes that such totals of unrisked and risked totals are arithmetically summed and are not statistically summed. GLJ also notes that the *Guidelines for Application of the Petroleum Resources Management System* published November 2011 states in Section 6.4 Aggregation over Resource Classes, "*However, a common practice to assess a total portfolio of assets is the use of "risked volumes" calculated by multiplying mean success volumes (MSVs) by the probability of success (POS). POS includes both geological chances (presence of hydrocarbons) and probability of commercial development. This is usually deemed to be applicable for a large portfolio of independent projects. In adding up such volumes, a meaningful total can be defined only by adding the risked volumes (POS x MSV) resulting in a statistical expectation of the recovery.*" The PRMS describes a "best estimate" as "*…the most realistic assessment of recoverable quantities.*" Summation of unrisked quantities implies that all prospects result in discoveries, a statistically unlikely event. This fact, as well as the definition of "best estimate" in the PRMS implies that summations of unrisked quantities should be used with caution. For these reasons, both risked and unrisked totals are presented.

Risk Analysis Results

For each prospect, a total of 10,000 iterations were run in order to define the probability distribution for the UPIIP. From this analysis the low, best and high estimates for undiscovered petroleum initially-in-place and prospective resources, corresponding to the P90, P50 and P10 realizations, respectively, were calculated.

GLJ's estimates for UPIIP, unrisked and risked prospective resources are summarized in Tables 1 and 2. These estimates are also summarized by block and included in Appendices A through F as Table 4, and in Appendices G and H as Table 3.

15°30'0"E 15°40'0"E 15°50'0"E 16°0'0"E 16°10'0"E 16°20'0"E 16°30'0"E 16°40'0"E 16°50'0"E 17°0'0"E 17°10'0"E 17°20'0"E 17°30'0"E 17°40'0"E 17°50'0"E 18°0'0"E 18°10'0"E 18°20'0"E 18°30'0"E 18°40'0"E 18°50'0"E 19°0'0"E 19°10'0"E 19°20'0"E 19°30'0"E 19°40'0"E 19°50'0"E 20°0'0"E 20°10'0"E 20°20'0"E 20°30'0"E

10°20'0"N 10°10'0"N 10°0'0"N 9°50'0"N 9°40'0"N 9°30'0"N 9°20'0"N 9°10'0"N 9°0'0"N 8°50'0"N 8°40'0"N 8°30'0"N 8°20'0"N 8°10'0"N 8°0'0"N 7°50'0"N 7°40'0"N 7°30'0"N

Cameroon

Chad

Central African Republic

Cameroon

Proposed Pipeline

Pipeline (To Cameroon)

Kibea North
Beche
Kibea
Beche B
Beche C
Baouda NE
Baouda NW
Baouda East
Baouda West
Sako North B
Sako North
Sako South
Sako SE
Bahr
Tega NE
Tega
Tega SW
Tega East A
Tega East B
Tega South
Maku NE
Maku
Maku DrE
Mahimi
Maka SW
Dokolo B
Dokolo A
Mahimi B
Sahr
Ouham J
Ouham E
Mahimi D
Ouham I
Ouham I West
Ouham D
Ouham F
Ouham C
Ouham G
Ouham H
Chari G
Gondey
Emok
Hori
Keumogo
Mainon
Bangong
Goro
Daba
Mainon
Boura
Kou
Bepara
Beyara
Bessama
Yel North
Yel South
Damala East
Derguigui
Damala
Bedaya
Damala SE
N'Doolandjo
Bekondro
Bedogo
Langue
Soumna
Soumna East
Lote
Kribi
Mangara
Tocoro East
Tocoro West
Dorop
Mankola
Mankou
Malkore
Bodjama North
Bendo Bando
Bodjama
Maybor
Bebann
Ngobe
Badila
Badila Deep
Badila West
Badila South
Bitanda
Badila East
Man Lia SW
Man Lia NE

Map 1
Prospect Map

Company: Griffiths Energy International Inc.
Property: Chad

Effective Date: December 31, 2012
Project: s1132107/comm01

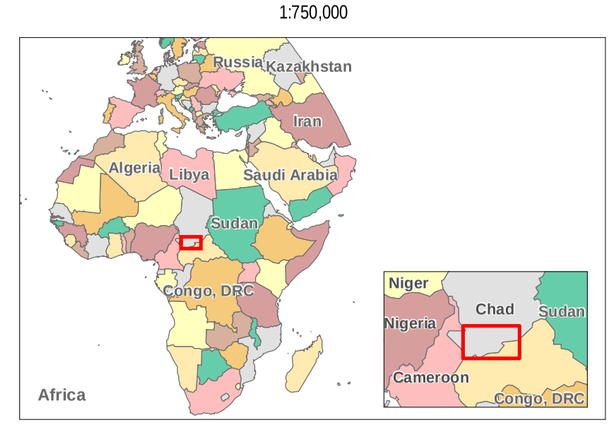
Legend

- RESERVES PROPERTIES
- 2D Seismic Line
- GLJ EVALUATED PROSPECTS
- UNEVALUATED PROSPECTS

N

0 20 40
Km

1:750,000



UTM Zone 33 North [12 E - 18 E Longitude]

GLJ Petroleum Consultants

TABLE 1
SUMMARY OF GROSS LEASE UNDISCOVERED PETROLEUM IN PLACE AND PROSPECTIVE RESOURCES
INCLUDING ADJUSTMENT FOR MINIMUM ECONOMIC FIELD SIZE
GRIFFITHS ENERGY INTERNATIONAL INC.
EFFECTIVE DATE: DECEMBER 31, 2012

	Gross Lease Unrisked UPIIP (MMSTB)							Gross Lease Unrisked Prospective Resources (MMSTB)				Gross Lease Partially Risked Prospective Resources (MMSTB)			
Prospect	P90	P50	Mean	P10	P_g	P_{mefs}	P_c	P90	P50	Mean	P10	P90	P50	Mean	P10
Badila Deep	1.9	3.1	7.4	16.1	0.36	0.27	0.10	1.7	3.1	5.1	11.4	0.2	0.3	0.5	1.1
Badila East	2.0	7.0	9.6	20.6	0.36	0.54	0.20	1.7	2.9	3.8	7.0	0.3	0.6	0.7	1.4
Badila South	8.5	18.9	34.2	76.8	0.36	1.00	0.36	2.0	4.5	8.8	20.0	0.7	1.6	3.2	7.3
Badila West	7.4	17.6	20.8	38.8	0.03	0.83	0.02	1.9	3.9	4.8	9.5	0.0	0.1	0.1	0.2
Bahr	4.5	17.1	44.6	110.9	0.40	0.77	0.31	2.0	5.9	14.4	35.4	0.6	1.9	4.5	11.0
Bangono	5.7	24.6	73.3	184.0	0.30	0.84	0.25	2.1	7.7	22.1	55.1	0.5	1.9	5.5	13.8
Baouda East	9.9	57.6	68.3	141.2	0.45	0.93	0.41	3.6	14.6	18.5	38.6	1.5	6.0	7.6	15.9
Baouda Northeast	1.8	5.2	10.1	23.8	0.45	0.43	0.19	1.7	3.3	5.1	10.9	0.3	0.6	1.0	2.1
Baouda Northwest	4.0	11.3	21.3	50.1	0.45	0.69	0.31	1.8	4.2	7.4	16.9	0.6	1.3	2.3	5.2
Baouda West	5.5	30.9	38.6	82.3	0.44	0.87	0.39	2.7	8.4	10.9	23.1	1.0	3.2	4.2	8.9
Bebann	1.8	3.8	6.2	13.5	0.36	0.31	0.11	1.6	2.6	3.5	6.7	0.2	0.3	0.4	0.7
Beche	14.5	100.3	196.1	508.6	0.41	0.95	0.39	4.4	26.2	50.7	132.3	1.7	10.3	19.9	52.0
Beche B	12.9	80.0	134.6	337.2	0.41	0.95	0.39	4.0	20.2	35.3	85.8	1.6	7.9	13.8	33.6
Beche C	2.5	21.4	118.5	287.9	0.41	0.73	0.30	2.2	10.4	41.5	103.4	0.7	3.2	12.6	31.3
Bedaya	0.1	0.7	0.8	1.8	0.10	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bekondijo	0.3	1.6	4.7	12.0	0.16	0.20	0.03	1.7	3.1	4.6	9.9	0.1	0.1	0.1	0.3
Bendo Bindo	2.0	5.3	6.3	11.2	0.03	0.29	0.01	1.6	2.1	2.4	3.6	0.0	0.0	0.0	0.0
Beongo	0.7	4.5	13.3	34.2	0.42	0.41	0.17	1.8	4.2	7.9	18.6	0.3	0.7	1.3	3.2
Bepara	65.8	149.7	157.9	261.9	0.16	1.00	0.16	14.4	35.7	39.4	68.1	2.4	5.8	6.4	11.1
Bessama	0.0	0.0	0.0	0.1	0.17	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Beyara	0.5	4.5	5.9	13.2	0.17	0.37	0.06	1.7	2.6	3.1	5.2	0.1	0.2	0.2	0.3
Bitanda	37.2	189.1	218.1	442.7	0.36	0.97	0.35	10.2	45.5	56.1	115.0	3.5	15.8	19.5	39.9
Bodjama	1.6	4.4	4.7	7.9	0.36	0.28	0.10	1.6	1.9	2.1	2.8	0.2	0.2	0.2	0.3
Bodjama North	3.4	8.1	15.2	34.9	0.36	0.60	0.22	1.7	3.5	5.8	12.9	0.4	0.8	1.3	2.8
Bouna	3.1	11.2	28.3	70.0	0.18	0.65	0.12	1.9	4.9	10.5	25.3	0.2	0.6	1.3	3.0
Chari G	5.7	25.4	78.1	196.1	0.30	0.84	0.25	2.1	7.9	23.5	58.8	0.5	2.0	5.9	14.7
Daba	17.0	86.5	174.9	395.3	0.08	0.97	0.07	4.1	19.9	46.0	109.6	0.3	1.5	3.4	8.1
Damalla	0.2	3.1	6.5	17.4	0.28	0.34	0.09	1.8	3.2	4.0	7.3	0.2	0.3	0.4	0.7
Damalla East	3.8	38.2	49.8	109.8	0.42	0.85	0.36	2.8	10.4	14.4	31.1	1.0	3.7	5.1	11.1
Damalla SE	0.6	12.0	24.7	65.8	0.29	0.61	0.18	2.0	6.3	9.6	21.4	0.4	1.1	1.7	3.7
Derguigui	0.2	1.6	2.0	4.1	0.18	0.04	0.01	1.6	1.9	2.0	2.6	0.0	0.0	0.0	0.0
Dokolo A	1.5	11.6	54.9	136.1	0.30	0.61	0.18	2.0	7.2	22.9	57.6	0.4	1.3	4.2	10.5
Dokolo B	8.6	37.6	83.8	208.7	0.30	0.93	0.28	2.4	9.6	22.6	56.4	0.7	2.7	6.3	15.6
Dono	4.8	11.4	11.9	19.6	0.36	0.81	0.29	1.9	3.2	3.4	5.5	0.6	0.9	1.0	1.6
Emok	12.4	132.2	172.7	396.5	0.19	0.93	0.17	4.7	29.3	46.0	105.5	0.8	5.1	7.9	18.2
Gondey	2.2	13.0	24.2	59.0	0.19	0.70	0.13	2.0	5.1	8.7	19.6	0.3	0.7	1.1	2.5
Goro	1.5	4.9	10.3	24.9	0.07	0.41	0.03	1.7	3.4	5.3	11.7	0.1	0.1	0.2	0.3
Hori	3.2	12.2	31.3	77.7	0.30	0.67	0.20	1.9	5.2	11.4	27.5	0.4	1.0	2.3	5.5
Kibea North	6.0	21.3	52.6	129.7	0.41	0.85	0.35	2.0	6.3	15.5	38.1	0.7	2.2	5.4	13.4
Kou	2.6	7.2	15.5	36.9	0.07	0.53	0.04	1.8	3.7	6.6	15.1	0.1	0.1	0.3	0.6
Koumogo	15.4	70.2	87.1	185.2	0.11	0.96	0.10	3.8	15.9	22.2	49.1	0.4	1.7	2.3	5.1

TABLE 1
SUMMARY OF GROSS LEASE UNDISCOVERED PETROLEUM IN PLACE AND PROSPECTIVE RESOURCES
INCLUDING ADJUSTMENT FOR MINIMUM ECONOMIC FIELD SIZE
GRIFFITHS ENERGY INTERNATIONAL INC.
EFFECTIVE DATE: DECEMBER 31, 2012

	Gross Lease Unrisked UPIIP (MMSTB)							Gross Lease Unrisked Prospective Resources (MMSTB)				Gross Lease Partially Risked Prospective Resources (MMSTB)			
Prospect	P90	P50	Mean	P10	P_g	P_{mefs}	P_c	P90	P50	Mean	P10	P90	P50	Mean	P10
Krim	9.2	36.7	40.0	75.2	0.36	0.93	0.34	3.1	9.2	10.7	20.4	1.1	3.1	3.6	6.9
Langue	0.7	3.5	4.2	8.6	0.06	0.23	0.01	1.6	2.3	2.6	4.0	0.0	0.0	0.0	0.1
Lore	2.3	6.4	9.5	20.6	0.36	0.51	0.19	1.7	2.9	3.9	7.6	0.3	0.5	0.7	1.4
Mahimi	6.5	78.4	128.3	327.1	0.30	0.89	0.26	3.7	20.9	36.1	88.4	1.0	5.5	9.5	23.4
Mahimi B	9.7	34.9	87.2	215.6	0.30	0.98	0.29	2.2	8.2	22.6	56.2	0.6	2.4	6.6	16.3
Mahimi D	3.0	11.5	30.2	75.2	0.30	0.65	0.19	1.9	5.1	11.3	27.4	0.4	1.0	2.2	5.3
Maikoro	0.1	0.5	0.6	1.2	0.20	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mainon	42.9	193.9	287.4	614.6	0.07	0.99	0.07	8.9	42.9	73.9	168.2	0.7	3.2	5.5	12.5
Maku D+E	6.1	62.8	107.5	275.1	0.39	0.89	0.35	3.4	18.2	30.6	76.1	1.2	6.3	10.6	26.3
Maku NE	6.3	48.7	74.6	176.4	0.30	0.89	0.27	2.8	13.1	20.9	48.7	0.8	3.5	5.6	13.0
Maku SW	4.8	50.6	84.1	212.2	0.30	0.87	0.26	2.9	14.4	24.2	58.4	0.8	3.7	6.3	15.1
Man Lia NE	0.1	1.1	1.5	3.4	0.10	0.03	0.00	1.5	1.7	1.8	2.3	0.0	0.0	0.0	0.0
Man Lia SW	0.5	5.3	5.8	11.3	0.02	0.36	0.01	1.6	2.7	2.9	4.9	0.0	0.0	0.0	0.0
Mankola	8.3	13.1	20.3	40.2	0.36	0.99	0.36	1.7	2.9	4.8	10.0	0.6	1.1	1.7	3.6
Mankou	8.6	15.5	39.7	88.8	0.36	1.00	0.36	1.9	3.7	10.2	23.2	0.7	1.3	3.6	8.3
Maybor	18.5	90.3	126.5	275.7	0.36	0.96	0.35	5.5	22.5	33.3	74.1	1.9	7.9	11.6	25.8
N'Donambo	0.1	1.0	1.5	3.7	0.24	0.04	0.01	1.6	1.8	2.0	2.7	0.0	0.0	0.0	0.0
Ngebe	36.9	123.1	144.7	277.2	0.36	0.99	0.36	8.9	30.0	36.7	72.8	3.2	10.8	13.1	26.1
Ouham C	2.8	21.4	30.7	70.4	0.17	0.78	0.13	2.3	6.6	9.4	20.0	0.3	0.9	1.2	2.6
Ouham D	2.8	30.3	40.2	91.6	0.11	0.82	0.09	2.4	8.9	12.0	26.8	0.2	0.8	1.1	2.4
Ouham E	29.0	180.1	267.9	655.4	0.11	0.97	0.11	8.0	38.9	68.3	173.9	0.9	4.2	7.3	18.7
Ouham F	0.1	2.4	3.5	8.5	0.17	0.19	0.03	1.6	2.2	2.6	4.0	0.1	0.1	0.1	0.1
Ouham G	0.2	1.2	1.4	3.1	0.17	0.02	0.00	1.6	1.7	1.9	2.5	0.0	0.0	0.0	0.0
Ouham H	0.3	2.1	2.7	5.8	0.17	0.11	0.02	1.6	2.0	2.2	3.1	0.0	0.0	0.0	0.1
Ouham I	2.1	20.7	32.4	79.5	0.17	0.75	0.13	2.3	7.1	10.3	22.1	0.3	0.9	1.3	2.8
Ouham I West	2.0	17.6	23.7	54.1	0.17	0.73	0.13	2.2	6.2	7.9	16.2	0.3	0.8	1.0	2.0
Sahr	1.5	20.0	35.2	93.5	0.17	0.73	0.12	2.2	7.7	12.0	27.4	0.3	0.9	1.5	3.4
Sako North	0.9	4.5	7.2	17.4	0.49	0.39	0.19	1.7	2.9	3.7	6.7	0.3	0.5	0.7	1.3
Sako North B	3.4	17.4	20.6	42.8	0.47	0.79	0.37	2.1	5.2	6.3	12.0	0.8	1.9	2.3	4.4
Sako SE	71.0	314.0	355.9	697.5	0.40	0.99	0.40	16.7	74.5	89.6	178.5	6.7	29.9	36.0	71.7
Sako South	2.5	10.7	31.8	79.7	0.40	0.62	0.25	1.9	5.4	12.6	30.8	0.5	1.4	3.2	7.8
Sourma	6.8	21.9	23.1	40.8	0.36	0.89	0.33	2.5	5.7	6.4	11.2	0.8	1.9	2.1	3.7
Sourma East	3.8	9.0	9.2	14.8	0.36	0.72	0.26	1.7	2.6	2.8	4.3	0.4	0.7	0.7	1.1
Tega East A	3.7	11.5	25.6	62.0	0.19	0.68	0.13	1.8	4.5	9.0	21.3	0.2	0.6	1.1	2.7
Tega East B	3.8	12.3	28.4	69.3	0.19	0.69	0.13	1.9	4.8	9.9	23.6	0.2	0.6	1.3	3.0
Tega NE	0.1	1.3	4.1	10.5	0.16	0.14	0.02	1.8	3.5	5.2	10.9	0.0	0.1	0.1	0.3
Tega South	1.9	9.3	31.6	79.4	0.19	0.58	0.11	1.9	5.5	13.4	33.2	0.2	0.6	1.4	3.6
Tega SW	0.0	0.5	1.5	4.2	0.14	0.06	0.01	1.6	2.5	2.9	4.8	0.0	0.0	0.0	0.0
Togoro East	26.2	62.7	67.5	114.3	0.36	0.99	0.36	6.0	15.5	17.0	29.8	2.1	5.6	6.1	10.7
Togoro West	17.5	39.8	41.3	67.1	0.36	0.98	0.36	4.1	9.8	10.5	17.7	1.5	3.5	3.8	6.3
Yei N	0.1	1.1	1.3	2.8	0.20	0.01	0.00	1.6	1.9	1.9	2.3	0.0	0.0	0.0	0.0
Yei S	0.0	0.2	0.3	0.6	0.15	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Arithmetic Sum	630.3	2,855.4	4,400.1	9,911.4				234.5	788.0	1,274.3	2,863.2	53.0	193.9	307.4	690.3

Note:
(1) UPIIP - Undiscovered Petroleum Initially in Place
(2) Truncated for Minimum Economic Field Size (MEFS) of 1.5 MMSTB
(3) UPIIP values do not include an implied truncation for minimum economic field size
(4) Please review discussion in Summary concerning summation of unrisked totals.

TABLE 2.1
MANGARA-BADILA PSC
SUMMARY OF GROSS LEASE UNDISCOVERED PETROLEUM IN PLACE AND PROSPECTIVE RESOURCES
INCLUDING ADJUSTMENT FOR MINIMUM ECONOMIC FIELD SIZE
GRIFFITHS ENERGY INTERNATIONAL INC.
EFFECTIVE DATE: DECEMBER 31, 2012

	Gross Lease Unrisked UPIIP (MMSTB)							Gross Lease Unrisked Prospective Resources (MMSTB)				Gross Lease Partially Risked Prospective Resources (MMSTB)			
Prospect	P90	P50	Mean	P10	P_g	P_{mefs}	P_c	P90	P50	Mean	P10	P90	P50	Mean	P10
Badila Deep	1.9	3.1	7.4	16.1	0.36	0.27	0.10	1.7	3.1	5.1	11.4	0.2	0.3	0.5	1.1
Badila East	2.0	7.0	9.6	20.6	0.36	0.54	0.20	1.7	2.9	3.8	7.0	0.3	0.6	0.7	1.4
Badila South	8.5	18.9	34.2	76.8	0.36	1.00	0.36	2.0	4.5	8.8	20.0	0.7	1.6	3.2	7.3
Badila West	7.4	17.6	20.8	38.8	0.03	0.83	0.02	1.9	3.9	4.8	9.5	0.0	0.1	0.1	0.2
Bebann	1.8	3.8	6.2	13.5	0.36	0.31	0.11	1.6	2.6	3.5	6.7	0.2	0.3	0.4	0.7
Bendo Bindo	2.0	5.3	6.3	11.2	0.03	0.29	0.01	1.6	2.1	2.4	3.6	0.0	0.0	0.0	0.0
Bitanda	37.2	189.1	218.1	442.7	0.36	0.97	0.35	10.2	45.5	56.1	115.0	3.5	15.8	19.5	39.9
Bodjama	1.6	4.4	4.7	7.9	0.36	0.28	0.10	1.6	1.9	2.1	2.8	0.2	0.2	0.2	0.3
Bodjama North	3.4	8.1	15.2	34.9	0.36	0.60	0.22	1.7	3.5	5.8	12.9	0.4	0.8	1.3	2.8
Dono	4.8	11.4	11.9	19.6	0.36	0.81	0.29	1.9	3.2	3.4	5.5	0.6	0.9	1.0	1.6
Krim	9.2	36.7	40.0	75.2	0.36	0.93	0.34	3.1	9.2	10.7	20.4	1.1	3.1	3.6	6.9
Langue	0.7	3.5	4.2	8.6	0.06	0.23	0.01	1.6	2.3	2.6	4.0	0.0	0.0	0.0	0.1
Lore	2.3	6.4	9.5	20.6	0.36	0.51	0.19	1.7	2.9	3.9	7.6	0.3	0.5	0.7	1.4
Maikoro	0.1	0.5	0.6	1.2	0.20	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Man Lia NE	0.1	1.1	1.5	3.4	0.10	0.03	0.00	1.5	1.7	1.8	2.3	0.0	0.0	0.0	0.0
Man Lia SW	0.5	5.3	5.8	11.3	0.02	0.36	0.01	1.6	2.7	2.9	4.9	0.0	0.0	0.0	0.0
Mankola	8.3	13.1	20.3	40.2	0.36	0.99	0.36	1.7	2.9	4.8	10.0	0.6	1.1	1.7	3.6
Mankou	8.6	15.5	39.7	88.8	0.36	1.00	0.36	1.9	3.7	10.2	23.2	0.7	1.3	3.6	8.3
Maybor	18.5	90.3	126.5	275.7	0.36	0.96	0.35	5.5	22.5	33.3	74.1	1.9	7.9	11.6	25.8
Ngebe	36.9	123.1	144.7	277.2	0.36	0.99	0.36	8.9	30.0	36.7	72.8	3.2	10.8	13.1	26.1
Sourma	6.8	21.9	23.1	40.8	0.36	0.89	0.33	2.5	5.7	6.4	11.2	0.8	1.9	2.1	3.7
Sourma East	3.8	9.0	9.2	14.8	0.36	0.72	0.26	1.7	2.6	2.8	4.3	0.4	0.7	0.7	1.1
Togoro East	26.2	62.7	67.5	114.3	0.36	0.99	0.36	6.0	15.5	17.0	29.8	2.1	5.6	6.1	10.7
Togoro West	17.5	39.8	41.3	67.1	0.36	0.98	0.36	4.1	9.8	10.5	17.7	1.5	3.5	3.8	6.3
Total: Mangara-Badila PSC	210.1	697.6	868.3	1,721.4				67.6	184.8	239.6	476.7	18.7	56.9	74.2	149.5

Note:
(1) UPIIP - Undiscovered Petroleum Initially in Place
(2) Truncated for Minimum Economic Field Size (MEFS) of 1.5 MMSTB
(3) UPIIP values do not include an implied truncation for minimum economic field size
(4) Please review discussion in Summary concerning summation of unrisked totals.

TABLE 2.2
DOH PSC
SUMMARY OF GROSS LEASE UNDISCOVERED PETROLEUM IN PLACE AND PROSPECTIVE RESOURCES
INCLUDING ADJUSTMENT FOR MINIMUM ECONOMIC FIELD SIZE
GRIFFITHS ENERGY INTERNATIONAL INC.
EFFECTIVE DATE: DECEMBER 31, 2012

	Gross Lease Unrisked UPIIP (MMSTB)							Gross Lease Unrisked Prospective Resources (MMSTB)				Gross Lease Partially Risked Prospective Resources (MMSTB)			
Prospect	P90	P50	Mean	P10	P_g	P_{mefs}	P_c	P90	P50	Mean	P10	P90	P50	Mean	P10
Bedaya	0.1	0.7	0.8	1.8	0.10	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bekondijo	0.3	1.6	4.7	12.0	0.16	0.20	0.03	1.7	3.1	4.6	9.9	0.1	0.1	0.1	0.3
Beongo	0.7	4.5	13.3	34.2	0.42	0.41	0.17	1.8	4.2	7.9	18.6	0.3	0.7	1.3	3.2
Bessama	0.0	0.0	0.0	0.1	0.17	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Beyara	0.5	4.5	5.9	13.2	0.17	0.37	0.06	1.7	2.6	3.1	5.2	0.1	0.2	0.2	0.3
Damalla	0.2	3.1	6.5	17.4	0.28	0.34	0.09	1.8	3.2	4.0	7.3	0.2	0.3	0.4	0.7
Damalla East	3.8	38.2	49.8	109.8	0.42	0.85	0.36	2.8	10.4	14.4	31.1	1.0	3.7	5.1	11.1
Damalla SE	0.6	12.0	24.7	65.8	0.29	0.61	0.18	2.0	6.3	9.6	21.4	0.4	1.1	1.7	3.7
Derguigui	0.2	1.6	2.0	4.1	0.18	0.04	0.01	1.6	1.9	2.0	2.6	0.0	0.0	0.0	0.0
N'Donambo	0.1	1.0	1.5	3.7	0.24	0.04	0.01	1.6	1.8	2.0	2.7	0.0	0.0	0.0	0.0
Yei N	0.1	1.1	1.3	2.8	0.20	0.01	0.00	1.6	1.9	1.9	2.3	0.0	0.0	0.0	0.0
Yei S	0.0	0.2	0.3	0.6	0.15	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total: DOH PSC	6.6	68.4	110.9	265.5				16.5	35.3	49.5	101.3	2.0	6.1	8.9	19.4

Note:
(1) UPIIP - Undiscovered Petroleum Initially in Place
(2) Truncated for Minimum Economic Field Size (MEFS) of 1.5 MMSTB
(3) UPIIP values do not include an implied truncation for minimum economic field size
(4) Please review discussion in Summary concerning summation of unrisked totals.

TABLE 2.3
CHARI EAST DOSEO-BOROGOP PSC
SUMMARY OF GROSS LEASE UNDISCOVERED PETROLEUM IN PLACE AND PROSPECTIVE RESOURCES
INCLUDING ADJUSTMENT FOR MINIMUM ECONOMIC FIELD SIZE
GRIFFITHS ENERGY INTERNATIONAL INC.
EFFECTIVE DATE: DECEMBER 31, 2012

	Gross Lease Unrisked UPIIP (MMSTB)							Gross Lease Unrisked Prospective Resources (MMSTB)				Gross Lease Partially Risked Prospective Resources (MMSTB)			
Prospect	P90	P50	Mean	P10	P_g	P_{mefs}	P_c	P90	P50	Mean	P10	P90	P50	Mean	P10
Bahr	4.5	17.1	44.6	110.9	0.40	0.77	0.31	2.0	5.9	14.4	35.4	0.6	1.9	4.5	11.0
Bangono	5.7	24.6	73.3	184.0	0.30	0.84	0.25	2.1	7.7	22.1	55.1	0.5	1.9	5.5	13.8
Baouda East	9.9	57.6	68.3	141.2	0.45	0.93	0.41	3.6	14.6	18.5	38.6	1.5	6.0	7.6	15.9
Baouda Northeast	1.8	5.2	10.1	23.8	0.45	0.43	0.19	1.7	3.3	5.1	10.9	0.3	0.6	1.0	2.1
Baouda Northwest	4.0	11.3	21.3	50.1	0.45	0.69	0.31	1.8	4.2	7.4	16.9	0.6	1.3	2.3	5.2
Baouda West	5.5	30.9	38.6	82.3	0.44	0.87	0.39	2.7	8.4	10.9	23.1	1.0	3.2	4.2	8.9
Beche	14.5	100.3	196.1	508.6	0.41	0.95	0.39	4.4	26.2	50.7	132.3	1.7	10.3	19.9	52.0
Beche B	12.9	80.0	134.6	337.2	0.41	0.95	0.39	4.0	20.2	35.3	85.8	1.6	7.9	13.8	33.6
Beche C	2.5	21.4	118.5	287.9	0.41	0.73	0.30	2.2	10.4	41.5	103.4	0.7	3.2	12.6	31.3
Bepara	65.8	149.7	157.9	261.9	0.16	1.00	0.16	14.4	35.7	39.4	68.1	2.4	5.8	6.4	11.1
Bouna	3.1	11.2	28.3	70.0	0.18	0.65	0.12	1.9	4.9	10.5	25.3	0.2	0.6	1.3	3.0
Chari G	5.7	25.4	78.1	196.1	0.30	0.84	0.25	2.1	7.9	23.5	58.8	0.5	2.0	5.9	14.7
Daba	17.0	86.5	174.9	395.3	0.08	0.97	0.07	4.1	19.9	46.0	109.6	0.3	1.5	3.4	8.1
Dokolo A	1.5	11.6	54.9	136.1	0.30	0.61	0.18	2.0	7.2	22.9	57.6	0.4	1.3	4.2	10.5
Dokolo B	8.6	37.6	83.8	208.7	0.30	0.93	0.28	2.4	9.6	22.6	56.4	0.7	2.7	6.3	15.6
Emok	12.4	132.2	172.7	396.5	0.19	0.93	0.17	4.7	29.3	46.0	105.5	0.8	5.1	7.9	18.2
Gondey	2.2	13.0	24.2	59.0	0.19	0.70	0.13	2.0	5.1	8.7	19.6	0.3	0.7	1.1	2.5
Goro	1.5	4.9	10.3	24.9	0.07	0.41	0.03	1.7	3.4	5.3	11.7	0.1	0.1	0.2	0.3
Hori	3.2	12.2	31.3	77.7	0.30	0.67	0.20	1.9	5.2	11.4	27.5	0.4	1.0	2.3	5.5
Kibea North	6.0	21.3	52.6	129.7	0.41	0.85	0.35	2.0	6.3	15.5	38.1	0.7	2.2	5.4	13.4
Kou	2.6	7.2	15.5	36.9	0.07	0.53	0.04	1.8	3.7	6.6	15.1	0.1	0.1	0.3	0.6
Koumogo	15.4	70.2	87.1	185.2	0.11	0.96	0.10	3.8	15.9	22.2	49.1	0.4	1.7	2.3	5.1
Mahimi	6.5	78.4	128.3	327.1	0.30	0.89	0.26	3.7	20.9	36.1	88.4	1.0	5.5	9.5	23.4
Mahimi B	9.7	34.9	87.2	215.6	0.30	0.98	0.29	2.2	8.2	22.6	56.2	0.6	2.4	6.6	16.3
Mahimi D	3.0	11.5	30.2	75.2	0.30	0.65	0.19	1.9	5.1	11.3	27.4	0.4	1.0	2.2	5.3
Mainon	42.9	193.9	287.4	614.6	0.07	0.99	0.07	8.9	42.9	73.9	168.2	0.7	3.2	5.5	12.5
Maku D+E	6.1	62.8	107.5	275.1	0.39	0.89	0.35	3.4	18.2	30.6	76.1	1.2	6.3	10.6	26.3
Maku NE	6.3	48.7	74.6	176.4	0.30	0.89	0.27	2.8	13.1	20.9	48.7	0.8	3.5	5.6	13.0
Maku SW	4.8	50.6	84.1	212.2	0.30	0.87	0.26	2.9	14.4	24.2	58.4	0.8	3.7	6.3	15.1

TABLE 2.3
CHARI EAST DOSEO-BOROGOP PSC
SUMMARY OF GROSS LEASE UNDISCOVERED PETROLEUM IN PLACE AND PROSPECTIVE RESOURCES
INCLUDING ADJUSTMENT FOR MINIMUM ECONOMIC FIELD SIZE
GRIFFITHS ENERGY INTERNATIONAL INC.
EFFECTIVE DATE: DECEMBER 31, 2012

	Gross Lease Unrisked UPIIP (MMSTB)							Gross Lease Unrisked Prospective Resources (MMSTB)				Gross Lease Partially Risked Prospective Resources (MMSTB)			
Prospect	P90	P50	Mean	P10	P_g	P_{mefs}	P_c	P90	P50	Mean	P10	P90	P50	Mean	P10
Ouham C	2.8	21.4	30.7	70.4	0.17	0.78	0.13	2.3	6.6	9.4	20.0	0.3	0.9	1.2	2.6
Ouham D	2.8	30.3	40.2	91.6	0.11	0.82	0.09	2.4	8.9	12.0	26.8	0.2	0.8	1.1	2.4
Ouham E	29.0	180.1	267.9	655.4	0.11	0.97	0.11	8.0	38.9	68.3	173.9	0.9	4.2	7.3	18.7
Ouham F	0.1	2.4	3.5	8.5	0.17	0.19	0.03	1.6	2.2	2.6	4.0	0.1	0.1	0.1	0.1
Ouham G	0.2	1.2	1.4	3.1	0.17	0.02	0.00	1.6	1.7	1.9	2.5	0.0	0.0	0.0	0.0
Ouham H	0.3	2.1	2.7	5.8	0.17	0.11	0.02	1.6	2.0	2.2	3.1	0.0	0.0	0.0	0.1
Ouham I	2.1	20.7	32.4	79.5	0.17	0.75	0.13	2.3	7.1	10.3	22.1	0.3	0.9	1.3	2.8
Ouham I West	2.0	17.6	23.7	54.1	0.17	0.73	0.13	2.2	6.2	7.9	16.2	0.3	0.8	1.0	2.0
Sahr	1.5	20.0	35.2	93.5	0.17	0.73	0.12	2.2	7.7	12.0	27.4	0.3	0.9	1.5	3.4
Sako North	0.9	4.5	7.2	17.4	0.49	0.39	0.19	1.7	2.9	3.7	6.7	0.3	0.5	0.7	1.3
Sako North B	3.4	17.4	20.6	42.8	0.47	0.79	0.37	2.1	5.2	6.3	12.0	0.8	1.9	2.3	4.4
Sako SE	71.0	314.0	355.9	697.5	0.40	0.99	0.40	16.7	74.5	89.6	178.5	6.7	29.9	36.0	71.7
Sako South	2.5	10.7	31.8	79.7	0.40	0.62	0.25	1.9	5.4	12.6	30.8	0.5	1.4	3.2	7.8
Tega East A	3.7	11.5	25.6	62.0	0.19	0.68	0.13	1.8	4.5	9.0	21.3	0.2	0.6	1.1	2.7
Tega East B	3.8	12.3	28.4	69.3	0.19	0.69	0.13	1.9	4.8	9.9	23.6	0.2	0.6	1.3	3.0
Tega NE	0.1	1.3	4.1	10.5	0.16	0.14	0.02	1.8	3.5	5.2	10.9	0.0	0.1	0.1	0.3
Tega South	1.9	9.3	31.6	79.4	0.19	0.58	0.11	1.9	5.5	13.4	33.2	0.2	0.6	1.4	3.6
Tega SW	0.0	0.5	1.5	4.2	0.14	0.06	0.01	1.6	2.5	2.9	4.8	0.0	0.0	0.0	0.0
Total: Chari East Doseo-Borogop PSC	413.7	2,089.4	3,421.0	7,924.5				150.5	567.8	985.3	2,285.3	32.2	130.9	224.3	521.5

Note:
(1) UPIIP - Undiscovered Petroleum Initially in Place
(2) Truncated for Minimum Economic Field Size (MEFS) of 1.5 MMSTB
(3) UPIIP values do not include an implied truncation for minimum economic field size
(4) Please review discussion in Summary concerning summation of unrisked totals.

SPE-PRMS RESOURCE AND RESERVES DEFINITIONS

GLJ Petroleum Consultants (GLJ) has prepared estimates of resources and reserves in accordance with the definitions and standards contained in the Petroleum Resources Management System (SPE-PRMS) prepared by the Society of Petroleum Engineers (SPE). The SPE-PRMS document was reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Evaluation Engineers (SPEE). The SPE-PRMS definitions and guidelines are similar to those contained in the Canadian Oil and Gas Evaluation (COGE) Handbook, which is referenced by the Canadian Securities Administrators in "National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities" and the standards normally used in Canadian oil and gas evaluations. Reserve and resource volumes derived under the SPE-PRMS and COGEH standards would not generally be materially different. The following are excerpts from the SPE-PRMS.

A. Fundamental Resource Definitions

Total Petroleum Initially-In-Place (PIIP) 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 (equivalent to discovered resources) is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

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 (equivalent to undiscovered resources) is that quantity of petroleum estimated, on 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.

B. Uncertainty Categories for Resource Estimates

The range of uncertainty of estimated recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

Low Estimate: There should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

Best Estimate: There should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

High Estimate: There should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines.

These same approaches to describing uncertainty may be applied to reserves, contingent resources, and prospective resources. There may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production. However, it is useful to consider and identify the range of potentially recoverable quantities independently of such risk or consideration of the resource class to which the quantities will be assigned.

C. Reserves Categories

The following summarizes the definitions of each Reserves category in terms of both the deterministic incremental approach and scenario approach and also provides the probability criteria if probabilistic methods are applied.

Proved Reserves
Proved reserves are those quantities of petroleum, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

Probable Reserves
Probable reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated proved plus probable reserves (2P).

In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

Possible Reserves
Possible reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of proved plus probable plus possible (3P) reserves, which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

Development and Production Status

Each of the reserves categories (proved, probable, and possible) may be divided into developed and undeveloped categories.

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

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

Developed Non-producing Reserves
Developed non-producing reserves include shut-in and behind-pipe reserves.

Undeveloped Reserves
Undeveloped reserves are quantities expected to be recovered through future investments.

D. Discovered and Commercial

Discovery Status

A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons.

In this context, “significant” implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume determined by the well(s) and for evaluating the potential for economic recovery.

Commercial Status

Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:

- Evidence to support a reasonable timetable for development;
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria;
- A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development;

- Evidence that the necessary production and transportation facilities are available or can be made available;
- Evidence that legal, contractual, environmental, governmental, and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.

E. Economic Status of Resource Estimates

Projects may be further characterized by their Economic Status. All projects classified as Reserves must be economic under defined conditions. Based on assumptions regarding future conditions and their impact on ultimate economic viability, projects currently classified as Contingent Resources may be broadly divided into two groups:

Marginal Contingent Resources are those quantities associated with technically feasible projects that are either currently economic or projected to be economic under reasonably forecasted improvements in commercial conditions but are not committed for development because of one or more contingencies.

Sub-Marginal Contingent Resources are those quantities associated with discoveries for which analysis indicates that technically feasible development projects would not be economic and/or other contingencies would not be satisfied under current or reasonably forecasted improvements in commercial conditions. These projects nonetheless should be retained in the inventory of discovered resources pending unforeseen major changes in commercial conditions.

Where evaluations are incomplete such that it is premature to clearly define ultimate chance of commerciality, it is acceptable to note that project economic status is “undetermined” (i.e., “contingent resources – economic status undetermined”).

PRODUCT PRICE AND MARKET FORECASTS
January 1, 2013

GLJ Petroleum Consultants has prepared its January 1, 2013 price and market forecasts as summarized in the attached Tables 1 and 2 after a comprehensive review of information. Information sources include numerous government agencies, industry publications, Canadian oil refiners and natural gas marketers. The forecasts presented herein are based on an informed interpretation of currently available data. While these forecasts are considered reasonable at this time, users of these forecasts should understand the inherent high uncertainty in forecasting any commodity or market. These forecasts will be revised periodically as market, economic and political conditions change. These future revisions may be significant. Operating cost and capital costs were inflated using the inflation rate forecast presented in Table 1.

It is expected that the produced crude can be sold to the West African crude market and will compete with other light crudes in that area. Based on the oil density and historical relationships between Brent crude and West African crudes, it was forecast that the received price for the crude will be 95 percent of Brent, less a forecast pipeline tariff of $6.50/bbl for the export pipeline through Cameroon and an additional ITA tariff. As the ITA tariff is a capital cost and volume dependent, different received prices are forecast in each reserves or resource class.

Table 1
GLJ Petroleum Consultants Ltd.
Crude Oil and Natural Gas Liquids
Price Forecast
Effective January 1, 2013

Year	Inflation %	Bank of Canada Average Noon Exchange Rate USD/CAD	NYMEX WTI Near Month Futures Contract Crude Oil at Cushing Oklahoma Constant 2013 $ USD/bbl	NYMEX WTI Near Month Futures Contract Crude Oil at Cushing Oklahoma Then Current USD/bbl	ICE Brent Near Month Futures Contract Crude Oil FOB North Sea Then Current USD/bbl	Light Sweet Crude Oil (40 API, 0.3%S) at Edmonton Then Current CAD/bbl	Bow River Crude Oil Stream Quality at Hardisty Then Current CAD/bbl	Lloyd Blend Crude Oil Stream Quality at Hardisty Then Current CAD/bbl	WCS Stream Quality at Hardisty Then Current CAD/bbl	Heavy Crude Oil Proxy (12 API) at Hardisty Then Current CAD/bbl	Light Crude Oil (35 API, 1.2%S) at Cromer Then Current CAD/bbl	Medium Crude Oil (29 API, 2.0%S) at Cromer Then Current CAD/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Spec Ethane CAD/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Edmonton Propane CAD/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Edmonton Butane CAD/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Edmonton Pentanes Plus CAD/bbl
2000	2.7	0.673	39.71	30.23	28.41	44.57	35.28	32.61	N/A	27.49	43.28	39.92	N/A	32.15	35.59	46.31
2001	2.5	0.646	33.27	26.00	24.87	39.44	27.69	23.47	N/A	16.77	35.22	31.58	N/A	31.92	31.25	42.48
2002	2.3	0.637	32.52	26.08	25.02	40.33	31.83	30.60	N/A	26.57	37.43	35.48	N/A	21.39	27.08	40.73
2003	2.8	0.716	37.90	31.07	28.47	43.66	32.11	31.18	N/A	26.26	40.09	37.55	N/A	32.14	34.36	44.23
2004	1.8	0.770	49.12	41.38	38.02	52.96	37.43	36.31	N/A	29.11	49.14	45.64	N/A	34.70	39.97	53.94
2005	2.2	0.826	65.93	56.58	55.14	69.02	44.73	43.03	43.74	34.07	62.18	56.77	N/A	43.04	51.80	69.57
2006	2.0	0.882	75.49	66.22	66.16	73.21	51.82	50.36	50.66	41.84	66.38	62.26	N/A	43.85	60.17	75.41
2007	2.2	0.935	80.90	72.39	72.71	77.06	53.64	52.03	52.38	43.42	71.13	65.71	N/A	49.56	61.78	77.38
2008	2.4	0.943	108.98	99.64	98.30	102.89	84.31	82.60	82.95	74.94	96.08	93.10	N/A	58.38	75.33	104.78
2009	0.4	0.880	65.95	61.78	62.50	66.32	60.18	58.40	58.66	54.46	63.84	62.96	N/A	38.03	48.17	68.17
2010	1.8	0.971	84.62	79.52	80.25	77.87	68.45	66.95	67.27	60.76	76.58	73.76	N/A	46.84	65.91	84.27
2011	2.9	1.012	99.46	95.12	110.86	95.53	78.58	76.84	77.14	67.64	92.35	88.33	N/A	53.66	74.42	104.17
2012	1.6	1.001	95.62	94.10	111.60	86.86	74.78	73.22	73.29	63.87	84.76	81.56	N/A	28.97	66.23	101.06
2013 Q1	2.0	1.000	90.00	90.00	110.00	82.50	67.65	66.00	66.20	55.10	80.85	77.55	10.63	28.88	63.53	99.00
2013 Q2	2.0	1.000	90.00	90.00	105.00	85.00	72.25	70.55	70.75	61.39	83.30	79.90	10.63	34.00	65.45	97.75
2013 Q3	2.0	1.000	90.00	90.00	102.50	85.00	72.25	70.55	70.75	62.66	83.30	79.90	11.25	34.00	65.45	93.50
2013 Q4	2.0	1.000	90.00	90.00	102.50	87.50	74.38	72.63	72.83	64.54	85.75	82.25	11.87	39.38	67.38	96.25
2013 Full Year	2.0	1.000	90.00	90.00	105.00	85.00	71.63	69.93	70.13	60.92	83.30	79.90	11.09	34.06	65.45	96.63
2014	2.0	1.000	90.69	92.50	102.50	91.50	77.77	75.94	76.15	68.36	87.84	84.18	12.65	45.75	70.46	97.91
2015	2.0	1.000	91.31	95.00	102.50	94.00	79.90	78.02	78.22	71.10	90.24	86.48	14.20	56.40	72.38	97.76
2016	2.0	1.000	91.88	97.50	102.50	96.50	82.03	80.09	80.29	73.02	92.64	88.78	15.75	57.90	74.31	100.36
2017	2.0	1.000	90.07	97.50	100.00	96.50	82.03	80.09	80.29	73.02	92.64	88.78	16.53	57.90	74.31	100.36
2018	2.0	1.000	88.31	97.50	100.00	96.50	82.03	80.09	80.29	73.02	92.64	88.78	17.46	57.90	74.31	100.36
2019	2.0	1.000	87.50	98.54	101.35	97.54	82.91	80.96	81.16	73.81	93.64	89.74	17.81	58.52	75.11	101.44
2020	2.0	1.000	87.50	100.51	103.38	99.51	84.58	82.59	82.79	75.32	95.53	91.55	18.18	59.71	76.62	103.49
2021	2.0	1.000	87.50	102.52	105.45	101.52	86.29	84.26	84.46	76.87	97.46	93.40	18.55	60.91	78.17	105.58
2022	2.0	1.000	87.50	104.57	107.55	103.57	88.03	85.96	86.16	78.44	99.43	95.28	18.92	62.14	79.75	107.71
2023+	2.0	1.000	87.50	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Historical futures contract price is an average of the daily settlement price of the near month contract over the calendar month.

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Table 2
GLJ Petroleum Consultants Ltd.
Natural Gas and Sulphur
Price Forecast
Effective January 1, 2013

	NYMEX Henry Hub Near Month Contract		Midwest		Alberta Plant Gate				Saskatchewan Plant Gate			British Columbia			Alberta
					Spot									Sulphur	
	Constant 2013 $	Then Current	Price @ Chicago Then Current	AECO/NIT Spot Then Current	Constant 2013 $	Then Current	ARP	Alliance	SaskEnergy	Spot	Sumas Spot	Westcoast Station 2	Spot Plant Gate	FOB Vancouver	Sulphur at Plant Gate
Year	USD/MMBtu	USD/MMBtu	USD/MMBtu	CAD/MMBtu	CAD/MMBtu	CAD/MMBtu	CAD/MMBtu	CAD/MMBtu	CAD/MMBtu	CAD/MMBtu	USD/MMBtu	CAD/MMBtu	CAD/MMBtu	USD/lt	CAD/lt
2000	5.66	4.32	3.96	5.80	6.46	4.93	4.50	N/A	4.79	4.99	4.15	5.06	4.88	38.14	13.59
2001	5.17	4.03	4.45	5.65	7.79	6.07	5.41	5.31	5.72	6.15	4.57	6.32	6.29	18.29	-14.67
2002	4.19	3.36	3.25	4.27	4.84	3.88	3.88	3.65	4.04	3.96	2.68	4.18	3.93	29.38	3.04
2003	6.67	5.47	5.46	6.73	7.92	6.49	6.13	6.15	6.41	6.57	4.66	6.45	6.32	59.81	39.83
2004	7.34	6.18	6.13	6.90	7.95	6.70	6.31	6.39	6.48	6.78	5.26	6.56	6.45	62.99	38.61
2005	10.48	9.00	8.24	9.06	9.80	8.42	8.30	8.27	8.36	8.48	7.13	8.22	8.12	63.50	33.77
2006	7.97	6.99	6.93	6.71	7.94	6.96	6.57	6.36	6.67	7.06	6.27	6.58	6.45	55.07	19.27
2007	7.95	7.12	6.83	6.59	7.19	6.43	6.20	5.86	6.18	6.55	6.52	6.40	6.25	81.66	42.03
2008	9.73	8.90	8.91	8.25	8.66	7.92	7.88	7.83	8.07	8.04	8.33	8.21	8.09	497.39	488.64
2009	4.45	4.16	4.05	4.16	4.26	3.98	3.85	3.23	3.87	4.04	3.91	4.17	4.04	57.06	24.57
2010	4.68	4.40	4.53	4.03	4.18	3.93	3.77	3.31	3.96	4.00	4.31	4.01	3.91	88.94	48.26
2011	4.21	4.03	4.21	3.62	3.67	3.51	3.46	2.84	3.57	3.67	3.93	3.39	3.31	217.16	171.93
2012	2.88	2.83	2.92	2.45	2.26	2.23	2.22	1.65	2.27	2.29	2.77	2.35	2.24	201.03	157.91
2013 Q1	3.60	3.60	3.70	3.24	3.05	3.05	2.99	2.40	3.09	3.16	3.70	3.04	2.87	175.00	132.00
2013 Q2	3.60	3.60	3.70	3.24	3.05	3.05	2.99	2.40	3.09	3.16	3.20	3.04	2.87	175.00	132.00
2013 Q3	3.80	3.80	3.90	3.42	3.23	3.23	3.17	2.60	3.27	3.34	3.40	3.22	3.05	175.00	132.00
2013 Q4	4.00	4.00	4.10	3.60	3.41	3.41	3.34	2.79	3.44	3.52	4.10	3.40	3.23	175.00	132.00
2013 Full Year	3.75	3.75	3.85	3.38	3.19	3.19	3.12	2.55	3.22	3.30	3.60	3.18	3.00	175.00	132.00
2014	4.17	4.25	4.35	3.83	3.56	3.63	3.56	3.03	3.66	3.74	4.10	3.63	3.45	150.00	107.00
2015	4.57	4.75	4.85	4.28	3.92	4.08	4.00	3.51	4.10	4.20	4.60	4.08	3.90	125.00	82.00
2016	4.95	5.25	5.35	4.72	4.27	4.53	4.44	3.99	4.54	4.64	5.10	4.52	4.34	125.00	82.00
2017	5.08	5.50	5.60	4.95	4.39	4.75	4.66	4.23	4.76	4.87	5.35	4.75	4.57	127.50	84.50
2018	5.25	5.80	5.90	5.22	4.55	5.02	4.92	4.52	5.02	5.14	5.65	5.02	4.83	130.05	87.05
2019	5.25	5.91	6.01	5.32	4.54	5.12	5.01	4.62	5.11	5.24	5.76	5.12	4.93	132.65	89.65
2020	5.25	6.03	6.13	5.43	4.55	5.22	5.12	4.74	5.22	5.35	5.88	5.23	5.04	135.30	92.30
2021	5.25	6.15	6.25	5.54	4.55	5.33	5.22	4.85	5.32	5.46	6.00	5.34	5.15	138.01	95.01
2022	5.25	6.27	6.37	5.64	4.55	5.44	5.33	4.97	5.43	5.56	6.12	5.44	5.25	140.77	97.77
2023+	5.25	+2.0%/yr	+2.0%/yr	+2.0%/yr	4.55	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate.
The plant gate price represents the price before raw gas gathering and processing charges are deducted.
AECO-C Spot refers to the one month price averaged for the year.

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APPENDIX A

DOB BLOCK (MANGARA RELATED)

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TABLE A.1.1
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
DONO PROSPECT

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	997	11,323	16,415	Custom			
Net/Gross Ratio	v/v	0.15	0.34	0.56	Normal	0.05	0.75	
Porosity (ϕ)	%	14.2	18.0	21.8	Normal	11.0	25.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.23	1.32	1.43	Custom	1.15	1.55	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	997	11,324	16,417	Custom			
Net/Gross Ratio	v/v	0.15	0.34	0.56	Normal	0.05	0.75	
Porosity (ϕ)	%	14.2	18.0	21.8	Normal	11.0	25.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.23	1.32	1.43	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	997	11,323	16,414	Custom			
Net/Gross Ratio	v/v	0.15	0.34	0.56	Normal	0.05	0.75	
Porosity (ϕ)	%	14.2	18.0	21.8	Normal	11.0	25.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.23	1.32	1.43	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,453	13,196	18,092	Custom			
Net/Gross Ratio	v/v	0.30	0.40	0.50	Normal	0.15	0.65	
Porosity (ϕ)	%	10.4	14.0	17.6	Normal	8.0	20.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.27	1.35	1.44	Custom	1.19	1.60	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE A.1.1
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
DONO PROSPECT

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,452	13,197	18,093	Custom			
Net/Gross Ratio	v/v	0.30	0.40	0.50	Normal	0.15	0.65	
Porosity (ϕ)	%	10.4	14.0	17.6	Normal	8.0	20.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.27	1.35	1.44	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,452	13,197	18,089	Custom			
Net/Gross Ratio	v/v	0.30	0.40	0.50	Normal	0.15	0.65	
Porosity (ϕ)	%	10.4	14.0	17.6	Normal	8.0	20.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.27	1.35	1.44	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1A								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,452	13,197	18,089	Custom			
Net/Gross Ratio	v/v	0.41	0.58	0.75	Normal	0.30	0.90	
Porosity (ϕ)	%	10.3	13.5	16.7	Normal	8.0	19.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.28	1.39	1.52	Custom	1.20	1.66	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,454	13,196	18,093	Custom			
Net/Gross Ratio	v/v	0.41	0.58	0.75	Normal	0.30	0.90	
Porosity (ϕ)	%	10.3	13.5	16.7	Normal	8.0	19.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.28	1.39	1.52	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE A.1.2
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
KRIM PROSPECT

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,051	38,388	64,596	Custom			
Net/Gross Ratio	v/v	0.15	0.34	0.56	Normal	0.05	0.75	
Porosity (ϕ)	%	14.2	18.0	21.8	Normal	11.0	25.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.19	1.27	1.36	Custom	1.12	1.47	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,054	37,538	62,299	Custom			
Net/Gross Ratio	v/v	0.15	0.34	0.56	Normal	0.05	0.75	
Porosity (ϕ)	%	14.2	18.0	21.8	Normal	11.0	25.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.19	1.27	1.36	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,049	37,608	62,174	Custom			
Net/Gross Ratio	v/v	0.15	0.34	0.56	Normal	0.05	0.75	
Porosity (ϕ)	%	14.2	18.0	21.8	Normal	11.0	25.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.19	1.27	1.36	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	401	5,737	9,080	Custom			
Net/Gross Ratio	v/v	0.30	0.40	0.50	Normal	0.15	0.65	
Porosity (ϕ)	%	10.4	14.0	17.6	Normal	8.0	20.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.23	1.31	1.39	Custom	1.15	1.53	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE A.1.2
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
KRIM PROSPECT

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	400	5,736	9,078	Custom			
Net/Gross Ratio	v/v	0.30	0.40	0.50	Normal	0.15	0.65	
Porosity (ϕ)	%	10.4	14.0	17.6	Normal	8.0	20.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.23	1.31	1.39	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	401	5,736	9,081	Custom			
Net/Gross Ratio	v/v	0.30	0.40	0.50	Normal	0.15	0.65	
Porosity (ϕ)	%	10.4	14.0	17.6	Normal	8.0	20.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.23	1.31	1.39	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1A								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	4,508	83,830	126,981	Custom			
Net/Gross Ratio	v/v	0.41	0.58	0.75	Normal	0.30	0.90	
Porosity (ϕ)	%	10.3	13.5	16.7	Normal	8.0	19.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.25	1.35	1.47	Custom	1.17	1.60	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	4,484	67,393	105,236	Custom			
Net/Gross Ratio	v/v	0.41	0.58	0.75	Normal	0.30	0.90	
Porosity (ϕ)	%	10.3	13.5	16.7	Normal	8.0	19.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.25	1.35	1.47	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE A.1.3
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
LANGUE PROSPECT

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,054	14,473	20,401	Custom			
Net/Gross Ratio	v/v	0.15	0.34	0.56	Normal	0.05	0.75	
Porosity (ϕ)	%	14.2	18.0	21.8	Normal	11.0	25.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.14	1.21	1.28	Custom	1.08	1.38	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,054	14,475	20,400	Custom			
Net/Gross Ratio	v/v	0.15	0.34	0.56	Normal	0.05	0.75	
Porosity (ϕ)	%	14.2	18.0	21.8	Normal	11.0	25.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.14	1.21	1.28	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,056	14,473	20,403	Custom			
Net/Gross Ratio	v/v	0.15	0.34	0.56	Normal	0.05	0.75	
Porosity (ϕ)	%	14.2	18.0	21.8	Normal	11.0	25.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.14	1.21	1.28	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,055	14,475	20,401	Custom			
Net/Gross Ratio	v/v	0.30	0.40	0.50	Normal	0.15	0.65	
Porosity (ϕ)	%	10.4	14.0	17.6	Normal	8.0	20.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.18	1.24	1.31	Custom	1.11	1.41	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE A.1.3
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
LANGUE PROSPECT

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,055	14,473	20,403	Custom			
Net/Gross Ratio	v/v	0.30	0.40	0.50	Normal	0.15	0.65	
Porosity (ϕ)	%	10.4	14.0	17.6	Normal	8.0	20.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.18	1.24	1.31	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,056	14,474	20,403	Custom			
Net/Gross Ratio	v/v	0.30	0.40	0.50	Normal	0.15	0.65	
Porosity (ϕ)	%	10.4	14.0	17.6	Normal	8.0	20.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.18	1.24	1.31	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1A								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,056	14,474	20,404	Custom			
Net/Gross Ratio	v/v	0.41	0.58	0.75	Normal	0.30	0.90	
Porosity (ϕ)	%	10.3	13.5	16.7	Normal	8.0	19.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.20	1.28	1.38	Custom	1.13	1.49	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,055	14,473	20,402	Custom			
Net/Gross Ratio	v/v	0.41	0.58	0.75	Normal	0.30	0.90	
Porosity (ϕ)	%	10.3	13.5	16.7	Normal	8.0	19.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.20	1.28	1.38	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE A.1.4
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
SOURMA PROSPECT

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,549	32,800	46,313	Custom			
Net/Gross Ratio	v/v	0.15	0.34	0.56	Normal	0.05	0.75	
Porosity (ϕ)	%	14.2	18.0	21.8	Normal	11.0	25.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.20	1.28	1.38	Custom	1.13	1.50	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,547	32,803	46,312	Custom			
Net/Gross Ratio	v/v	0.15	0.34	0.56	Normal	0.05	0.75	
Porosity (ϕ)	%	14.2	18.0	21.8	Normal	11.0	25.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.20	1.28	1.38	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,545	32,799	46,312	Custom			
Net/Gross Ratio	v/v	0.15	0.34	0.56	Normal	0.05	0.75	
Porosity (ϕ)	%	14.2	18.0	21.8	Normal	11.0	25.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.20	1.28	1.38	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	511	2,732	3,734	Custom			
Net/Gross Ratio	v/v	0.30	0.40	0.50	Normal	0.15	0.65	
Porosity (ϕ)	%	10.4	14.0	17.6	Normal	8.0	20.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.23	1.31	1.39	Custom	1.15	1.52	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE A.1.4
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
SOURMA PROSPECT

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	512	2,732	3,734	Custom			
Net/Gross Ratio	v/v	0.30	0.40	0.50	Normal	0.15	0.65	
Porosity (ϕ)	%	10.4	14.0	17.6	Normal	8.0	20.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.23	1.31	1.39	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	512	2,732	3,734	Custom			
Net/Gross Ratio	v/v	0.30	0.40	0.50	Normal	0.15	0.65	
Porosity (ϕ)	%	10.4	14.0	17.6	Normal	8.0	20.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.23	1.31	1.39	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1A								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	4,698	38,126	51,165	Custom			
Net/Gross Ratio	v/v	0.41	0.58	0.75	Normal	0.30	0.90	
Porosity (ϕ)	%	10.3	13.5	16.7	Normal	8.0	19.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.23	1.31	1.43	Custom	1.16	1.55	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	4,700	30,394	42,675	Custom			
Net/Gross Ratio	v/v	0.41	0.58	0.75	Normal	0.30	0.90	
Porosity (ϕ)	%	10.3	13.5	16.7	Normal	8.0	19.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.23	1.31	1.43	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE A.1.5
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
TOGORO EAST PROSPECT

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	6,128	67,964	102,138	Custom			
Net/Gross Ratio	v/v	0.15	0.34	0.56	Normal	0.05	0.75	
Porosity (ϕ)	%	14.2	18.0	21.8	Normal	11.0	25.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.23	1.32	1.44	Custom	1.16	1.56	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	6,130	67,960	102,148	Custom			
Net/Gross Ratio	v/v	0.15	0.34	0.56	Normal	0.05	0.75	
Porosity (ϕ)	%	14.2	18.0	21.8	Normal	11.0	25.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.23	1.32	1.44	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	6,135	67,967	102,150	Custom			
Net/Gross Ratio	v/v	0.15	0.34	0.56	Normal	0.05	0.75	
Porosity (ϕ)	%	14.2	18.0	21.8	Normal	11.0	25.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.23	1.32	1.44	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,434	69,337	109,821	Custom			
Net/Gross Ratio	v/v	0.30	0.40	0.50	Normal	0.15	0.65	
Porosity (ϕ)	%	10.4	14.0	17.6	Normal	8.0	20.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.30	1.39	1.50	Custom	1.19	1.68	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE A.1.5
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
TOGORO EAST PROSPECT

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,440	69,322	109,821	Custom			
Net/Gross Ratio	v/v	0.30	0.40	0.50	Normal	0.15	0.65	
Porosity (ϕ)	%	10.4	14.0	17.6	Normal	8.0	20.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.30	1.39	1.50	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,441	69,319	109,816	Custom			
Net/Gross Ratio	v/v	0.30	0.40	0.50	Normal	0.15	0.65	
Porosity (ϕ)	%	10.4	14.0	17.6	Normal	8.0	20.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.30	1.39	1.50	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1A								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,434	69,326	109,836	Custom			
Net/Gross Ratio	v/v	0.41	0.58	0.75	Normal	0.30	0.90	
Porosity (ϕ)	%	10.3	13.5	16.7	Normal	8.0	19.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.33	1.43	1.55	Custom	1.21	1.74	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,436	69,323	109,821	Custom			
Net/Gross Ratio	v/v	0.41	0.58	0.75	Normal	0.30	0.90	
Porosity (ϕ)	%	10.3	13.5	16.7	Normal	8.0	19.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.33	1.43	1.55	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE A.1.6
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
TOGORO WEST PROSPECT

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,910	44,998	61,934	Custom			
Net/Gross Ratio	v/v	0.15	0.34	0.56	Normal	0.05	0.75	
Porosity (ϕ)	%	14.2	18.0	21.8	Normal	11.0	25.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.23	1.32	1.44	Custom	1.16	1.56	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,911	44,996	61,797	Custom			
Net/Gross Ratio	v/v	0.15	0.34	0.56	Normal	0.05	0.75	
Porosity (ϕ)	%	14.2	18.0	21.8	Normal	11.0	25.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.23	1.32	1.44	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,907	44,994	61,768	Custom			
Net/Gross Ratio	v/v	0.15	0.34	0.56	Normal	0.05	0.75	
Porosity (ϕ)	%	14.2	18.0	21.8	Normal	11.0	25.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.23	1.32	1.44	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	5,202	44,111	59,489	Custom			
Net/Gross Ratio	v/v	0.30	0.40	0.50	Normal	0.15	0.65	
Porosity (ϕ)	%	10.4	14.0	17.6	Normal	8.0	20.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.28	1.36	1.45	Custom	1.19	1.59	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE A.1.6
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
TOGORO WEST PROSPECT

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	5,199	44,109	59,490	Custom			
Net/Gross Ratio	v/v	0.30	0.40	0.50	Normal	0.15	0.65	
Porosity (ϕ)	%	10.4	14.0	17.6	Normal	8.0	20.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.28	1.36	1.45	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	5,195	44,106	59,489	Custom			
Net/Gross Ratio	v/v	0.30	0.40	0.50	Normal	0.15	0.65	
Porosity (ϕ)	%	10.4	14.0	17.6	Normal	8.0	20.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.1	80.0	
B_{oi}	rbbl/STB	1.28	1.36	1.45	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1A								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	5,199	44,111	59,456	Custom			
Net/Gross Ratio	v/v	0.41	0.58	0.75	Normal	0.30	0.90	
Porosity (ϕ)	%	10.3	13.5	16.7	Normal	8.0	19.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.31	1.39	1.49	Custom	1.20	1.62	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	5,200	39,232	52,880	Custom			
Net/Gross Ratio	v/v	0.41	0.58	0.75	Normal	0.30	0.90	
Porosity (ϕ)	%	10.3	13.5	16.7	Normal	8.0	19.0	
Oil Saturation (S_o)	%	60.0	67.4	74.5	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.31	1.39	1.49	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE A.2.1
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
DONO PROSPECT

Field Dependent Risks					
Source	Maturity	Migration	Timing	Seal	$P_{Dependent}$
1.00	0.90	0.90	0.90	0.50	0.36

Independent Risks			
Formation	Reservoir	Trap	$P_{Independent}$
C1	0.70	0.80	0.56
C2	0.70	0.80	0.56
C3	0.70	0.80	0.56
D2	0.70	0.80	0.56
D3	0.70	0.80	0.56
D4	0.70	0.80	0.56
E1a	0.70	0.80	0.56
E2	0.70	0.80	0.56

Pg	**0.36**

TABLE A.2.2
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
KRIM PROSPECT

Field Dependent Risks					
Source	**Maturity**	**Migration**	**Timing**	**Seal**	**$P_{Dependent}$**
1.00	0.90	0.90	0.90	0.50	0.36

Independent Risks			
Formation	**Reservoir**	**Trap**	**$P_{Independent}$**
C1	0.70	0.80	0.56
C2	0.70	0.80	0.56
C3	0.70	0.80	0.56
D2	0.70	0.80	0.56
D3	0.70	0.80	0.56
D4	0.70	0.80	0.56
E1a	0.70	0.80	0.56
E2	0.70	0.80	0.56

Pg	**0.36**

TABLE A.2.3
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
LANGUE PROSPECT

Field Dependent Risks					
Source	**Maturity**	**Migration**	**Timing**	**Seal**	**$P_{Dependent}$**
1.00	0.90	0.90	0.90	0.20	0.15

Independent Risks			
Formation	**Reservoir**	**Trap**	**$P_{Independent}$**
C1	0.20	0.30	0.06
C2	0.20	0.30	0.06
C3	0.20	0.30	0.06
D2	0.20	0.30	0.06
D3	0.20	0.30	0.06
D4	0.20	0.30	0.06
E1a	0.20	0.30	0.06
E2	0.20	0.30	0.06

Pg	**0.06**

TABLE A.2.4
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
SOURMA PROSPECT

Field Dependent Risks					
Source	**Maturity**	**Migration**	**Timing**	**Seal**	**$P_{Dependent}$**
1.00	0.90	0.90	0.90	0.50	0.36

Independent Risks			
Formation	**Reservoir**	**Trap**	**$P_{Independent}$**
C1	0.70	0.80	0.56
C2	0.70	0.80	0.56
C3	0.70	0.80	0.56
D2	0.70	0.80	0.56
D3	0.70	0.80	0.56
D4	0.70	0.80	0.56
E1a	0.70	0.80	0.56
E2	0.70	0.80	0.56

Pg	**0.36**

TABLE A.2.5
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
TOGORO EAST PROSPECT

Field Dependent Risks					
Source	Maturity	Migration	Timing	Seal	$P_{Dependent}$
1.00	0.90	0.90	0.90	0.50	0.36

Independent Risks			
Formation	Reservoir	Trap	$P_{Independent}$
C1	0.70	0.80	0.56
C2	0.70	0.80	0.56
C3	0.70	0.80	0.56
D2	0.70	0.80	0.56
D3	0.70	0.80	0.56
D4	0.70	0.80	0.56
E1a	0.70	0.80	0.56
E2	0.70	0.80	0.56

Pg	**0.36**

TABLE A.2.6
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
TOGORO WEST PROSPECT

Field Dependent Risks					
Source	**Maturity**	**Migration**	**Timing**	**Seal**	**$P_{Dependent}$**
1.00	0.90	0.90	0.90	0.50	0.36

Independent Risks			
Formation	**Reservoir**	**Trap**	**$P_{Independent}$**
C1	0.70	0.80	0.56
C2	0.70	0.80	0.56
C3	0.70	0.80	0.56
D2	0.70	0.80	0.56
D3	0.70	0.80	0.56
D4	0.70	0.80	0.56
E1a	0.70	0.80	0.56
E2	0.70	0.80	0.56

Pg	**0.36**

TABLE A.3
SUMMARY OF INPUT PARAMETERS - ANALOGY METHOD PROSPECTS
GRIFFITHS ENERGY INTERNATIONAL INC.
DOB BLOCK (MANGARA RELATED)

Prospect	Pg	Prospect Area (Acre)			Undiscovered Petroleum Initially In Place per Area (MMSTB/Acre)			Unrisked Prospective Resources per Area (MMSTB/Acre)			Comment
		P90	P50	P10	P90	P50	P10	P90	P50	P10	
Lore	0.36	74	171	395	30.7	37.2	54.5	6.7	8.9	14.4	Average DOB ratios, reduced P90.
Mankola	0.36	371	840	1,903	22.2	15.6	22.2	4.5	3.5	5.6	Average DOB ratios, adjusted for C-sand only.
Sourma East	0.36	185	502	544	18.8	17.9	27.2	4.0	4.2	7.2	Sourma ratios, adjusted for C and D sands.

TABLE A.4
SUMMARY OF GROSS LEASE UNDISCOVERED PETROLEUM IN PLACE AND PROSPECTIVE RESOURCES
INCLUDING ADJUSTMENT FOR MINIMUM ECONOMIC FIELD SIZE
GRIFFITHS ENERGY INTERNATIONAL INC.
EFFECTIVE DATE: DECEMBER 31, 2012

	Gross Lease Unrisked UPIIP (MMSTB)							Gross Lease Unrisked Prospective Resources (MMSTB)				Gross Lease Partially Risked Prospective Resources (MMSTB)			
Prospect	P90	P50	Mean	P10	P_g	P_{mefs}	P_c	P90	P50	Mean	P10	P90	P50	Mean	P10
Dono	4.8	11.4	11.9	19.6	0.36	0.81	0.29	1.9	3.2	3.4	5.5	0.6	0.9	1.0	1.6
Krim	9.2	36.7	40.0	75.2	0.36	0.93	0.34	3.1	9.2	10.7	20.4	1.1	3.1	3.6	6.9
Langue	0.7	3.5	4.2	8.6	0.06	0.23	0.01	1.6	2.3	2.6	4.0	0.0	0.0	0.0	0.1
Lore	2.3	6.4	9.5	20.6	0.36	0.51	0.19	1.7	2.9	3.9	7.6	0.3	0.5	0.7	1.4
Mankola	8.3	13.1	20.3	40.2	0.36	0.99	0.36	1.7	2.9	4.8	10.0	0.6	1.1	1.7	3.6
Sourma	6.8	21.9	23.1	40.8	0.36	0.89	0.33	2.5	5.7	6.4	11.2	0.8	1.9	2.1	3.7
Sourma East	3.8	9.0	9.2	14.8	0.36	0.72	0.26	1.7	2.6	2.8	4.3	0.4	0.7	0.7	1.1
Togoro East	26.2	62.7	67.5	114.3	0.36	0.99	0.36	6.0	15.5	17.0	29.8	2.1	5.6	6.1	10.7
Togoro West	17.5	39.8	41.3	67.1	0.36	0.98	0.36	4.1	9.8	10.5	17.7	1.5	3.5	3.8	6.3
Arithmetic Sum	79.6	204.5	227.0	401.3				24.2	54.1	62.2	110.5	7.4	17.3	19.8	35.4

Note:
(1) UPIIP - Undiscovered Petroleum Initially in Place
(2) Truncated for Minimum Economic Field Size (MEFS) of 1.5 MMSTB
(3) UPIIP values do not include an implied truncation for minimum economic field size
(4) Please review discussion in Summary concerning summation of unrisked totals.

APPENDIX B

DOI BLOCK (BADILA RELATED)

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TABLE B.1.1
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BITANDA PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	9,800	342,433	560,076	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.4	80.0	
B_{oi}	rbbl/STB	1.08	1.13	1.19	Custom	1.03	1.26	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	7,391	136,322	273,110	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.6	80.0	
B_{oi}	rbbl/STB	1.08	1.13	1.19	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	9,355	222,020	370,236	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.8	80.0	
B_{oi}	rbbl/STB	1.08	1.13	1.19	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,706	59,693	113,299	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.7	80.0	
B_{oi}	rbbl/STB	1.08	1.13	1.19	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE B.1.1
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BITANDA PROSPECT

D5								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	5,210	86,102	179,302	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.1	80.0	
B_{oi}	rbbl/STB	1.08	1.13	1.19	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D6								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	6,904	119,649	282,386	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.4	80.0	
B_{oi}	rbbl/STB	1.08	1.13	1.19	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D8								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	9,793	347,375	563,163	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.9	79.9	
B_{oi}	rbbl/STB	1.08	1.13	1.19	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D9								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	9,797	305,395	496,564	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.2	80.0	
B_{oi}	rbbl/STB	1.08	1.13	1.19	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE B.1.1
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BITANDA PROSPECT

D10								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	9,805	366,549	588,730	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.9	80.0	
B_{oi}	rbbl/STB	1.08	1.13	1.19	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,311	202,521	368,106	Custom			
Net/Gross Ratio	v/v	0.41	0.58	0.75	Normal	0.30	0.90	
Porosity (ϕ)	%	17.7	21.2	24.9	Normal	16.0	28.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.6	80.0	
B_{oi}	rbbl/STB	1.12	1.18	1.26	Custom	1.06	1.34	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,307	199,242	357,267	Custom			
Net/Gross Ratio	v/v	0.41	0.58	0.75	Normal	0.30	0.90	
Porosity (ϕ)	%	17.7	21.2	24.9	Normal	16.0	28.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.4	80.0	
B_{oi}	rbbl/STB	1.12	1.18	1.26	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE B.1.2
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BODJAMA PROSPECT

C1A (UPPER)								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	143	3,629	4,540	Custom			
Net/Gross Ratio	v/v	0.17	0.42	0.68	Normal	0.05	0.80	
Porosity (ϕ)	%	17.0	20.5	24.0	Normal	12.1	29.8	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.7	80.0	
B_{oi}	rbbl/STB	1.10	1.16	1.23	Custom	1.05	1.30	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C1B (LOWER)								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	143	3,619	4,538	Custom			
Net/Gross Ratio	v/v	0.17	0.42	0.68	Normal	0.05	0.80	
Porosity (ϕ)	%	17.0	20.5	24.0	Normal	12.0	30.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.1	80.0	
B_{oi}	rbbl/STB	1.10	1.16	1.23	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	143	3,629	4,540	Custom			
Net/Gross Ratio	v/v	0.17	0.42	0.68	Normal	0.05	0.80	
Porosity (ϕ)	%	17.0	20.5	24.0	Normal	12.0	29.8	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.7	80.0	
B_{oi}	rbbl/STB	1.10	1.16	1.23	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	143	3,629	4,540	Custom			
Net/Gross Ratio	v/v	0.17	0.42	0.68	Normal	0.05	0.80	
Porosity (ϕ)	%	17.0	20.5	24.0	Normal	12.1	29.8	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.9	80.0	
B_{oi}	rbbl/STB	1.10	1.16	1.23	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE B.1.2
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BODJAMA PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	535	4,622	6,451	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.0	80.0	
B_{oi}	rbbl/STB	1.12	1.19	1.27	Custom	1.06	1.35	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	535	4,308	6,146	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.9	80.0	
B_{oi}	rbbl/STB	1.12	1.19	1.27	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	535	4,622	6,452	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.4	80.0	
B_{oi}	rbbl/STB	1.12	1.19	1.27	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	379	2,354	4,331	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.9	80.0	
B_{oi}	rbbl/STB	1.12	1.19	1.27	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE B.1.2
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BODJAMA PROSPECT

D5								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	477	3,206	5,436	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.3	80.0	
B_{oi}	rbbl/STB	1.12	1.19	1.27	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D6								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	512	3,874	5,982	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.7	80.0	
B_{oi}	rbbl/STB	1.12	1.19	1.27	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D8								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	535	4,622	6,451	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.4	80.0	
B_{oi}	rbbl/STB	1.12	1.19	1.27	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D9								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	535	4,622	6,451	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.6	80.0	
B_{oi}	rbbl/STB	1.12	1.19	1.27	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE B.1.2
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BODJAMA PROSPECT

D10								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	535	4,621	6,451	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.8	80.0	
B_{oi}	rbbl/STB	1.12	1.19	1.27	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	423	3,287	4,585	Custom			
Net/Gross Ratio	v/v	0.41	0.58	0.75	Normal	0.30	0.90	
Porosity (ϕ)	%	17.7	21.2	24.9	Normal	16.0	28.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.8	80.0	
B_{oi}	rbbl/STB	1.15	1.23	1.32	Custom	1.09	1.41	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	423	3,287	4,585	Custom			
Net/Gross Ratio	v/v	0.41	0.58	0.75	Normal	0.30	0.90	
Porosity (ϕ)	%	17.7	21.2	24.9	Normal	16.0	28.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.1	80.0	
B_{oi}	rbbl/STB	1.15	1.23	1.32	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE B.1.3
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAIKORO PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	241	1,660	2,442	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.0	80.0	
B_{oi}	rbbl/STB	1.14	1.21	1.30	Custom	1.08	1.38	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	241	1,641	2,384	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.4	80.0	
B_{oi}	rbbl/STB	1.14	1.21	1.30	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	241	1,660	2,442	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.0	80.0	
B_{oi}	rbbl/STB	1.14	1.21	1.30	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	233	1,244	1,836	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.4	80.0	
B_{oi}	rbbl/STB	1.14	1.21	1.30	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE B.1.3
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAIKORO PROSPECT

D5								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	240	1,431	2,143	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.9	80.0	
B_{oi}	rbbl/STB	1.14	1.21	1.30	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D6								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	240	1,542	2,308	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.1	80.0	
B_{oi}	rbbl/STB	1.14	1.21	1.30	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D8								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	241	1,660	2,442	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.7	80.0	
B_{oi}	rbbl/STB	1.14	1.21	1.30	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D9								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	241	1,660	2,442	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.2	80.0	
B_{oi}	rbbl/STB	1.14	1.21	1.30	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE B.1.3
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAIKORO PROSPECT

D10								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	241	1,660	2,442	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.6	80.0	
B_{oi}	rbbl/STB	1.14	1.21	1.30	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE B.1.4
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAN LIA NE PROSPECT

C1A (UPPER)								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	104	1,427	2,192	Custom			
Net/Gross Ratio	v/v	0.17	0.42	0.68	Normal	0.05	0.80	
Porosity (ϕ)	%	17.0	20.5	24.0	Normal	12.1	29.8	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.3	80.0	
B_{oi}	rbbl/STB	1.08	1.13	1.19	Custom	1.03	1.26	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C1B (LOWER)								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	104	1,403	2,169	Custom			
Net/Gross Ratio	v/v	0.17	0.42	0.68	Normal	0.05	0.80	
Porosity (ϕ)	%	17.0	20.5	24.0	Normal	12.0	29.9	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.5	80.0	
B_{oi}	rbbl/STB	1.08	1.13	1.19	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	104	1,427	2,189	Custom			
Net/Gross Ratio	v/v	0.17	0.42	0.68	Normal	0.05	0.80	
Porosity (ϕ)	%	17.0	20.5	24.0	Normal	12.1	29.8	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.9	80.0	
B_{oi}	rbbl/STB	1.08	1.13	1.19	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	104	1,426	2,192	Custom			
Net/Gross Ratio	v/v	0.17	0.42	0.68	Normal	0.05	0.80	
Porosity (ϕ)	%	17.0	20.5	24.0	Normal	12.1	29.9	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.7	80.0	
B_{oi}	rbbl/STB	1.08	1.13	1.19	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE B.1.4
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAN LIA NE PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	391	5,180	8,026	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.7	80.0	
B_{oi}	rbbl/STB	1.10	1.17	1.24	Custom	1.05	1.31	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	389	3,915	6,432	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.7	80.0	
B_{oi}	rbbl/STB	1.10	1.17	1.24	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	392	5,005	7,647	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.3	80.0	
B_{oi}	rbbl/STB	1.10	1.17	1.24	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	311	2,146	3,798	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.1	80.0	
B_{oi}	rbbl/STB	1.10	1.17	1.24	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE B.1.4
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAN LIA NE PROSPECT

D5								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	349	2,804	5,176	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.7	80.0	
B_{oi}	rbbl/STB	1.10	1.17	1.24	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D6								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	375	3,565	6,380	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.1	80.0	
B_{oi}	rbbl/STB	1.10	1.17	1.24	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D8								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	392	5,179	8,025	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.8	80.0	
B_{oi}	rbbl/STB	1.10	1.17	1.24	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D9								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	391	5,180	8,021	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.1	80.0	
B_{oi}	rbbl/STB	1.10	1.17	1.24	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE B.1.4
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAN LIA NE PROSPECT

D10								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	391	5,179	8,026	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.3	80.0	
B_{oi}	rbbl/STB	1.10	1.17	1.24	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE B.1.5
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAN LIA SW PROSPECT

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,182	13,156	19,831	Custom			
Net/Gross Ratio	v/v	0.41	0.58	0.75	Normal	0.30	0.90	
Porosity (ϕ)	%	17.7	21.2	24.9	Normal	16.0	28.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.6	80.0	
B_{oi}	rbbl/STB	1.12	1.19	1.26	Custom	1.06	1.35	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,181	13,156	19,833	Custom			
Net/Gross Ratio	v/v	0.41	0.58	0.75	Normal	0.30	0.90	
Porosity (ϕ)	%	17.7	21.2	24.9	Normal	16.0	28.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.2	79.9	
B_{oi}	rbbl/STB	1.12	1.19	1.26	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE B.1.6
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAYBOR PROSPECT

C1A (UPPER)								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,189	3,775	13,559	Custom			
Net/Gross Ratio	v/v	0.17	0.42	0.68	Normal	0.05	0.80	
Porosity (ϕ)	%	17.0	20.5	24.0	Normal	12.0	29.8	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.08	1.14	1.20	Custom	1.03	1.26	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C1B (LOWER)								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,190	3,740	13,355	Custom			
Net/Gross Ratio	v/v	0.17	0.42	0.68	Normal	0.05	0.80	
Porosity (ϕ)	%	17.0	20.5	24.0	Normal	12.1	29.8	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.08	1.14	1.20	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,190	3,772	13,530	Custom			
Net/Gross Ratio	v/v	0.17	0.42	0.68	Normal	0.05	0.80	
Porosity (ϕ)	%	17.0	20.5	24.0	Normal	12.0	29.9	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.08	1.14	1.20	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,189	3,774	13,560	Custom			
Net/Gross Ratio	v/v	0.17	0.42	0.68	Normal	0.05	0.80	
Porosity (ϕ)	%	17.0	20.5	24.0	Normal	12.0	30.0	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.08	1.14	1.20	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE B.1.6
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAYBOR PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	6,060	88,230	131,837	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.11	1.17	1.24	Custom	1.05	1.32	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	5,944	56,059	96,263	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.11	1.17	1.24	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	6,058	78,518	116,512	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.11	1.17	1.24	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,563	26,616	48,350	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.11	1.17	1.24	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE B.1.6
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAYBOR PROSPECT

D5								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	4,772	37,522	71,103	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.11	1.17	1.24	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D6								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	5,481	50,017	97,333	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.11	1.17	1.24	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D8								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	6,060	88,305	132,004	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.11	1.17	1.24	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D9								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	6,058	87,501	130,207	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.11	1.17	1.24	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE B.1.6
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAYBOR PROSPECT

D10								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	6,057	88,322	131,993	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.11	1.17	1.24	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	43,411	322,117	442,782	Custom			
Net/Gross Ratio	v/v	0.41	0.58	0.75	Normal	0.30	0.90	
Porosity (ϕ)	%	17.7	21.2	24.9	Normal	16.0	28.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.8	80.0	
B_{oi}	rbbl/STB	1.15	1.22	1.31	Custom	1.08	1.40	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	43,392	304,763	392,488	Custom			
Net/Gross Ratio	v/v	0.41	0.58	0.75	Normal	0.30	0.90	
Porosity (ϕ)	%	17.7	21.2	24.9	Normal	16.0	28.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.7	80.0	
B_{oi}	rbbl/STB	1.15	1.22	1.31	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE B.1.7
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
NGEBE PROSPECT

C1A (UPPER)								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	28,269	238,002	333,696	Custom			
Net/Gross Ratio	v/v	0.17	0.42	0.68	Normal	0.05	0.80	
Porosity (ϕ)	%	17.0	20.5	24.0	Normal	12.0	29.9	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.1	80.0	
B_{oi}	rbbl/STB	1.09	1.15	1.21	Custom	1.04	1.28	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	25,140	141,063	290,585	Custom			
Net/Gross Ratio	v/v	0.17	0.42	0.68	Normal	0.05	0.80	
Porosity (ϕ)	%	17.0	20.5	24.0	Normal	12.0	29.9	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.9	80.0	
B_{oi}	rbbl/STB	1.09	1.15	1.21	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	26,927	155,422	278,874	Custom			
Net/Gross Ratio	v/v	0.17	0.42	0.68	Normal	0.05	0.80	
Porosity (ϕ)	%	17.0	20.5	24.0	Normal	12.1	29.9	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.9	80.0	
B_{oi}	rbbl/STB	1.09	1.15	1.21	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	28,284	268,096	396,160	Custom			
Net/Gross Ratio	v/v	0.17	0.42	0.68	Normal	0.05	0.80	
Porosity (ϕ)	%	17.0	20.5	24.0	Normal	12.1	29.9	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.3	80.0	
B_{oi}	rbbl/STB	1.09	1.15	1.21	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE B.1.7
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
NGEBE PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	9,777	95,762	132,235	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.3	80.0	
B_{oi}	rbbl/STB	1.11	1.18	1.25	Custom	1.05	1.33	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	8,609	41,006	74,848	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.4	80.0	
B_{oi}	rbbl/STB	1.11	1.18	1.25	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	9,775	65,905	96,653	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.2	80.0	
B_{oi}	rbbl/STB	1.11	1.18	1.25	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	4,617	18,129	31,406	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.2	80.0	
B_{oi}	rbbl/STB	1.11	1.18	1.25	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE B.1.7
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
NGEBE PROSPECT

D5								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	6,402	26,307	49,106	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.4	80.0	
B_{oi}	rbbl/STB	1.11	1.18	1.25	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D6								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	7,716	37,722	77,485	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.7	80.0	
B_{oi}	rbbl/STB	1.11	1.18	1.25	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D8								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	9,780	97,063	133,589	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.9	80.0	
B_{oi}	rbbl/STB	1.11	1.18	1.25	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D9								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	9,773	88,784	120,837	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.7	80.0	
B_{oi}	rbbl/STB	1.11	1.18	1.25	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE B.1.7
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
NGEBE PROSPECT

D10								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	9,768	99,267	137,121	Custom			
Net/Gross Ratio	v/v	0.15	0.31	0.50	Normal	0.07	0.75	
Porosity (ϕ)	%	19.0	22.0	25.0	Normal	15.0	29.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.6	80.0	
B_{oi}	rbbl/STB	1.11	1.18	1.25	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,438	75,509	112,731	Custom			
Net/Gross Ratio	v/v	0.41	0.58	0.75	Normal	0.30	0.90	
Porosity (ϕ)	%	17.7	21.2	24.9	Normal	16.0	28.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	31.1	80.0	
B_{oi}	rbbl/STB	1.14	1.21	1.29	Custom	1.08	1.38	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,439	74,846	110,314	Custom			
Net/Gross Ratio	v/v	0.41	0.58	0.75	Normal	0.30	0.90	
Porosity (ϕ)	%	17.7	21.2	24.9	Normal	16.0	28.0	
Oil Saturation (S_o)	%	50.0	59.9	69.8	Normal	30.3	80.0	
B_{oi}	rbbl/STB	1.14	1.21	1.29	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE B.2.1
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
BITANDA PROSPECT

Field Dependent Risks					
Source	Maturity	Migration	Timing	Seal	$P_{Dependent}$
1.00	0.90	0.90	0.90	0.50	0.36

Independent Risks			
Formation	Reservoir	Trap	$P_{Independent}$
D1	0.60	0.50	0.30
D2	0.60	0.50	0.30
D3	0.60	0.50	0.30
D4	0.60	0.50	0.30
D5	0.60	0.50	0.30
D6	0.60	0.50	0.30
D8	0.60	0.50	0.30
D9	0.60	0.50	0.30
D10	0.60	0.50	0.30
E1	0.60	0.50	0.30
E2	0.60	0.50	0.30

Pg	**0.36**

TABLE B.2.2
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
BODJAMA PROSPECT

Field Dependent Risks					
Source	**Maturity**	**Migration**	**Timing**	**Seal**	**$P_{Dependent}$**
1.00	0.90	0.90	0.90	0.50	0.36

Independent Risks			
Formation	**Reservoir**	**Trap**	**$P_{Independent}$**
C1a (Upper)	0.60	0.50	0.30
C1b (Lower)	0.60	0.50	0.30
C2	0.60	0.50	0.30
C3	0.60	0.50	0.30
D1	0.60	0.50	0.30
D2	0.60	0.50	0.30
D3	0.60	0.50	0.30
D4	0.60	0.50	0.30
D5	0.60	0.50	0.30
D6	0.60	0.50	0.30
D8	0.60	0.50	0.30
D9	0.60	0.50	0.30
D10	0.60	0.50	0.30
E1	0.60	0.50	0.30
E2	0.60	0.50	0.30

Pg	**0.36**

TABLE B.2.3
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAIKORO PROSPECT

Field Dependent Risks					
Source	Maturity	Migration	Timing	Seal	$P_{Dependent}$
1.00	0.90	0.90	0.90	0.40	0.29

Independent Risks			
Formation	Reservoir	Trap	$P_{Independent}$
D1	0.40	0.30	0.12
D2	0.40	0.30	0.12
D3	0.40	0.30	0.12
D4	0.40	0.30	0.12
D5	0.40	0.30	0.12
D6	0.40	0.30	0.12
D8	0.40	0.30	0.12
D9	0.40	0.30	0.12
D10	0.40	0.30	0.12

Pg	0.20

TABLE B.2.4
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
NGEBE PROSPECT

Field Dependent Risks					
Source	**Maturity**	**Migration**	**Timing**	**Seal**	**$P_{Dependent}$**
1.00	0.90	0.90	0.90	0.50	0.36

Independent Risks			
Formation	**Reservoir**	**Trap**	**$P_{Independent}$**
C1a (Upper)	0.60	0.50	0.30
C2	0.60	0.50	0.30
C3	0.60	0.50	0.30
C4	0.60	0.50	0.30
D1	0.60	0.50	0.30
D2	0.60	0.50	0.30
D3	0.60	0.50	0.30
D4	0.60	0.50	0.30
D5	0.60	0.50	0.30
D6	0.60	0.50	0.30
D8	0.60	0.50	0.30
D9	0.60	0.50	0.30
D10	0.60	0.50	0.30
E1	0.60	0.50	0.30
E2	0.60	0.50	0.30

Pg	**0.36**

TABLE B.2.5
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAN LIA NE PROSPECT

Field Dependent Risks					
Source	**Maturity**	**Migration**	**Timing**	**Seal**	**$P_{Dependent}$**
1.00	0.90	0.90	0.90	0.20	0.15

Independent Risks			
Formation	**Reservoir**	**Trap**	**$P_{Independent}$**
C1a (Upper)	0.40	0.20	0.08
C1b (Lower)	0.40	0.20	0.08
C2	0.40	0.20	0.08
C3	0.40	0.20	0.08
D1	0.40	0.20	0.08
D2	0.40	0.20	0.08
D3	0.40	0.20	0.08
D4	0.40	0.20	0.08
D5	0.40	0.20	0.08
D6	0.40	0.20	0.08
D8	0.40	0.20	0.08
D9	0.40	0.20	0.08
D10	0.40	0.20	0.08

Pg	**0.10**

TABLE B.2.6
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAN LIA SW PROSPECT

Field Dependent Risks					
Source	**Maturity**	**Migration**	**Timing**	**Seal**	**$P_{Dependent}$**
1.00	0.90	0.90	0.90	0.20	0.15

Independent Risks			
Formation	**Reservoir**	**Trap**	**$P_{Independent}$**
E1	0.40	0.20	0.08
E2	0.40	0.20	0.08

Pg	**0.02**

TABLE B.2.7
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAYBOR PROSPECT

Field Dependent Risks					
Source	Maturity	Migration	Timing	Seal	$P_{Dependent}$
1.00	0.90	0.90	0.90	0.50	0.36

Independent Risks			
Formation	Reservoir	Trap	$P_{Independent}$
C1a (Upper)	0.60	0.50	0.30
C1b (Lower)	0.60	0.50	0.30
C2	0.60	0.50	0.30
C3	0.60	0.50	0.30
D1	0.60	0.50	0.30
D2	0.60	0.50	0.30
D3	0.60	0.50	0.30
D4	0.60	0.50	0.30
D5	0.60	0.50	0.30
D6	0.60	0.50	0.30
D8	0.60	0.50	0.30
D9	0.60	0.50	0.30
D10	0.60	0.50	0.30
E1	0.60	0.50	0.30
E2	0.60	0.50	0.30

Pg	0.36

TABLE B.3
SUMMARY OF INPUT PARAMETERS - ANALOGY METHOD PROSPECTS
GRIFFITHS ENERGY INTERNATIONAL INC.
DOI BLOCK (BADILA RELATED)

Prospect	Pg	Prospect Area (Acre)			Undiscovered Petroleum Initially In Place per Area (MMSTB/Acre)			Unrisked Prospective Resources per Area (MMSTB/Acre)			Comment
		P90	P50	P10	P90	P50	P10	P90	P50	P10	
Badila Deep	0.36	222	659	1,952	8.7	4.8	8.9	1.9	1.1	2.3	Average DOI ratios, adjusted for E-Sand only.
Badila East	0.36	99	182	297	19.3	38.6	72.1	4.6	9.2	18.9	Average DOI ratios, reduced P90.
Badila South	0.36	247	559	1,285	33.9	33.9	63.2	8.0	8.0	16.6	Average DOI ratios, adjusted for C and D sands.
Bebann	0.36	49	99	198	35.1	38.6	72.1	7.6	9.2	18.9	Average DOI
Bodjama North	0.36	124	303	741	26.8	26.8	49.9	6.4	6.4	13.1	Average DOI UPIIP and Unrisked PR per area.
Mankou	0.36	148	492	1,631	57.3	31.5	58.8	12.5	7.5	15.4	Average DOI ratios, adjusted for D and E sands.

TABLE B.4
SUMMARY OF GROSS LEASE UNDISCOVERED PETROLEUM IN PLACE AND PROSPECTIVE RESOURCES
INCLUDING ADJUSTMENT FOR MINIMUM ECONOMIC FIELD SIZE
GRIFFITHS ENERGY INTERNATIONAL INC.
EFFECTIVE DATE: DECEMBER 31, 2012

	Gross Lease Unrisked UPIIP (MMSTB)							Gross Lease Unrisked Prospective Resources (MMSTB)				Gross Lease Partially Risked Prospective Resources (MMSTB)			
Prospect	P90	P50	Mean	P10	P_g	P_{mefs}	P_c	P90	P50	Mean	P10	P90	P50	Mean	P10
Badila Deep	1.9	3.1	7.4	16.1	0.36	0.27	0.10	1.7	3.1	5.1	11.4	0.2	0.3	0.5	1.1
Badila East	2.0	7.0	9.6	20.6	0.36	0.54	0.20	1.7	2.9	3.8	7.0	0.3	0.6	0.7	1.4
Badila South	8.5	18.9	34.2	76.8	0.36	1.00	0.36	2.0	4.5	8.8	20.0	0.7	1.6	3.2	7.3
Bebann	1.8	3.8	6.2	13.5	0.36	0.31	0.11	1.6	2.6	3.5	6.7	0.2	0.3	0.4	0.7
Bitanda	37.2	189.1	218.1	442.7	0.36	0.97	0.35	10.2	45.5	56.1	115.0	3.5	15.8	19.5	39.9
Bodjama	1.6	4.4	4.7	7.9	0.36	0.28	0.10	1.6	1.9	2.1	2.8	0.2	0.2	0.2	0.3
Bodjama North	3.4	8.1	15.2	34.9	0.36	0.60	0.22	1.7	3.5	5.8	12.9	0.4	0.8	1.3	2.8
Maikoro	0.1	0.5	0.6	1.2	0.20	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Man Lia NE	0.1	1.1	1.5	3.4	0.10	0.03	0.00	1.5	1.7	1.8	2.3	0.0	0.0	0.0	0.0
Man Lia SW	0.5	5.3	5.8	11.3	0.02	0.36	0.01	1.6	2.7	2.9	4.9	0.0	0.0	0.0	0.0
Mankou	8.6	15.5	39.7	88.8	0.36	1.00	0.36	1.9	3.7	10.2	23.2	0.7	1.3	3.6	8.3
Maybor	18.5	90.3	126.5	275.7	0.36	0.96	0.35	5.5	22.5	33.3	74.1	1.9	7.9	11.6	25.8
Ngebe	36.9	123.1	144.7	277.2	0.36	0.99	0.36	8.9	30.0	36.7	72.8	3.2	10.8	13.1	26.1
Arithmetic Sum	121.0	470.3	614.2	1,270.2				39.9	124.7	170.2	353.1	11.3	39.5	54.2	113.8

Note:
(1) UPIIP - Undiscovered Petroleum Initially in Place
(2) Truncated for Minimum Economic Field Size (MEFS) of 1.5 MMSTB
(3) UPIIP values do not include an implied truncation for minimum economic field size
(4) Please review discussion in Summary concerning summation of unrisked totals.

APPENDIX C

DOH BLOCK (N'DONAMBO-DAMALLA RELATED)

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TABLE C.1.1
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BEDAYA PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,238	13,385	19,801	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	15.3	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.8	76.2	
B_{oi}	rbbl/STB	1.24	1.34	1.49	Custom	1.16	1.63	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,239	13,384	19,799	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	15.2	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	43.7	74.6	
B_{oi}	rbbl/STB	1.24	1.34	1.49	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,239	13,380	19,784	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	15.7	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	43.4	75.0	
B_{oi}	rbbl/STB	1.24	1.34	1.49	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,237	13,384	19,803	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	15.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.3	75.1	
B_{oi}	rbbl/STB	1.24	1.34	1.49	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.1
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BEDAYA PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,238	13,384	19,801	Custom			
Net/Gross Ratio	v/v	0.06	0.13	0.20	Normal	0.01	0.34	
Porosity (ϕ)	%	10.3	13.5	16.9	Normal	8.0	20.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.31	1.44	1.61	Custom	1.21	1.77	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,239	12,460	19,108	Custom			
Net/Gross Ratio	v/v	0.06	0.13	0.20	Normal	0.01	0.34	
Porosity (ϕ)	%	10.3	13.5	16.9	Normal	8.0	20.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.31	1.44	1.61	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.2
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BESSAMA PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	83	527	671	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	14.9	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.2	74.8	
B_{oi}	rbbl/STB	1.29	1.41	1.58	Custom	1.19	1.73	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	83	527	671	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	14.9	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.8	76.4	
B_{oi}	rbbl/STB	1.29	1.41	1.58	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	83	527	671	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	14.9	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.2	75.4	
B_{oi}	rbbl/STB	1.29	1.41	1.58	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	83	527	671	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	15.1	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.0	75.7	
B_{oi}	rbbl/STB	1.29	1.41	1.58	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.2
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BESSAMA PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	83	527	671	Custom			
Net/Gross Ratio	v/v	0.06	0.13	0.20	Normal	0.01	0.34	
Porosity (ϕ)	%	10.3	13.5	16.9	Normal	8.0	20.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.32	1.46	1.64	Custom	1.22	1.81	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	83	527	671	Custom			
Net/Gross Ratio	v/v	0.06	0.13	0.20	Normal	0.01	0.34	
Porosity (ϕ)	%	10.3	13.5	16.9	Normal	8.0	20.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.32	1.46	1.64	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.3
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BEYARA PROSPECT

M1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,986	21,684	38,626	Custom			
Net/Gross Ratio	v/v	0.07	0.19	0.32	Normal	0.01	0.50	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.9	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.3	76.1	
B_{oi}	rbbl/STB	1.10	1.17	1.25	Custom	1.05	1.33	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

M2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,018	29,418	46,241	Custom			
Net/Gross Ratio	v/v	0.07	0.19	0.32	Normal	0.01	0.50	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.8	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.5	75.8	
B_{oi}	rbbl/STB	1.10	1.17	1.25	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

M3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,015	29,675	46,529	Custom			
Net/Gross Ratio	v/v	0.07	0.19	0.32	Normal	0.01	0.50	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.8	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.3	77.3	
B_{oi}	rbbl/STB	1.10	1.17	1.25	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

A1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,909	21,041	36,541	Custom			
Net/Gross Ratio	v/v	0.10	0.18	0.25	Normal	0.05	0.40	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.3	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.1	75.2	
B_{oi}	rbbl/STB	1.10	1.17	1.25	Custom	1.05	1.34	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.3
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BEYARA PROSPECT

A3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,997	29,173	47,290	Custom			
Net/Gross Ratio	v/v	0.10	0.18	0.25	Normal	0.05	0.39	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.5	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	43.9	75.3	
B_{oi}	rbbl/STB	1.10	1.17	1.25	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

B1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,779	19,311	38,412	Custom			
Net/Gross Ratio	v/v	0.11	0.25	0.42	Normal	0.05	0.70	
Porosity (ϕ)	%	19.0	20.5	22.0	Normal	15.8	24.8	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.6	74.7	
B_{oi}	rbbl/STB	1.13	1.21	1.30	Custom	1.07	1.40	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

B2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,246	5,632	13,015	Custom			
Net/Gross Ratio	v/v	0.11	0.25	0.42	Normal	0.05	0.69	
Porosity (ϕ)	%	19.0	20.5	22.0	Normal	15.9	24.8	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.0	76.3	
B_{oi}	rbbl/STB	1.13	1.21	1.30	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

B3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,014	34,256	52,116	Custom			
Net/Gross Ratio	v/v	0.11	0.25	0.42	Normal	0.05	0.70	
Porosity (ϕ)	%	19.0	20.5	22.0	Normal	15.7	24.8	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	43.7	75.7	
B_{oi}	rbbl/STB	1.13	1.21	1.30	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.4
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
DAMALLA PROSPECT

M1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	177	3,756	8,410	Custom			
Net/Gross Ratio	v/v	0.07	0.19	0.32	Normal	0.01	0.50	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.8	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.5	74.6	
B_{oi}	rbbl/STB	1.09	1.15	1.22	Custom	1.04	1.31	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

M2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	177	4,110	8,908	Custom			
Net/Gross Ratio	v/v	0.07	0.19	0.32	Normal	0.01	0.50	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.6	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.9	76.0	
B_{oi}	rbbl/STB	1.09	1.15	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

M3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	177	4,115	8,887	Custom			
Net/Gross Ratio	v/v	0.07	0.19	0.32	Normal	0.01	0.50	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.9	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.9	74.5	
B_{oi}	rbbl/STB	1.09	1.15	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

A1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	177	3,644	8,230	Custom			
Net/Gross Ratio	v/v	0.10	0.18	0.25	Normal	0.05	0.39	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.7	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.5	74.9	
B_{oi}	rbbl/STB	1.09	1.15	1.22	Custom	1.04	1.31	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.4
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
DAMALLA PROSPECT

A3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	177	4,053	8,804	Custom			
Net/Gross Ratio	v/v	0.10	0.18	0.25	Normal	0.05	0.40	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.1	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.9	75.1	
B_{oi}	rbbl/STB	1.09	1.15	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

B1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,551	35,483	69,014	Custom			
Net/Gross Ratio	v/v	0.11	0.25	0.42	Normal	0.05	0.70	
Porosity (ϕ)	%	19.0	20.5	22.0	Normal	15.5	24.8	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.4	75.0	
B_{oi}	rbbl/STB	1.14	1.22	1.32	Custom	1.08	1.43	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

B2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	786	10,515	23,283	Custom			
Net/Gross Ratio	v/v	0.11	0.25	0.42	Normal	0.05	0.69	
Porosity (ϕ)	%	19.0	20.5	22.0	Normal	16.1	24.8	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.4	74.7	
B_{oi}	rbbl/STB	1.14	1.22	1.32	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

B3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,651	57,756	91,113	Custom			
Net/Gross Ratio	v/v	0.11	0.25	0.42	Normal	0.05	0.70	
Porosity (ϕ)	%	19.0	20.5	22.0	Normal	16.0	24.8	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.5	74.7	
B_{oi}	rbbl/STB	1.14	1.22	1.32	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.4
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
DAMALLA PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	17,852	164,790	217,148	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	15.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.8	75.1	
B_{oi}	rbbl/STB	1.26	1.38	1.53	Custom	1.17	1.67	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	17,851	165,375	221,016	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	14.9	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.4	78.0	
B_{oi}	rbbl/STB	1.26	1.38	1.53	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	17,843	129,820	188,291	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	14.9	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.9	74.7	
B_{oi}	rbbl/STB	1.26	1.38	1.53	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	17,839	165,391	222,016	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	15.6	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.9	75.7	
B_{oi}	rbbl/STB	1.26	1.38	1.53	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.4
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
DAMALLA PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,859	37,459	65,952	Custom			
Net/Gross Ratio	v/v	0.06	0.13	0.20	Normal	0.01	0.35	
Porosity (ϕ)	%	10.3	13.5	16.9	Normal	8.0	20.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.29	1.42	1.59	Custom	1.20	1.75	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,495	26,329	53,773	Custom			
Net/Gross Ratio	v/v	0.06	0.13	0.20	Normal	0.01	0.34	
Porosity (ϕ)	%	10.3	13.5	16.9	Normal	8.0	20.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.29	1.42	1.59	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.5
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
DAMALLA EAST PROSPECT

M1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	9,078	102,809	209,149	Custom			
Net/Gross Ratio	v/v	0.07	0.19	0.32	Normal	0.01	0.50	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.2	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.7	74.6	
B_{oi}	rbbl/STB	1.09	1.14	1.21	Custom	1.03	1.29	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

M2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	10,749	155,837	278,891	Custom			
Net/Gross Ratio	v/v	0.07	0.19	0.32	Normal	0.01	0.50	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.4	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.5	77.2	
B_{oi}	rbbl/STB	1.09	1.14	1.21	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

M3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	10,732	157,947	284,213	Custom			
Net/Gross Ratio	v/v	0.07	0.19	0.32	Normal	0.01	0.50	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	16.0	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.6	74.9	
B_{oi}	rbbl/STB	1.09	1.14	1.21	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

A1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	8,719	99,356	191,556	Custom			
Net/Gross Ratio	v/v	0.10	0.18	0.25	Normal	0.05	0.39	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.3	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	42.9	74.8	
B_{oi}	rbbl/STB	1.08	1.14	1.21	Custom	1.03	1.29	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.5
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
DAMALLA EAST PROSPECT

A3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	10,561	157,041	290,493	Custom			
Net/Gross Ratio	v/v	0.10	0.18	0.25	Normal	0.05	0.39	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.3	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	43.0	75.7	
B_{oi}	rbbl/STB	1.08	1.14	1.21	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

B1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	5,046	76,601	193,352	Custom			
Net/Gross Ratio	v/v	0.11	0.25	0.42	Normal	0.05	0.69	
Porosity (ϕ)	%	19.0	20.5	22.0	Normal	15.9	24.7	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.2	75.9	
B_{oi}	rbbl/STB	1.13	1.21	1.30	Custom	1.07	1.40	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

B2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,486	19,864	50,831	Custom			
Net/Gross Ratio	v/v	0.11	0.25	0.42	Normal	0.05	0.69	
Porosity (ϕ)	%	19.0	20.5	22.0	Normal	15.9	24.8	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	43.0	74.6	
B_{oi}	rbbl/STB	1.13	1.21	1.30	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

B3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	7,841	223,481	404,316	Custom			
Net/Gross Ratio	v/v	0.11	0.25	0.42	Normal	0.05	0.70	
Porosity (ϕ)	%	19.0	20.5	22.0	Normal	16.1	25.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.2	76.3	
B_{oi}	rbbl/STB	1.13	1.21	1.30	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.5
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
DAMALLA EAST PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	34,949	437,767	622,526	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	15.1	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.4	74.6	
B_{oi}	rbbl/STB	1.25	1.37	1.52	Custom	1.16	1.67	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	34,947	462,937	659,372	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	15.1	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	43.4	74.8	
B_{oi}	rbbl/STB	1.25	1.37	1.52	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	34,819	317,437	522,830	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	15.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.6	75.0	
B_{oi}	rbbl/STB	1.25	1.37	1.52	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	34,947	511,501	744,640	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	15.2	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.7	74.7	
B_{oi}	rbbl/STB	1.25	1.37	1.52	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.5
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
DAMALLA EAST PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	4,716	111,148	188,593	Custom			
Net/Gross Ratio	v/v	0.06	0.13	0.20	Normal	0.01	0.34	
Porosity (ϕ)	%	10.3	13.5	16.9	Normal	8.0	20.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.31	1.44	1.62	Custom	1.21	1.77	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,998	73,602	147,286	Custom			
Net/Gross Ratio	v/v	0.06	0.13	0.20	Normal	0.01	0.35	
Porosity (ϕ)	%	10.3	13.5	16.9	Normal	8.0	20.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.31	1.44	1.62	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.6
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
DAMALLA SE PROSPECT

M1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,063	91,920	167,959	Custom			
Net/Gross Ratio	v/v	0.07	0.19	0.32	Normal	0.01	0.50	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.9	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.5	74.5	
B_{oi}	rbbl/STB	1.09	1.15	1.21	Custom	1.03	1.29	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

M2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,126	130,710	208,609	Custom			
Net/Gross Ratio	v/v	0.07	0.19	0.32	Normal	0.01	0.50	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.0	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.0	75.7	
B_{oi}	rbbl/STB	1.09	1.15	1.21	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

M3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,129	130,185	212,010	Custom			
Net/Gross Ratio	v/v	0.07	0.19	0.32	Normal	0.01	0.50	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.9	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.2	76.3	
B_{oi}	rbbl/STB	1.09	1.15	1.21	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

A1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,013	90,160	160,725	Custom			
Net/Gross Ratio	v/v	0.10	0.18	0.25	Normal	0.05	0.39	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.5	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.3	74.6	
B_{oi}	rbbl/STB	1.09	1.14	1.21	Custom	1.03	1.30	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.6
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
DAMALLA SE PROSPECT

A3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,099	126,953	212,788	Custom			
Net/Gross Ratio	v/v	0.10	0.18	0.25	Normal	0.05	0.39	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.8	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.9	76.6	
B_{oi}	rbbl/STB	1.09	1.14	1.21	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

B1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	20,834	127,342	275,952	Custom			
Net/Gross Ratio	v/v	0.11	0.25	0.42	Normal	0.05	0.70	
Porosity (ϕ)	%	19.0	20.5	22.0	Normal	15.6	24.8	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.2	74.8	
B_{oi}	rbbl/STB	1.13	1.21	1.30	Custom	1.07	1.40	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

B2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	8,017	32,909	70,335	Custom			
Net/Gross Ratio	v/v	0.11	0.25	0.42	Normal	0.05	0.70	
Porosity (ϕ)	%	19.0	20.5	22.0	Normal	16.1	24.7	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.2	74.7	
B_{oi}	rbbl/STB	1.13	1.21	1.30	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

B3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	24,344	329,228	463,742	Custom			
Net/Gross Ratio	v/v	0.11	0.25	0.42	Normal	0.05	0.69	
Porosity (ϕ)	%	19.0	20.5	22.0	Normal	15.7	24.7	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	43.1	74.6	
B_{oi}	rbbl/STB	1.13	1.21	1.30	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.6
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
DAMALLA SE PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,751	84,365	141,276	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	14.9	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.2	75.8	
B_{oi}	rbbl/STB	1.25	1.37	1.52	Custom	1.16	1.67	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,753	84,407	141,735	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	14.9	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.7	76.4	
B_{oi}	rbbl/STB	1.25	1.37	1.52	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,750	77,485	130,090	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	14.9	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.7	75.3	
B_{oi}	rbbl/STB	1.25	1.37	1.52	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,750	84,395	141,705	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	14.9	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.6	77.0	
B_{oi}	rbbl/STB	1.25	1.37	1.52	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.6
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
DAMALLA SE PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,876	37,614	65,834	Custom			
Net/Gross Ratio	v/v	0.06	0.13	0.20	Normal	0.01	0.34	
Porosity (ϕ)	%	10.3	13.5	16.9	Normal	8.0	20.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.29	1.42	1.59	Custom	1.20	1.75	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,514	26,470	53,559	Custom			
Net/Gross Ratio	v/v	0.06	0.13	0.20	Normal	0.01	0.34	
Porosity (ϕ)	%	10.3	13.5	16.9	Normal	8.0	20.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.29	1.42	1.59	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.7
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
DERGUIGUI PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,828	30,449	44,153	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	15.1	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.2	76.5	
B_{oi}	rbbl/STB	1.25	1.36	1.51	Custom	1.16	1.65	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,827	30,450	44,153	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	14.9	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.4	76.3	
B_{oi}	rbbl/STB	1.25	1.36	1.51	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,828	30,451	44,154	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	15.2	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.3	75.2	
B_{oi}	rbbl/STB	1.25	1.36	1.51	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,826	30,450	44,154	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	15.6	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	43.4	74.9	
B_{oi}	rbbl/STB	1.25	1.36	1.51	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.7
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
DERGUIGUI PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,826	30,450	44,159	Custom			
Net/Gross Ratio	v/v	0.06	0.13	0.20	Normal	0.01	0.34	
Porosity (ϕ)	%	10.3	13.5	16.9	Normal	8.0	20.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.30	1.42	1.59	Custom	1.20	1.75	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,826	29,610	43,372	Custom			
Net/Gross Ratio	v/v	0.06	0.13	0.20	Normal	0.01	0.34	
Porosity (ϕ)	%	10.3	13.5	16.9	Normal	8.0	20.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.30	1.42	1.59	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.8
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
N'DONAMBO PROSPECT

A1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	827	7,174	12,619	Custom			
Net/Gross Ratio	v/v	0.10	0.18	0.25	Normal	0.05	0.40	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.4	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.0	75.6	
B_{oi}	rbbl/STB	1.07	1.12	1.18	Custom	1.02	1.25	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

A3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	873	11,318	18,558	Custom			
Net/Gross Ratio	v/v	0.10	0.18	0.25	Normal	0.05	0.39	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.7	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.2	75.8	
B_{oi}	rbbl/STB	1.07	1.12	1.18	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

B1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	795	6,428	13,812	Custom			
Net/Gross Ratio	v/v	0.11	0.25	0.42	Normal	0.05	0.70	
Porosity (ϕ)	%	19.0	20.5	22.0	Normal	16.0	24.9	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.5	75.0	
B_{oi}	rbbl/STB	1.12	1.19	1.27	Custom	1.06	1.37	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

B2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	310	1,718	3,751	Custom			
Net/Gross Ratio	v/v	0.11	0.25	0.42	Normal	0.05	0.69	
Porosity (ϕ)	%	19.0	20.5	22.0	Normal	16.0	25.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.1	74.5	
B_{oi}	rbbl/STB	1.12	1.19	1.27	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.8
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
N'DONAMBO PROSPECT

B3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	897	15,042	22,116	Custom			
Net/Gross Ratio	v/v	0.11	0.25	0.42	Normal	0.05	0.69	
Porosity (ϕ)	%	19.0	20.5	22.0	Normal	15.9	24.8	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.0	75.3	
B_{oi}	rbbl/STB	1.12	1.19	1.27	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	896	15,040	22,083	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	15.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.6	75.7	
B_{oi}	rbbl/STB	1.23	1.34	1.48	Custom	1.15	1.62	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	896	15,041	22,116	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	14.9	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.6	74.8	
B_{oi}	rbbl/STB	1.23	1.34	1.48	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	897	13,331	19,882	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	15.7	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.1	74.6	
B_{oi}	rbbl/STB	1.23	1.34	1.48	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.8
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
N'DONAMBO PROSPECT

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	897	15,042	22,116	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	14.9	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.2	76.5	
B_{oi}	rbbl/STB	1.23	1.34	1.48	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	896	13,456	19,714	Custom			
Net/Gross Ratio	v/v	0.06	0.13	0.20	Normal	0.01	0.35	
Porosity (ϕ)	%	10.3	13.5	16.9	Normal	8.0	20.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.27	1.39	1.54	Custom	1.18	1.69	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	878	9,623	16,917	Custom			
Net/Gross Ratio	v/v	0.06	0.13	0.20	Normal	0.01	0.35	
Porosity (ϕ)	%	10.3	13.5	16.9	Normal	8.0	20.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.27	1.39	1.54	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.9
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
YEI N PROSPECT

M1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	550	6,075	8,698	Custom			
Net/Gross Ratio	v/v	0.07	0.19	0.32	Normal	0.01	0.50	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.6	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.3	74.6	
B_{oi}	rbbl/STB	1.12	1.18	1.27	Custom	1.05	1.36	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

M2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	549	6,102	8,721	Custom			
Net/Gross Ratio	v/v	0.07	0.19	0.32	Normal	0.01	0.50	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.8	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.0	74.9	
B_{oi}	rbbl/STB	1.12	1.18	1.27	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

M3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	549	6,102	8,719	Custom			
Net/Gross Ratio	v/v	0.07	0.19	0.32	Normal	0.01	0.50	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.2	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.2	75.0	
B_{oi}	rbbl/STB	1.12	1.18	1.27	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

A1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	549	5,982	8,606	Custom			
Net/Gross Ratio	v/v	0.10	0.18	0.25	Normal	0.05	0.39	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.6	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.5	75.8	
B_{oi}	rbbl/STB	1.12	1.18	1.27	Custom	1.06	1.36	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.9
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
YEI N PROSPECT

A3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	549	6,069	8,703	Custom			
Net/Gross Ratio	v/v	0.10	0.18	0.25	Normal	0.05	0.40	
Porosity (ϕ)	%	25.0	30.0	34.9	Normal	15.7	40.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.1	75.7	
B_{oi}	rbbl/STB	1.12	1.18	1.27	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

B1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	549	5,789	8,444	Custom			
Net/Gross Ratio	v/v	0.11	0.25	0.42	Normal	0.05	0.69	
Porosity (ϕ)	%	19.0	20.5	22.0	Normal	16.2	24.9	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	42.4	75.5	
B_{oi}	rbbl/STB	1.14	1.22	1.32	Custom	1.08	1.42	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

B2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	433	2,931	5,647	Custom			
Net/Gross Ratio	v/v	0.11	0.25	0.42	Normal	0.05	0.69	
Porosity (ϕ)	%	19.0	20.5	22.0	Normal	16.0	24.7	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.4	75.4	
B_{oi}	rbbl/STB	1.14	1.22	1.32	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

B3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	549	6,103	8,721	Custom			
Net/Gross Ratio	v/v	0.11	0.25	0.42	Normal	0.05	0.70	
Porosity (ϕ)	%	19.0	20.5	22.0	Normal	16.1	24.7	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.9	75.5	
B_{oi}	rbbl/STB	1.14	1.22	1.32	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.10
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
YEI S PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	491	4,122	6,321	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	15.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.3	74.8	
B_{oi}	rbbl/STB	1.24	1.35	1.49	Custom	1.15	1.64	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	490	4,122	6,322	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	15.3	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.8	75.7	
B_{oi}	rbbl/STB	1.24	1.35	1.49	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	491	4,122	6,323	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	15.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	45.3	75.5	
B_{oi}	rbbl/STB	1.24	1.35	1.49	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	491	4,123	6,322	Custom			
Net/Gross Ratio	v/v	0.06	0.17	0.30	Normal	0.01	0.50	
Porosity (ϕ)	%	9.1	10.5	12.0	Normal	8.0	15.0	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.6	76.5	
B_{oi}	rbbl/STB	1.24	1.35	1.49	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.1.10
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
YEI S PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	491	4,122	6,322	Custom			
Net/Gross Ratio	v/v	0.06	0.13	0.20	Normal	0.01	0.34	
Porosity (ϕ)	%	10.3	13.5	16.9	Normal	8.0	20.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.31	1.44	1.62	Custom	1.21	1.79	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	490	4,122	6,312	Custom			
Net/Gross Ratio	v/v	0.06	0.13	0.20	Normal	0.01	0.34	
Porosity (ϕ)	%	10.3	13.5	16.9	Normal	8.0	20.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.31	1.44	1.62	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE C.2.1
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
BEDAYA PROSPECT

Field Dependent Risks				
Source	Maturity	Migration	Timing	$P_{Dependent}$
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	Reservoir	Trap	Seal	$P_{Independent}$
C1	0.60	0.20	0.30	0.04
C2	0.60	0.20	0.30	0.04
C3	0.60	0.20	0.30	0.04
C4	0.60	0.20	0.30	0.04
D1	0.60	0.20	0.30	0.04
D2	0.60	0.20	0.30	0.04

Pg	0.10

TABLE C.2.2
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
BESSAMA PROSPECT

Field Dependent Risks				
Source	**Maturity**	**Migration**	**Timing**	**$P_{Dependent}$**
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	**Reservoir**	**Trap**	**Seal**	**$P_{Independent}$**
C1	0.70	0.30	0.30	0.06
C2	0.70	0.30	0.30	0.06
C3	0.70	0.30	0.30	0.06
C4	0.70	0.30	0.30	0.06
D1	0.70	0.30	0.30	0.06
D2	0.70	0.30	0.30	0.06

Pg	**0.17**

TABLE C.2.3
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
BEYARA PROSPECT

Field Dependent Risks				
Source	Maturity	Migration	Timing	$P_{Dependent}$
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	Reservoir	Trap	Seal	$P_{Independent}$
M1	0.60	0.40	0.20	0.05
M2	0.60	0.40	0.20	0.05
M3	0.60	0.40	0.20	0.05
A1	0.60	0.40	0.20	0.05
A3	0.60	0.40	0.20	0.05
B1	0.60	0.40	0.20	0.05
B2	0.60	0.40	0.20	0.05
B3	0.60	0.40	0.20	0.05

Pg	0.17

TABLE C.2.4
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
DAMALLA PROSPECT

Field Dependent Risks				
Source	**Maturity**	**Migration**	**Timing**	**$P_{Dependent}$**
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	**Reservoir**	**Trap**	**Seal**	**$P_{Independent}$**
M1	0.60	0.30	0.30	0.05
M2	0.60	0.30	0.30	0.05
M3	0.60	0.30	0.30	0.05
A1	0.60	0.30	0.30	0.05
A3	0.60	0.30	0.30	0.05
B1	0.60	0.30	0.30	0.05
B2	0.60	0.30	0.30	0.05
B3	0.60	0.30	0.30	0.05
C1	0.60	0.30	0.30	0.05
C2	0.60	0.30	0.30	0.05
C3	0.60	0.30	0.30	0.05
C4	0.60	0.30	0.30	0.05
D1	0.60	0.30	0.30	0.05
D2	0.60	0.30	0.30	0.05

Pg	**0.28**

TABLE C.2.5
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
DAMALLA EAST PROSPECT

Field Dependent Risks				
Source	Maturity	Migration	Timing	$P_{Dependent}$
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	Reservoir	Trap	Seal	$P_{Independent}$
M1	0.60	0.70	0.30	0.13
M2	0.60	0.70	0.30	0.13
M3	0.60	0.70	0.30	0.13
A1	0.60	0.70	0.30	0.13
A3	0.60	0.70	0.30	0.13
B1	0.60	0.70	0.30	0.13
B2	0.60	0.70	0.30	0.13
B3	0.60	0.70	0.30	0.13
C1	0.60	0.60	0.30	0.11
C2	0.60	0.60	0.30	0.11
C3	0.60	0.60	0.30	0.11
C4	0.60	0.60	0.30	0.11
D1	0.60	0.60	0.30	0.11
D2	0.60	0.60	0.30	0.11

Pg	0.42

TABLE C.2.6
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
DAMALLA SE PROSPECT

Field Dependent Risks				
Source	Maturity	Migration	Timing	$P_{Dependent}$
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	Reservoir	Trap	Seal	$P_{Independent}$
M1	0.60	0.30	0.30	0.05
M2	0.60	0.30	0.30	0.05
M3	0.60	0.30	0.30	0.05
A1	0.60	0.30	0.30	0.05
A3	0.60	0.30	0.30	0.05
B1	0.60	0.30	0.30	0.05
B2	0.60	0.30	0.30	0.05
B3	0.60	0.30	0.30	0.05
C1	0.60	0.30	0.30	0.05
C2	0.60	0.30	0.30	0.05
C3	0.60	0.30	0.30	0.05
C4	0.60	0.30	0.30	0.05
D1	0.60	0.30	0.30	0.05
D2	0.60	0.30	0.30	0.05

Pg	**0.29**

TABLE C.2.7
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
DERGUIGUI PROSPECT

Field Dependent Risks				
Source	**Maturity**	**Migration**	**Timing**	**$P_{Dependent}$**
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	**Reservoir**	**Trap**	**Seal**	**$P_{Independent}$**
C1	0.60	0.40	0.30	0.07
C2	0.60	0.40	0.30	0.07
C3	0.60	0.40	0.30	0.07
C4	0.60	0.40	0.30	0.07
D1	0.60	0.40	0.30	0.07
D2	0.60	0.40	0.30	0.07

Pg	**0.18**

TABLE C.2.8
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
N'DONAMBO PROSPECT

Field Dependent Risks				
Source	Maturity	Migration	Timing	$P_{Dependent}$
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	Reservoir	Trap	Seal	$P_{Independent}$
A1	0.60	0.30	0.30	0.05
A3	0.60	0.30	0.30	0.05
B1	0.60	0.30	0.30	0.05
B2	0.60	0.30	0.30	0.05
B3	0.60	0.30	0.30	0.05
C1	0.60	0.30	0.30	0.05
C2	0.60	0.30	0.30	0.05
C3	0.60	0.30	0.30	0.05
C4	0.60	0.30	0.30	0.05
D1	0.60	0.30	0.30	0.05
D2	0.60	0.30	0.30	0.05

Pg	0.24

TABLE C.2.9
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
YEI N PROSPECT

Field Dependent Risks				
Source	**Maturity**	**Migration**	**Timing**	**$P_{Dependent}$**
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	**Reservoir**	**Trap**	**Seal**	**$P_{Independent}$**
M1	0.50	0.40	0.30	0.06
M2	0.50	0.40	0.30	0.06
M3	0.50	0.40	0.30	0.06
A1	0.50	0.40	0.30	0.06
A3	0.50	0.40	0.30	0.06
B1	0.50	0.40	0.30	0.06
B2	0.50	0.40	0.30	0.06
B3	0.50	0.40	0.30	0.06

Pg	**0.20**

TABLE C.2.10
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
YEI S PROSPECT

Field Dependent Risks				
Source	**Maturity**	**Migration**	**Timing**	**$P_{Dependent}$**
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	**Reservoir**	**Trap**	**Seal**	**$P_{Independent}$**
C1	0.50	0.40	0.30	0.06
C2	0.50	0.40	0.30	0.06
C3	0.50	0.40	0.30	0.06
C4	0.50	0.40	0.30	0.06
D1	0.50	0.40	0.30	0.06
D2	0.50	0.40	0.30	0.06

Pg	**0.15**

TABLE C.3
SUMMARY OF INPUT PARAMETERS - ANALOGY METHOD PROSPECTS
GRIFFITHS ENERGY INTERNATIONAL INC.
DOH BLOCK (N'DONAMBO-DAMALLA RELATED)

Prospect	Pg	Prospect Area (Acre)			Undiscovered Petroleum Initially In Place per Area (MMSTB/Acre)			Unrisked Prospective Resources per Area (MMSTB/Acre)			Comment
		P90	P50	P10	P90	P50	P10	P90	P50	P10	
Bekondijo	0.16	74	193	494	3.4	8.4	26.1	0.7	1.9	6.9	Average DOH UPIIP and Unrisked PR per area.
Beongo	0.42	185	530	1,409	3.4	8.4	26.1	0.7	1.9	6.9	Average DOH ratios.

TABLE C.4
SUMMARY OF GROSS LEASE UNDISCOVERED PETROLEUM IN PLACE AND PROSPECTIVE RESOURCES
INCLUDING ADJUSTMENT FOR MINIMUM ECONOMIC FIELD SIZE
GRIFFITHS ENERGY INTERNATIONAL INC.
EFFECTIVE DATE: DECEMBER 31, 2012

	Gross Lease Unrisked UPIIP (MMSTB)							Gross Lease Unrisked Prospective Resources (MMSTB)				Gross Lease Partially Risked Prospective Resources (MMSTB)			
Prospect	P90	P50	Mean	P10	P_g	P_{mefs}	P_c	P90	P50	Mean	P10	P90	P50	Mean	P10
Bedaya	0.1	0.7	0.8	1.8	0.10	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bekondijo	0.3	1.6	4.7	12.0	0.16	0.20	0.03	1.7	3.1	4.6	9.9	0.1	0.1	0.1	0.3
Beongo	0.7	4.5	13.3	34.2	0.42	0.41	0.17	1.8	4.2	7.9	18.6	0.3	0.7	1.3	3.2
Bessama	0.0	0.0	0.0	0.1	0.17	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Beyara	0.5	4.5	5.9	13.2	0.17	0.37	0.06	1.7	2.6	3.1	5.2	0.1	0.2	0.2	0.3
Damalla	0.2	3.1	6.5	17.4	0.28	0.34	0.09	1.8	3.2	4.0	7.3	0.2	0.3	0.4	0.7
Damalla East	3.8	38.2	49.8	109.8	0.42	0.85	0.36	2.8	10.4	14.4	31.1	1.0	3.7	5.1	11.1
Damalla SE	0.6	12.0	24.7	65.8	0.29	0.61	0.18	2.0	6.3	9.6	21.4	0.4	1.1	1.7	3.7
Derguigui	0.2	1.6	2.0	4.1	0.18	0.04	0.01	1.6	1.9	2.0	2.6	0.0	0.0	0.0	0.0
N'Donambo	0.1	1.0	1.5	3.7	0.24	0.04	0.01	1.6	1.8	2.0	2.7	0.0	0.0	0.0	0.0
Yei N	0.1	1.1	1.3	2.8	0.20	0.01	0.00	1.6	1.9	1.9	2.3	0.0	0.0	0.0	0.0
Yei S	0.0	0.2	0.3	0.6	0.15	0.00	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Arithmetic Sum	6.6	68.4	110.9	265.5				16.5	35.3	49.5	101.3	2.0	6.1	8.9	19.4

Note:
(1) UPIIP - Undiscovered Petroleum Initially in Place
(2) Truncated for Minimum Economic Field Size (MEFS) of 1.5 MMSTB
(3) UPIIP values do not include an implied truncation for minimum economic field size
(4) Please review discussion in Summary concerning summation of unrisked totals.

APPENDIX D

CHARI EAST DOSEO BLOCK

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TABLE D.3 - ANALOGY METHOD INPUT PARAMATERS

Table D.3 Analogy Method Input Parameters **197**

TABLE D.4 - UPIIP AND PROSPECTIVE RESOURCES

Table D.4 Summary of Gross Lease Petroleum in Place and Prospective Resources **198**

TABLE D.1.1
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
EMOK PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	11,020	63,469	148,774	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	30.0	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	30.8	76.9	
B_{oi}	rbbl/STB	1.12	1.18	1.27	Custom	1.05	1.37	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	87,231	588,836	1,061,805	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	30.0	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	31.2	75.0	
B_{oi}	rbbl/STB	1.12	1.18	1.27	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	54,335	294,828	512,570	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	30.0	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	30.2	74.5	
B_{oi}	rbbl/STB	1.12	1.18	1.27	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	87,540	565,650	878,321	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	29.9	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	30.5	76.6	
B_{oi}	rbbl/STB	1.12	1.18	1.27	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.2
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAHIMI PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	12,248	88,480	254,246	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.78	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.0	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.3	
B_{oi}	rbbl/STB	1.14	1.23	1.33	Custom	1.07	1.45	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	7,544	45,887	127,411	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.74	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.1	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.7	
B_{oi}	rbbl/STB	1.14	1.23	1.33	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	12,635	89,057	237,708	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.77	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.0	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.7	
B_{oi}	rbbl/STB	1.14	1.23	1.33	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	31,965	200,234	410,917	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.79	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.1	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	76.8	
B_{oi}	rbbl/STB	1.14	1.23	1.33	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.2
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAHIMI PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	67,623	397,527	758,682	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.1	
B_{oi}	rbbl/STB	1.17	1.26	1.38	Custom	1.08	1.52	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	74,942	607,060	967,529	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.5	
B_{oi}	rbbl/STB	1.17	1.26	1.38	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	44,969	211,778	474,117	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.6	
B_{oi}	rbbl/STB	1.17	1.26	1.38	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	36,211	452,752	736,687	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.1	22.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	76.0	
B_{oi}	rbbl/STB	1.21	1.32	1.45	Custom	1.11	1.60	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.2
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAHIMI PROSPECT

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	13,299	115,853	305,959	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.1	21.9	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.0	
B_{oi}	rbbl/STB	1.21	1.32	1.45	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	29,350	332,856	708,245	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.0	21.9	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.0	
B_{oi}	rbbl/STB	1.21	1.32	1.45	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.3
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAKU D+E PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	6,183	59,415	115,290	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.7	
B_{oi}	rbbl/STB	1.14	1.22	1.32	Custom	1.06	1.44	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	6,720	80,483	138,499	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.2	
B_{oi}	rbbl/STB	1.14	1.22	1.32	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	4,285	34,663	81,522	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	77.6	
B_{oi}	rbbl/STB	1.14	1.22	1.32	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	45,952	480,335	764,128	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.1	21.9	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.6	
B_{oi}	rbbl/STB	1.18	1.28	1.40	Custom	1.10	1.55	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.3
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAKU D+E PROSPECT

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	16,254	127,282	327,653	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.0	22.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	76.6	
B_{oi}	rbbl/STB	1.18	1.28	1.40	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	35,957	352,150	739,280	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.1	21.9	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	77.1	
B_{oi}	rbbl/STB	1.18	1.28	1.40	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.4
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAKU NE PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	18,140	84,671	203,409	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.80	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.1	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.5	
B_{oi}	rbbl/STB	1.12	1.19	1.28	Custom	1.04	1.39	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	13,063	46,468	113,170	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.77	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.0	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	78.6	
B_{oi}	rbbl/STB	1.12	1.19	1.28	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	18,136	85,538	193,297	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.73	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.2	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.9	
B_{oi}	rbbl/STB	1.12	1.19	1.28	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	35,125	172,398	299,252	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.75	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.2	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.2	
B_{oi}	rbbl/STB	1.12	1.19	1.28	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.4
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAKU NE PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	37,507	266,411	428,403	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.5	
B_{oi}	rbbl/STB	1.16	1.25	1.35	Custom	1.07	1.48	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	37,620	338,464	476,125	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.6	
B_{oi}	rbbl/STB	1.16	1.25	1.35	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	32,286	164,968	328,366	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	76.1	
B_{oi}	rbbl/STB	1.16	1.25	1.35	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	37,902	214,318	327,011	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.0	21.9	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.7	
B_{oi}	rbbl/STB	1.20	1.30	1.43	Custom	1.11	1.57	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.4
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAKU NE PROSPECT

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	18,882	64,313	153,853	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.0	22.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.2	
B_{oi}	rbbl/STB	1.20	1.30	1.43	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	32,557	161,714	310,043	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.0	22.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	76.0	
B_{oi}	rbbl/STB	1.20	1.30	1.43	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.5
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAKU SW PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	9,269	73,328	201,309	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.75	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.0	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	76.7	
B_{oi}	rbbl/STB	1.09	1.17	1.24	Custom	1.03	1.34	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	6,357	39,128	106,050	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.74	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.1	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.7	
B_{oi}	rbbl/STB	1.09	1.17	1.24	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	9,517	72,379	191,641	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.74	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.2	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.6	
B_{oi}	rbbl/STB	1.09	1.17	1.24	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	20,695	157,763	317,135	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.74	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.1	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.7	
B_{oi}	rbbl/STB	1.09	1.17	1.24	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.5
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAKU SW PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	27,339	278,551	551,669	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.7	
B_{oi}	rbbl/STB	1.13	1.22	1.31	Custom	1.06	1.43	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	29,269	416,311	690,874	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.8	
B_{oi}	rbbl/STB	1.13	1.22	1.31	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	19,353	152,183	349,024	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.6	
B_{oi}	rbbl/STB	1.13	1.22	1.31	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	24,252	204,847	355,931	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.0	22.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.6	
B_{oi}	rbbl/STB	1.18	1.27	1.39	Custom	1.09	1.54	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.5
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAKU SW PROSPECT

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	8,937	56,156	149,705	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.0	22.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.8	
B_{oi}	rbbl/STB	1.18	1.27	1.39	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	19,314	150,038	329,729	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.0	22.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	76.5	
B_{oi}	rbbl/STB	1.18	1.27	1.39	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.6
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM C PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	8,365	55,148	120,724	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.76	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.1	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.0	
B_{oi}	rbbl/STB	1.08	1.15	1.23	Custom	1.02	1.32	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	6,704	33,285	78,205	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.73	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.1	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.5	
B_{oi}	rbbl/STB	1.08	1.15	1.23	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	8,389	56,535	118,857	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.77	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.1	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.1	
B_{oi}	rbbl/STB	1.08	1.15	1.23	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	10,745	96,963	148,253	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.75	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.2	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.6	
B_{oi}	rbbl/STB	1.08	1.15	1.23	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.6
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM C PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	10,746	111,907	166,603	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.3	
B_{oi}	rbbl/STB	1.12	1.20	1.29	Custom	1.04	1.39	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	10,746	117,041	170,001	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.8	
B_{oi}	rbbl/STB	1.12	1.20	1.29	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	10,429	90,513	148,620	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.9	
B_{oi}	rbbl/STB	1.12	1.20	1.29	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	10,752	111,289	159,909	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.0	21.9	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	78.9	
B_{oi}	rbbl/STB	1.16	1.25	1.35	Custom	1.08	1.48	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.6
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM C PROSPECT

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	8,772	45,511	99,701	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.1	21.9	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.8	
B_{oi}	rbbl/STB	1.16	1.25	1.35	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	10,565	90,360	147,444	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.0	21.9	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.2	
B_{oi}	rbbl/STB	1.16	1.25	1.35	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.7
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM D PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	10,524	122,913	185,046	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	76.2	
B_{oi}	rbbl/STB	1.08	1.15	1.22	Custom	1.02	1.31	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	10,521	130,161	189,756	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.7	
B_{oi}	rbbl/STB	1.08	1.15	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	10,301	98,303	163,818	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.5	
B_{oi}	rbbl/STB	1.08	1.15	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	10,525	121,627	174,656	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.1	21.9	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	76.0	
B_{oi}	rbbl/STB	1.12	1.20	1.29	Custom	1.05	1.40	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.7
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM D PROSPECT

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	8,235	47,736	107,483	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.1	22.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.6	
B_{oi}	rbbl/STB	1.12	1.20	1.29	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	10,274	97,733	161,719	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.1	21.9	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.2	
B_{oi}	rbbl/STB	1.12	1.20	1.29	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.8
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM E PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	182,080	829,203	1,578,776	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.1	
B_{oi}	rbbl/STB	1.06	1.13	1.20	Custom	1.01	1.28	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	214,223	1,332,231	2,112,445	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.7	
B_{oi}	rbbl/STB	1.06	1.13	1.20	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	110,340	423,790	923,761	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.8	
B_{oi}	rbbl/STB	1.06	1.13	1.20	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	154,985	545,562	857,129	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.0	21.9	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.5	
B_{oi}	rbbl/STB	1.11	1.18	1.26	Custom	1.04	1.37	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.8
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM E PROSPECT

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	47,493	142,602	366,609	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.0	21.9	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	76.1	
B_{oi}	rbbl/STB	1.11	1.18	1.26	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	109,713	406,667	836,490	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.1	22.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.9	
B_{oi}	rbbl/STB	1.11	1.18	1.26	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.9
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM F PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	301	5,672	13,940	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.74	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.0	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.7	
B_{oi}	rbbl/STB	1.08	1.14	1.22	Custom	1.02	1.30	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	212	3,232	8,848	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.73	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.1	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	77.1	
B_{oi}	rbbl/STB	1.08	1.14	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	319	5,712	13,611	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.73	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.1	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.7	
B_{oi}	rbbl/STB	1.08	1.14	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	427	10,422	18,181	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.73	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.1	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	78.6	
B_{oi}	rbbl/STB	1.08	1.14	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.9
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM F PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	433	12,551	21,242	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.6	
B_{oi}	rbbl/STB	1.11	1.19	1.27	Custom	1.04	1.38	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	436	13,409	22,007	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.7	
B_{oi}	rbbl/STB	1.11	1.19	1.27	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	413	9,717	18,231	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.9	
B_{oi}	rbbl/STB	1.11	1.19	1.27	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	436	12,360	19,675	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.0	22.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.9	
B_{oi}	rbbl/STB	1.15	1.24	1.34	Custom	1.07	1.47	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.9
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM F PROSPECT

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	291	4,658	11,413	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.1	22.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	76.7	
B_{oi}	rbbl/STB	1.15	1.24	1.34	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	413	9,646	18,010	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.0	21.9	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.7	
B_{oi}	rbbl/STB	1.15	1.24	1.34	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.10
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM G PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	416	3,639	5,922	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.78	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.0	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	77.5	
B_{oi}	rbbl/STB	1.06	1.13	1.20	Custom	1.01	1.27	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	393	2,679	5,081	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.75	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.0	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.2	
B_{oi}	rbbl/STB	1.06	1.13	1.20	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	434	3,663	5,919	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.79	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.0	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.7	
B_{oi}	rbbl/STB	1.06	1.13	1.20	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	467	4,614	6,739	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.73	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.2	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.9	
B_{oi}	rbbl/STB	1.06	1.13	1.20	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.10
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM G PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	467	4,656	6,782	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.6	
B_{oi}	rbbl/STB	1.10	1.17	1.25	Custom	1.03	1.35	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	467	4,656	6,786	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.8	
B_{oi}	rbbl/STB	1.10	1.17	1.25	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	466	4,491	6,627	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.8	
B_{oi}	rbbl/STB	1.10	1.17	1.25	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	467	4,656	6,786	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.1	22.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.2	
B_{oi}	rbbl/STB	1.14	1.22	1.32	Custom	1.06	1.44	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.10
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM G PROSPECT

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	452	3,433	5,589	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.0	22.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.8	
B_{oi}	rbbl/STB	1.14	1.22	1.32	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	467	4,516	6,625	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.0	22.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.7	
B_{oi}	rbbl/STB	1.14	1.22	1.32	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.11
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM H PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	774	5,600	10,557	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.73	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.1	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.1	
B_{oi}	rbbl/STB	1.06	1.13	1.20	Custom	1.01	1.28	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	676	3,630	8,018	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.72	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.1	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	77.1	
B_{oi}	rbbl/STB	1.06	1.13	1.20	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	766	5,717	10,490	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.76	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.1	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.0	
B_{oi}	rbbl/STB	1.06	1.13	1.20	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	893	8,407	12,246	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.75	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.0	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.6	
B_{oi}	rbbl/STB	1.06	1.13	1.20	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.11
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM H PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	893	8,857	12,720	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.9	
B_{oi}	rbbl/STB	1.10	1.17	1.25	Custom	1.03	1.36	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	893	8,908	12,791	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.3	
B_{oi}	rbbl/STB	1.10	1.17	1.25	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	889	7,968	12,107	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.3	
B_{oi}	rbbl/STB	1.10	1.17	1.25	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	892	8,903	12,765	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.1	21.9	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.6	
B_{oi}	rbbl/STB	1.14	1.22	1.32	Custom	1.06	1.44	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.11
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM H PROSPECT

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	827	4,809	9,385	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.0	22.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	76.6	
B_{oi}	rbbl/STB	1.14	1.22	1.32	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	887	7,979	12,044	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.0	22.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.7	
B_{oi}	rbbl/STB	1.14	1.22	1.32	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.12
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM I PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	5,923	44,289	112,340	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.75	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.0	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	77.7	
B_{oi}	rbbl/STB	1.08	1.15	1.22	Custom	1.02	1.31	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	4,107	24,368	65,889	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.75	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.0	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.5	
B_{oi}	rbbl/STB	1.08	1.15	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	5,952	44,994	108,565	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.80	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.0	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.9	
B_{oi}	rbbl/STB	1.08	1.15	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	10,024	87,935	158,447	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.75	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.1	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.6	
B_{oi}	rbbl/STB	1.08	1.15	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.12
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM I PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	10,788	121,647	203,242	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	76.8	
B_{oi}	rbbl/STB	1.11	1.19	1.28	Custom	1.04	1.38	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	10,881	143,021	224,147	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.6	
B_{oi}	rbbl/STB	1.11	1.19	1.28	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	9,775	83,327	165,448	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.9	
B_{oi}	rbbl/STB	1.11	1.19	1.28	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	10,795	107,180	171,761	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.1	22.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.6	
B_{oi}	rbbl/STB	1.15	1.24	1.35	Custom	1.07	1.48	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.12
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM I PROSPECT

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	5,832	35,095	87,194	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.0	21.9	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.9	
B_{oi}	rbbl/STB	1.15	1.24	1.35	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	9,640	82,061	160,042	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.1	22.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.6	
B_{oi}	rbbl/STB	1.15	1.24	1.35	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.13
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM I WEST PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	6,127	45,944	97,019	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.74	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.1	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.1	
B_{oi}	rbbl/STB	1.08	1.15	1.22	Custom	1.02	1.30	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	5,005	28,049	65,017	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.73	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.1	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	76.3	
B_{oi}	rbbl/STB	1.08	1.15	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	6,185	46,834	95,799	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.74	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.0	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	77.1	
B_{oi}	rbbl/STB	1.08	1.15	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	7,134	78,367	117,082	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.78	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.1	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.9	
B_{oi}	rbbl/STB	1.08	1.15	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.13
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM I WEST PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	7,147	88,922	129,138	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.7	
B_{oi}	rbbl/STB	1.11	1.19	1.28	Custom	1.04	1.38	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	7,149	91,384	131,381	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.4	
B_{oi}	rbbl/STB	1.11	1.19	1.28	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	7,093	73,959	116,622	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.6	
B_{oi}	rbbl/STB	1.11	1.19	1.28	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	7,147	89,113	126,161	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.0	22.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.8	
B_{oi}	rbbl/STB	1.15	1.24	1.34	Custom	1.07	1.47	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.13
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM I WEST PROSPECT

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	6,274	37,884	81,250	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.0	21.9	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.5	
B_{oi}	rbbl/STB	1.15	1.24	1.34	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	7,074	74,012	116,238	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.0	22.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.6	
B_{oi}	rbbl/STB	1.15	1.24	1.34	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.14
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
SAHR PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,658	39,267	122,867	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.77	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.1	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	77.1	
B_{oi}	rbbl/STB	1.08	1.14	1.22	Custom	1.02	1.31	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,674	21,808	69,538	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.73	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.1	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.6	
B_{oi}	rbbl/STB	1.08	1.14	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,765	38,805	117,611	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.74	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.2	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.7	
B_{oi}	rbbl/STB	1.08	1.14	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	5,348	84,070	185,158	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.73	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	15.1	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	76.2	
B_{oi}	rbbl/STB	1.08	1.14	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.14
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
SAHR PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	6,625	125,956	275,178	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.9	
B_{oi}	rbbl/STB	1.11	1.19	1.27	Custom	1.04	1.38	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	7,039	164,740	334,141	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.1	
B_{oi}	rbbl/STB	1.11	1.19	1.27	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	4,882	77,766	197,832	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.8	
B_{oi}	rbbl/STB	1.11	1.19	1.27	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	6,088	106,278	209,009	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.1	22.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.9	
B_{oi}	rbbl/STB	1.15	1.24	1.34	Custom	1.07	1.46	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.14
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
SAHR PROSPECT

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,367	32,495	92,821	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.1	22.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.8	
B_{oi}	rbbl/STB	1.15	1.24	1.34	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	4,766	76,202	189,755	Custom			
Net/Gross Ratio	v/v	0.43	0.67	0.90	Normal	0.30	1.00	
Porosity (ϕ)	%	10.0	13.5	17.0	Normal	5.0	22.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.9	
B_{oi}	rbbl/STB	1.15	1.24	1.34	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.15
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
TEGA NE PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	183	26,576	87,209	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.6	
B_{oi}	rbbl/STB	1.18	1.28	1.39	Custom	1.09	1.53	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	75	9,646	39,694	Custom			
Net/Gross Ratio	v/v	0.24	0.56	0.86	Normal	0.05	1.00	
Porosity (ϕ)	%	13.5	18.6	23.8	Normal	10.0	28.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.6	
B_{oi}	rbbl/STB	1.18	1.28	1.39	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	623	3,638	7,115	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.80	
Porosity (ϕ)	%	10.0	11.5	13.0	Normal	7.0	15.9	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.9	
B_{oi}	rbbl/STB	1.23	1.34	1.48	Custom	1.13	1.63	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,301	20,328	30,221	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.74	
Porosity (ϕ)	%	10.0	11.5	13.0	Normal	6.9	16.2	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.0	
B_{oi}	rbbl/STB	1.23	1.34	1.48	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.15
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
TEGA NE PROSPECT

E3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,801	12,211	22,560	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.77	
Porosity (ϕ)	%	10.0	11.5	13.0	Normal	6.8	16.4	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.2	
B_{oi}	rbbl/STB	1.23	1.34	1.48	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,797	12,235	22,644	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.73	
Porosity (ϕ)	%	10.0	11.5	13.0	Normal	6.8	16.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.6	
B_{oi}	rbbl/STB	1.23	1.34	1.48	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E5								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,301	20,265	30,148	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.74	
Porosity (ϕ)	%	10.0	11.5	13.0	Normal	6.8	16.1	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.2	
B_{oi}	rbbl/STB	1.23	1.34	1.48	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.16
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
TEGA SW PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,247	31,606	81,341	Custom			
Net/Gross Ratio	v/v	0.15	0.20	0.24	Normal	0.06	0.33	
Porosity (ϕ)	%	14.3	19.5	24.9	Normal	10.0	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.6	
B_{oi}	rbbl/STB	1.11	1.18	1.27	Custom	1.04	1.37	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	97	1,577	3,689	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.78	
Porosity (ϕ)	%	10.0	11.5	13.0	Normal	6.9	15.9	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	76.5	
B_{oi}	rbbl/STB	1.23	1.34	1.48	Custom	1.13	1.64	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	73	6,907	13,518	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.73	
Porosity (ϕ)	%	10.0	11.5	13.0	Normal	7.1	16.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	76.3	
B_{oi}	rbbl/STB	1.23	1.34	1.48	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	68	4,447	9,848	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.75	
Porosity (ϕ)	%	10.0	11.5	13.0	Normal	6.9	16.2	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.3	
B_{oi}	rbbl/STB	1.23	1.34	1.48	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.1.16
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
TEGA SW PROSPECT

E4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	69	4,520	9,844	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.76	
Porosity (ϕ)	%	10.0	11.5	13.0	Normal	7.1	16.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.5	
B_{oi}	rbbl/STB	1.23	1.34	1.48	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E5								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	73	6,894	13,520	Custom			
Net/Gross Ratio	v/v	0.11	0.26	0.42	Normal	0.01	0.73	
Porosity (ϕ)	%	10.0	11.5	13.0	Normal	7.1	16.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	74.9	
B_{oi}	rbbl/STB	1.23	1.34	1.48	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE D.2.1
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
EMOK PROSPECT

Field Dependent Risks				
Source	Maturity	Migration	Timing	$P_{Dependent}$
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	Reservoir	Trap	Seal	$P_{Independent}$
C1	0.50	0.70	0.30	0.11
C2	0.50	0.70	0.30	0.11
C3	0.50	0.70	0.30	0.11
C4	0.50	0.70	0.30	0.11

Pg	0.19

TABLE D.2.2
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAHIMI PROSPECT

Field Dependent Risks				
Source	**Maturity**	**Migration**	**Timing**	**$P_{Dependent}$**
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	**Reservoir**	**Trap**	**Seal**	**$P_{Independent}$**
C1	0.30	0.70	0.40	0.08
C2	0.30	0.70	0.40	0.08
C3	0.30	0.70	0.40	0.08
C4	0.30	0.70	0.40	0.08
D1	0.30	0.70	0.40	0.08
D2	0.30	0.70	0.40	0.08
D3	0.30	0.70	0.40	0.08
E1	0.30	0.70	0.40	0.08
E2	0.30	0.70	0.40	0.08
E3	0.30	0.70	0.40	0.08

Pg	**0.30**

TABLE D.2.3
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAKU D+E PROSPECT

Field Dependent Risks				
Source	**Maturity**	**Migration**	**Timing**	**$P_{Dependent}$**
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	**Reservoir**	**Trap**	**Seal**	**$P_{Independent}$**
D1	0.50	0.70	0.60	0.21
D2	0.50	0.70	0.60	0.21
D3	0.50	0.70	0.60	0.21
E1	0.50	0.70	0.60	0.21
E2	0.50	0.70	0.60	0.21
E3	0.50	0.70	0.60	0.21

Pg	**0.39**

TABLE D.2.4
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAKU NE PROSPECT

Field Dependent Risks				
Source	**Maturity**	**Migration**	**Timing**	**$P_{Dependent}$**
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	**Reservoir**	**Trap**	**Seal**	**$P_{Independent}$**
C1	0.30	0.70	0.40	0.08
C2	0.30	0.70	0.40	0.08
C3	0.30	0.70	0.40	0.08
C4	0.30	0.70	0.40	0.08
D1	0.30	0.70	0.40	0.08
D2	0.30	0.70	0.40	0.08
D3	0.30	0.70	0.40	0.08
E1	0.30	0.70	0.40	0.08
E2	0.30	0.70	0.40	0.08
E3	0.30	0.70	0.40	0.08

Pg	**0.30**

TABLE D.2.5
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAKU SW PROSPECT

Field Dependent Risks				
Source	**Maturity**	**Migration**	**Timing**	**$P_{Dependent}$**
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	**Reservoir**	**Trap**	**Seal**	**$P_{Independent}$**
C1	0.30	0.70	0.40	0.08
C2	0.30	0.70	0.40	0.08
C3	0.30	0.70	0.40	0.08
C4	0.30	0.70	0.40	0.08
D1	0.30	0.70	0.40	0.08
D2	0.30	0.70	0.40	0.08
D3	0.30	0.70	0.40	0.08
E1	0.30	0.70	0.40	0.08
E2	0.30	0.70	0.40	0.08
E3	0.30	0.70	0.40	0.08

Pg	**0.30**

TABLE D.2.6
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM C PROSPECT

Field Dependent Risks				
Source	Maturity	Migration	Timing	$P_{Dependent}$
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	Reservoir	Trap	Seal	$P_{Independent}$
C1	0.40	0.50	0.20	0.04
C2	0.40	0.50	0.20	0.04
C3	0.40	0.50	0.20	0.04
C4	0.40	0.50	0.20	0.04
D1	0.40	0.50	0.20	0.04
D2	0.40	0.50	0.20	0.04
D3	0.40	0.50	0.20	0.04
E1	0.40	0.50	0.20	0.04
E2	0.40	0.50	0.20	0.04
E3	0.40	0.50	0.20	0.04

Pg	0.17

TABLE D.2.7
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM D PROSPECT

Field Dependent Risks				
Source	**Maturity**	**Migration**	**Timing**	**$P_{Dependent}$**
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	**Reservoir**	**Trap**	**Seal**	**$P_{Independent}$**
D1	0.40	0.50	0.20	0.04
D2	0.40	0.50	0.20	0.04
D3	0.40	0.50	0.20	0.04
E1	0.40	0.50	0.20	0.04
E2	0.40	0.50	0.20	0.04
E3	0.40	0.50	0.20	0.04

Pg	**0.11**

TABLE D.2.8
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM E PROSPECT

Field Dependent Risks				
Source	**Maturity**	**Migration**	**Timing**	**$P_{Dependent}$**
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	**Reservoir**	**Trap**	**Seal**	**$P_{Independent}$**
D1	0.40	0.50	0.20	0.04
D2	0.40	0.50	0.20	0.04
D3	0.40	0.50	0.20	0.04
E1	0.40	0.50	0.20	0.04
E2	0.40	0.50	0.20	0.04
E3	0.40	0.50	0.20	0.04

Pg	**0.11**

TABLE D.2.9
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM F PROSPECT

Field Dependent Risks				
Source	Maturity	Migration	Timing	$P_{Dependent}$
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	Reservoir	Trap	Seal	$P_{Independent}$
C1	0.40	0.50	0.20	0.04
C2	0.40	0.50	0.20	0.04
C3	0.40	0.50	0.20	0.04
C4	0.40	0.50	0.20	0.04
D1	0.40	0.50	0.20	0.04
D2	0.40	0.50	0.20	0.04
D3	0.40	0.50	0.20	0.04
E1	0.40	0.50	0.20	0.04
E2	0.40	0.50	0.20	0.04
E3	0.40	0.50	0.20	0.04

Pg	0.17

TABLE D.2.10
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM G PROSPECT

Field Dependent Risks				
Source	**Maturity**	**Migration**	**Timing**	**$P_{Dependent}$**
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	**Reservoir**	**Trap**	**Seal**	**$P_{Independent}$**
C1	0.40	0.50	0.20	0.04
C2	0.40	0.50	0.20	0.04
C3	0.40	0.50	0.20	0.04
C4	0.40	0.50	0.20	0.04
D1	0.40	0.50	0.20	0.04
D2	0.40	0.50	0.20	0.04
D3	0.40	0.50	0.20	0.04
E1	0.40	0.50	0.20	0.04
E2	0.40	0.50	0.20	0.04
E3	0.40	0.50	0.20	0.04

Pg	**0.17**

TABLE D.2.11
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM H PROSPECT

Field Dependent Risks				
Source	Maturity	Migration	Timing	$P_{Dependent}$
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	Reservoir	Trap	Seal	$P_{Independent}$
C1	0.40	0.50	0.20	0.04
C2	0.40	0.50	0.20	0.04
C3	0.40	0.50	0.20	0.04
C4	0.40	0.50	0.20	0.04
D1	0.40	0.50	0.20	0.04
D2	0.40	0.50	0.20	0.04
D3	0.40	0.50	0.20	0.04
E1	0.40	0.50	0.20	0.04
E2	0.40	0.50	0.20	0.04
E3	0.40	0.50	0.20	0.04

Pg	0.17

TABLE D.2.12
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM I PROSPECT

Field Dependent Risks				
Source	**Maturity**	**Migration**	**Timing**	**$P_{Dependent}$**
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	**Reservoir**	**Trap**	**Seal**	**$P_{Independent}$**
C1	0.40	0.50	0.20	0.04
C2	0.40	0.50	0.20	0.04
C3	0.40	0.50	0.20	0.04
C4	0.40	0.50	0.20	0.04
D1	0.40	0.50	0.20	0.04
D2	0.40	0.50	0.20	0.04
D3	0.40	0.50	0.20	0.04
E1	0.40	0.50	0.20	0.04
E2	0.40	0.50	0.20	0.04
E3	0.40	0.50	0.20	0.04

Pg	**0.17**

TABLE D.2.13
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
OUHAM I WEST PROSPECT

Field Dependent Risks				
Source	Maturity	Migration	Timing	$P_{Dependent}$
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	Reservoir	Trap	Seal	$P_{Independent}$
C1	0.40	0.50	0.20	0.04
C2	0.40	0.50	0.20	0.04
C3	0.40	0.50	0.20	0.04
C4	0.40	0.50	0.20	0.04
D1	0.40	0.50	0.20	0.04
D2	0.40	0.50	0.20	0.04
D3	0.40	0.50	0.20	0.04
E1	0.40	0.50	0.20	0.04
E2	0.40	0.50	0.20	0.04
E3	0.40	0.50	0.20	0.04

Pg	0.17

TABLE D.2.14
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
SARH PROSPECT

Field Dependent Risks				
Source	Maturity	Migration	Timing	$P_{Dependent}$
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	Reservoir	Trap	Seal	$P_{Independent}$
C1	0.40	0.50	0.20	0.04
C2	0.40	0.50	0.20	0.04
C3	0.40	0.50	0.20	0.04
C4	0.40	0.50	0.20	0.04
D1	0.40	0.50	0.20	0.04
D2	0.40	0.50	0.20	0.04
D3	0.40	0.50	0.20	0.04
E1	0.40	0.50	0.20	0.04
E2	0.40	0.50	0.20	0.04
E3	0.40	0.50	0.20	0.04

Pg	0.17

TABLE D.2.15
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
TEGA NE PROSPECT

Field Dependent Risks				
Source	**Maturity**	**Migration**	**Timing**	**$P_{Dependent}$**
1.00	0.90	0.90	0.90	0.73

Independent Risks				
Formation	**Reservoir**	**Trap**	**Seal**	**$P_{Independent}$**
D1	0.30	0.40	0.30	0.04
D2	0.30	0.40	0.30	0.04
E1	0.30	0.40	0.30	0.04
E2	0.30	0.40	0.30	0.04
E3	0.30	0.40	0.30	0.04
E4	0.30	0.40	0.30	0.04
E5	0.30	0.40	0.30	0.04

Pg	**0.16**

TABLE D.2.16
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
TEGA SW PROSPECT

Field Dependent Risks				
Source	**Maturity**	**Migration**	**Timing**	**$P_{Dependent}$**
1.00	0.90	0.90	0.90	0.73

Independent Risks				
Formation	**Reservoir**	**Trap**	**Seal**	**$P_{Independent}$**
C1	0.30	0.40	0.30	0.04
E1	0.30	0.40	0.30	0.04
E2	0.30	0.40	0.30	0.04
E3	0.30	0.40	0.30	0.04
E4	0.30	0.40	0.30	0.04
E5	0.30	0.40	0.30	0.04

Pg	**0.14**

TABLE D.3
SUMMARY OF INPUT PARAMETERS - ANALOGY METHOD PROSPECTS
GRIFFITHS ENERGY INTERNATIONAL INC.
CHARI EAST DOSEO BLOCK

Prospect	Pg	Prospect Area (Acre)			Undiscovered Petroleum Initially In Place per Area (MMSTB/Acre)			Unrisked Prospective Resources per Area (MMSTB/Acre)			Comment
		P90	P50	P10	P90	P50	P10	P90	P50	P10	
Bangono	0.30	371	1,172	3,707	14.8	21.0	53.5	3.1	4.7	13.7	Average Doseo UPIIP and Unrisked PR per area.
Chari G	0.30	371	1,211	3,954	14.8	21.0	53.5	3.1	4.7	13.7	Average Doseo ratios.
Dokolo A	0.30	99	553	2,780	14.8	21.0	53.5	3.1	4.7	13.7	Average Doseo ratios.
Dokolo B	0.30	556	1,790	4,151	14.8	21.0	53.5	3.1	4.7	13.7	Average Doseo ratios.
Gondey	0.19	297	1,495	3,015	5.6	8.4	19.9	1.1	1.9	5.2	Doseo ratios, adjusted for C-sand only.
Goro	0.07	99	234	494	14.8	21.0	53.5	3.1	4.7	13.7	Average Doseo ratios.
Hori	0.30	210	580	1,557	14.8	21.0	53.5	3.1	4.7	13.7	Average Doseo ratios.
Mahimi B	0.30	640	1,662	4,314	14.8	21.0	53.5	3.1	4.7	13.7	Average Doseo ratios.
Mahimi D	0.30	198	546	1,507	14.8	21.0	53.5	3.1	4.7	13.7	Average Doseo ratios.
Tega East A	0.19	247	547	1,236	14.8	21.0	53.5	3.1	4.7	13.7	Average Doseo ratios.
Tega East B	0.19	247	586	1,384	14.8	21.0	53.5	3.1	4.7	13.7	Average Doseo ratios.
Tega South	0.19	124	445	1,606	14.8	21.0	53.5	3.1	4.7	13.7	Average Doseo ratios.

TABLE D.4
SUMMARY OF GROSS LEASE UNDISCOVERED PETROLEUM IN PLACE AND PROSPECTIVE RESOURCES
INCLUDING ADJUSTMENT FOR MINIMUM ECONOMIC FIELD SIZE
GRIFFITHS ENERGY INTERNATIONAL INC.
EFFECTIVE DATE: DECEMBER 31, 2012

	Gross Lease Unrisked UPIIP (MMSTB)							Gross Lease Unrisked Prospective Resources (MMSTB)				Gross Lease Partially Risked Prospective Resources (MMSTB)			
Prospect	P90	P50	Mean	P10	P_g	P_{mefs}	P_c	P90	P50	Mean	P10	P90	P50	Mean	P10
Bangono	5.7	24.6	73.3	184.0	0.30	0.84	0.25	2.1	7.7	22.1	55.1	0.5	1.9	5.5	13.8
Chari G	5.7	25.4	78.1	196.1	0.30	0.84	0.25	2.1	7.9	23.5	58.8	0.5	2.0	5.9	14.7
Dokolo A	1.5	11.6	54.9	136.1	0.30	0.61	0.18	2.0	7.2	22.9	57.6	0.4	1.3	4.2	10.5
Dokolo B	8.6	37.6	83.8	208.7	0.30	0.93	0.28	2.4	9.6	22.6	56.4	0.7	2.7	6.3	15.6
Emok	12.4	132.2	172.7	396.5	0.19	0.93	0.17	4.7	29.3	46.0	105.5	0.8	5.1	7.9	18.2
Gondey	2.2	13.0	24.2	59.0	0.19	0.70	0.13	2.0	5.1	8.7	19.6	0.3	0.7	1.1	2.5
Goro	1.5	4.9	10.3	24.9	0.07	0.41	0.03	1.7	3.4	5.3	11.7	0.1	0.1	0.2	0.3
Hori	3.2	12.2	31.3	77.7	0.30	0.67	0.20	1.9	5.2	11.4	27.5	0.4	1.0	2.3	5.5
Mahimi	6.5	78.4	128.3	327.1	0.30	0.89	0.26	3.7	20.9	36.1	88.4	1.0	5.5	9.5	23.4
Mahimi B	9.7	34.9	87.2	215.6	0.30	0.98	0.29	2.2	8.2	22.6	56.2	0.6	2.4	6.6	16.3
Mahimi D	3.0	11.5	30.2	75.2	0.30	0.65	0.19	1.9	5.1	11.3	27.4	0.4	1.0	2.2	5.3
Maku D+E	6.1	62.8	107.5	275.1	0.39	0.89	0.35	3.4	18.2	30.6	76.1	1.2	6.3	10.6	26.3
Maku NE	6.3	48.7	74.6	176.4	0.30	0.89	0.27	2.8	13.1	20.9	48.7	0.8	3.5	5.6	13.0
Maku SW	4.8	50.6	84.1	212.2	0.30	0.87	0.26	2.9	14.4	24.2	58.4	0.8	3.7	6.3	15.1
Ouham C	2.8	21.4	30.7	70.4	0.17	0.78	0.13	2.3	6.6	9.4	20.0	0.3	0.9	1.2	2.6
Ouham D	2.8	30.3	40.2	91.6	0.11	0.82	0.09	2.4	8.9	12.0	26.8	0.2	0.8	1.1	2.4
Ouham E	29.0	180.1	267.9	655.4	0.11	0.97	0.11	8.0	38.9	68.3	173.9	0.9	4.2	7.3	18.7
Ouham F	0.1	2.4	3.5	8.5	0.17	0.19	0.03	1.6	2.2	2.6	4.0	0.1	0.1	0.1	0.1
Ouham G	0.2	1.2	1.4	3.1	0.17	0.02	0.00	1.6	1.7	1.9	2.5	0.0	0.0	0.0	0.0
Ouham H	0.3	2.1	2.7	5.8	0.17	0.11	0.02	1.6	2.0	2.2	3.1	0.0	0.0	0.0	0.1
Ouham I	2.1	20.7	32.4	79.5	0.17	0.75	0.13	2.3	7.1	10.3	22.1	0.3	0.9	1.3	2.8
Ouham I West	2.0	17.6	23.7	54.1	0.17	0.73	0.13	2.2	6.2	7.9	16.2	0.3	0.8	1.0	2.0
Sahr	1.5	20.0	35.2	93.5	0.17	0.73	0.12	2.2	7.7	12.0	27.4	0.3	0.9	1.5	3.4
Tega East A	3.7	11.5	25.6	62.0	0.19	0.68	0.13	1.8	4.5	9.0	21.3	0.2	0.6	1.1	2.7
Tega East B	3.8	12.3	28.4	69.3	0.19	0.69	0.13	1.9	4.8	9.9	23.6	0.2	0.6	1.3	3.0
Tega NE	0.1	1.3	4.1	10.5	0.16	0.14	0.02	1.8	3.5	5.2	10.9	0.0	0.1	0.1	0.3
Tega South	1.9	9.3	31.6	79.4	0.19	0.58	0.11	1.9	5.5	13.4	33.2	0.2	0.6	1.4	3.6
Tega SW	0.0	0.5	1.5	4.2	0.14	0.06	0.01	1.6	2.5	2.9	4.8	0.0	0.0	0.0	0.0
Arithmetic Sum	127.4	879.1	1,569.7	3,851.7				68.9	257.2	475.2	1,137.3	11.3	47.6	91.6	222.3

Note:
(1) UPIIP - Undiscovered Petroleum Initially in Place
(2) Truncated for Minimum Economic Field Size (MEFS) of 1.5 MMSTB
(3) UPIIP values do not include an implied truncation for minimum economic field size
(4) Please review discussion in Summary concerning summation of unrisked totals.

APPENDIX E

CHARI EAST DOSEO BLOCK (KIBEA-SAKO RELATED)

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TABLE E.1.1
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BAOUDA EAST PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	7,027	31,650	67,613	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	29.9	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	31.0	77.5	
B_{oi}	rbbl/STB	1.10	1.18	1.26	Custom	1.04	1.36	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	15,312	146,916	208,376	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	29.9	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	30.3	75.5	
B_{oi}	rbbl/STB	1.10	1.18	1.26	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	15,141	110,340	160,175	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	30.0	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	30.6	75.9	
B_{oi}	rbbl/STB	1.10	1.18	1.26	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	15,352	155,090	209,608	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	29.9	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	31.1	74.4	
B_{oi}	rbbl/STB	1.10	1.18	1.26	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.1
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BAOUDA EAST PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	15,351	157,781	217,336	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.15	1.24	1.34	Custom	1.07	1.46	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	15,367	158,587	219,009	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.15	1.24	1.34	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	15,342	123,507	176,308	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.1	90.0	
B_{oi}	rbbl/STB	1.15	1.24	1.34	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	13,950	86,260	145,286	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.19	1.29	1.42	Custom	1.10	1.56	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.1
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BAOUDA EAST PROSPECT

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	9,399	43,182	73,726	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.19	1.29	1.42	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	10,195	50,020	86,410	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.19	1.29	1.42	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	9,522	42,788	85,463	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.19	1.29	1.42	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E5								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	15,311	124,196	177,047	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.1	90.0	
B_{oi}	rbbl/STB	1.19	1.29	1.42	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.1
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BAOUDA EAST PROSPECT

E6								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	8,060	39,893	77,237	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.19	1.29	1.42	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.2
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BAOUDA WEST PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,653	20,270	48,056	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	29.9	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	30.9	77.4	
B_{oi}	rbbl/STB	1.10	1.18	1.26	Custom	1.04	1.36	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	5,618	72,701	116,362	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	29.9	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	31.2	74.9	
B_{oi}	rbbl/STB	1.10	1.18	1.26	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	5,573	61,550	98,547	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	30.0	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	30.6	74.3	
B_{oi}	rbbl/STB	1.10	1.18	1.26	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	5,628	75,537	117,278	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	29.9	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	31.4	74.7	
B_{oi}	rbbl/STB	1.10	1.18	1.26	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.2
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BAOUDA WEST PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	5,620	76,062	118,557	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.15	1.24	1.34	Custom	1.07	1.46	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	5,624	76,160	118,722	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.15	1.24	1.34	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	5,589	66,930	105,085	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.15	1.24	1.34	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	5,082	50,747	89,421	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.19	1.30	1.42	Custom	1.10	1.57	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.2
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BAOUDA WEST PROSPECT

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,501	27,694	53,003	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.19	1.30	1.42	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,881	31,447	60,142	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.19	1.30	1.42	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,492	27,440	58,149	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.19	1.30	1.42	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E5								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	5,611	67,042	105,487	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.19	1.30	1.42	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.2
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BAOUDA WEST PROSPECT

E6								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	3,197	24,898	54,396	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.19	1.30	1.42	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.3
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BECHE PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	13,697	70,935	156,088	Custom			
Net/Gross Ratio	v/v	0.41	0.67	0.89	Normal	0.10	1.00	
Porosity (ϕ)	%	13.2	15.0	16.8	Normal	12.0	18.0	
Oil Saturation (S_o)	%	55.9	65.0	74.1	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.14	1.23	1.33	Custom	1.06	1.45	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	14,484	88,582	205,322	Custom			
Net/Gross Ratio	v/v	0.41	0.67	0.89	Normal	0.10	1.00	
Porosity (ϕ)	%	13.2	15.0	16.8	Normal	12.0	18.0	
Oil Saturation (S_o)	%	55.9	65.0	74.1	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.14	1.23	1.33	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	26,948	119,047	245,778	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.26	1.34	1.44	Custom	1.16	1.56	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	14,370	55,556	116,366	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.26	1.34	1.44	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.3
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BECHE PROSPECT

E3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	17,028	66,185	123,153	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.26	1.34	1.44	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	16,156	62,214	119,121	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.26	1.34	1.44	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E5								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	43,137	225,828	290,354	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.26	1.34	1.44	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E6								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	15,005	59,258	111,784	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.1	90.0	
B_{oi}	rbbl/STB	1.26	1.34	1.44	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.3
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BECHE PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	121,403	993,665	1,330,131	Custom			
Net/Gross Ratio	v/v	0.16	0.41	0.67	Normal	0.05	0.80	
Porosity (ϕ)	%	20.0	23.5	27.0	Normal	15.0	33.9	
Oil Saturation (S_o)	%	50.0	56.5	63.0	Normal	40.1	75.7	
B_{oi}	rbbl/STB	1.11	1.17	1.24	Custom	1.05	1.31	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	120,813	592,625	764,050	Custom			
Net/Gross Ratio	v/v	0.16	0.41	0.67	Normal	0.05	0.80	
Porosity (ϕ)	%	20.0	23.5	27.0	Normal	15.0	34.2	
Oil Saturation (S_o)	%	50.0	56.5	63.0	Normal	40.2	78.1	
B_{oi}	rbbl/STB	1.11	1.17	1.24	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	121,404	878,370	1,132,574	Custom			
Net/Gross Ratio	v/v	0.16	0.41	0.67	Normal	0.05	0.80	
Porosity (ϕ)	%	20.0	23.5	27.0	Normal	15.0	33.7	
Oil Saturation (S_o)	%	50.0	56.5	63.0	Normal	40.1	75.5	
B_{oi}	rbbl/STB	1.11	1.17	1.24	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	121,390	660,018	913,908	Custom			
Net/Gross Ratio	v/v	0.16	0.41	0.67	Normal	0.05	0.80	
Porosity (ϕ)	%	20.0	23.5	27.0	Normal	15.0	34.5	
Oil Saturation (S_o)	%	50.0	56.5	63.0	Normal	40.2	77.0	
B_{oi}	rbbl/STB	1.11	1.17	1.24	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.3
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BECHE PROSPECT

C5								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	45,029	139,342	254,926	Custom			
Net/Gross Ratio	v/v	0.16	0.41	0.67	Normal	0.05	0.80	
Porosity (ϕ)	%	20.0	23.5	27.0	Normal	15.0	35.3	
Oil Saturation (S_o)	%	50.0	56.5	63.0	Normal	40.2	78.3	
B_{oi}	rbbl/STB	1.11	1.17	1.24	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.4
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BECHE B PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	20,289	77,246	168,871	Custom			
Net/Gross Ratio	v/v	0.41	0.67	0.89	Normal	0.10	1.00	
Porosity (ϕ)	%	13.2	15.0	16.8	Normal	12.0	18.0	
Oil Saturation (S_o)	%	55.9	65.0	74.1	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.14	1.22	1.32	Custom	1.06	1.44	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	21,742	96,865	221,207	Custom			
Net/Gross Ratio	v/v	0.41	0.67	0.89	Normal	0.10	1.00	
Porosity (ϕ)	%	13.2	15.0	16.8	Normal	12.0	18.0	
Oil Saturation (S_o)	%	55.9	65.0	74.1	Normal	50.0	80.0	
B_{oi}	rbbl/STB	1.14	1.22	1.32	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	35,699	104,377	210,421	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.24	1.33	1.42	Custom	1.15	1.54	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	16,924	47,688	96,235	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.24	1.33	1.42	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.4
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BECHE B PROSPECT

E3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	20,863	56,546	100,427	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.24	1.33	1.42	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	19,237	53,345	99,847	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.24	1.33	1.42	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E5								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	64,014	195,413	241,977	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.24	1.33	1.42	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E6								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	18,225	50,244	92,153	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.24	1.33	1.42	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.4
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BECHE B PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	103,024	716,385	914,671	Custom			
Net/Gross Ratio	v/v	0.16	0.41	0.67	Normal	0.05	0.80	
Porosity (ϕ)	%	20.0	23.5	27.0	Normal	15.1	34.2	
Oil Saturation (S_o)	%	50.0	56.5	63.0	Normal	40.1	77.8	
B_{oi}	rbbl/STB	1.10	1.16	1.23	Custom	1.04	1.30	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	86,711	334,908	433,753	Custom			
Net/Gross Ratio	v/v	0.16	0.41	0.67	Normal	0.05	0.80	
Porosity (ϕ)	%	20.0	23.5	27.0	Normal	15.0	34.7	
Oil Saturation (S_o)	%	50.0	56.5	63.0	Normal	40.1	77.1	
B_{oi}	rbbl/STB	1.10	1.16	1.23	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	102,466	544,673	712,826	Custom			
Net/Gross Ratio	v/v	0.16	0.41	0.67	Normal	0.05	0.80	
Porosity (ϕ)	%	20.0	23.5	27.0	Normal	15.1	33.8	
Oil Saturation (S_o)	%	50.0	56.5	63.0	Normal	40.1	78.2	
B_{oi}	rbbl/STB	1.10	1.16	1.23	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	94,278	382,871	540,565	Custom			
Net/Gross Ratio	v/v	0.16	0.41	0.67	Normal	0.05	0.80	
Porosity (ϕ)	%	20.0	23.5	27.0	Normal	15.1	33.7	
Oil Saturation (S_o)	%	50.0	56.5	63.0	Normal	40.1	76.4	
B_{oi}	rbbl/STB	1.10	1.16	1.23	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.4
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BECHE B PROSPECT

C5								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	21,962	70,683	132,832	Custom			
Net/Gross Ratio	v/v	0.16	0.41	0.67	Normal	0.05	0.80	
Porosity (ϕ)	%	20.0	23.5	27.0	Normal	15.1	33.9	
Oil Saturation (S_o)	%	50.0	56.5	63.0	Normal	40.1	76.2	
B_{oi}	rbbl/STB	1.10	1.16	1.23	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.5
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
SAKO NORTH PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	239	1,178	2,648	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	29.9	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	31.4	76.0	
B_{oi}	rbbl/STB	1.09	1.15	1.22	Custom	1.04	1.30	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	468	3,930	5,640	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	29.9	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	30.6	74.9	
B_{oi}	rbbl/STB	1.09	1.15	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	467	3,466	5,009	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	30.0	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	30.2	76.1	
B_{oi}	rbbl/STB	1.09	1.15	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	468	4,019	5,705	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	30.0	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	30.7	75.6	
B_{oi}	rbbl/STB	1.09	1.15	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.5
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
SAKO NORTH PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	471	4,061	5,764	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.14	1.22	1.31	Custom	1.08	1.42	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	471	4,060	5,763	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.14	1.22	1.31	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	472	3,772	5,364	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.14	1.22	1.31	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,146	23,912	48,579	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.1	90.0	
B_{oi}	rbbl/STB	1.20	1.30	1.43	Custom	1.12	1.55	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.5
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
SAKO NORTH PROSPECT

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,331	12,491	26,098	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.20	1.30	1.43	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,445	14,175	30,353	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.20	1.30	1.43	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,352	12,336	29,350	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.20	1.30	1.43	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E5								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,681	34,908	61,639	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.20	1.30	1.43	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.5
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
SAKO NORTH PROSPECT

E6								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,141	11,346	27,011	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.20	1.30	1.43	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.6
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
SAKO NORTH B PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,278	11,069	25,262	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	29.9	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	31.4	75.7	
B_{oi}	rbbl/STB	1.10	1.16	1.23	Custom	1.04	1.31	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,002	36,897	54,990	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	30.0	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	30.2	75.1	
B_{oi}	rbbl/STB	1.10	1.16	1.23	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,003	32,527	49,329	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	30.0	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	30.2	74.4	
B_{oi}	rbbl/STB	1.10	1.16	1.23	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	2,002	37,723	55,593	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	30.0	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	31.3	75.0	
B_{oi}	rbbl/STB	1.10	1.16	1.23	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.6
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
SAKO NORTH B PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,940	36,748	54,024	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.15	1.23	1.33	Custom	1.08	1.44	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,937	36,746	54,044	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.15	1.23	1.33	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,935	33,727	50,495	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.15	1.23	1.33	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,725	19,460	32,065	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.21	1.31	1.44	Custom	1.13	1.58	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.6
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
SAKO NORTH B PROSPECT

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,251	11,265	20,933	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.21	1.31	1.44	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,339	12,817	23,227	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.21	1.31	1.44	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,235	11,103	22,801	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.21	1.31	1.44	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E5								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,778	24,697	36,635	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.21	1.31	1.44	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.6
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
SAKO NORTH B PROSPECT

E6								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,167	10,085	21,318	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.21	1.31	1.44	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.7
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
SAKO SE PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	4,460	23,169	51,568	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	30.0	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	31.4	74.5	
B_{oi}	rbbl/STB	1.12	1.19	1.28	Custom	1.06	1.37	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	81,469	463,755	771,185	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	29.9	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	30.3	74.9	
B_{oi}	rbbl/STB	1.12	1.19	1.28	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	56,313	241,250	368,459	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	30.0	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	31.2	74.5	
B_{oi}	rbbl/STB	1.12	1.19	1.28	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	84,645	455,511	630,476	Custom			
Net/Gross Ratio	v/v	0.34	0.58	0.82	Normal	0.10	1.00	
Porosity (ϕ)	%	16.1	20.0	24.0	Normal	12.0	29.9	
Oil Saturation (S_o)	%	45.0	52.5	60.0	Normal	30.5	75.1	
B_{oi}	rbbl/STB	1.12	1.19	1.28	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.7
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
SAKO SE PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	90,094	545,782	751,125	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.17	1.25	1.36	Custom	1.09	1.49	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	91,438	808,541	1,128,705	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.17	1.25	1.36	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	64,335	284,724	429,143	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.17	1.25	1.36	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	42,248	179,446	323,874	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.21	1.31	1.44	Custom	1.13	1.58	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.7
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
SAKO SE PROSPECT

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	20,930	82,544	143,605	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.1	90.0	
B_{oi}	rbbl/STB	1.21	1.31	1.44	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	23,966	94,968	172,413	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.21	1.31	1.44	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	21,595	81,998	169,602	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.21	1.31	1.44	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E5								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	65,140	286,540	437,511	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.21	1.31	1.44	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.1.7
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
SAKO SE PROSPECT

E6								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	17,968	76,027	150,822	Custom			
Net/Gross Ratio	v/v	0.40	0.66	0.89	Normal	0.20	1.00	
Porosity (ϕ)	%	10.2	13.0	15.8	Normal	8.0	18.0	
Oil Saturation (S_o)	%	49.3	64.3	79.0	Normal	35.0	90.0	
B_{oi}	rbbl/STB	1.21	1.31	1.44	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE E.2.1
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
BAOUDA EAST PROSPECT

Field Dependent Risks				
Source	**Maturity**	**Migration**	**Timing**	**$P_{Dependent}$**
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	**Reservoir**	**Trap**	**Seal**	**$P_{Independent}$**
C1	0.60	0.60	0.40	0.14
C2	0.60	0.60	0.40	0.14
C3	0.60	0.60	0.40	0.14
C4	0.60	0.60	0.40	0.14
D1	0.60	0.60	0.40	0.14
D2	0.60	0.60	0.40	0.14
D3	0.60	0.60	0.40	0.14
E1	0.60	0.60	0.40	0.14
E2	0.60	0.60	0.40	0.14
E3	0.60	0.60	0.40	0.14
E4	0.60	0.60	0.40	0.14
E5	0.60	0.60	0.40	0.14
E6	0.60	0.60	0.40	0.14

Pg	**0.45**

TABLE E.2.2
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
BAOUDA WEST PROSPECT

Field Dependent Risks				
Source	**Maturity**	**Migration**	**Timing**	**$P_{Dependent}$**
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	**Reservoir**	**Trap**	**Seal**	**$P_{Independent}$**
C1	0.60	0.60	0.40	0.14
C2	0.60	0.60	0.40	0.14
C3	0.60	0.60	0.40	0.14
C4	0.60	0.60	0.40	0.14
D1	0.60	0.60	0.40	0.14
D2	0.60	0.60	0.40	0.14
D3	0.60	0.60	0.40	0.14
E1	0.60	0.60	0.40	0.14
E2	0.60	0.60	0.40	0.14
E3	0.60	0.60	0.40	0.14
E4	0.60	0.60	0.40	0.14
E5	0.60	0.60	0.40	0.14
E6	0.60	0.60	0.40	0.14

Pg	**0.44**

TABLE E.2.3
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
BECHE PROSPECT

Field Dependent Risks				
Source	Maturity	Migration	Timing	$P_{Dependent}$
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	Reservoir	Trap	Seal	$P_{Independent}$
C1	0.50	0.60	0.40	0.12
C2	0.50	0.60	0.40	0.12
C3	0.50	0.60	0.40	0.12
C4	0.50	0.60	0.40	0.12
C5	0.50	0.60	0.40	0.12
D1	0.50	0.60	0.40	0.12
D2	0.50	0.60	0.40	0.12
E1	0.50	0.60	0.40	0.12
E2	0.50	0.60	0.40	0.12
E3	0.50	0.60	0.40	0.12
E4	0.50	0.60	0.40	0.12
E5	0.50	0.60	0.40	0.12
E6	0.50	0.60	0.40	0.12

Pg	0.41

TABLE E.2.4
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
BECHE B PROSPECT

Field Dependent Risks				
Source	Maturity	Migration	Timing	$P_{Dependent}$
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	Reservoir	Trap	Seal	$P_{Independent}$
C1	0.50	0.60	0.40	0.12
C2	0.50	0.60	0.40	0.12
C3	0.50	0.60	0.40	0.12
C4	0.50	0.60	0.40	0.12
C5	0.50	0.60	0.40	0.12
D1	0.50	0.60	0.40	0.12
D2	0.50	0.60	0.40	0.12
E1	0.50	0.60	0.40	0.12
E2	0.50	0.60	0.40	0.12
E3	0.50	0.60	0.40	0.12
E4	0.50	0.60	0.40	0.12
E5	0.50	0.60	0.40	0.12
E6	0.50	0.60	0.40	0.12

Pg	0.41

TABLE E.2.5
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
SAKO NORTH PROSPECT

Field Dependent Risks				
Source	Maturity	Migration	Timing	$P_{Dependent}$
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	Reservoir	Trap	Seal	$P_{Independent}$
C1	0.80	0.70	0.50	0.28
C2	0.80	0.70	0.50	0.28
C3	0.80	0.70	0.50	0.28
C4	0.80	0.70	0.50	0.28
D1	0.80	0.70	0.50	0.28
D2	0.80	0.70	0.50	0.28
D3	0.80	0.70	0.50	0.28
E1	0.40	0.60	0.50	0.12
E2	0.40	0.60	0.50	0.12
E3	0.40	0.60	0.50	0.12
E4	0.40	0.60	0.50	0.12
E5	0.40	0.60	0.50	0.12
E6	0.40	0.60	0.50	0.12

Pg	0.49

TABLE E.2.6
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
SAKO NORTH B PROSPECT

Field Dependent Risks				
Source	**Maturity**	**Migration**	**Timing**	**$P_{Dependent}$**
1.00	0.80	0.80	0.80	0.51

Independent Risks				
Formation	**Reservoir**	**Trap**	**Seal**	**$P_{Independent}$**
C1	0.60	0.70	0.50	0.21
C2	0.60	0.70	0.50	0.21
C3	0.60	0.70	0.50	0.21
C4	0.60	0.70	0.50	0.21
D1	0.60	0.70	0.50	0.21
D2	0.60	0.70	0.50	0.21
D3	0.60	0.70	0.50	0.21
E1	0.40	0.60	0.50	0.12
E2	0.40	0.60	0.50	0.12
E3	0.40	0.60	0.50	0.12
E4	0.40	0.60	0.50	0.12
E5	0.40	0.60	0.50	0.12
E6	0.40	0.60	0.50	0.12

Pg	**0.47**

TABLE E.2.7
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
SAKO SE PROSPECT

Field Dependent Risks				
Source	**Maturity**	**Migration**	**Timing**	**$P_{Dependent}$**
0.80	0.80	0.80	0.80	0.41

Independent Risks				
Formation	**Reservoir**	**Trap**	**Seal**	**$P_{Independent}$**
C1	0.60	0.70	0.70	0.29
C2	0.60	0.70	0.70	0.29
C3	0.60	0.70	0.70	0.29
C4	0.60	0.70	0.70	0.29
D1	0.60	0.70	0.70	0.29
D2	0.60	0.70	0.70	0.29
D3	0.60	0.70	0.70	0.29
E1	0.60	0.70	0.70	0.29
E2	0.60	0.70	0.70	0.29
E3	0.60	0.70	0.70	0.29
E4	0.60	0.70	0.70	0.29
E5	0.60	0.70	0.70	0.29
E6	0.60	0.70	0.70	0.29

Pg	**0.40**

TABLE E.3
SUMMARY OF INPUT PARAMETERS - ANALOGY METHOD PROSPECTS
GRIFFITHS ENERGY INTERNATIONAL INC.
CHARI EAST DOSEO BLOCK (KIBEA-MAKU RELATED)

Prospect	Pg	Prospect Area (Acre)			Undiscovered Petroleum Initially In Place per Area (MMSTB/Acre)			Unrisked Prospective Resources per Area (MMSTB/Acre)			Comment
		P90	P50	P10	P90	P50	P10	P90	P50	P10	
Bahr	0.40	297	812	2,224	14.8	21.0	53.5	3.1	4.7	13.7	Average Doseo UPIIP and Unrisked PR per area.
Baouda Northeast	0.45	89	210	494	19.6	25.0	51.1	4.0	5.8	13.5	Average Baouda East and Baouda West.
Baouda Northwest	0.45	198	452	1,038	19.6	25.0	51.1	4.0	5.8	13.5	Average Baouda East and Baouda West.
Beche C	0.41	371	1,305	4,547	6.4	16.4	69.6	1.3	3.9	17.8	Beche UPIIP and Unrisked PR per area.
Kibea North	0.41	395	1,013	2,595	14.8	21.0	53.5	3.1	4.7	13.7	Average Doseo ratios.
Sako South	0.40	161	508	1,606	14.8	21.0	53.5	3.1	4.7	13.7	Average Doseo ratios.

TABLE E.4
SUMMARY OF GROSS LEASE UNDISCOVERED PETROLEUM IN PLACE AND PROSPECTIVE RESOURCES
INCLUDING ADJUSTMENT FOR MINIMUM ECONOMIC FIELD SIZE
GRIFFITHS ENERGY INTERNATIONAL INC.
EFFECTIVE DATE: DECEMBER 31, 2012

	Gross Lease Unrisked UPIIP (MMSTB)							Gross Lease Unrisked Prospective Resources (MMSTB)				Gross Lease Partially Risked Prospective Resources (MMSTB)			
Prospect	P90	P50	Mean	P10	P_g	P_{mefs}	P_c	P90	P50	Mean	P10	P90	P50	Mean	P10
Bahr	4.5	17.1	44.6	110.9	0.40	0.77	0.31	2.0	5.9	14.4	35.4	0.6	1.9	4.5	11.0
Baouda East	9.9	57.6	68.3	141.2	0.45	0.93	0.41	3.6	14.6	18.5	38.6	1.5	6.0	7.6	15.9
Baouda Northeast	1.8	5.2	10.1	23.8	0.45	0.43	0.19	1.7	3.3	5.1	10.9	0.3	0.6	1.0	2.1
Baouda Northwest	4.0	11.3	21.3	50.1	0.45	0.69	0.31	1.8	4.2	7.4	16.9	0.6	1.3	2.3	5.2
Baouda West	5.5	30.9	38.6	82.3	0.44	0.87	0.39	2.7	8.4	10.9	23.1	1.0	3.2	4.2	8.9
Beche	14.5	100.3	196.1	508.6	0.41	0.95	0.39	4.4	26.2	50.7	132.3	1.7	10.3	19.9	52.0
Beche B	12.9	80.0	134.6	337.2	0.41	0.95	0.39	4.0	20.2	35.3	85.8	1.6	7.9	13.8	33.6
Beche C	2.5	21.4	118.5	287.9	0.41	0.73	0.30	2.2	10.4	41.5	103.4	0.7	3.2	12.6	31.3
Kibea North	6.0	21.3	52.6	129.7	0.41	0.85	0.35	2.0	6.3	15.5	38.1	0.7	2.2	5.4	13.4
Sako North	0.9	4.5	7.2	17.4	0.49	0.39	0.19	1.7	2.9	3.7	6.7	0.3	0.5	0.7	1.3
Sako North B	3.4	17.4	20.6	42.8	0.47	0.79	0.37	2.1	5.2	6.3	12.0	0.8	1.9	2.3	4.4
Sako SE	71.0	314.0	355.9	697.5	0.40	0.99	0.40	16.7	74.5	89.6	178.5	6.7	29.9	36.0	71.7
Sako South	2.5	10.7	31.8	79.7	0.40	0.62	0.25	1.9	5.4	12.6	30.8	0.5	1.4	3.2	7.8
Arithmetic Sum	139.5	691.6	1,100.2	2,509.0				46.7	187.6	311.5	712.5	16.9	70.4	113.6	258.7

Note:
(1) UPIIP - Undiscovered Petroleum Initially in Place
(2) Truncated for Minimum Economic Field Size (MEFS) of 1.5 MMSTB
(3) UPIIP values do not include an implied truncation for minimum economic field size
(4) Please review discussion in Summary concerning summation of unrisked totals.

Table 1

Company: **Griffiths Energy International Inc.**
Property: **Corporate**
Description: **Summary**
$US Dollars

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2013-01)**
Effective Date: **December 31, 2012**

Summary of Reserves and Values

	Proved Producing	Proved Developed Non-producing	Proved Undeveloped	Total Proved	Total Probable	Total Proved Plus Probable	Total Possible	Total PPP	Low Estimate Contingent Resources
MARKETABLE RESERVES									
Light/Medium Oil (Mbbl)									
Total Company Int.	0	0	11,251	11,251	20,514	31,765	32,138	63,902	3,949
Working Interest	0	0	11,251	11,251	20,514	31,765	32,138	63,902	3,949
Net After Royalty	0	0	11,251	11,251	20,514	31,765	32,138	63,902	3,949
Oil Equivalent (Mbbl)									
Total Company Int.	0	0	11,251	11,251	20,514	31,765	32,138	63,902	3,949
Working Interest	0	0	11,251	11,251	20,514	31,765	32,138	63,902	3,949
Net After Royalty	0	0	11,251	11,251	20,514	31,765	32,138	63,902	3,949
BEFORE TAX PRESENT VALUE (M$)									
0%	0	0	699,100	699,100	969,029	1,668,130	1,674,798	3,342,927	84,975
5%	0	0	619,077	619,077	697,973	1,317,050	1,138,051	2,455,101	27,761
8%	0	0	578,947	578,947	580,884	1,159,831	925,380	2,085,212	3,858
10%	0	0	554,870	554,870	516,311	1,071,182	812,843	1,884,025	-8,962
12%	0	0	532,665	532,665	460,393	993,057	718,065	1,711,122	-19,780
15%	0	0	502,438	502,438	389,713	892,150	601,780	1,493,931	-32,959
20%	0	0	458,955	458,955	298,624	757,579	457,668	1,215,247	-48,798
FIRST 6 YEARS BEFORE TAX CASH FLOW (M$)									
2013	0	0	127,822	127,822	-42,627	85,195	-24,702	60,493	-37,756
2014	0	0	193,741	193,741	-64,986	128,754	-37,534	91,220	-120,827
2015	0	0	157,480	157,480	61,572	219,051	107,292	326,343	-26,904
2016	0	0	86,628	86,628	198,839	285,468	116,968	402,435	54,078
2017	0	0	51,926	51,926	226,524	278,450	214,383	492,833	52,989
2018	0	0	40,608	40,608	132,403	173,011	270,139	443,151	44,268

BOE Factors: HVY OIL 1.0 COND 1.0 RES GAS 6.0 SLN GAS 6.0 PROPANE 1.0 BUTANE 1.0 ETHANE 1.0 SULPHUR 0.0

Run Date: January 22, 2013 10:03:20

APPENDIX F

BOROGOP BLOCK

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TABLE F.1.1
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BEPARA PROSPECT

C1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	41,483	238,119	349,827	Custom			
Net/Gross Ratio	v/v	0.08	0.20	0.35	Normal	0.02	0.50	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	13.8	30.0	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.08	1.13	1.18	Custom	1.00	1.23	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	19,218	70,076	169,785	Custom			
Net/Gross Ratio	v/v	0.08	0.20	0.35	Normal	0.02	0.50	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	14.3	30.0	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.08	1.13	1.18	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	41,207	237,494	354,380	Custom			
Net/Gross Ratio	v/v	0.08	0.20	0.35	Normal	0.02	0.50	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	13.9	30.0	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.08	1.13	1.18	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

C4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	41,565	302,121	415,104	Custom			
Net/Gross Ratio	v/v	0.08	0.20	0.35	Normal	0.02	0.50	
Porosity (ϕ)	%	20.0	23.0	26.0	Normal	13.6	30.0	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.08	1.13	1.18	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE F.1.1
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BEPARA PROSPECT

D1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	41,597	303,660	418,232	Custom			
Net/Gross Ratio	v/v	0.04	0.11	0.19	Normal	0.01	0.25	
Porosity (ϕ)	%	14.1	18.0	22.0	Normal	10.0	29.3	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.11	1.17	1.22	Custom	1.02	1.29	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	41,555	293,666	410,585	Custom			
Net/Gross Ratio	v/v	0.04	0.11	0.19	Normal	0.01	0.25	
Porosity (ϕ)	%	14.1	18.0	22.0	Normal	10.0	29.6	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.11	1.17	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D3								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	41,590	327,911	451,234	Custom			
Net/Gross Ratio	v/v	0.04	0.11	0.19	Normal	0.01	0.25	
Porosity (ϕ)	%	14.1	18.0	22.0	Normal	10.0	29.3	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.11	1.17	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D4								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	40,945	209,802	306,037	Custom			
Net/Gross Ratio	v/v	0.04	0.11	0.19	Normal	0.01	0.25	
Porosity (ϕ)	%	14.1	18.0	22.0	Normal	10.0	29.6	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.11	1.17	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE F.1.1
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BEPARA PROSPECT

D5								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	19,803	73,306	147,182	Custom			
Net/Gross Ratio	v/v	0.04	0.11	0.19	Normal	0.01	0.25	
Porosity (ϕ)	%	14.1	18.0	22.0	Normal	10.0	29.4	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.11	1.17	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

D6								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	41,606	301,030	410,347	Custom			
Net/Gross Ratio	v/v	0.04	0.11	0.19	Normal	0.01	0.25	
Porosity (ϕ)	%	14.1	18.0	22.0	Normal	10.0	29.7	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.11	1.17	1.22	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E1								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	41,592	269,800	411,584	Custom			
Net/Gross Ratio	v/v	0.07	0.21	0.37	Normal	0.01	0.50	
Porosity (ϕ)	%	11.0	15.0	18.8	Normal	5.0	22.0	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.14	1.20	1.27	Custom	1.04	1.35	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

E2								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	41,249	224,649	349,104	Custom			
Net/Gross Ratio	v/v	0.07	0.21	0.37	Normal	0.01	0.50	
Porosity (ϕ)	%	11.0	15.0	18.8	Normal	5.0	22.0	
Oil Saturation (S_o)	%	50.2	60.0	69.8	Normal	40.0	80.0	
B_{oi}	rbbl/STB	1.14	1.20	1.27	Custom			
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE F.2.1
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
BEPARA PROSPECT

Field Dependent Risks					
Source	Maturity	Migration	Timing	Seal	$P_{Dependent}$
0.80	0.80	0.80	0.80	0.40	0.16

Independent Risks			
Formation	Reservoir	Trap	$P_{Independent}$
C1	0.60	0.80	0.48
C2	0.60	0.80	0.48
C3	0.60	0.80	0.48
C4	0.60	0.80	0.48
D1	0.60	0.80	0.48
D2	0.60	0.80	0.48
D3	0.60	0.80	0.48
E1	0.60	0.80	0.48
E2	0.60	0.80	0.48
E3	0.60	0.80	0.48
E4	0.60	0.80	0.48
E5	0.60	0.80	0.48
E6	0.60	0.80	0.48

Pg	**0.16**

TABLE F.3
SUMMARY OF INPUT PARAMETERS - ANALOGY METHOD PROSPECTS
GRIFFITHS ENERGY INTERNATIONAL INC.
BOROGOP BLOCK

Prospect	Pg	Prospect Area (Acre)			Undiscovered Petroleum Initially In Place per Area (MMSTB/Acre)			Unrisked Prospective Resources per Area (MMSTB/Acre)			Comment
		P90	P50	P10	P90	P50	P10	P90	P50	P10	
Bouna	0.18	198	541	1,483	15.3	20.7	50.6	3.2	4.7	13.0	Average Doseo+Borogop UPIIP and Unrisked PR per area.
Kou	0.07	371	856	1,977	6.9	8.4	19.9	1.5	1.9	5.1	Average Doseo+Borogop ratios, adjusted for C-sand only.

TABLE F.4
SUMMARY OF GROSS LEASE UNDISCOVERED PETROLEUM IN PLACE AND PROSPECTIVE RESOURCES
INCLUDING ADJUSTMENT FOR MINIMUM ECONOMIC FIELD SIZE
GRIFFITHS ENERGY INTERNATIONAL INC.
EFFECTIVE DATE: DECEMBER 31, 2012

	Gross Lease Unrisked UPIIP (MMSTB)							Gross Lease Unrisked Prospective Resources (MMSTB)				Gross Lease Partially Risked Prospective Resources (MMSTB)			
Prospect	P90	P50	Mean	P10	P_g	P_{mefs}	P_c	P90	P50	Mean	P10	P90	P50	Mean	P10
Bepara	65.8	149.7	157.9	261.9	0.16	1.00	0.16	14.4	35.7	39.4	68.1	2.4	5.8	6.4	11.1
Bouna	3.1	11.2	28.3	70.0	0.18	0.65	0.12	1.9	4.9	10.5	25.3	0.2	0.6	1.3	3.0
Kou	2.6	7.2	15.5	36.9	0.07	0.53	0.04	1.8	3.7	6.6	15.1	0.1	0.1	0.3	0.6
Arithmetic Sum	71.6	168.1	201.7	368.7				18.1	44.3	56.5	108.5	2.7	6.6	8.0	14.8

Note:
(1) UPIIP - Undiscovered Petroleum Initially in Place
(2) Truncated for Minimum Economic Field Size (MEFS) of 1.5 MMSTB
(3) UPIIP values do not include an implied truncation for minimum economic field size
(4) Please review discussion in Summary concerning summation of unrisked totals.

APPENDIX G

STRATIGRAPHIC PROSPECTS

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TABLE G.1.1
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
DABA PROSPECT

L CRETACEOUS								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	152,746	648,052	2,609,585	Lognormal	1,730	58,797,110	
Net/Gross Ratio	v/v	0.15	0.20	0.42	Lognormal	0.14	0.80	
Porosity (ϕ)	%	10.1	15.0	20.0	Normal	5.0	29.2	
Oil Saturation (S_o)	%	55.0	60.0	65.0	Normal	44.1	74.9	
B_{oi}	rbbl/STB	1.10	1.19	1.42	Custom	1.05	1.65	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.1	50.0	

TABLE G.1.2
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
KOUMOGO PROSPECT

L CRETACEOUS								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	61,614	261,044	583,965	Lognormal	1,057	799,800	
Net/Gross Ratio	v/v	0.23	0.45	0.67	Normal	0.10	0.80	
Porosity (ϕ)	%	13.0	17.5	22.0	Normal	5.0	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.6	
B_{oi}	rbbl/STB	1.10	1.19	1.42	Custom	1.06	1.65	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE G.1.3
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAINON PROSPECT

L CRETACEOUS								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	368,468	1,311,095	3,582,710	Lognormal	181	7,980,763	
Net/Gross Ratio	v/v	0.15	0.20	0.42	Lognormal	0.13	0.80	
Porosity (ϕ)	%	10.4	17.5	24.6	Normal	5.0	30.0	
Oil Saturation (S_o)	%	55.1	60.0	65.0	Normal	50.0	75.2	
B_{oi}	rbbl/STB	1.10	1.19	1.42	Custom	1.06	1.65	
Recovery Factor	%	11.2	24.1	40.4	Lognormal	5.0	50.0	

TABLE G.2.1
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
DABA PROSPECT

Formation Target	Source	Maturity	Migration	Reservoir	Trap	Timing	Fault Seal	Pg
L Cretaceous	1.00	0.90	0.80	0.50	0.60	0.90	0.40	0.08

TABLE G.2.2
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
KOUMOGO PROSPECT

Formation Target	Source	Maturity	Migration	Reservoir	Trap	Timing	Fault Seal	Pg
L Cretaceous	0.90	0.90	0.80	0.50	0.70	0.80	0.60	0.11

TABLE G.2.3
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
MAINON PROSPECT

Formation Target	Source	Maturity	Migration	Reservoir	Trap	Timing	Fault Seal	Pg
L Cretaceous	0.90	0.90	0.80	0.50	0.70	0.80	0.40	0.07

TABLE G.3
SUMMARY OF GROSS LEASE UNDISCOVERED PETROLEUM IN PLACE AND PROSPECTIVE RESOURCES
INCLUDING ADJUSTMENT FOR MINIMUM ECONOMIC FIELD SIZE
GRIFFITHS ENERGY INTERNATIONAL INC.
EFFECTIVE DATE: DECEMBER 31, 2012

	Gross Lease Unrisked UPIIP (MMSTB)							Gross Lease Unrisked Prospective Resources (MMSTB)				Gross Lease Partially Risked Prospective Resources (MMSTB)			
Prospect	P90	P50	Mean	P10	P_g	P_{mefs}	P_c	P90	P50	Mean	P10	P90	P50	Mean	P10
Daba	17.0	86.5	174.9	395.3	0.08	0.97	0.07	4.1	19.9	46.0	109.6	0.3	1.5	3.4	8.1
Koumogo	15.4	70.2	87.1	185.2	0.11	0.96	0.10	3.8	15.9	22.2	49.1	0.4	1.7	2.3	5.1
Mainon	42.9	193.9	287.4	614.6	0.07	0.99	0.07	8.9	42.9	73.9	168.2	0.7	3.2	5.5	12.5
Arithmetic Sum	75.3	350.6	549.4	1,195.1				16.8	78.7	142.1	326.9	1.4	6.3	11.2	25.7

Note:
(1) UPIIP - Undiscovered Petroleum Initially in Place
(2) Truncated for Minimum Economic Field Size (MEFS) of 1.5 MMSTB
(3) UPIIP values do not include an implied truncation for minimum economic field size
(4) Please review discussion in Summary concerning summation of unrisked totals.

APPENDIX H

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TABLE H.1.1
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BADILA WEST PROSPECT

BASEMENT								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	1,610,661	2,667,056	3,476,930	Custom			
Net/Gross Ratio	v/v	0.18	0.33	0.50	Normal	0.10	0.80	
Porosity (ϕ)	%	0.5	0.8	1.0	Normal	0.1	1.5	
Oil Saturation (S_o)	%	40.0	50.0	60.0	Normal	21.4	78.6	
B_{oi}	rbbl/STB	1.16	1.25	1.36	Custom	1.08	1.49	
Recovery Factor	%	10.3	20.0	29.8	Normal	1.0	40.0	

TABLE H.1.2
SUMMARY OF INPUT PARAMETERS
GRIFFITHS ENERGY INTERNATIONAL INC.
BENDO BINDO PROSPECT

BASEMENT								
						Truncation		
Input	Units	P90	P50	P10	Distribution Type	Low	High	Comment
Gross Rock Volume	acre*ft	368,073	751,420	1,090,342	Custom			
Net/Gross Ratio	v/v	0.18	0.33	0.50	Normal	0.10	0.80	
Porosity (ϕ)	%	0.5	0.8	1.0	Normal	0.1	1.5	
Oil Saturation (S_o)	%	40.0	50.0	60.0	Normal	21.5	78.2	
B_{oi}	rbbl/STB	1.08	1.15	1.22	Custom	1.02	1.31	
Recovery Factor	%	10.3	20.0	29.8	Normal	1.0	40.0	

TABLE H.2.1
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
BADILA WEST PROSPECT

Formation Target	Source	Maturity	Migration	Reservoir	Trap	Timing	Fault Seal	Pg
Basement	1.00	0.90	0.80	0.20	0.40	0.80	0.60	0.03

TABLE H.2.2
SUMMARY OF GEOLOGICAL RISKS
GRIFFITHS ENERGY INTERNATIONAL INC.
BENDO BINDO PROSPECT

Formation Target	Source	Maturity	Migration	Reservoir	Trap	Timing	Fault Seal	Pg
Basement	1.00	0.90	0.80	0.20	0.40	0.80	0.60	0.03

TABLE H.3
SUMMARY OF GROSS LEASE UNDISCOVERED PETROLEUM IN PLACE AND PROSPECTIVE RESOURCES
INCLUDING ADJUSTMENT FOR MINIMUM ECONOMIC FIELD SIZE
GRIFFITHS ENERGY INTERNATIONAL INC.
EFFECTIVE DATE: DECEMBER 31, 2012

	Gross Lease Unrisked UPIIP (MMSTB)							Gross Lease Unrisked Prospective Resources (MMSTB)				Gross Lease Partially Risked Prospective Resources (MMSTB)			
Prospect	P90	P50	Mean	P10	P_g	P_{mefs}	P_c	P90	P50	Mean	P10	P90	P50	Mean	P10
Badila West	7.4	17.6	20.8	38.8	0.03	0.83	0.02	1.9	3.9	4.8	9.5	0.0	0.1	0.1	0.2
Bendo Bindo	2.0	5.3	6.3	11.2	0.03	0.29	0.01	1.6	2.1	2.4	3.6	0.0	0.0	0.0	0.0
Arithmetic Sum	9.4	22.9	27.1	50.0				3.5	6.0	7.2	13.1	0.1	0.1	0.1	0.2

Note:
(1) UPIIP - Undiscovered Petroleum Initially in Place
(2) Truncated for Minimum Economic Field Size (MEFS) of 1.5 MMSTB
(3) UPIIP values do not include an implied truncation for minimum economic field size
(4) Please review discussion in Summary concerning summation of unrisked totals.

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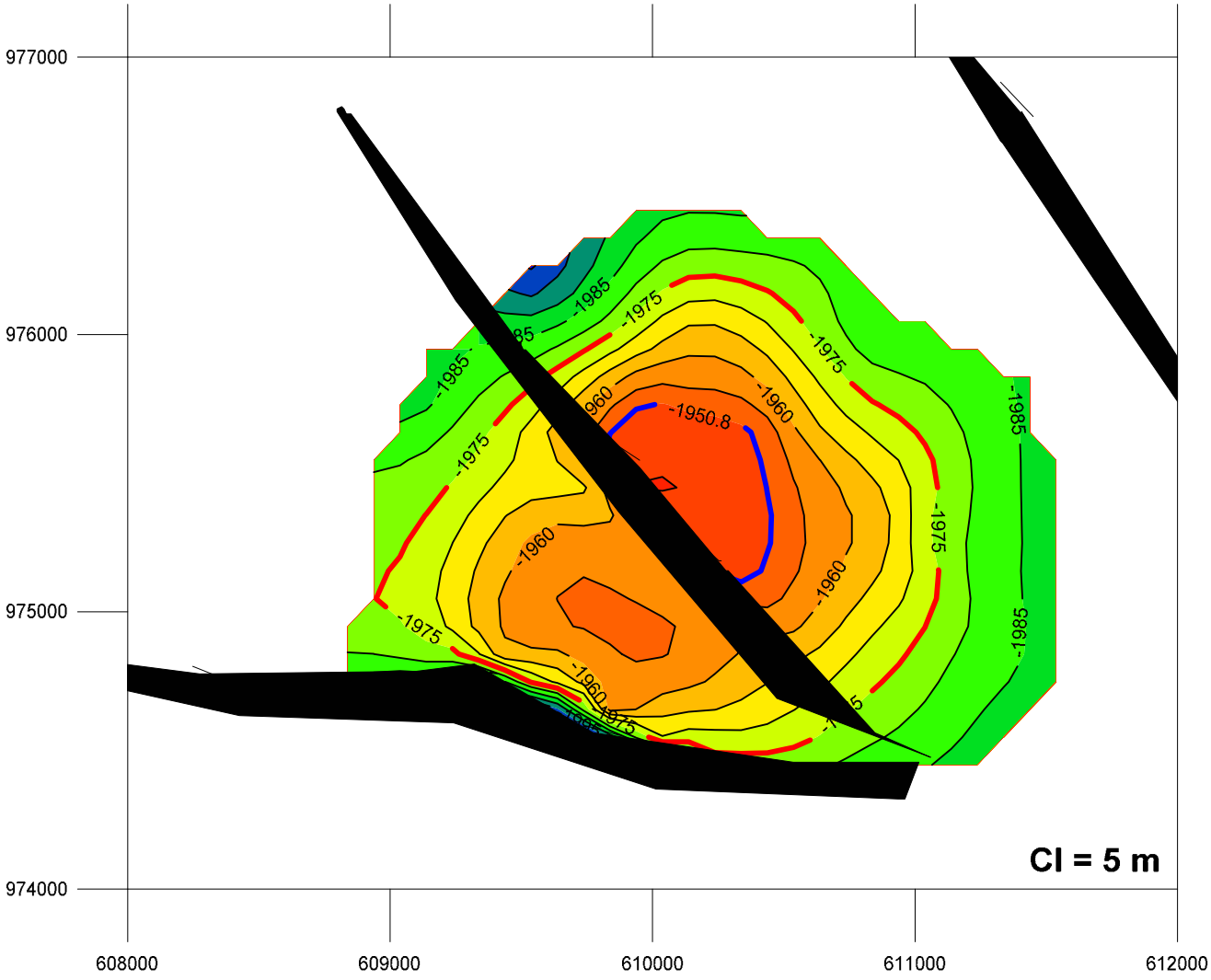
NOTES TO APPENDIX I

- All prospect maps are in UTM grids in metres and are oriented due north.
- P90 fill is labeled with blue toned contour, P10 fill is labeled with red contour.

Map 2
Dono Prospect
Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: DOB Block

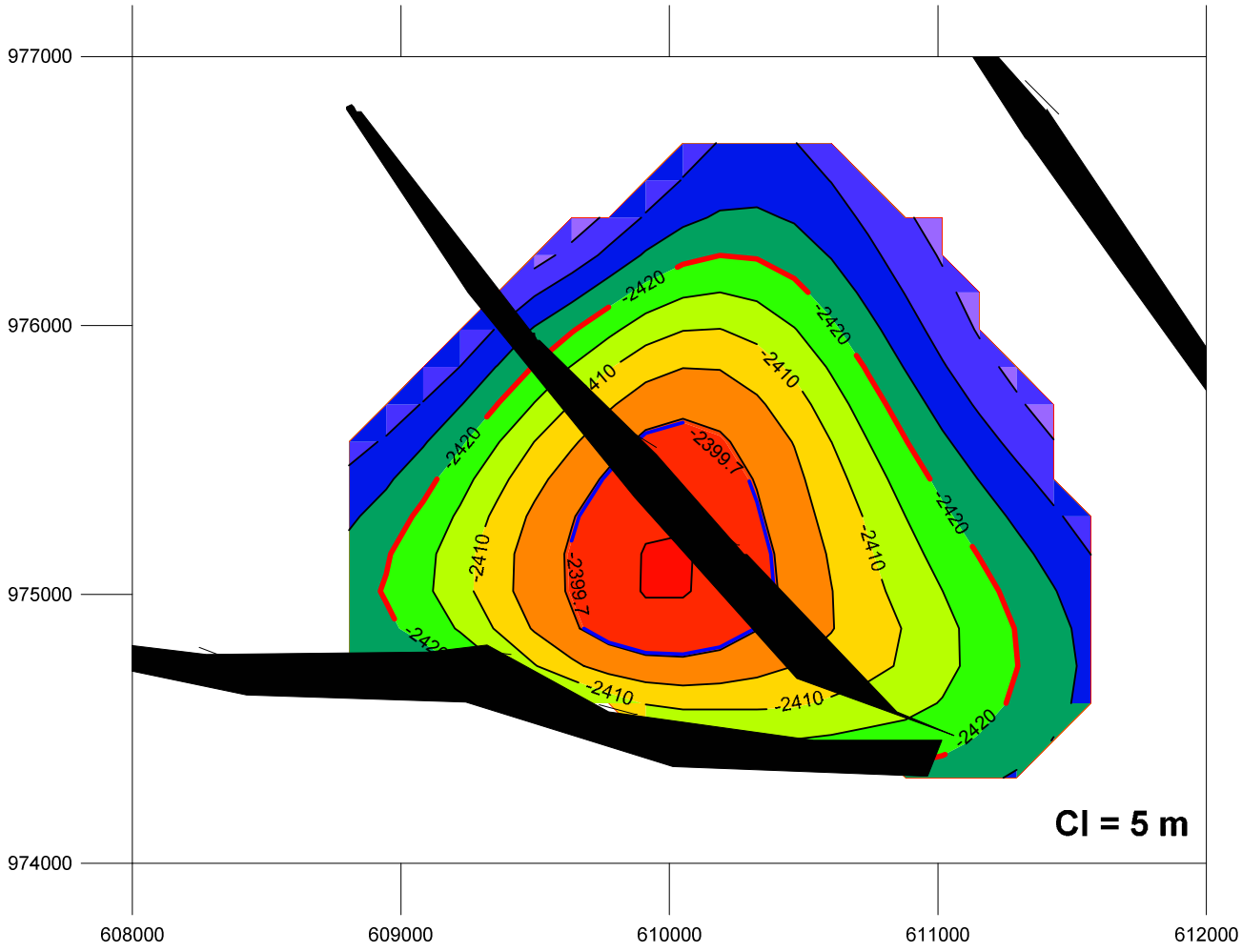
Effective Date: December 31, 2012
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Map 3
Dono Prospect
Depth Structure Map (metres)
D and E Sands

Company: Griffiths Energy International Inc.
Property: DOB Block

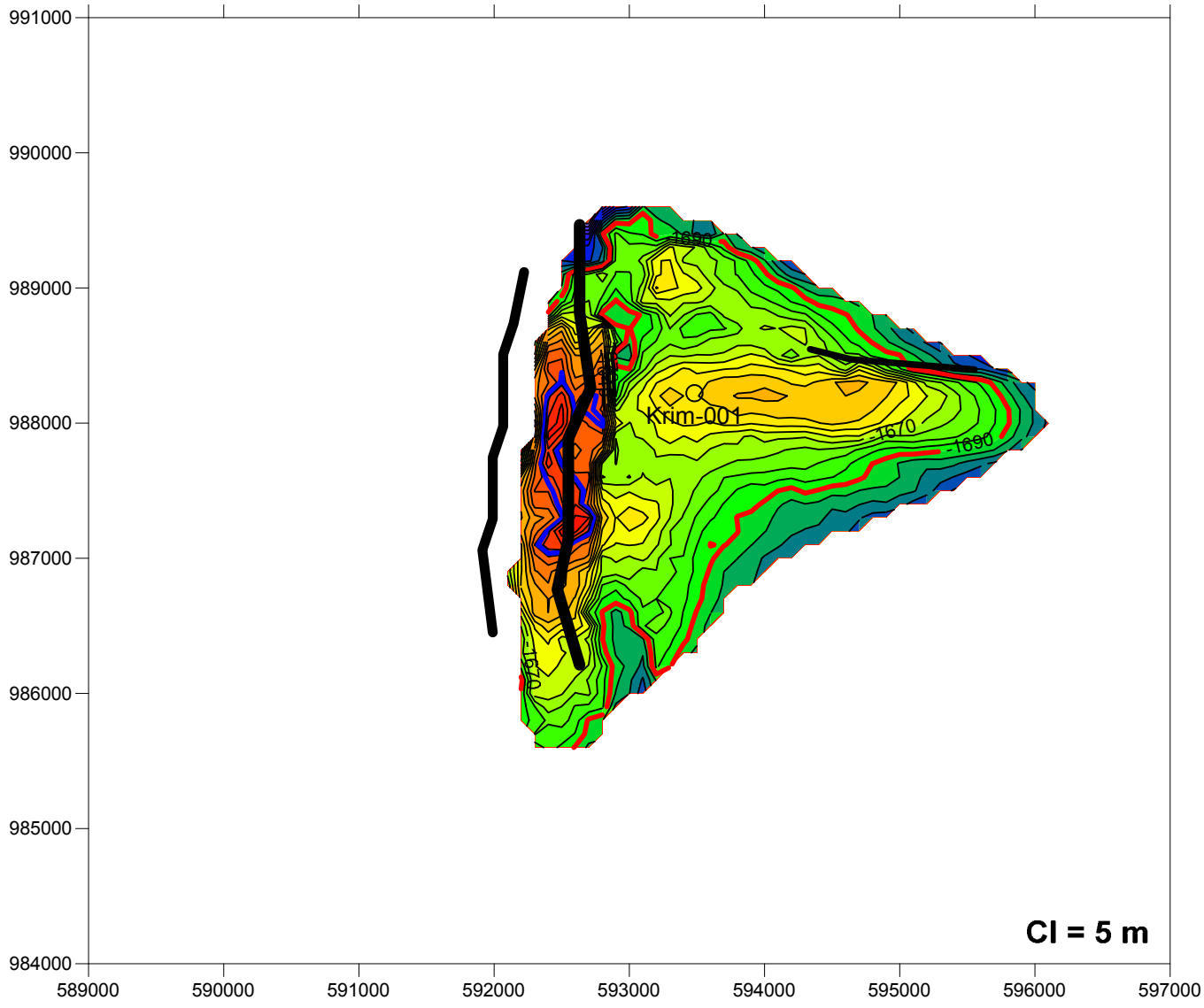
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Map 4
Krim Prospect
Depth Structure Map (metres)
C2 Sand

Company: Griffiths Energy International Inc.
Property: DOB Block

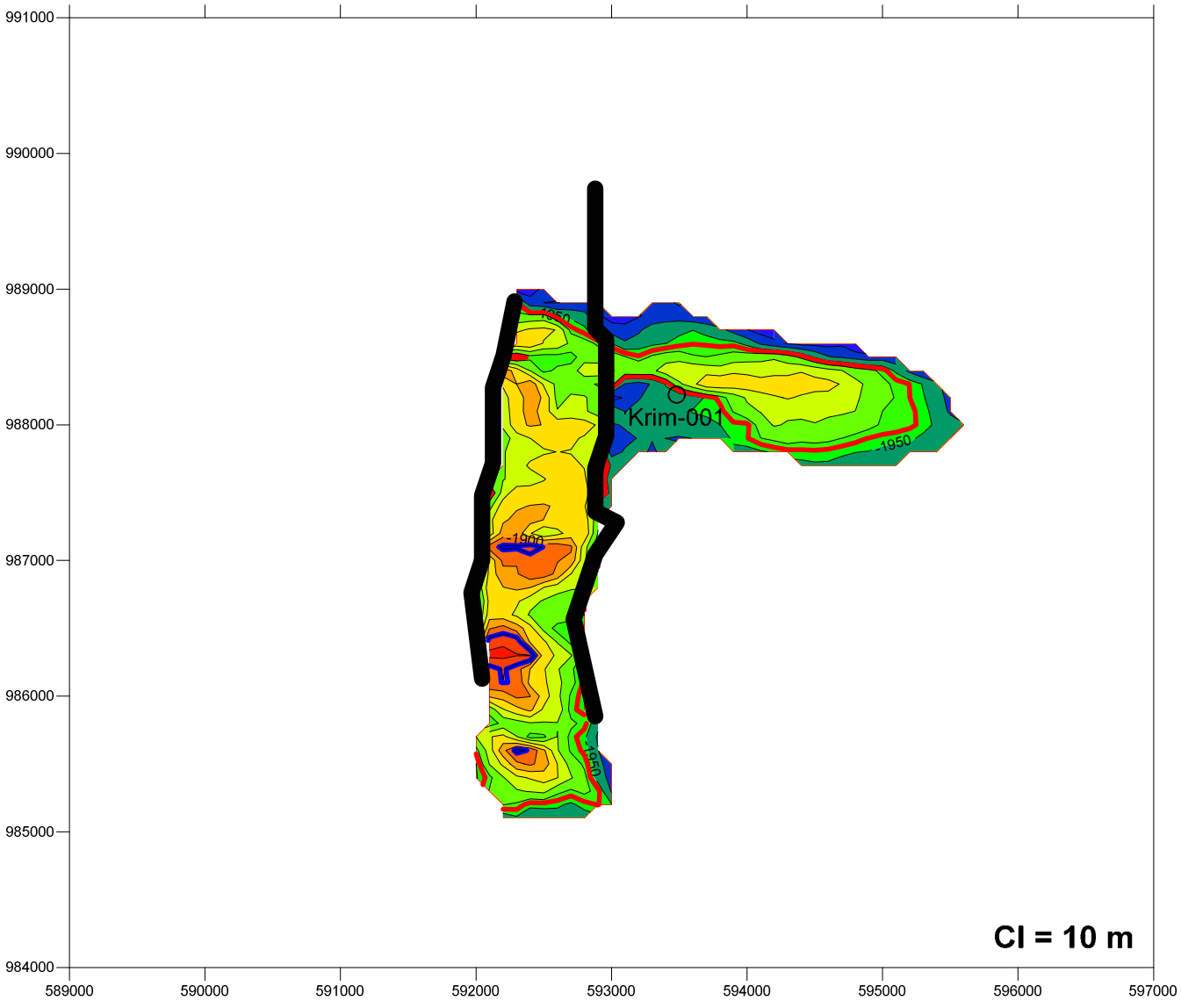
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Map 5
Krim Prospect
Depth Structure Map (metres)
D2 Sand

Company: Griffiths Energy International Inc.
Property: DOB Block

Effective Date: December 31, 2012
Scale: 1:50,000 s1132107



Map 6
Krim Prospect
Depth Structure Map (metres)
E1 Sand

Company: Griffiths Energy International Inc.
Property: DOB Block

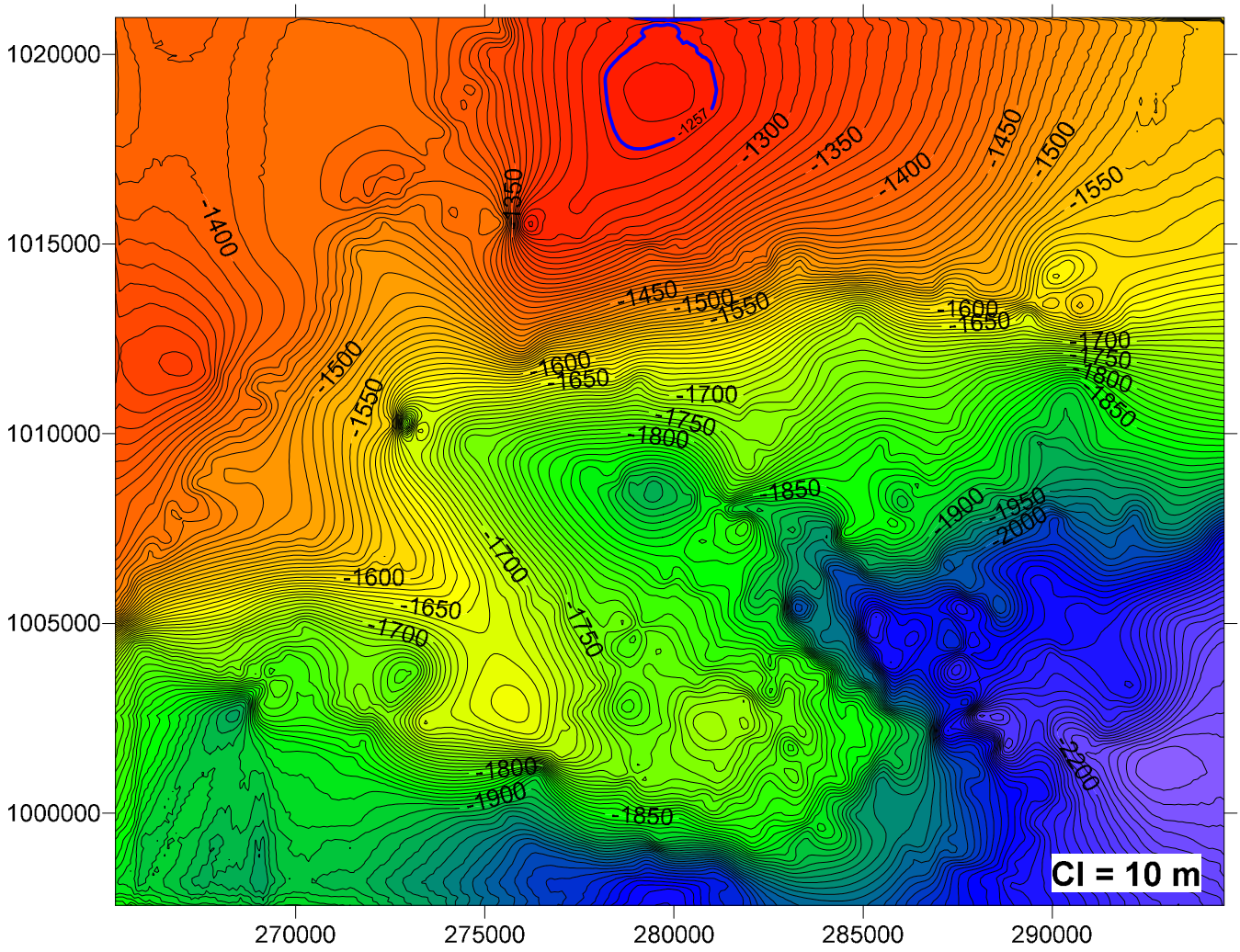
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Map 7
Langue Lead
Depth Structure Map (metres)
C2 Sand

Company: Griffiths Energy International Inc.
Property: DOB Block

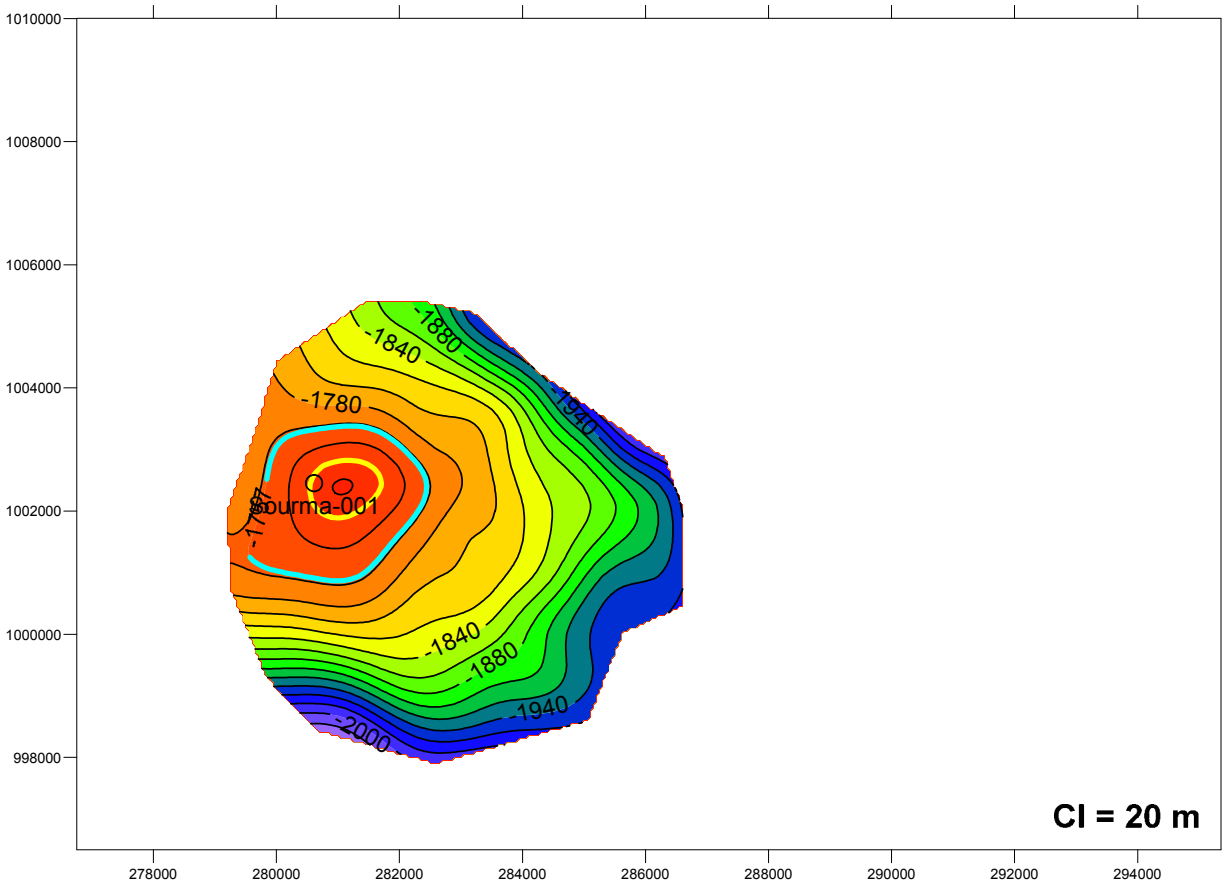
Effective Date: December 31, 2012
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Map 8
Sourma Prospect
Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: DOB Block

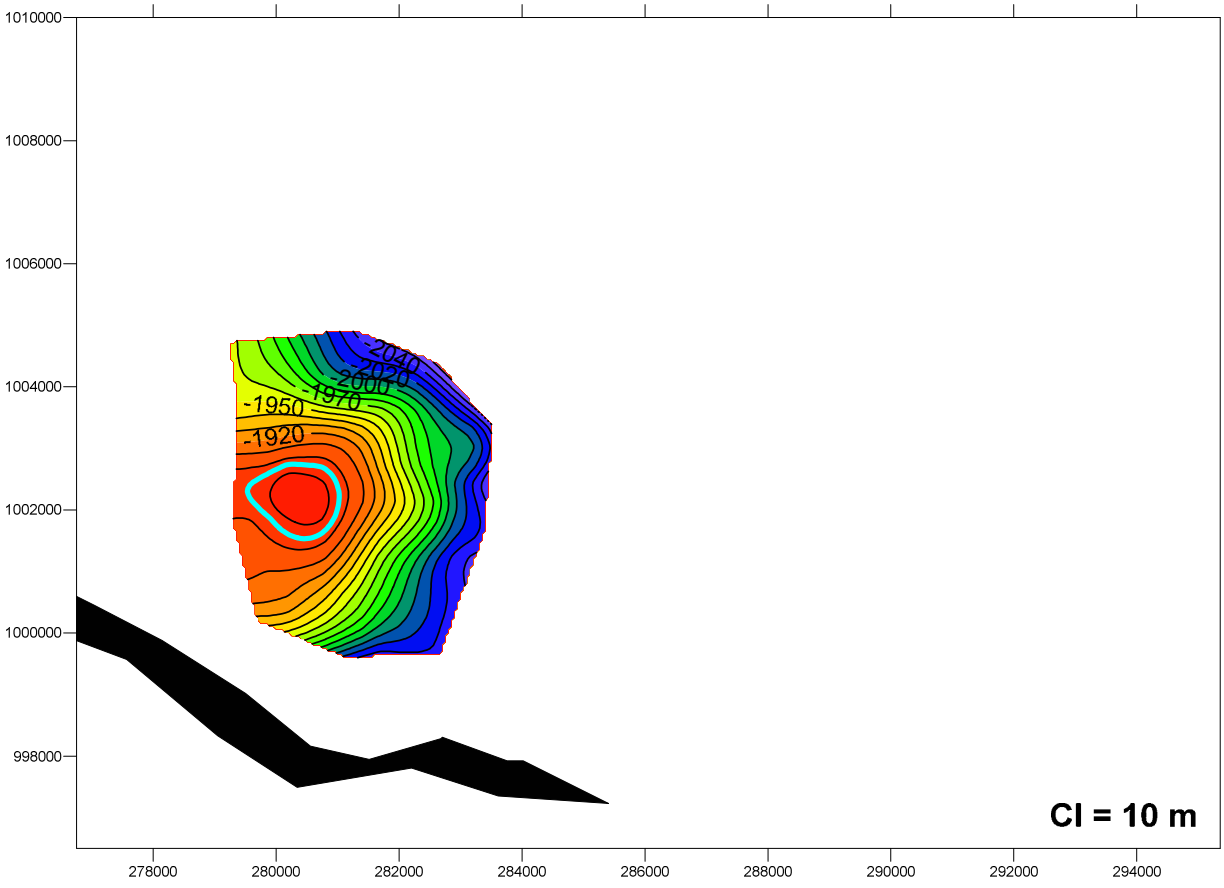
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Map 9
Sourma Prospect
Depth Structure Map (metres)
D2 Sand

Company: Griffiths Energy International Inc.
Property: DOB Block

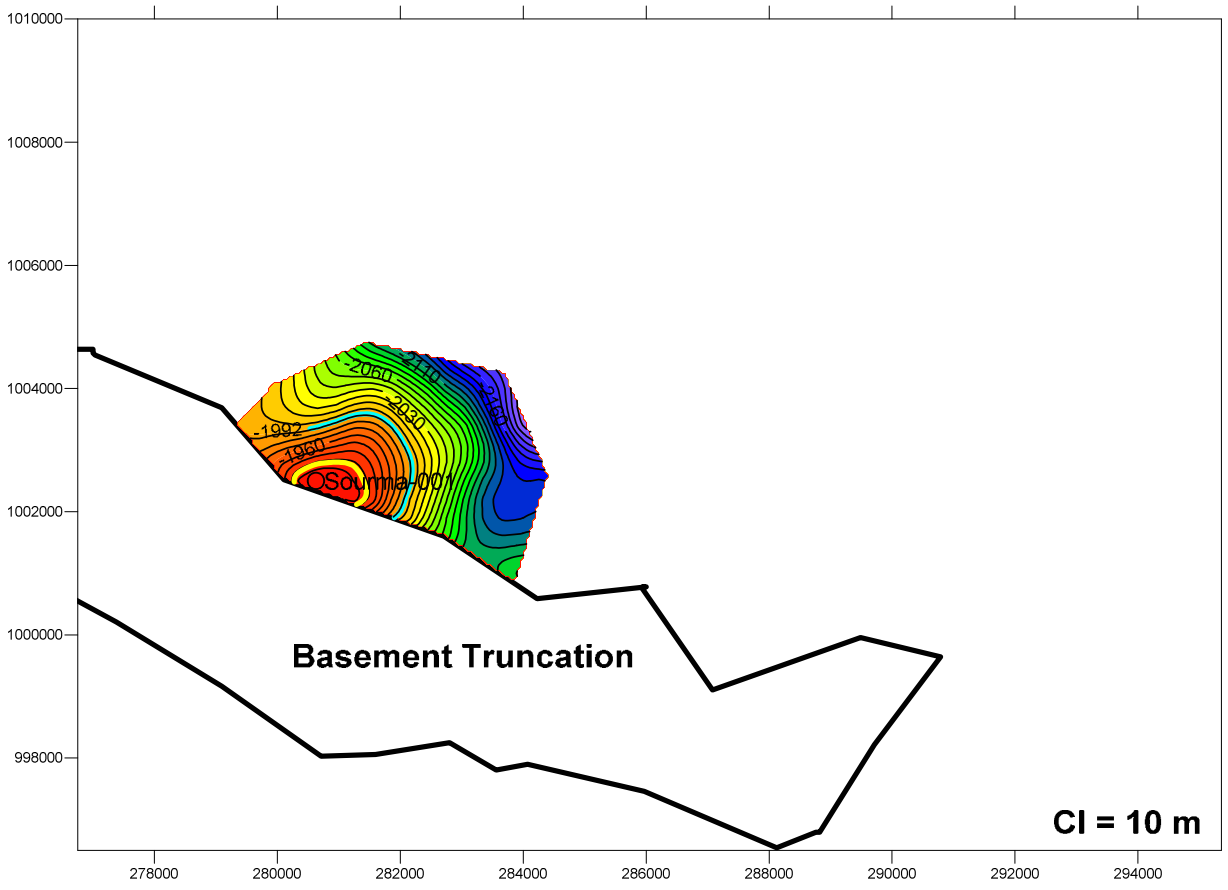
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Scale: 1:110,000 s1132107



Map 10
Sourma Prospect
Depth Structure Map (metres)
E1 Sand

Company: Griffiths Energy International Inc.
Property: DOB Block

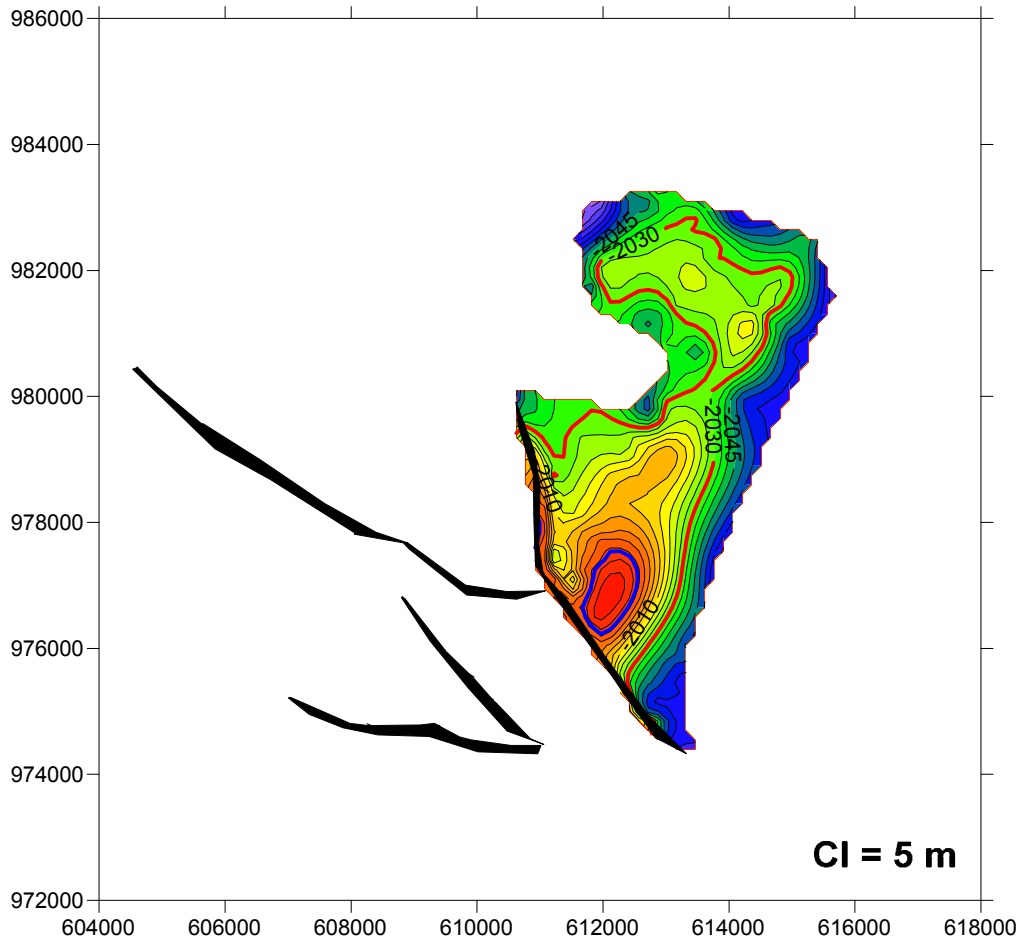
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Scale: 1:110,000 s1132107



Map 11
Togoro East Prospect
Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: DOB Block

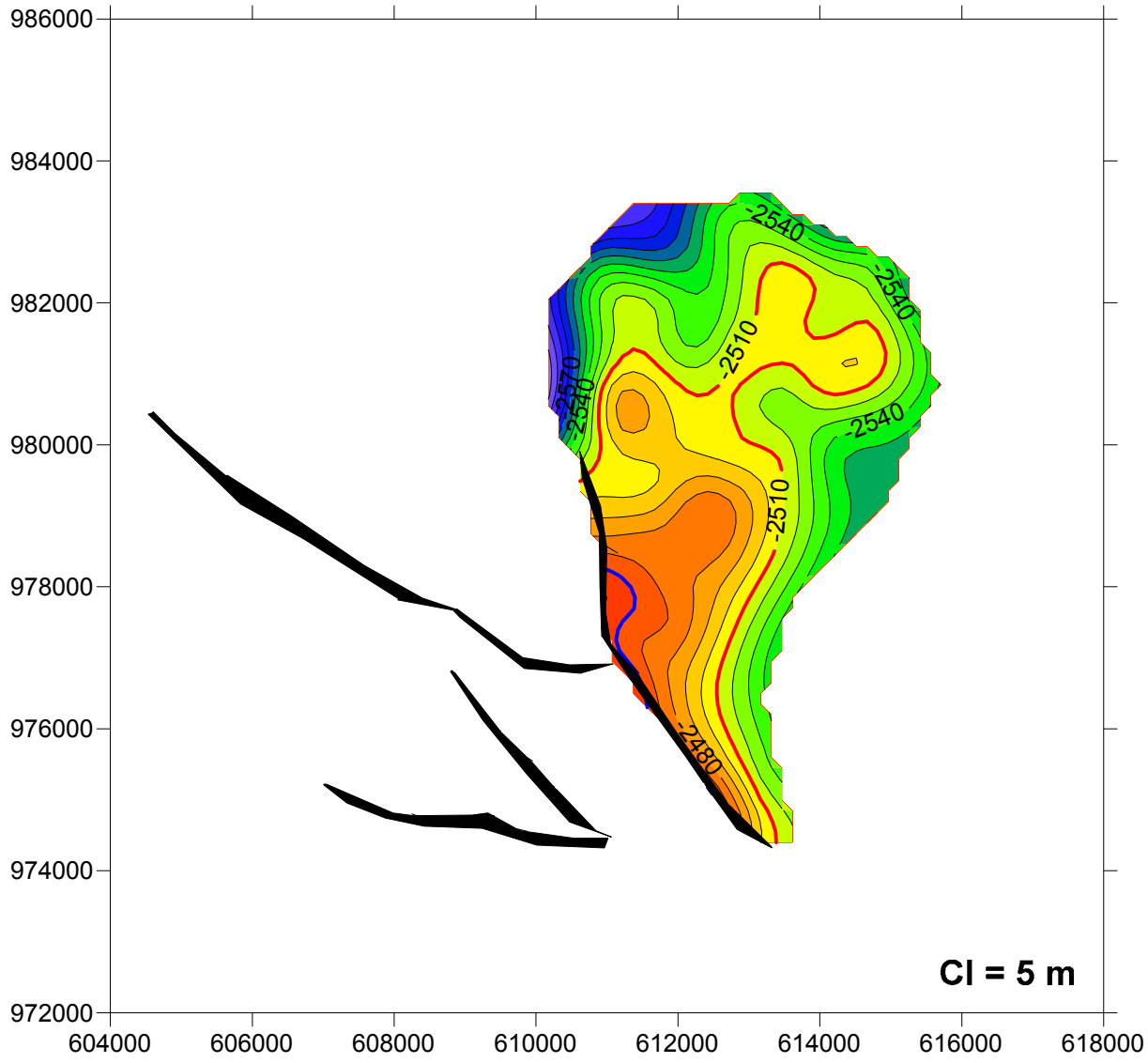
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Map 12
Togoro East Prospect
Depth Structure Map (metres)
D and E Sands

Company: Griffiths Energy International Inc.
Property: DOB Block

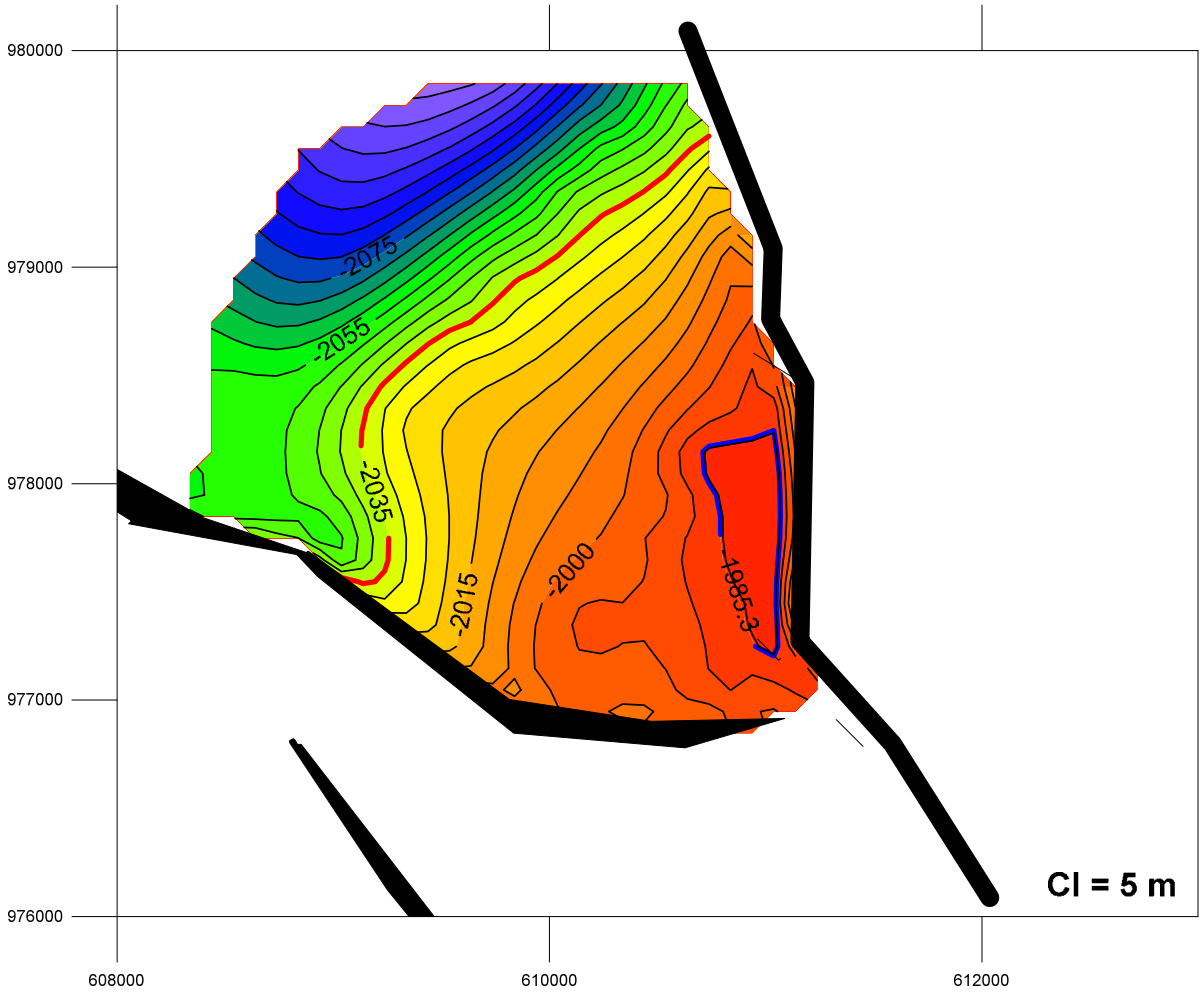
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Map 13
Togoro West Prospect
Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: DOB Block

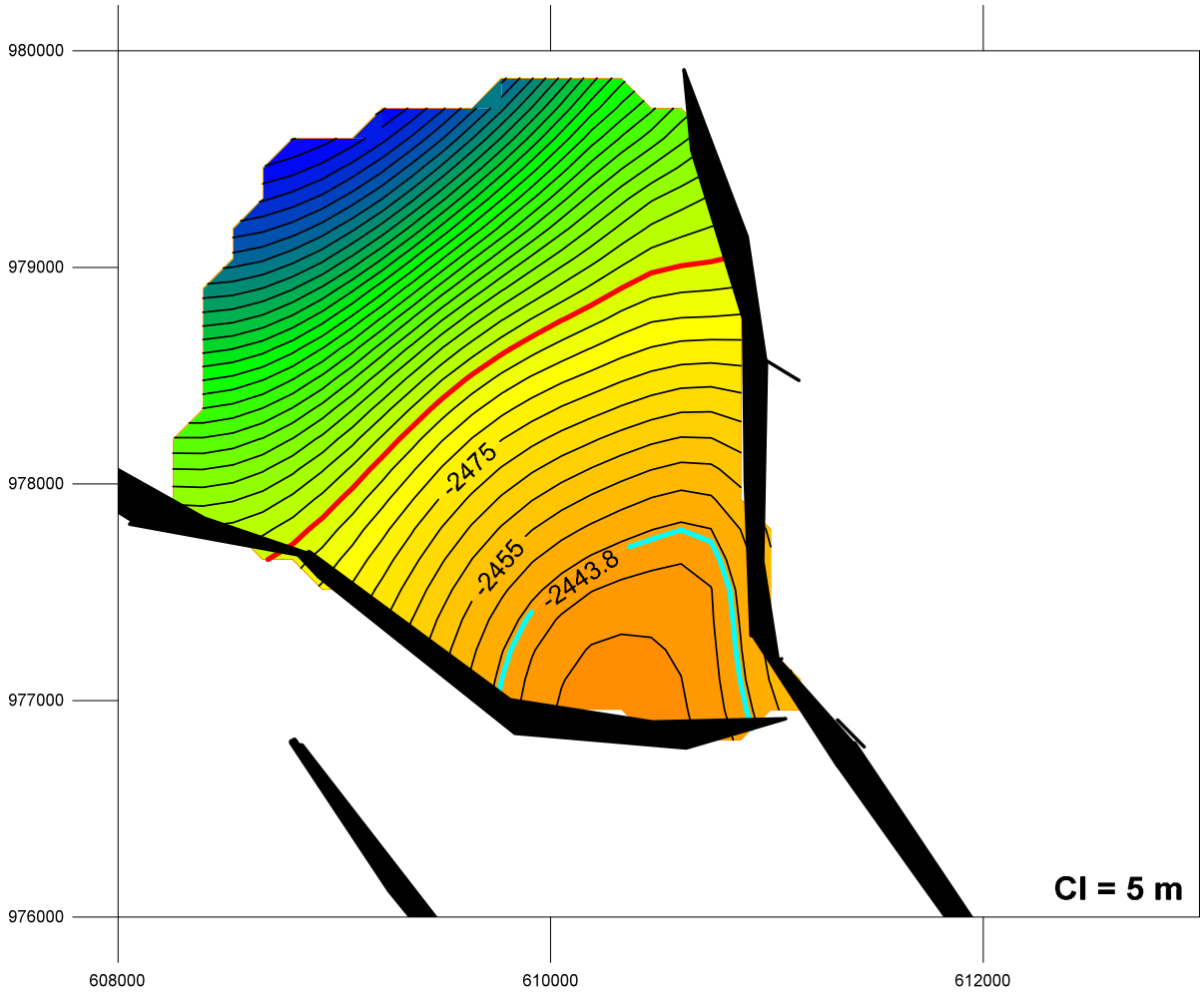
Effective Date: December 31, 2012
Scale: 1:110,000 s1132107



Map 14
Togoro West Prospect
Depth Structure Map (metres)
D and E Sands

Company: Griffiths Energy International Inc.
Property: DOB Block

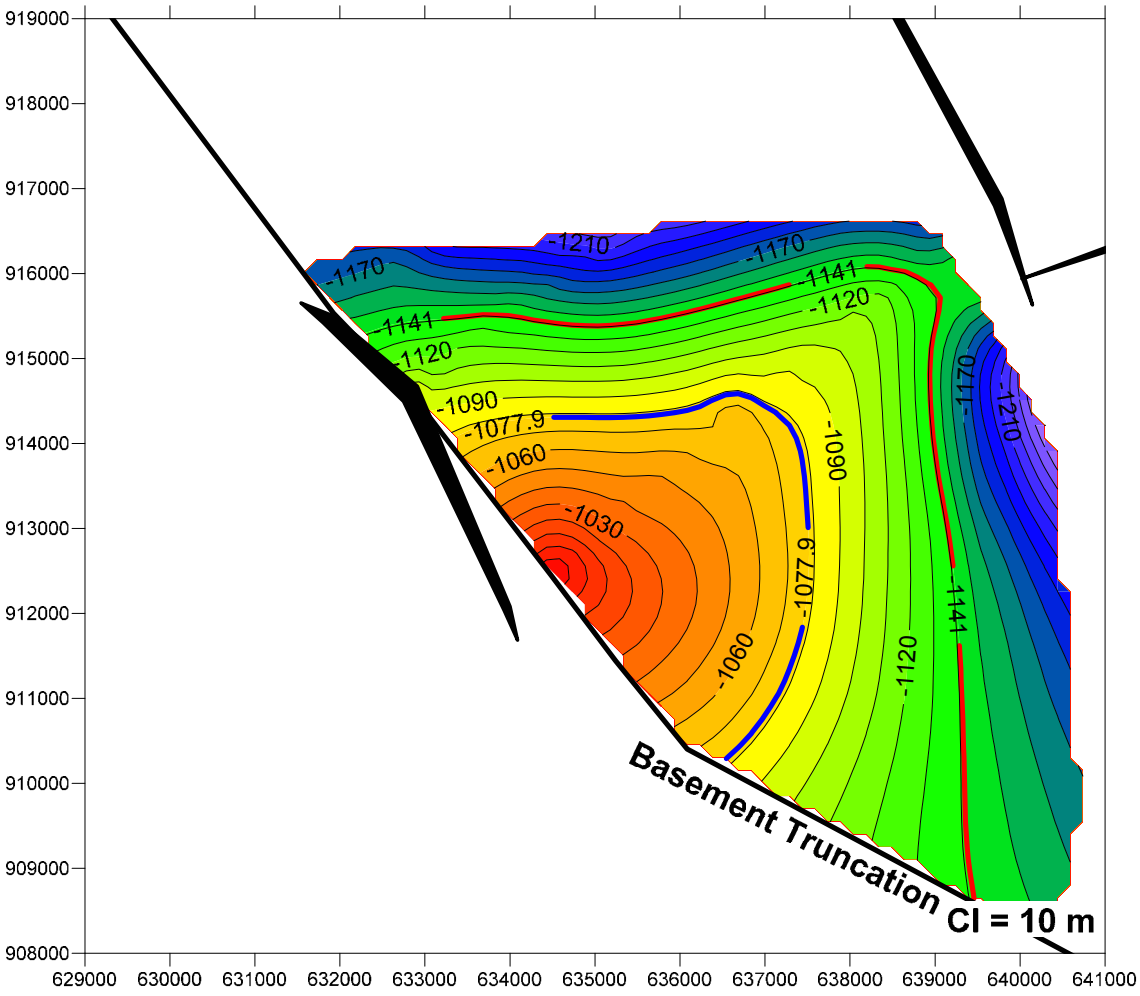
Effective Date: December 31, 2012
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Map 15
Bitanda Prospect
Depth Structure Map (metres)
D Sand

Company: Griffiths Energy International Inc.
Property: DOI Block

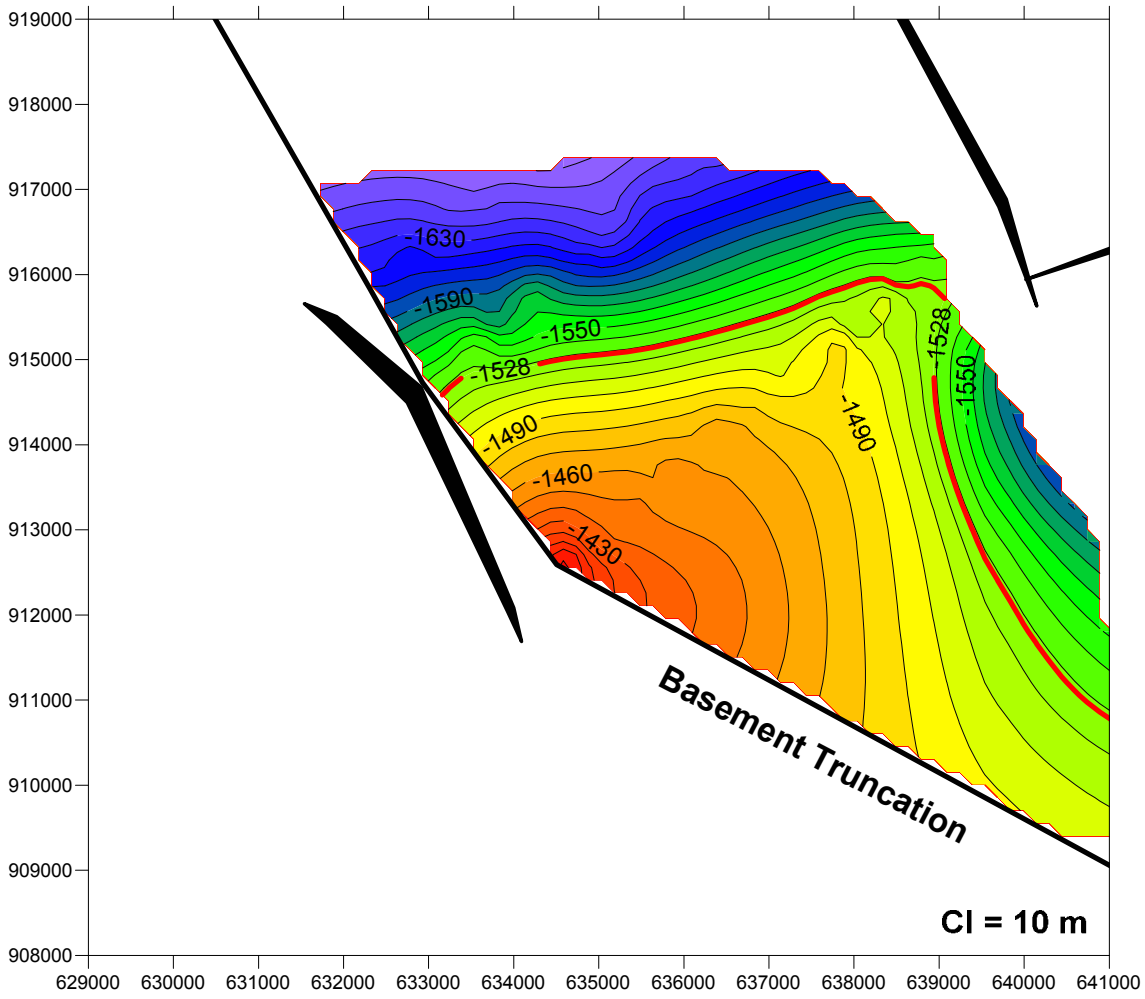
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Map 16
Bitanda Prospect
Depth Structure Map (metres)
E Sand

Company: Griffiths Energy International Inc.
Property: DOI Block

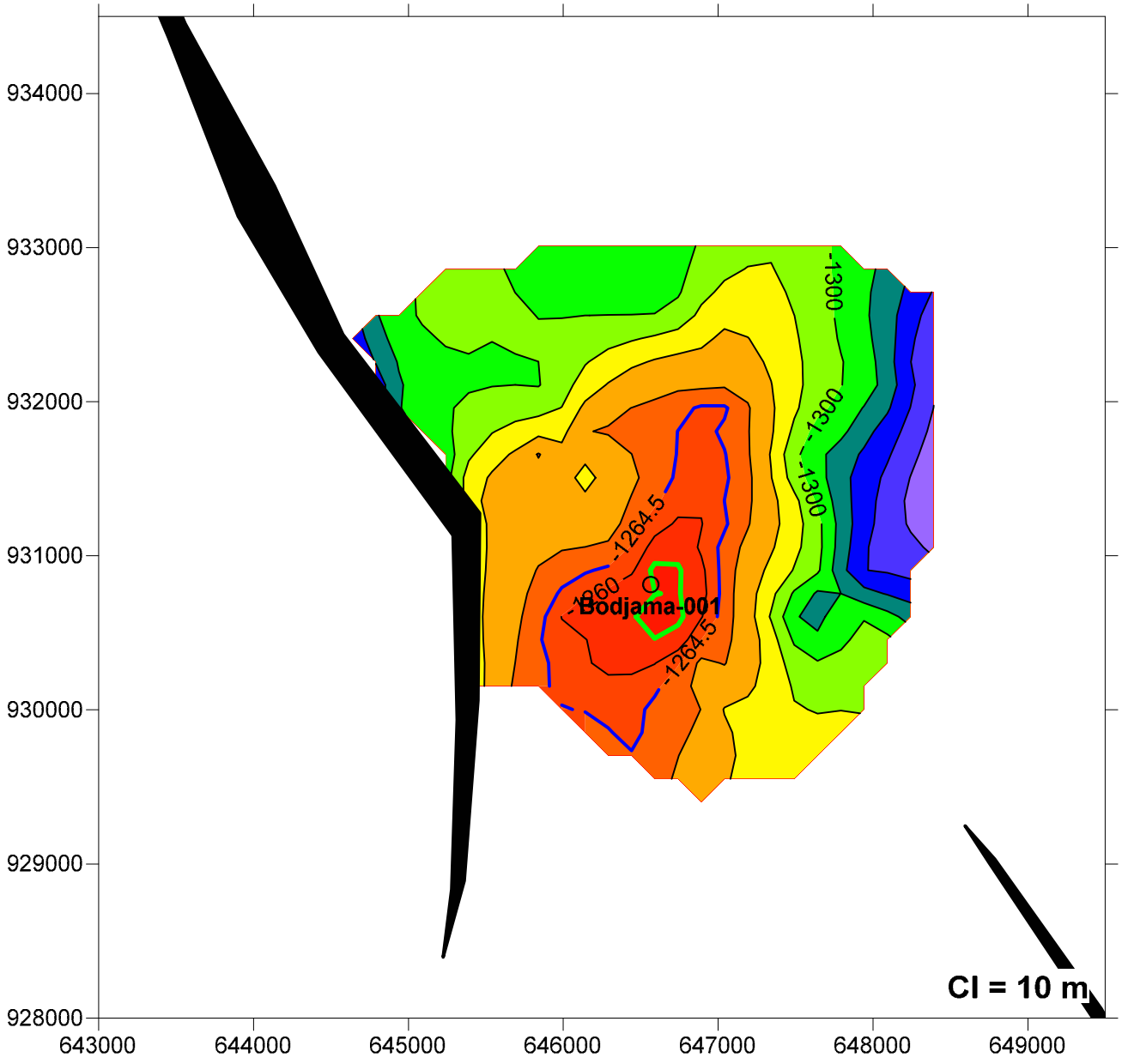
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Map 17
Bodjama Prospect
Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: DOI Block

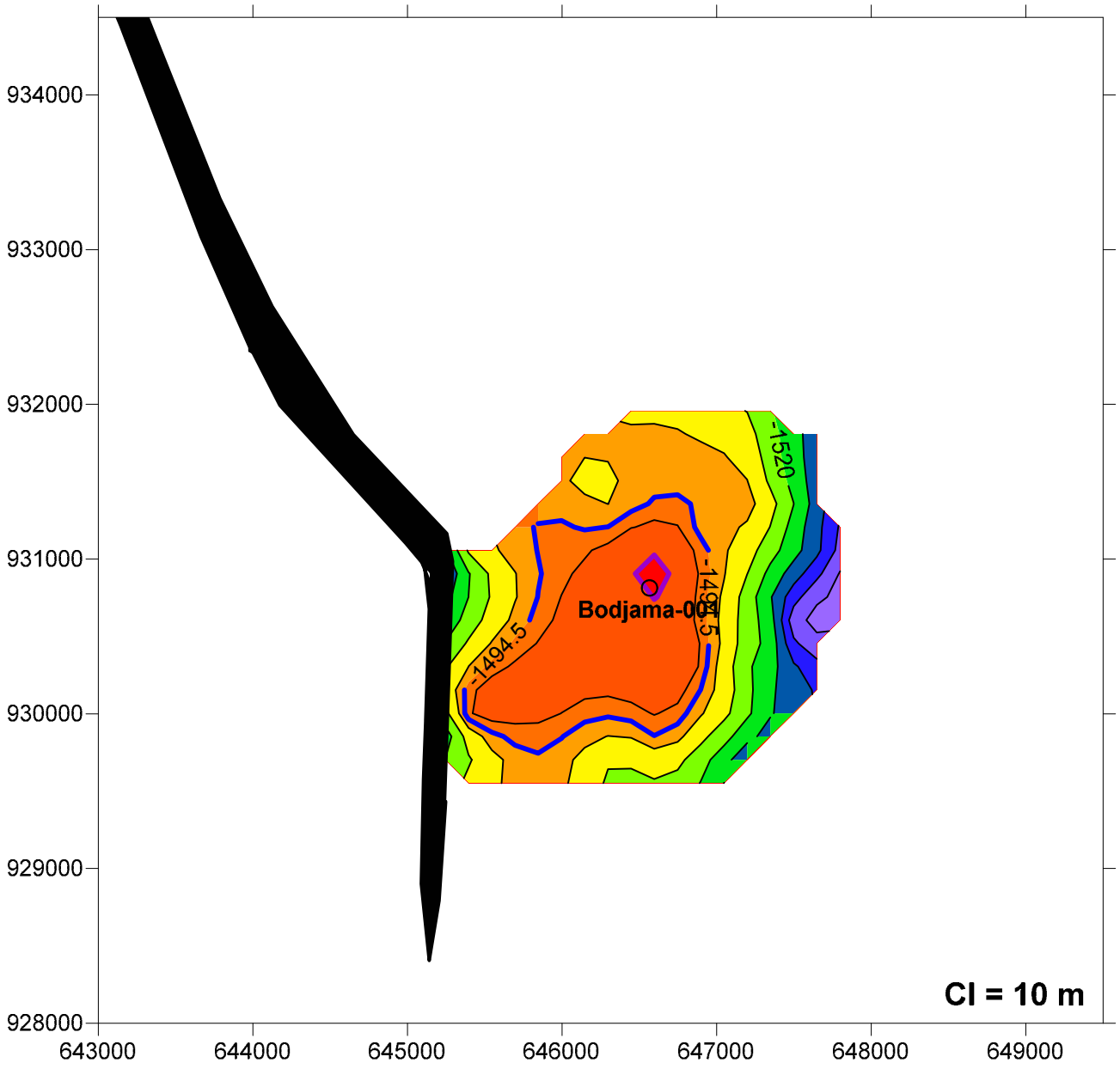
Effective Date: December 31, 2012
Scale: 1:42,000 s1132107



Map 18
Bodjama Prospect
Depth Structure Map (metres)
D Sand

Company: Griffiths Energy International Inc.
Property: DOI Block

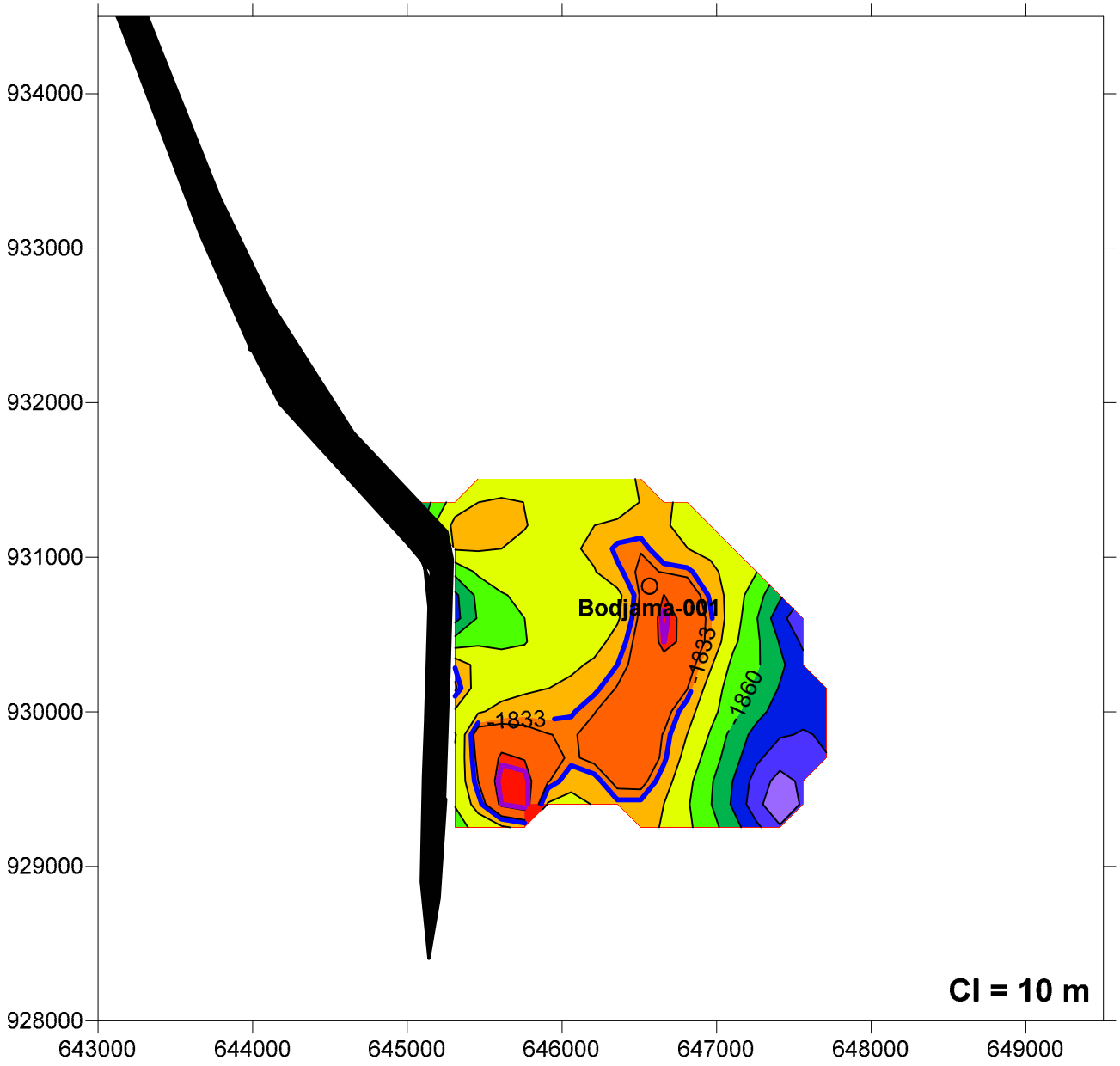
Effective Date: December 31, 2012
Scale: 1:42,000 s1132107



Map 19
Bodjama Prospect
Depth Structure Map (metres)
E Sand

Company: Griffiths Energy International Inc.
Property: DOI Block

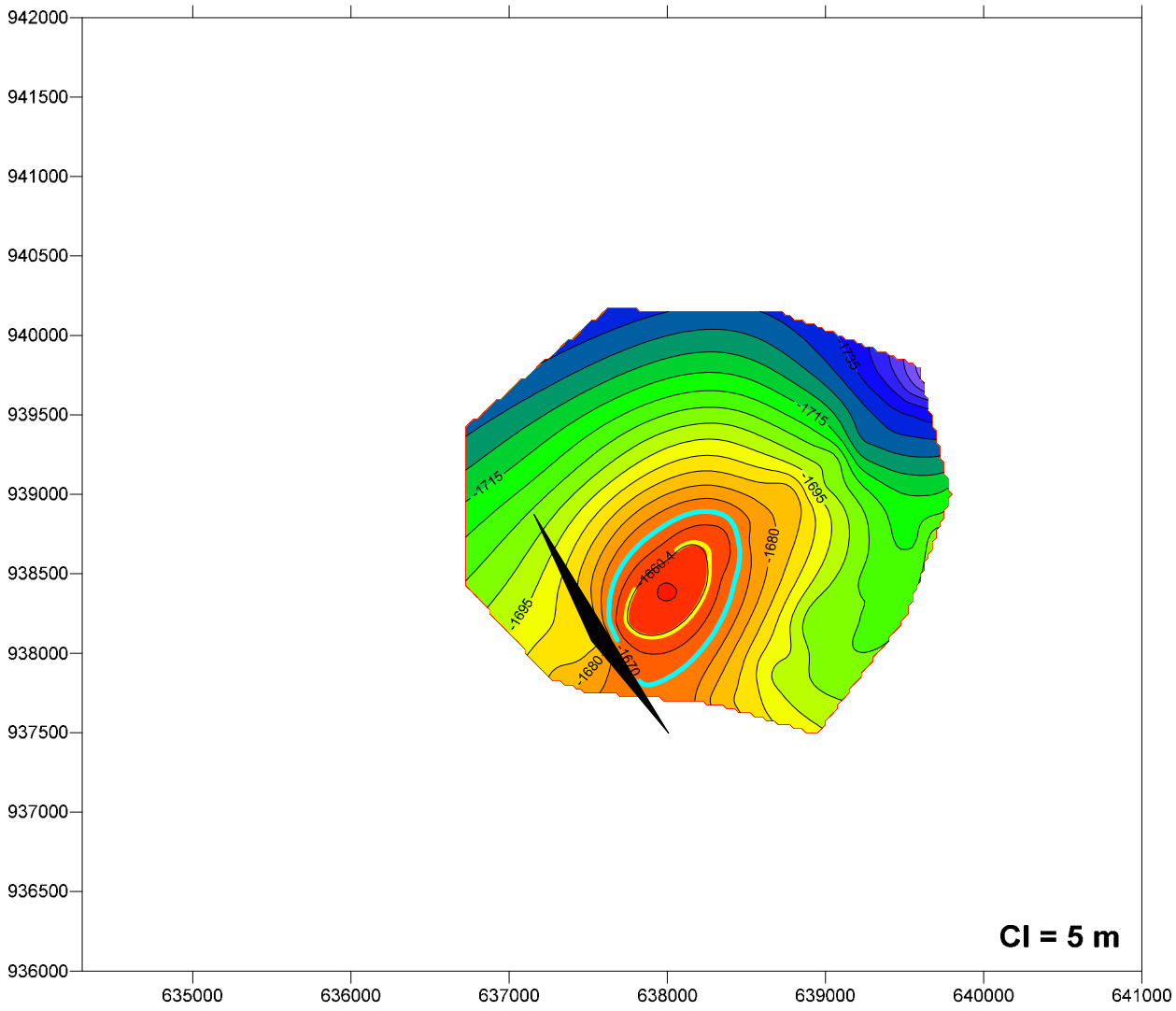
Effective Date: December 31, 2012
Scale: 1:42,000 s1132107



Map 20
Maikoro Prospect
Depth Structure Map (metres)
D Sand

Company: Griffiths Energy International Inc.
Property: DOI Block

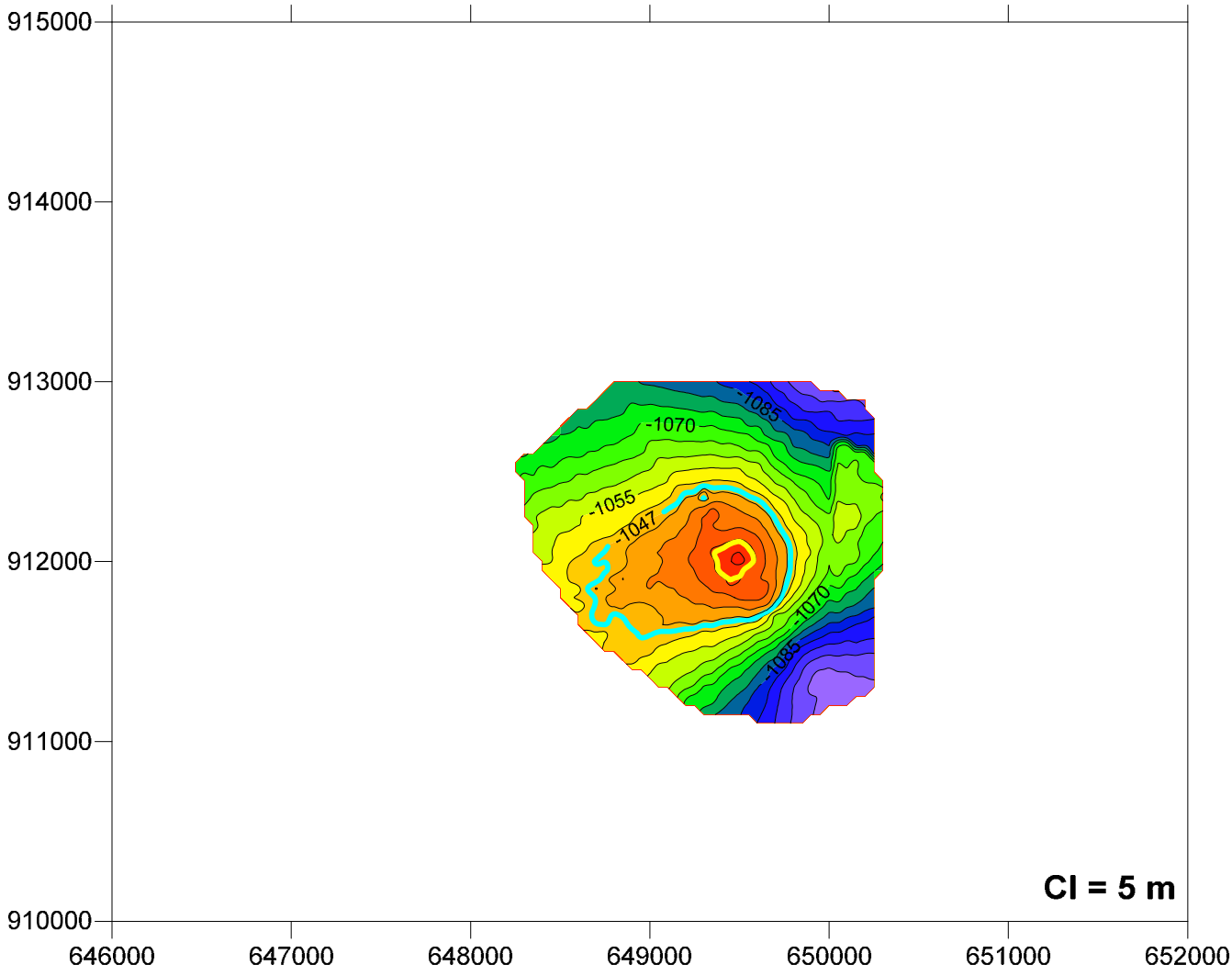
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Map 21
Man Lia Northeast Prospect
Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: DOI Block

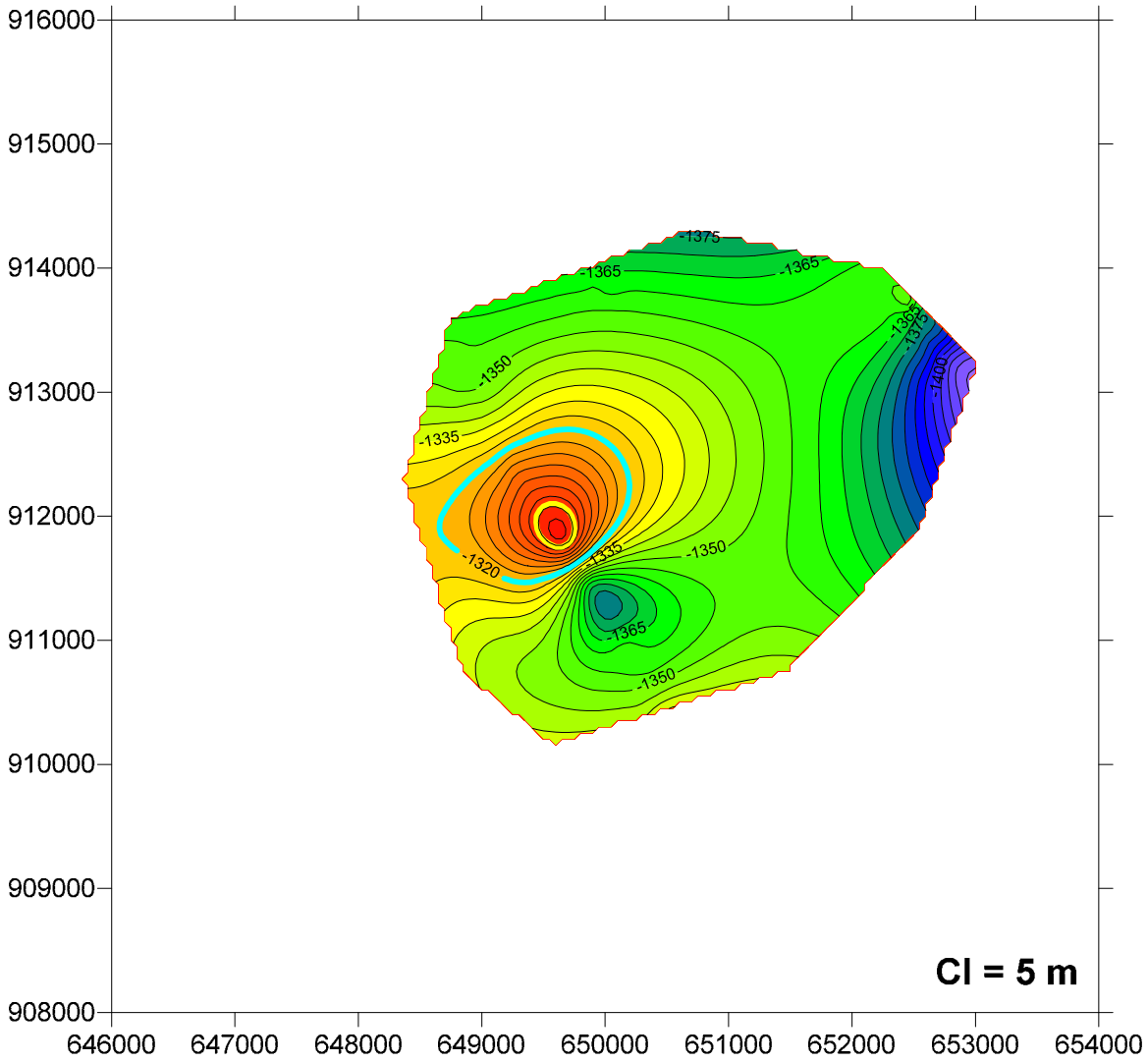
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Map 22
Man Lia Northeast Prospect
Depth Structure Map (metres)
D Sand

Company: Griffiths Energy International Inc.
Property: DOI Block

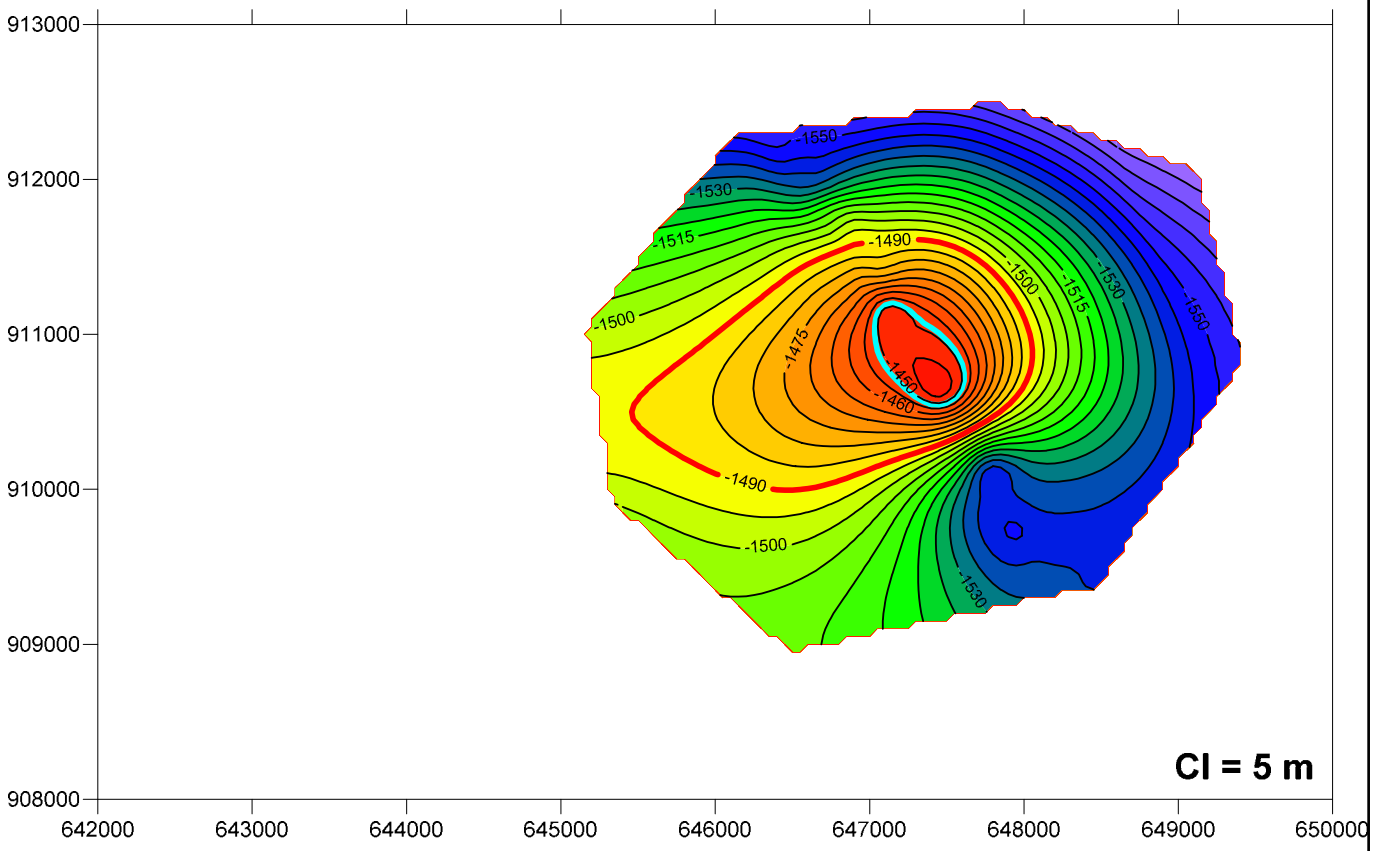
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Map 23
Man Lia Southwest Prospect
Depth Structure Map (metres)
E Sand

Company: Griffiths Energy International Inc.
Property: DOI Block

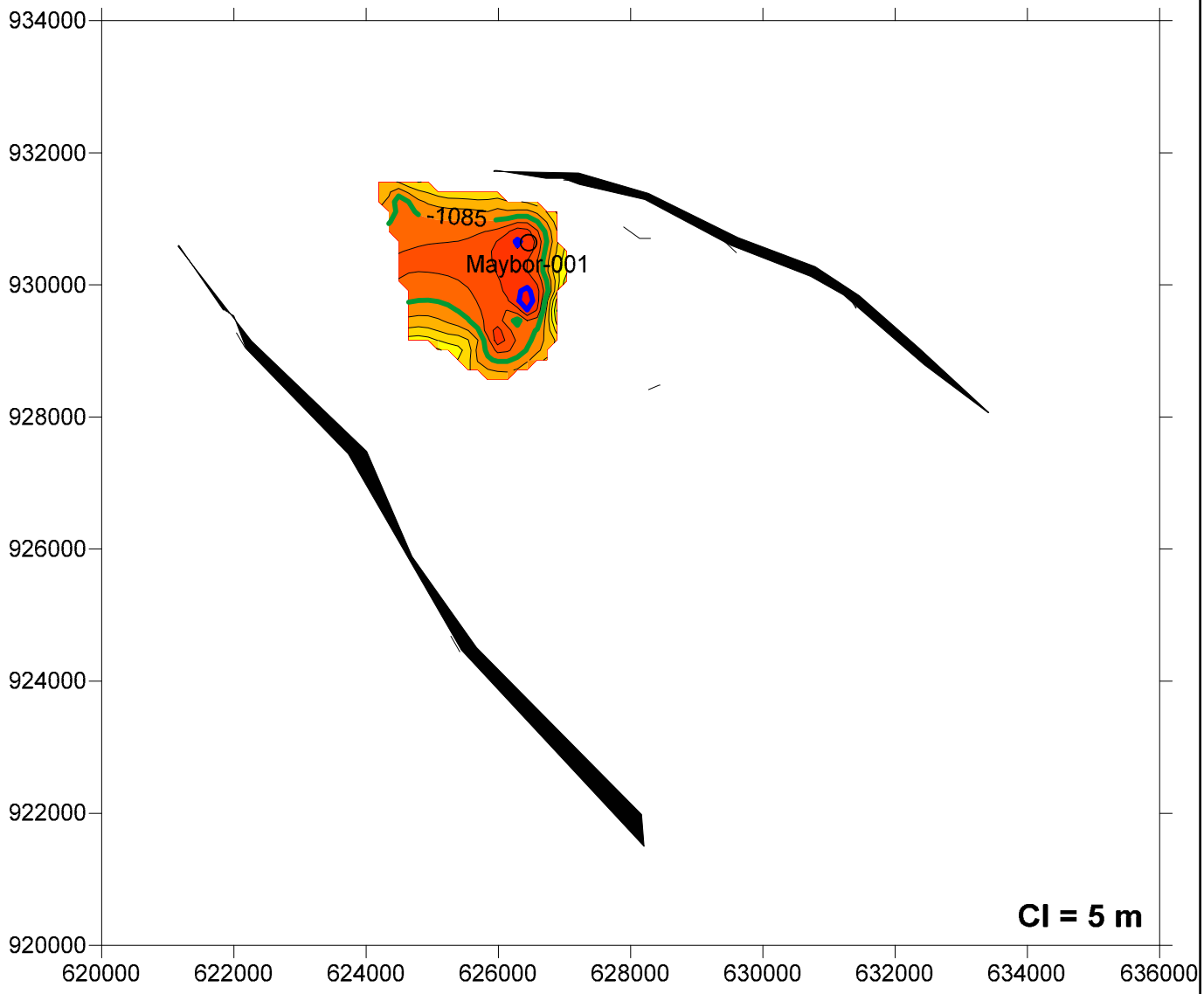
Effective Date: December 31, 2012
Scale: 1:50,000 s1132107



Map 24
Maybor Prospect
Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: DOI Block

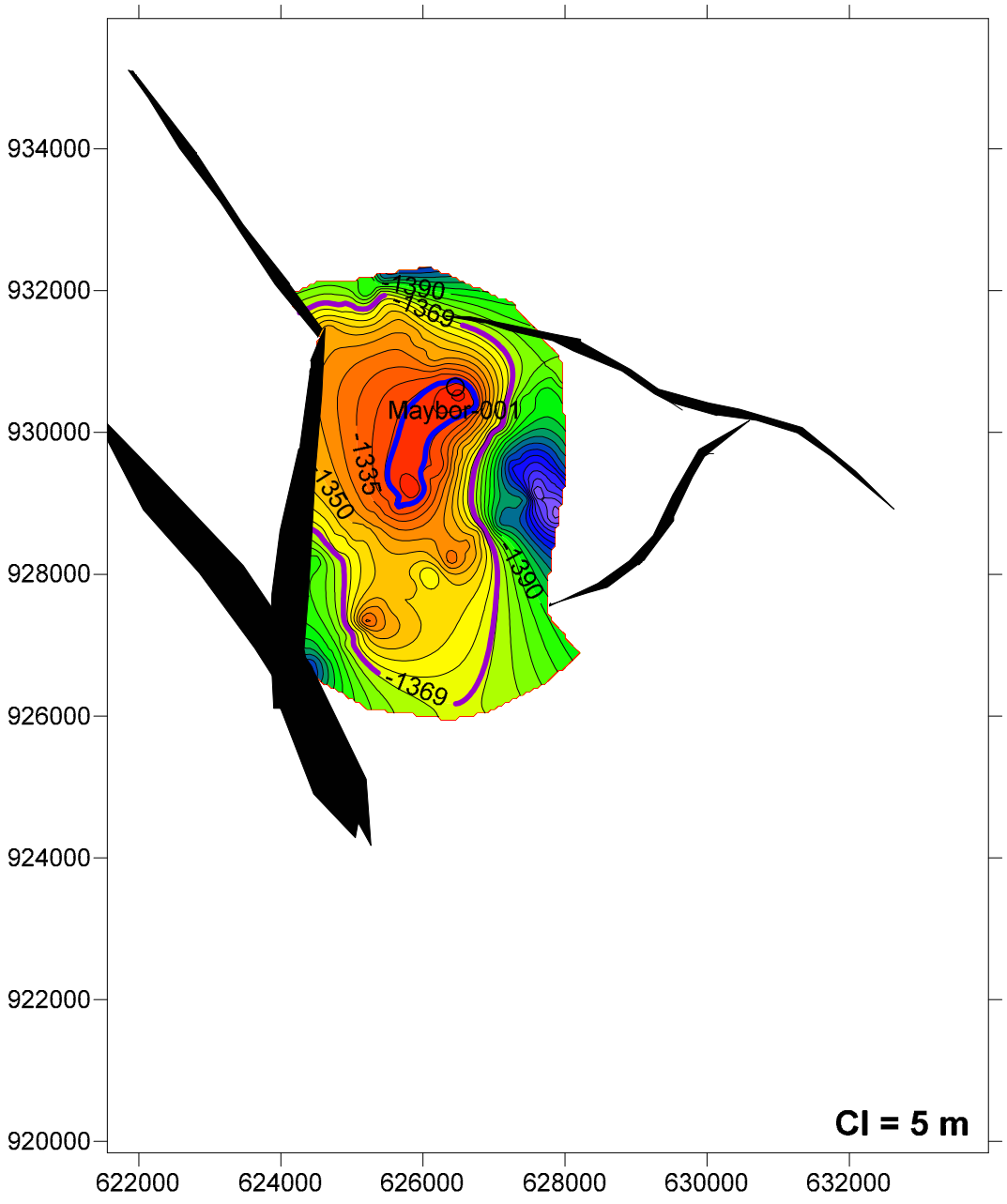
Effective Date: December 31, 2012
Scale: 1:100,000 s1132107



Map 25
Maybor Prospect
Depth Structure Map (metres)
D Sand

Company: Griffiths Energy International Inc.
Property: DOI Block

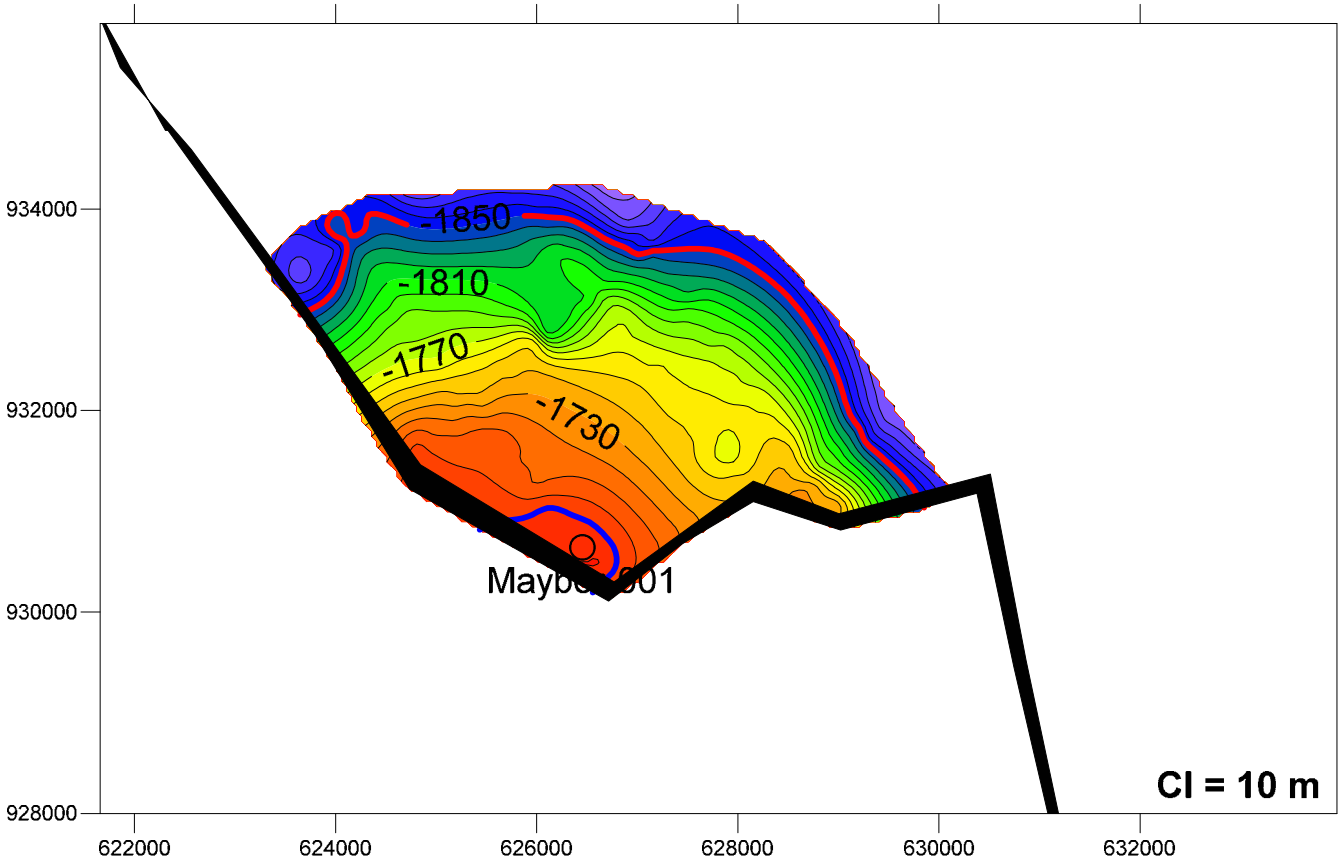
Effective Date: December 31, 2012
Scale: 1:100,000 s1132107



Map 26
Maybor Prospect
Depth Structure Map (metres)
E Sand

Company: Griffiths Energy International Inc.
Property: DOI Block

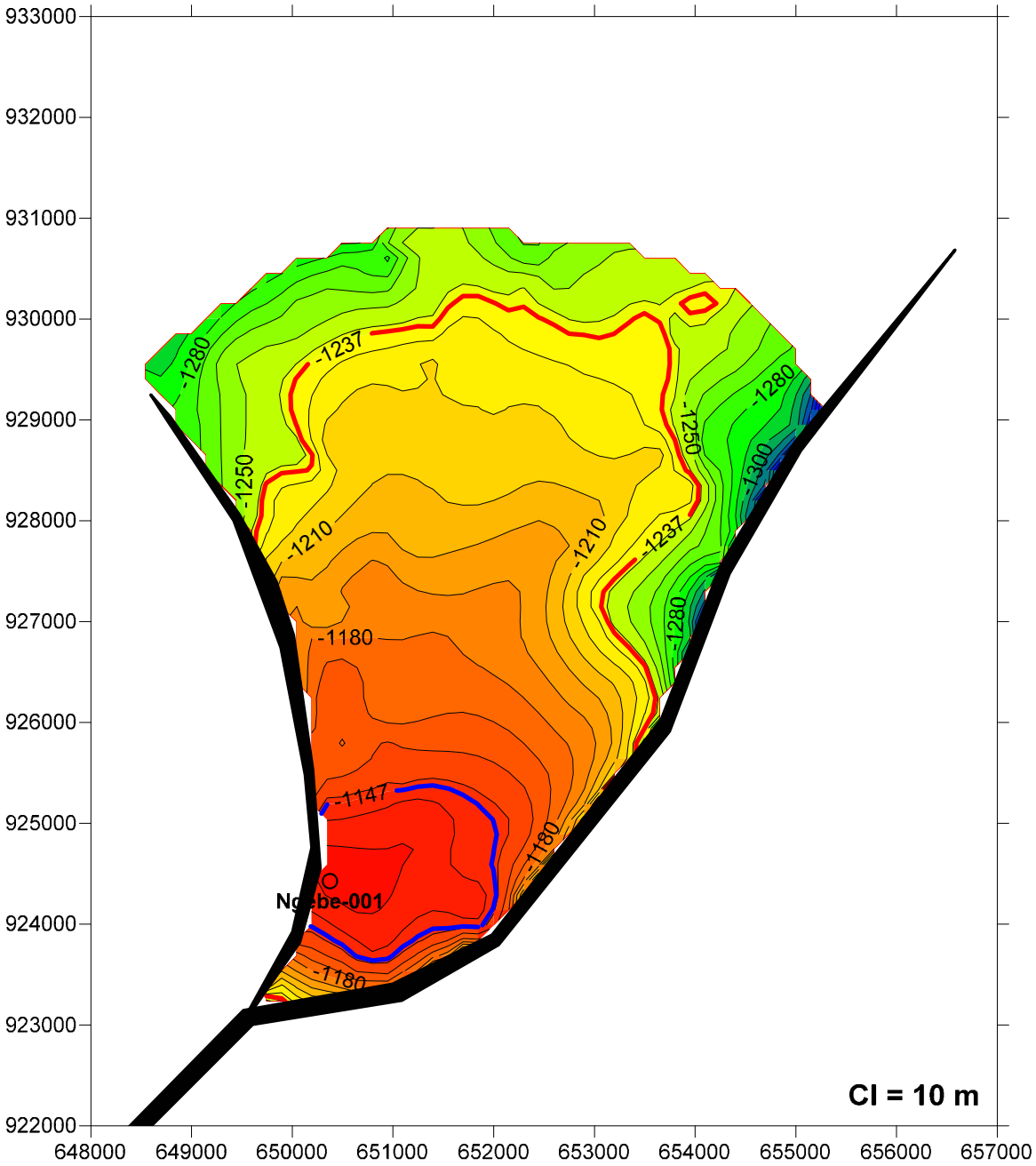
Effective Date: December 31, 2012
Scale: 1:100,000 s1132107



Map 27
Ngebe Prospect
Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: DOI Block

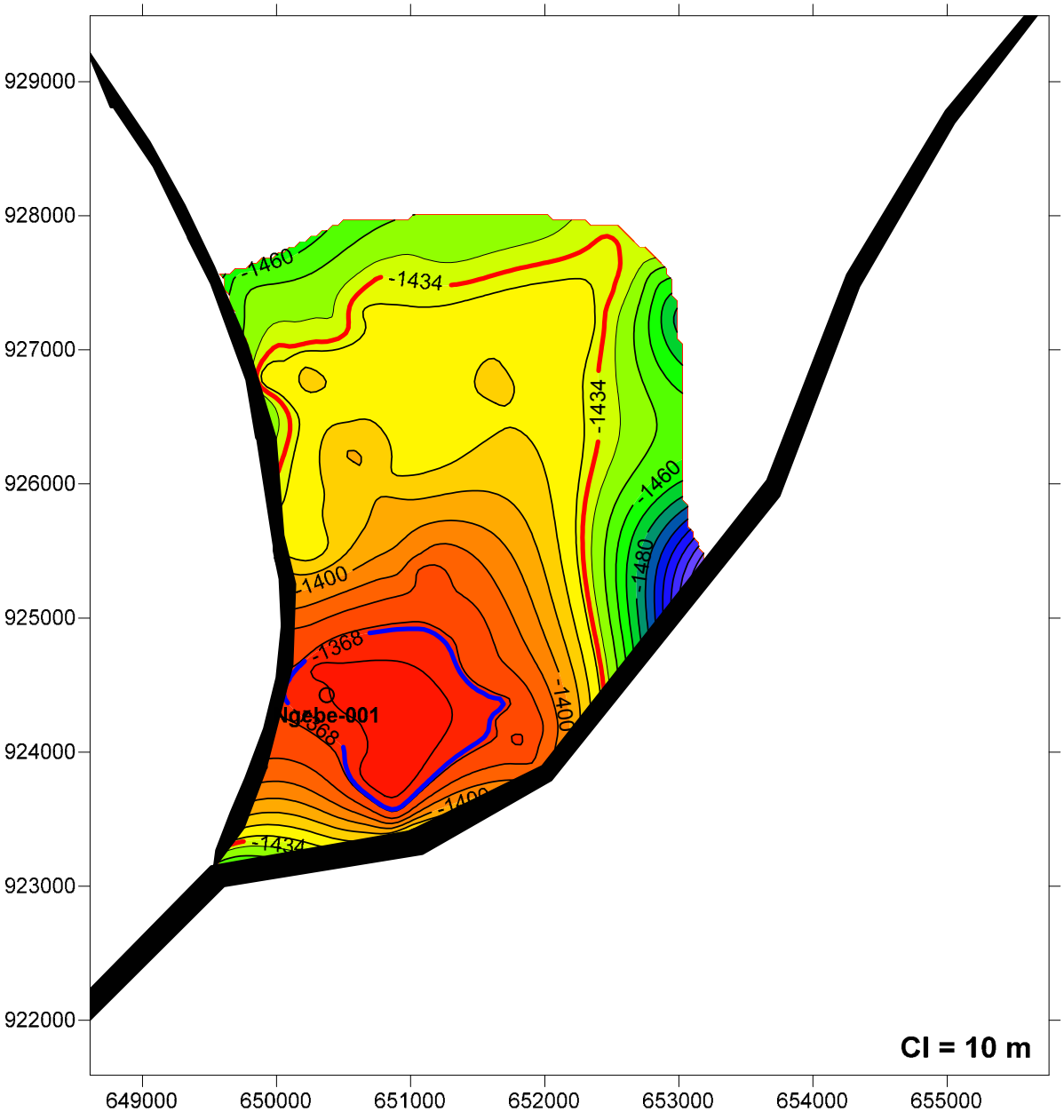
Effective Date: December 31, 2012
Scale: 1:60,000 s1132107



Map 28
Ngebe Prospect
Depth Structure Map (metres)
D Sand

Company: Griffiths Energy International Inc.
Property: DOI Block

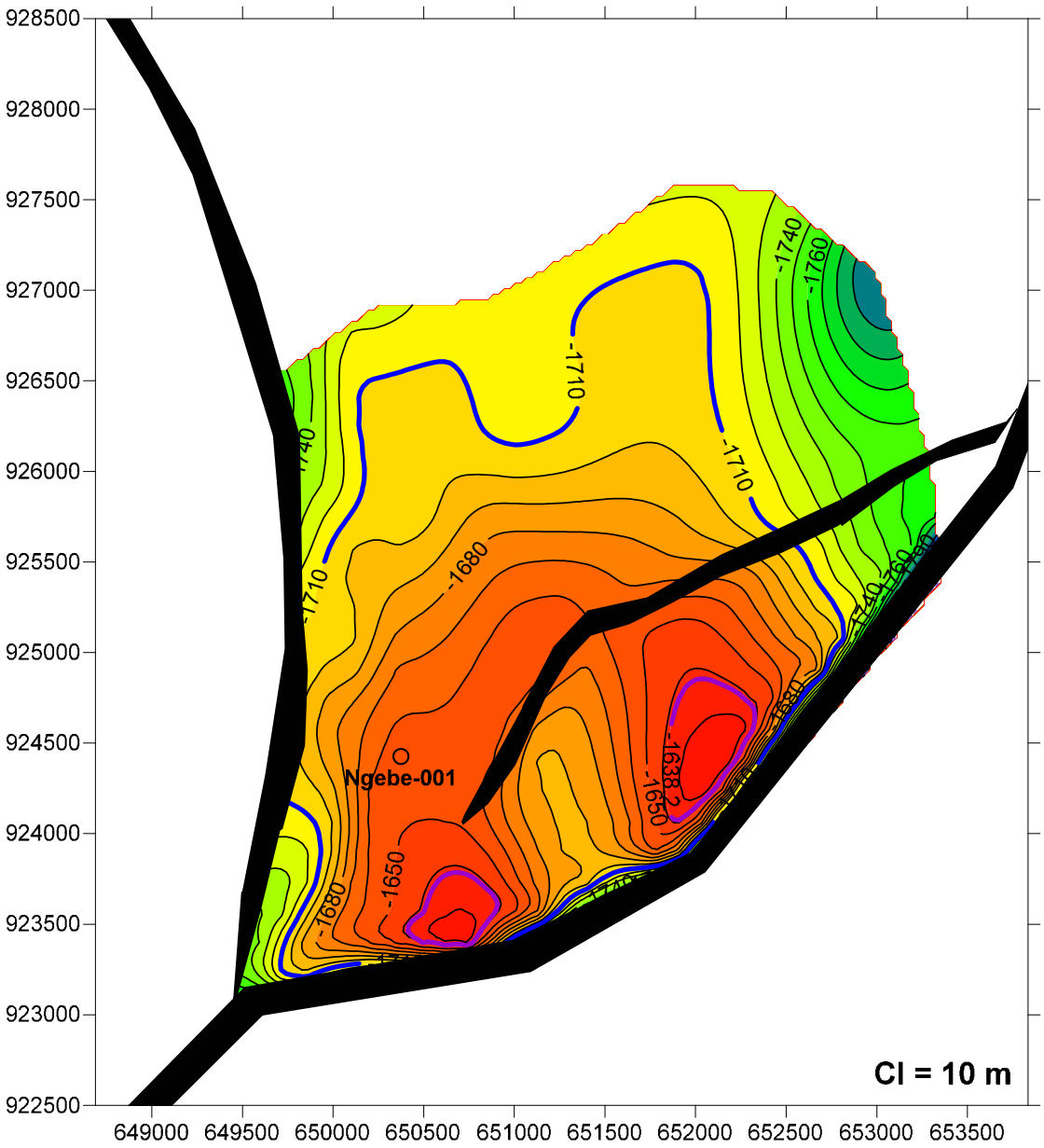
Effective Date: December 31, 2012
Scale: 1:41,000 s1132107



Map 29
Ngebe Prospect
Depth Structure Map (metres)
E Sand

Company: Griffiths Energy International Inc.
Property: DOI Block

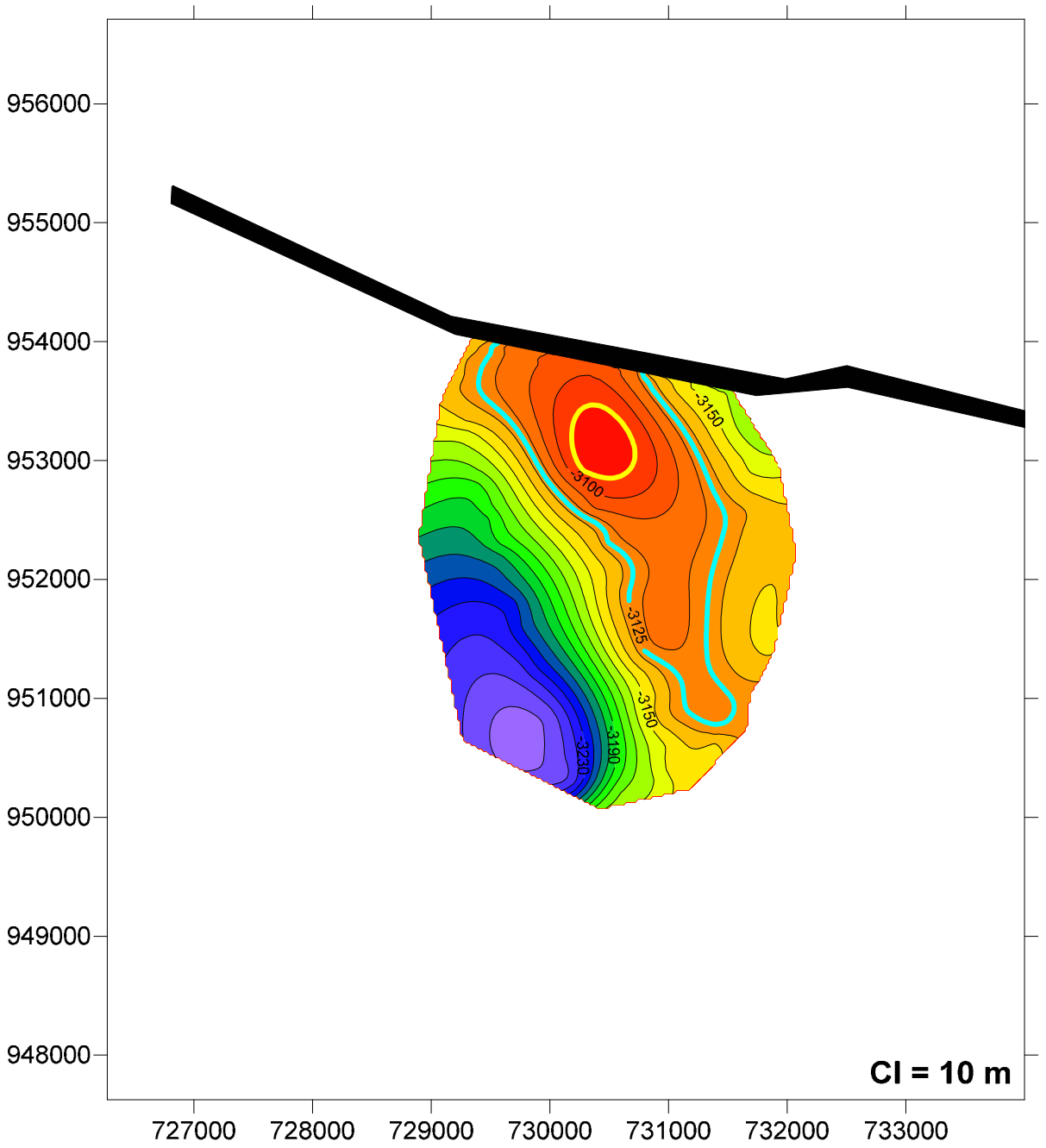
Effective Date: December 31, 2012
Scale: 1:35,000 s1132107



Map 30
Bedaya Prospect
Depth Structure Map (metres)
C and D Sands

Company: Griffiths Energy International Inc.
Property: DOH Block

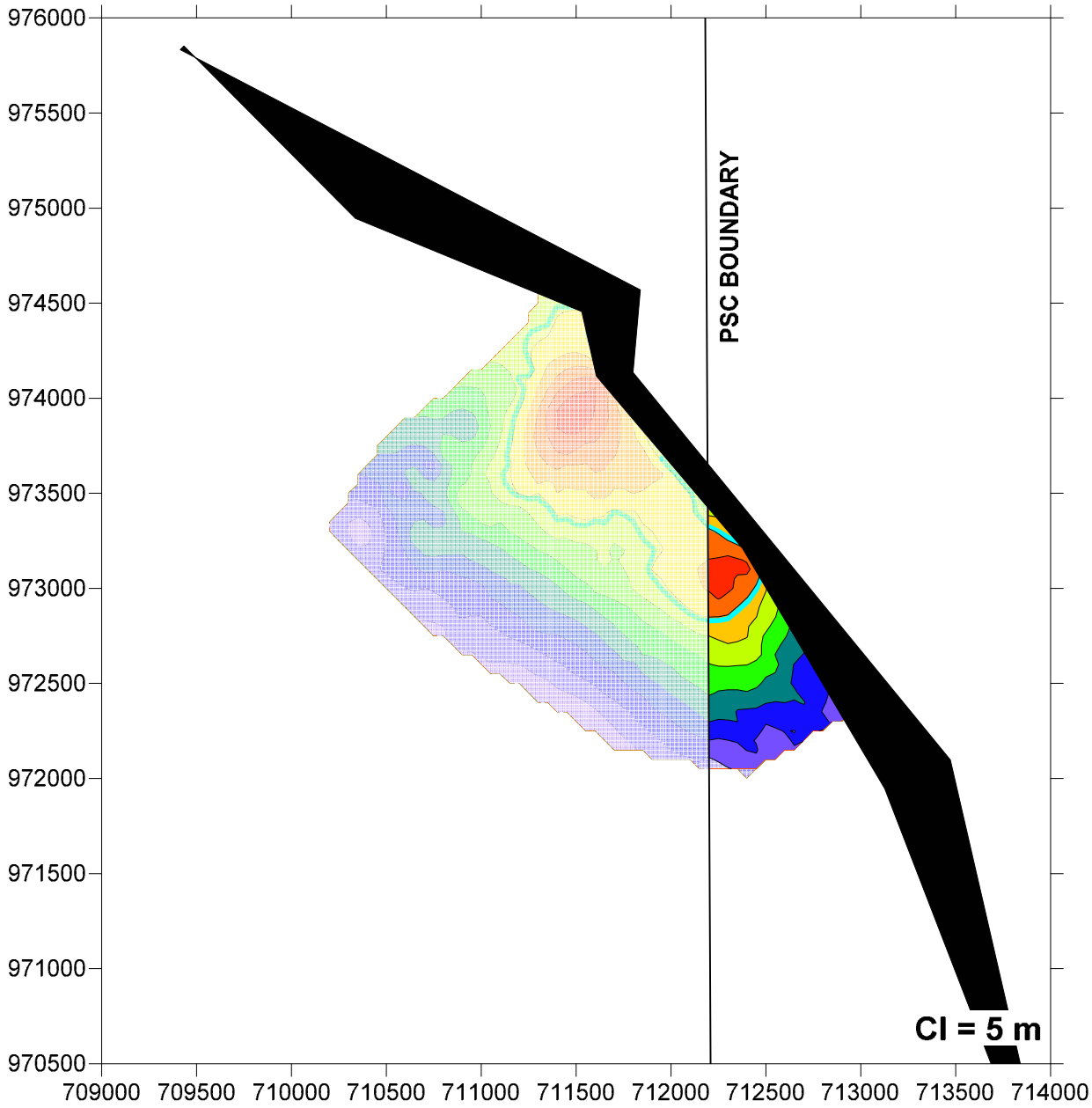
Effective Date: December 31, 2012
Scale: 1:60,000 s1132107



Map 31
Bessama Prospect
Depth Structure Map (metres)
C and D Sands

Company: Griffiths Energy International Inc.
Property: DOH Block

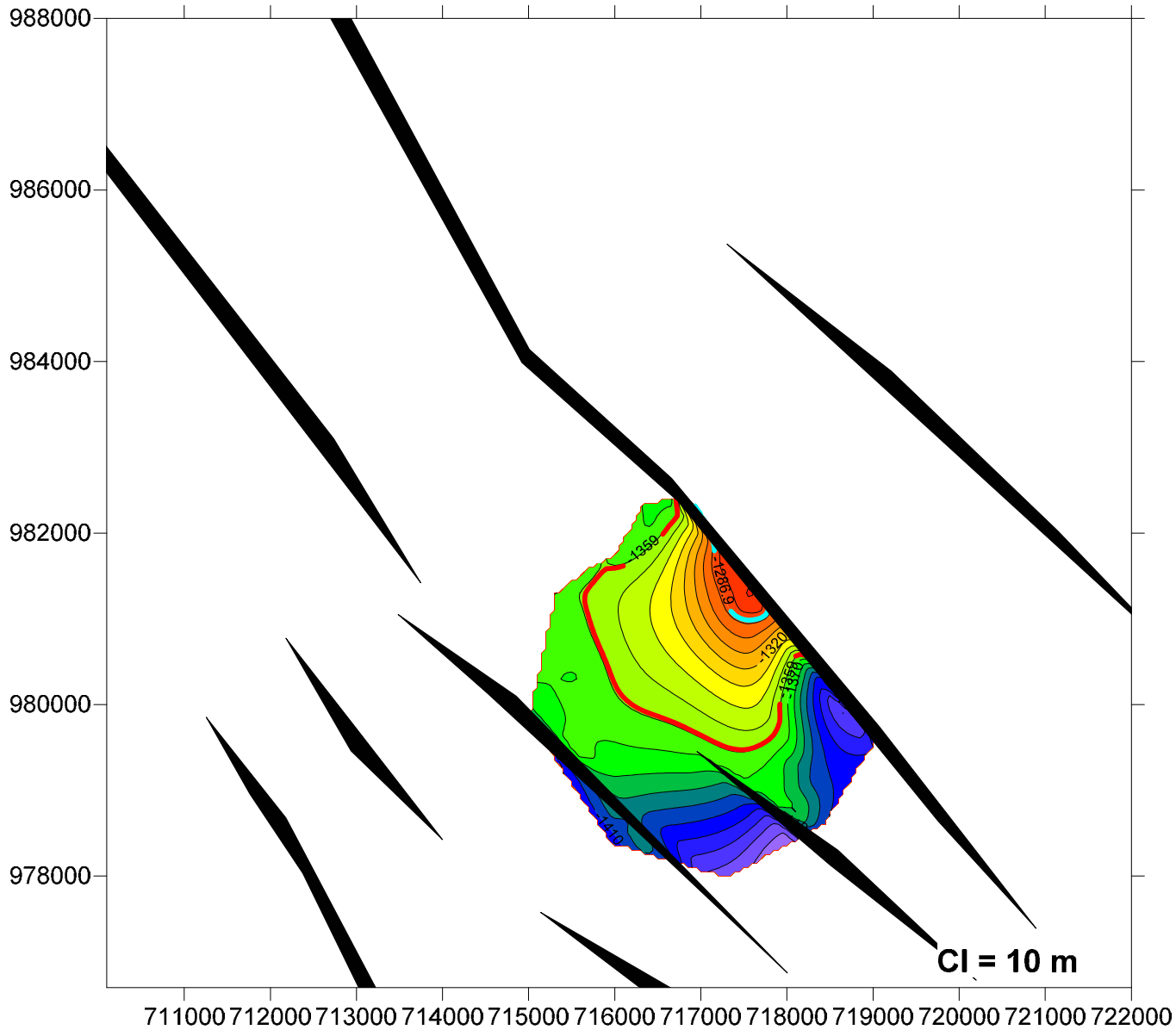
Effective Date: December 31, 2012
Scale: 1:35,000 s1132107



Map 32
Beyara Prospect
Depth Structure Map (metres)
A, M and B Sands

Company: Griffiths Energy International Inc.
Property: DOH Block

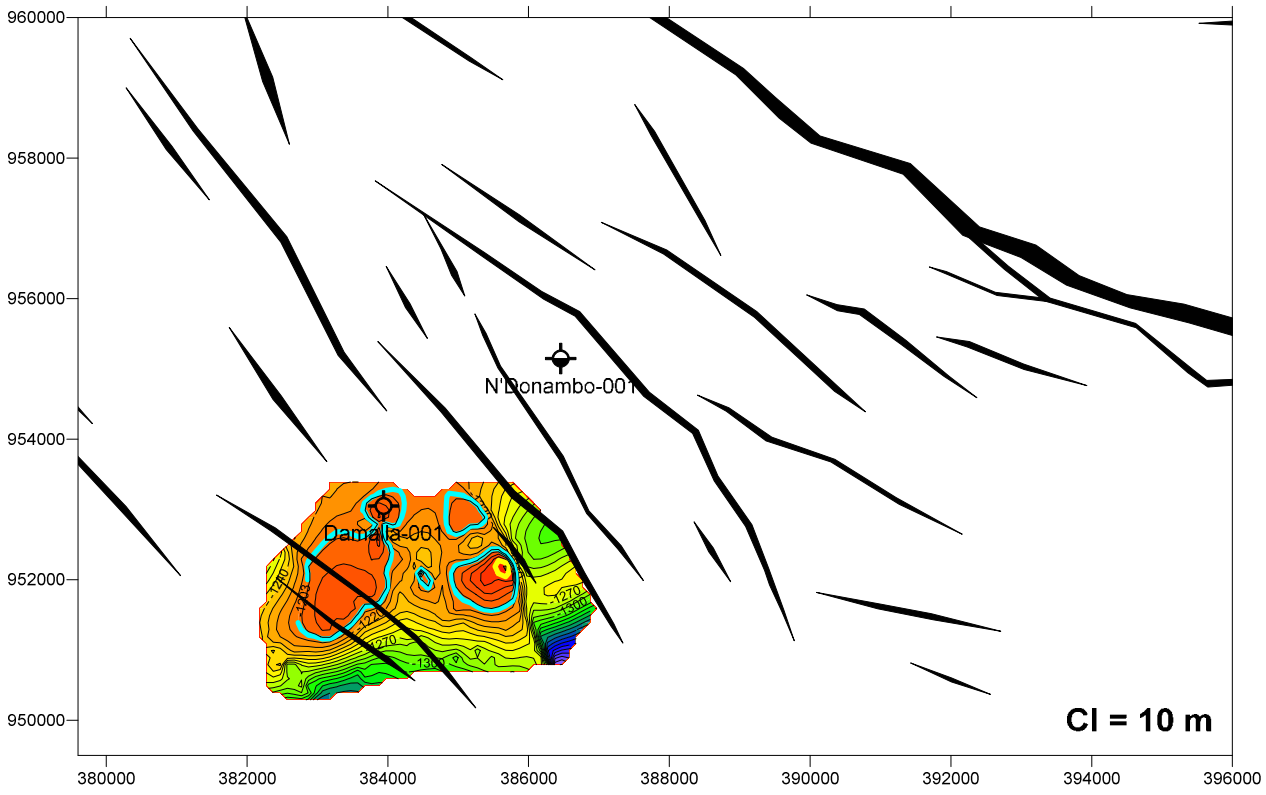
Effective Date: December 31, 2012
Scale: 1:80,000 s1132107



Map 33
Damalla Prospect
Depth Structure Map (metres)
A1 and M Sands

Company: Griffiths Energy International Inc.
Property: DOH Block

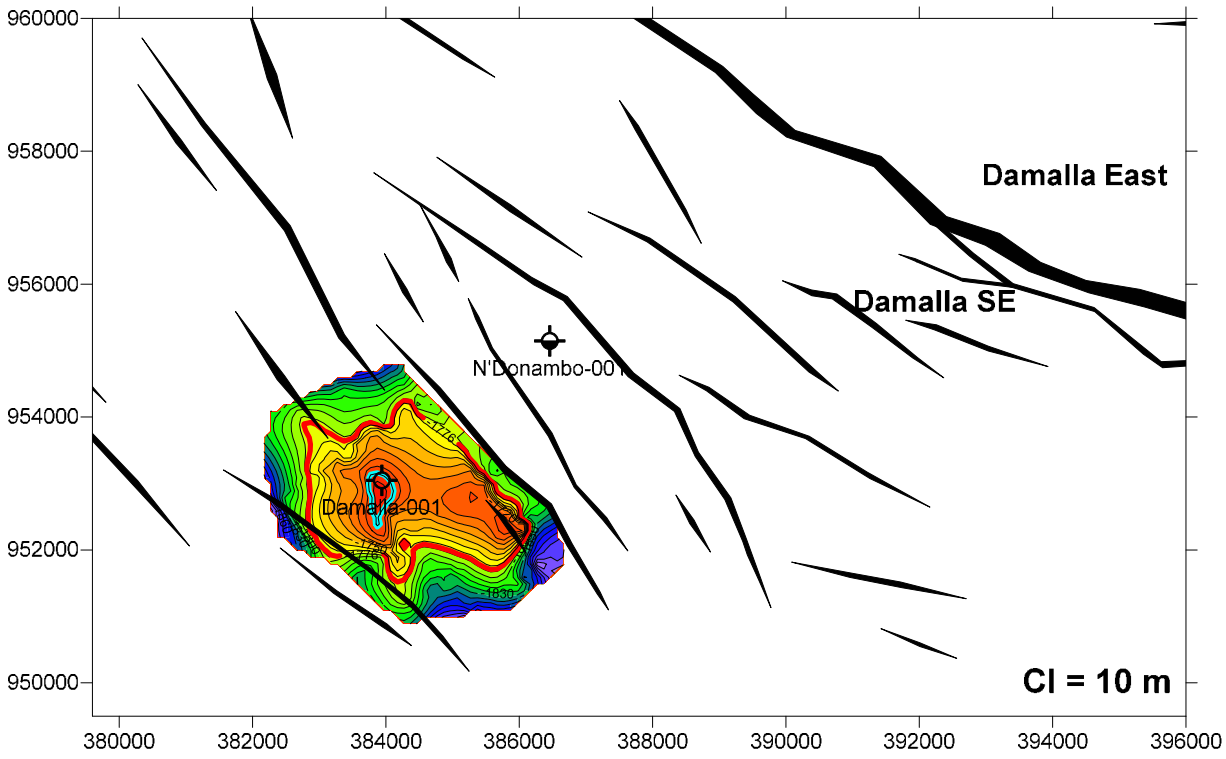
Effective Date: December 31, 2012
Scale: 1:85,000 s1132107



Map 34
Damalla Prospect
Depth Structure Map (metres)
B Sand

Company: Griffiths Energy International Inc.
Property: DOH Block

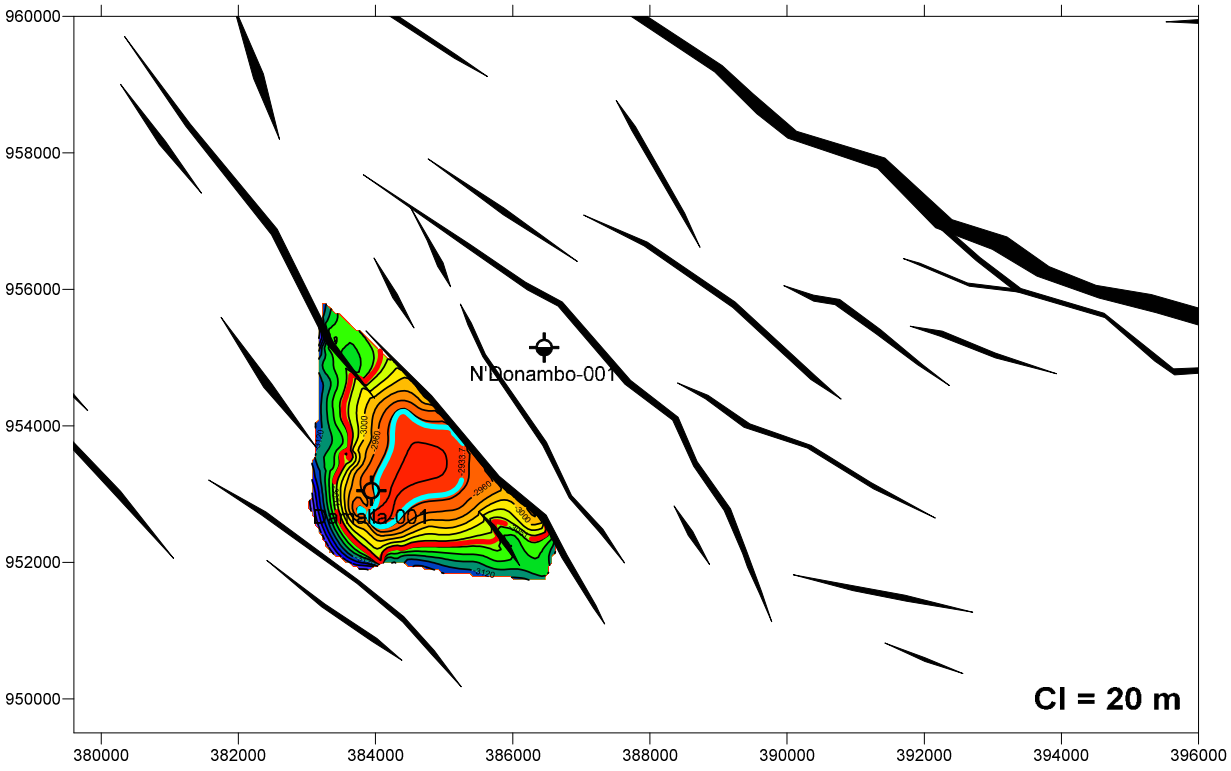
Effective Date: December 31, 2012
Scale: 1:90,000 s1132107



Map 35
Damalla Prospect
Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: DOH Block

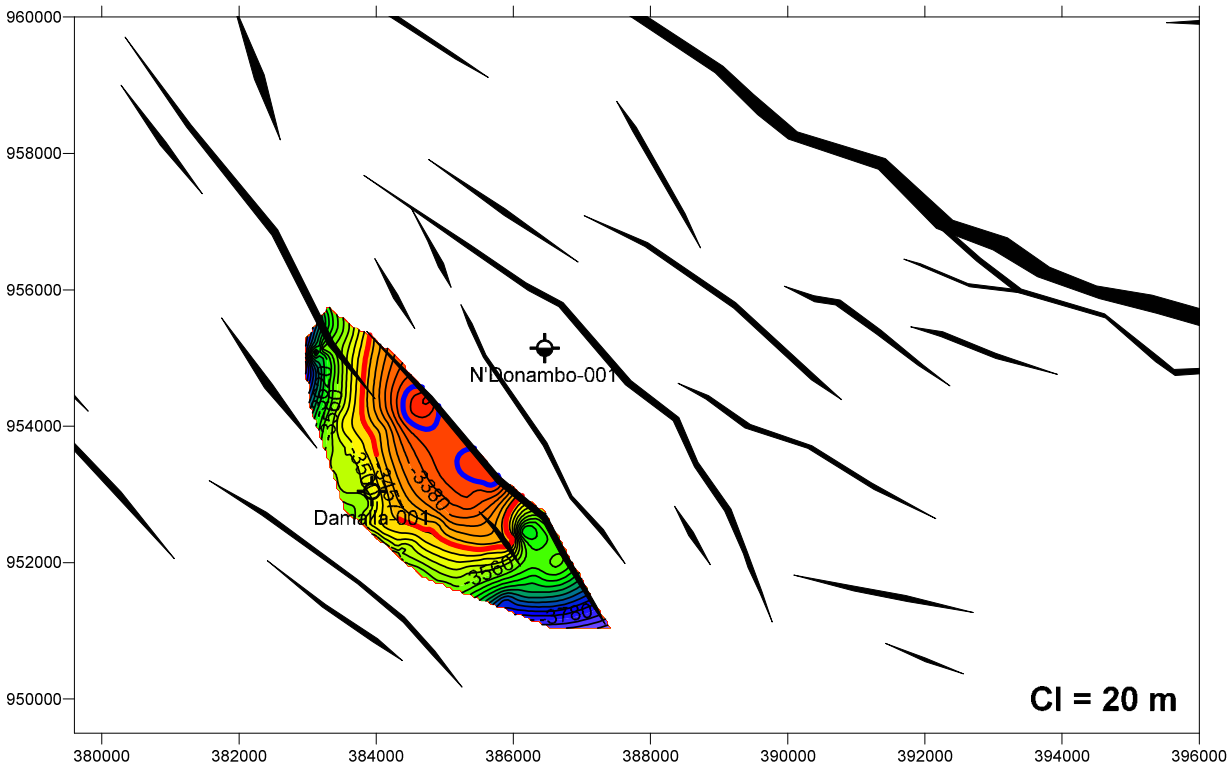
Effective Date: December 31, 2012
Scale: 1:85,000 s1132107



Map 36
Damalla Prospect
Depth Structure Map (metres)
D Sand

Company: Griffiths Energy International Inc.
Property: DOH Block

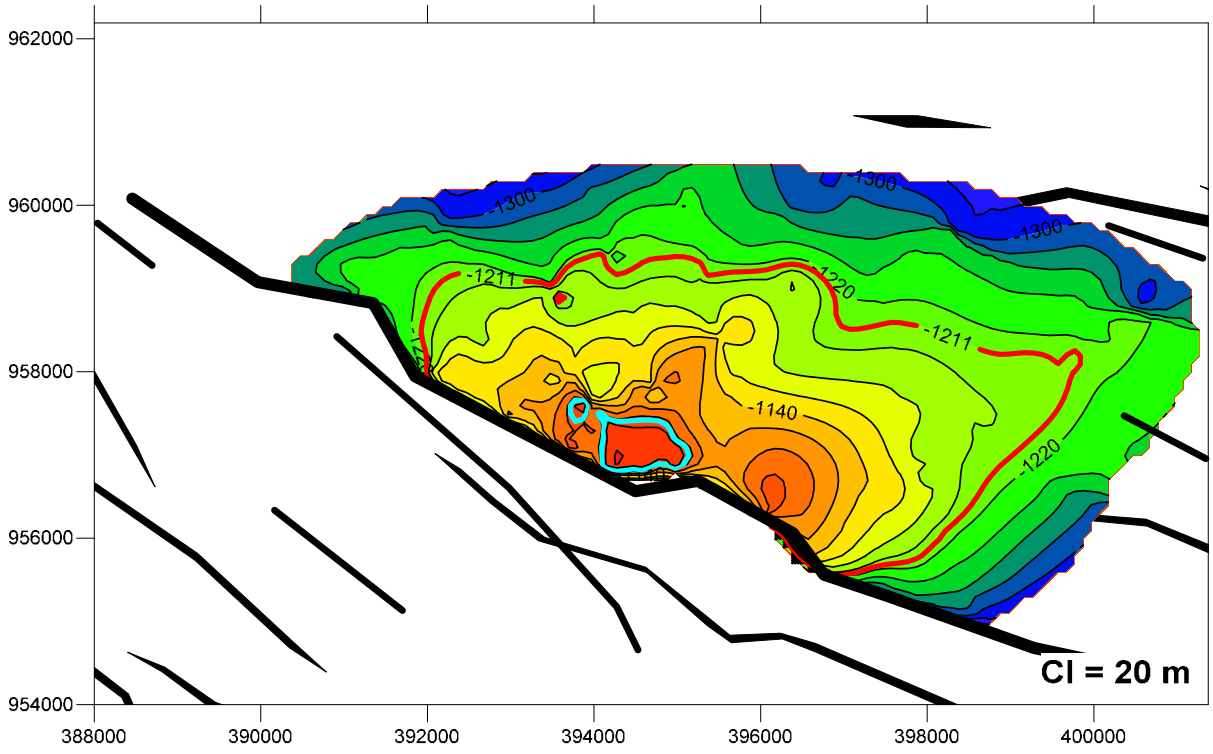
Effective Date: December 31, 2012
Scale: 1:85,000 s1132107



Map 37
Damalla East Prospect
Depth Structure Map (metres)
A1 and M Sands

Company: Griffiths Energy International Inc.
Property: DOH Block

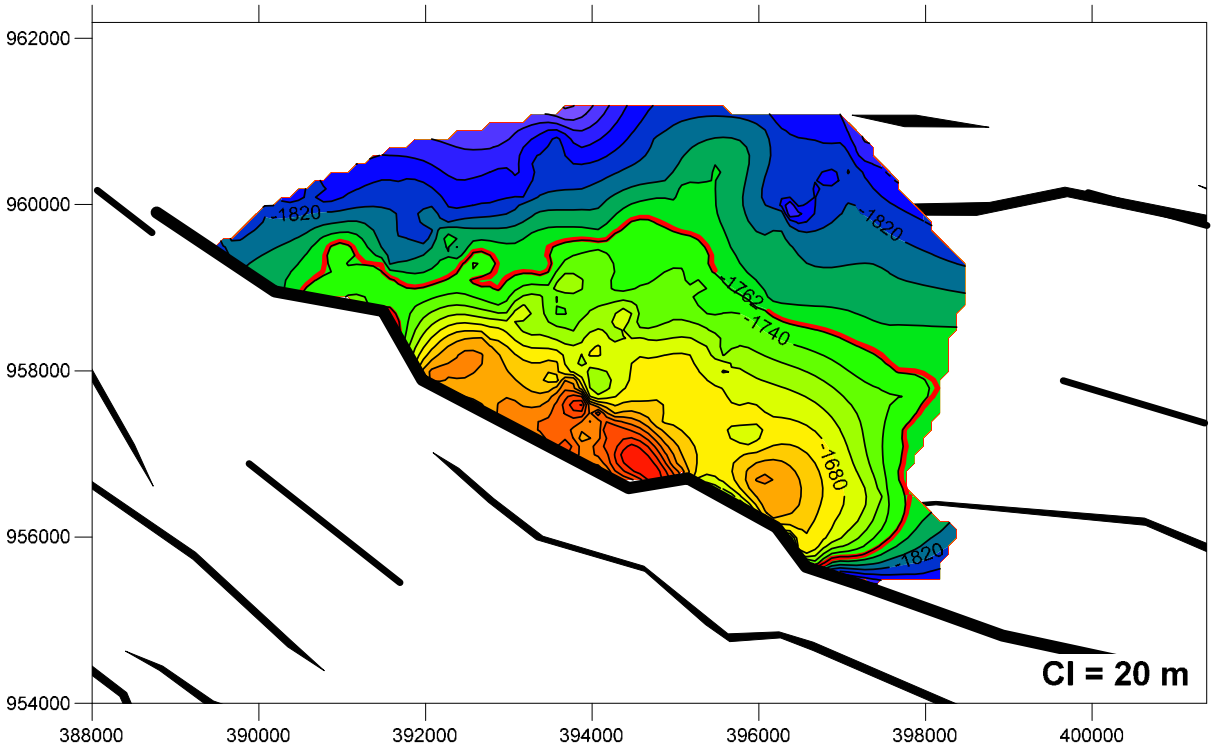
Effective Date: December 31, 2012
Scale: 1:110,000 s1132107



Map 38
Damalla East Prospect
Depth Structure Map (metres)
B Sand

Company: Griffiths Energy International Inc.
Property: DOH Block

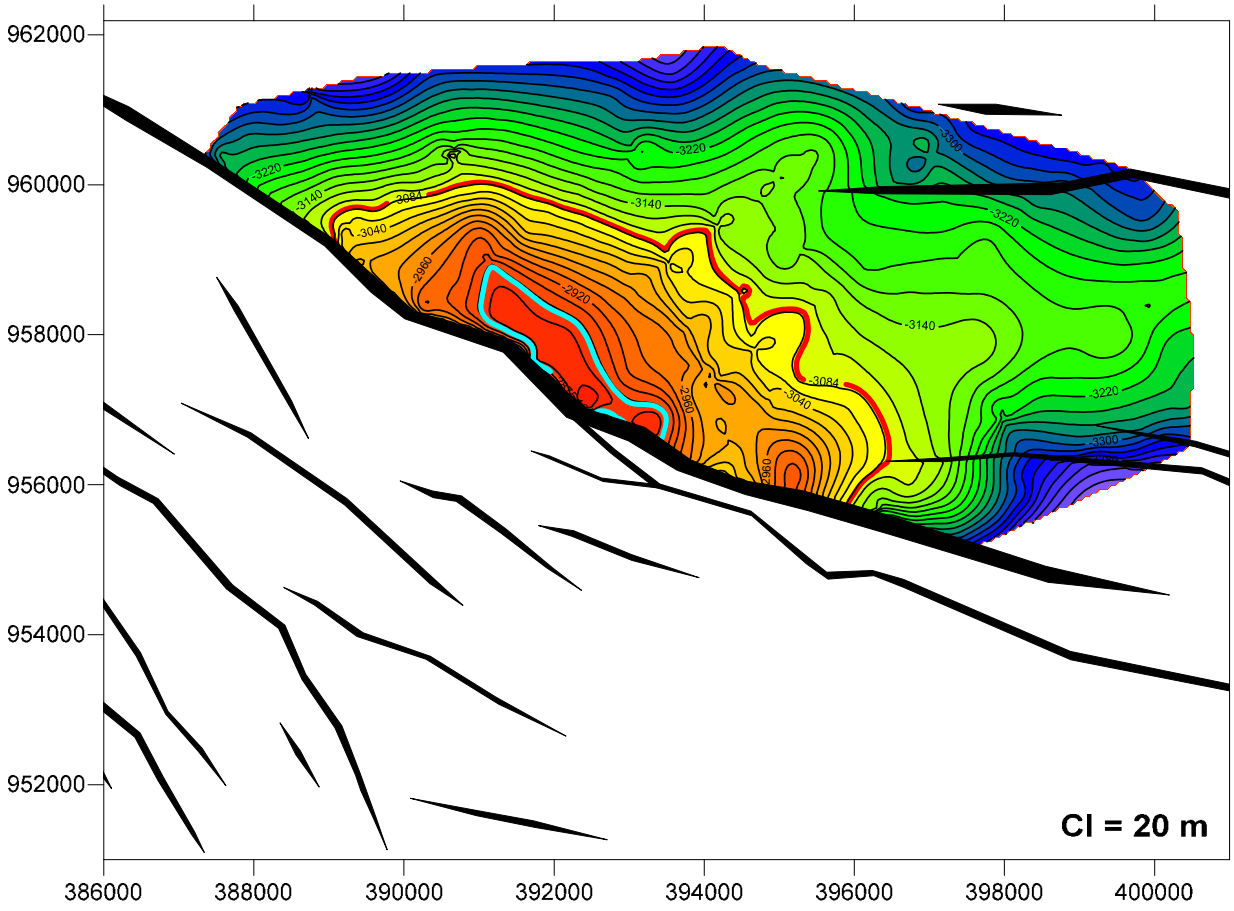
Effective Date: December 31, 2012
Scale: 1:110,000 s1132107



Map 39
Damalla East Prospect
Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: DOH Block

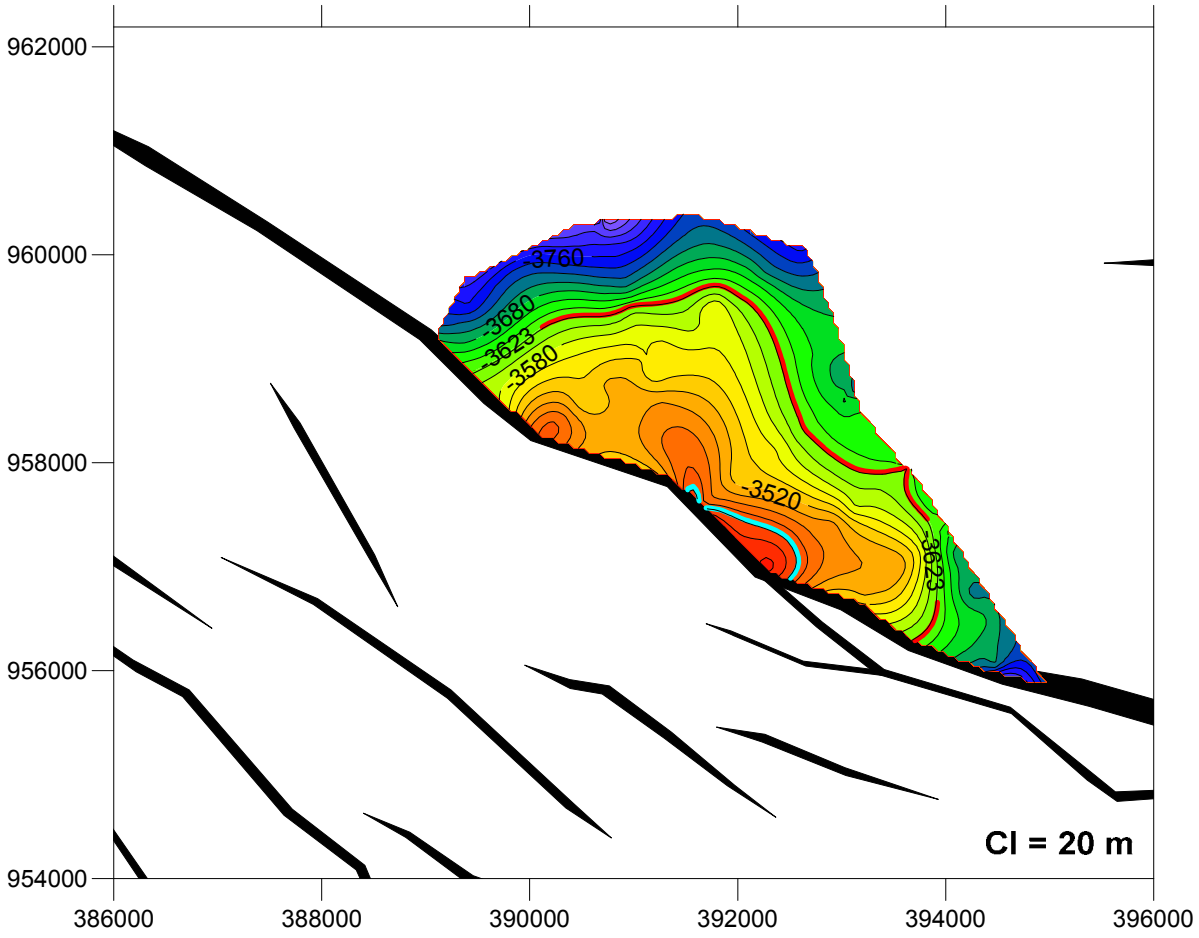
Effective Date: December 31, 2012
Scale: 1:100,000 s1132107



Map 40
Damalla East Prospect
Depth Structure Map (metres)
D1 Sand

Company: Griffiths Energy International Inc.
Property: DOH Block

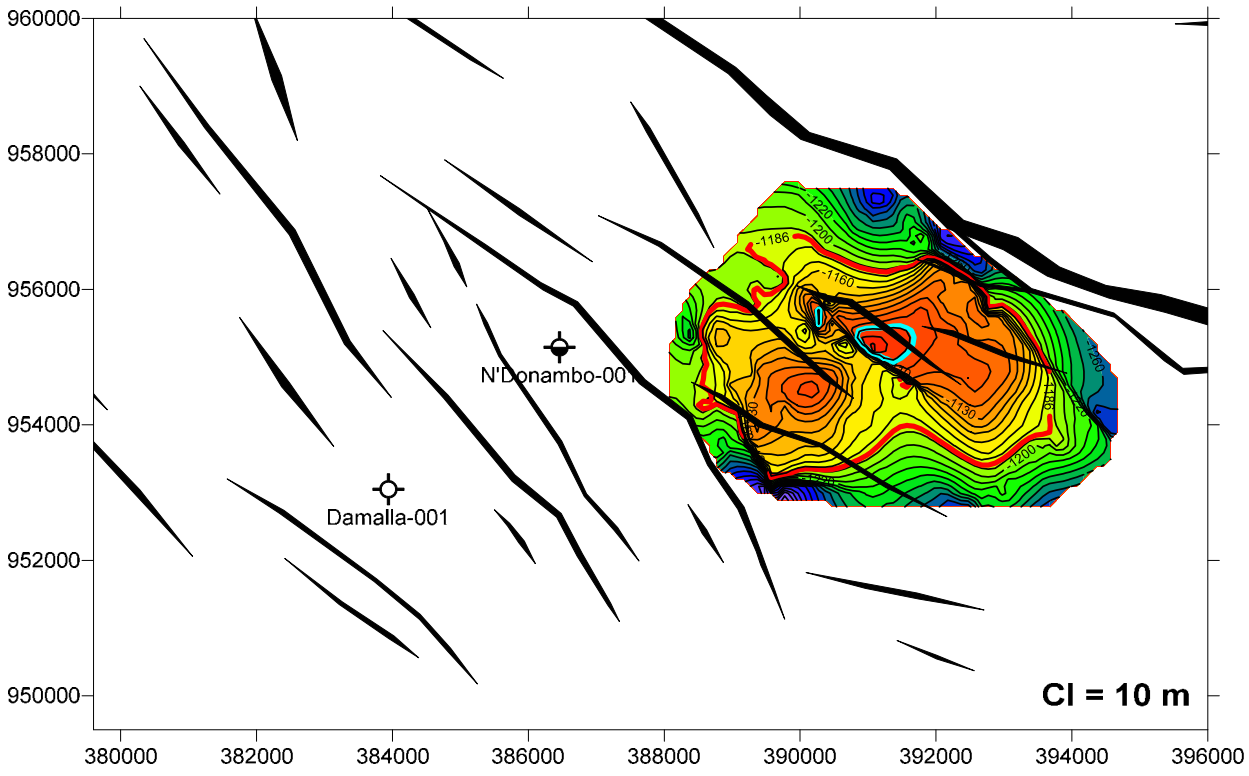
Effective Date: December 31, 2012
Scale: 1:110,000 s1132107



Map 41
Damalla Southeast Prospect
Depth Structure Map (metres)
A1 and M Sands

Company: Griffiths Energy International Inc.
Property: DOH Block

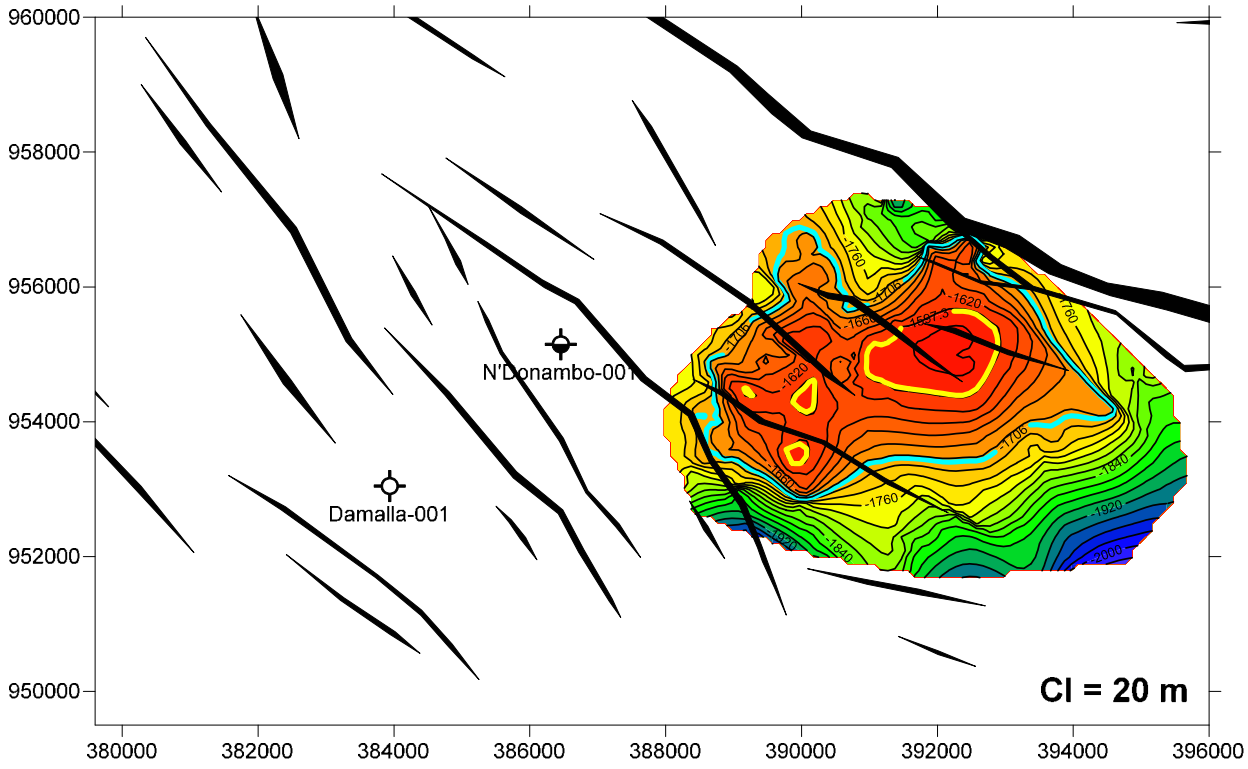
Effective Date: December 31, 2012
Scale: 1:80,000 s1132107



Map 42
Damalla Southeast Prospect
Depth Structure Map (metres)
B Sand

Company: Griffiths Energy International Inc.
Property: DOH Block

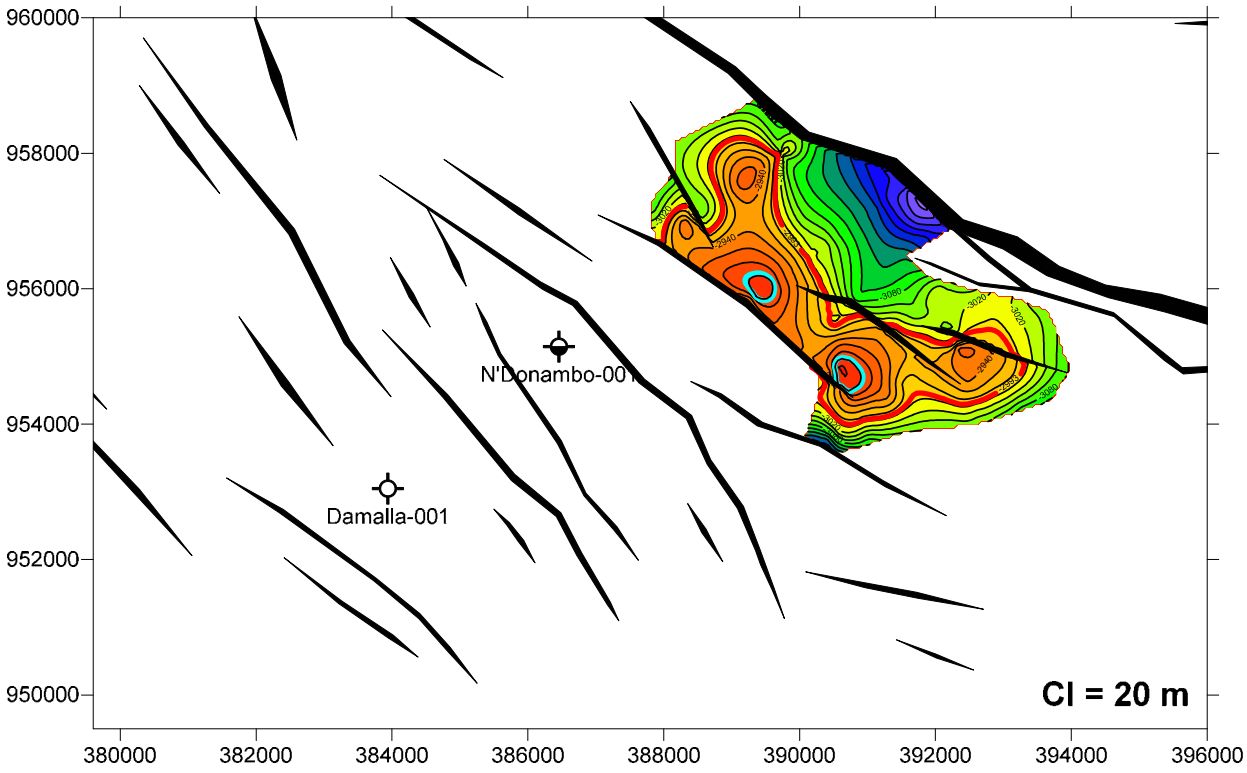
Effective Date: December 31, 2012
Scale: 1:90,000 s1132107



Map 43
Damalla Southeast Prospect
Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: DOH Block

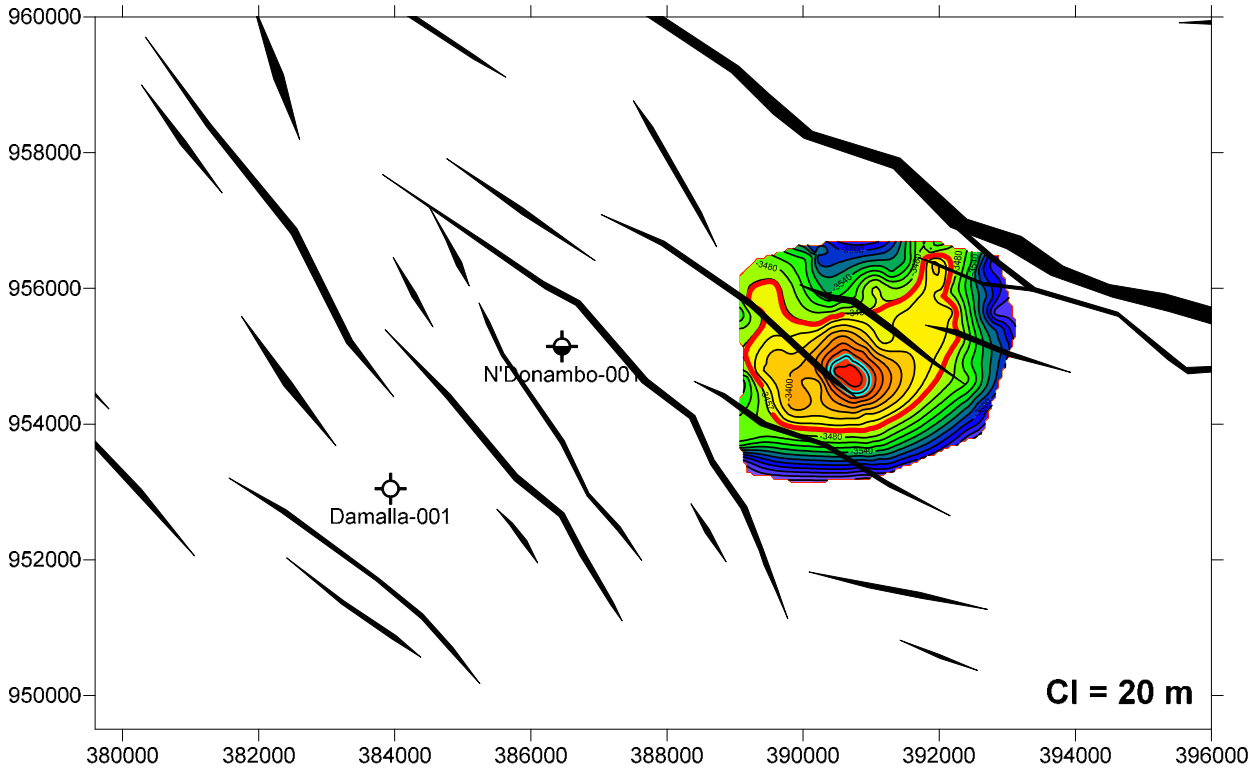
Effective Date: December 31, 2012
Scale: 1:90,000 s1132107



Map 44
Damalla Southeast Prospect
Depth Structure Map (metres)
D1 Sand

Company: Griffiths Energy International Inc.
Property: DOH Block

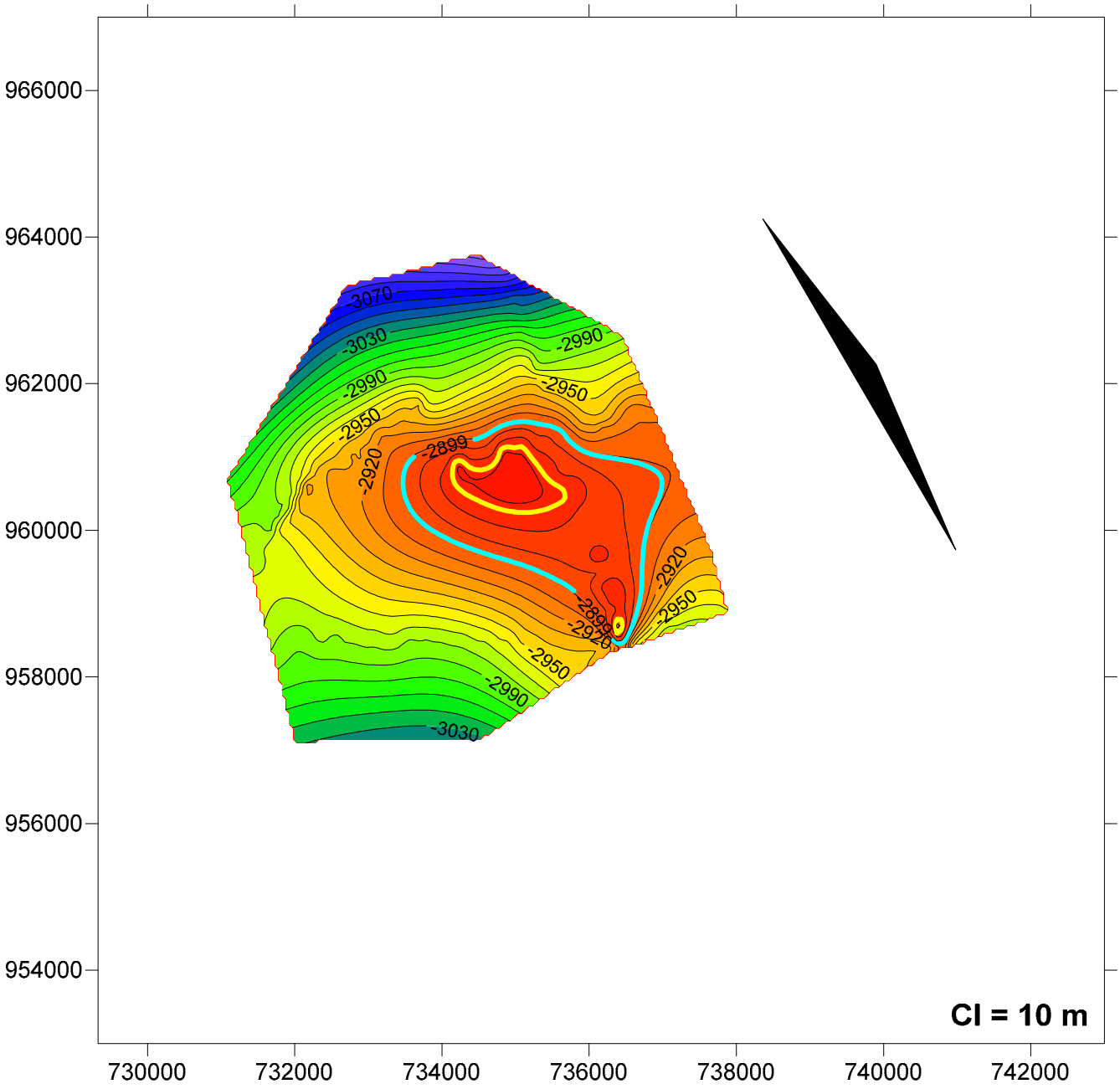
Effective Date: December 31, 2012
Scale: 1:90,000 s1132107



Map 45
Derguigui Prospect
Depth Structure Map (metres)
C and D Sands

Company: Griffiths Energy International Inc.
Property: DOH Block

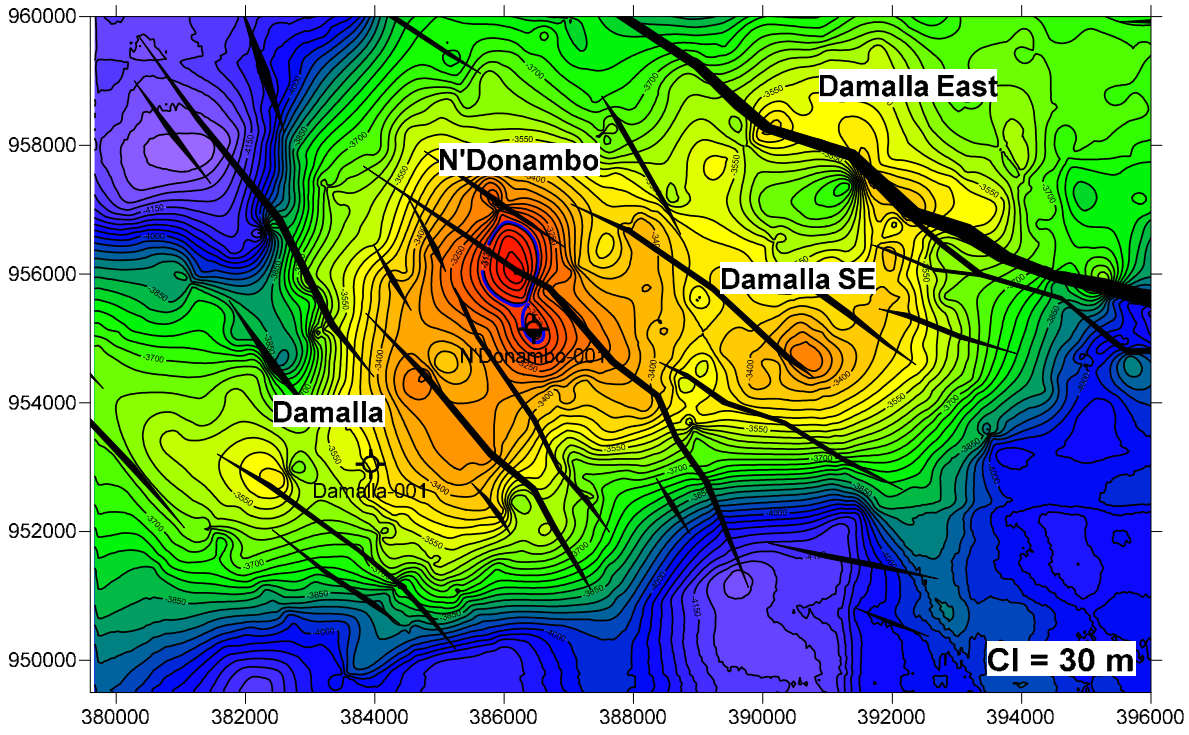
Effective Date: December 31, 2012
Scale: 1:90,000 s1132107



Map 46
N'Donambo Prospect
Depth Structure Map (metres)
A, B, C and D Sands

Company: Griffiths Energy International Inc.
Property: DOH Block

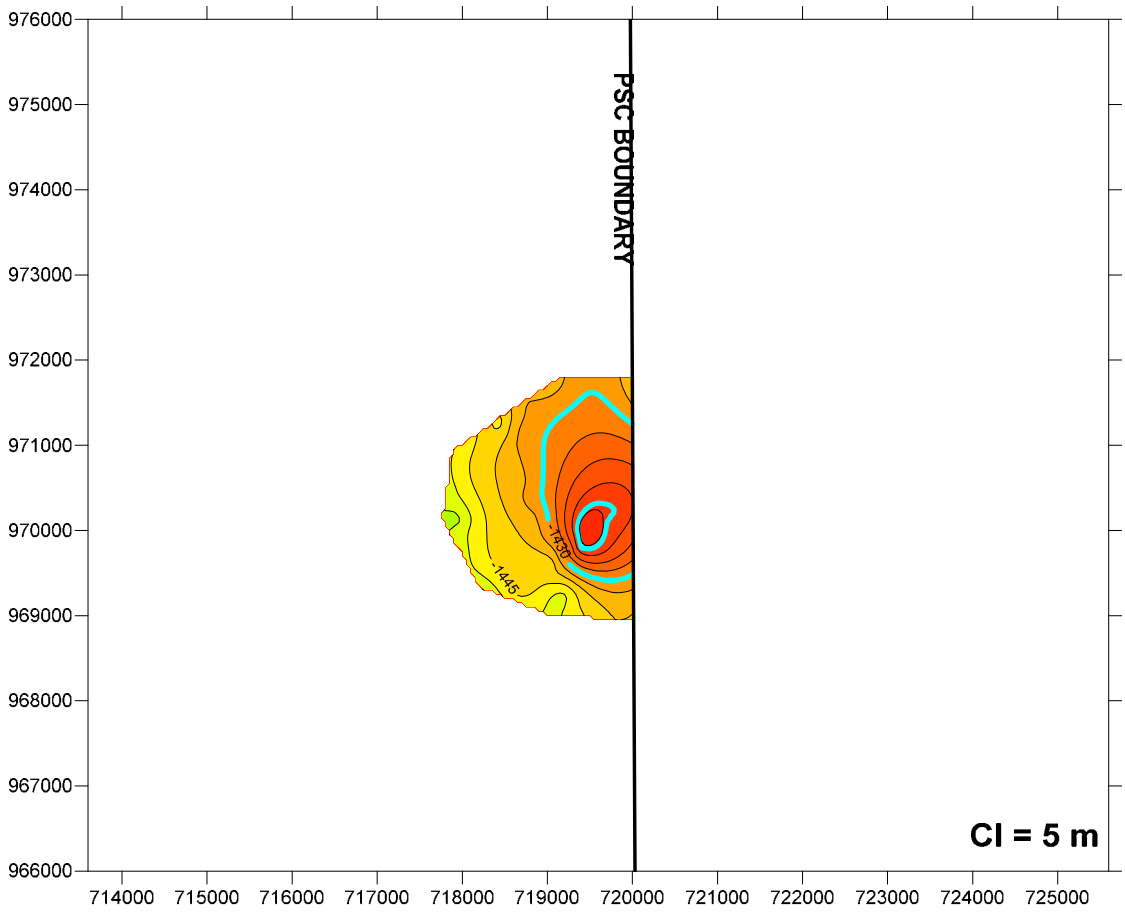
Effective Date: December 31, 2012
Scale: 1:90,000 s1132107



Map 47
Yei North Prospect
Depth Structure Map (metres)
A, M and B Sands

Company: Griffiths Energy International Inc.
Property: DOH Block

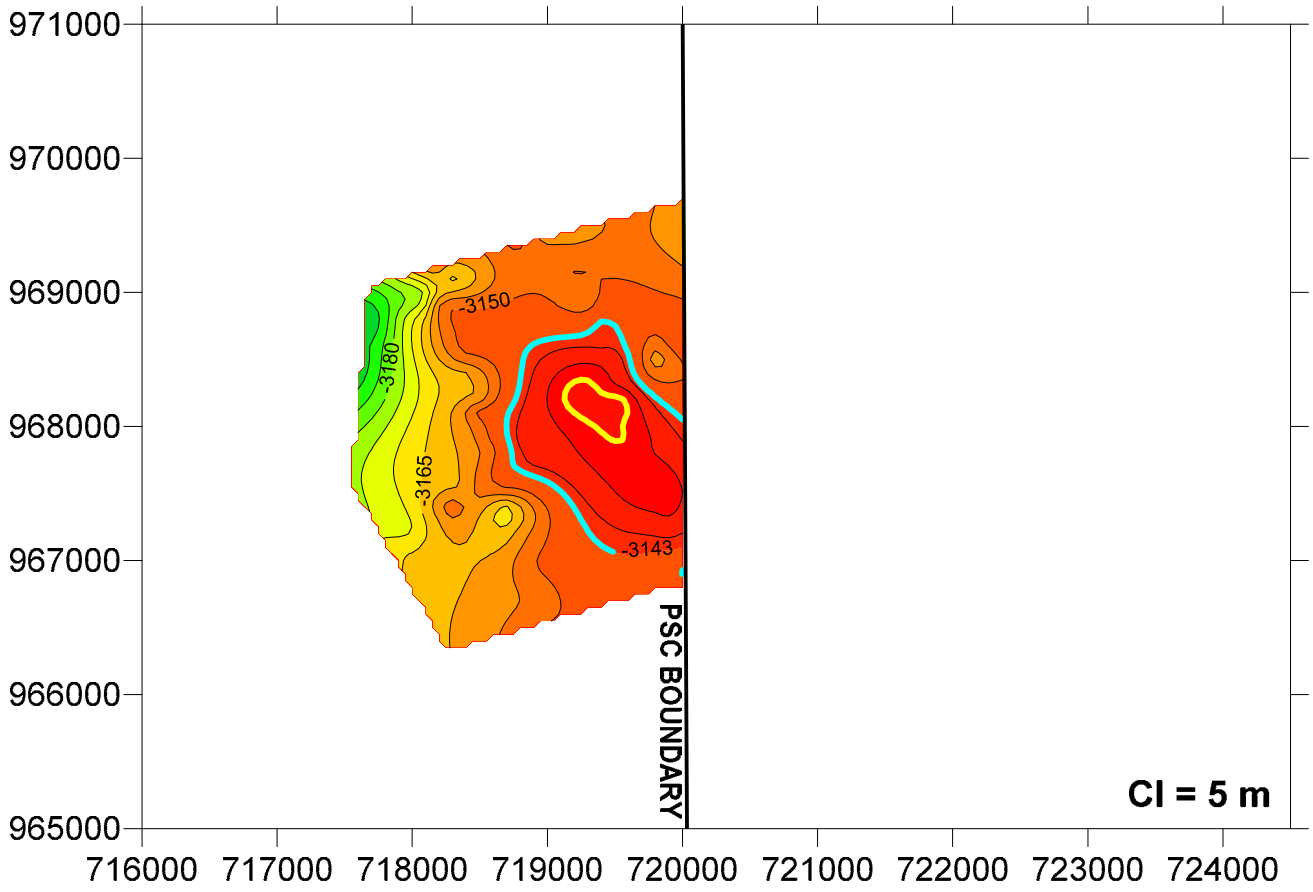
Effective Date: December 31, 2012
Scale: 1:80,000 s1132107



Map 48
Yei South Prospect
Depth Structure Map (metres)
C and D Sands

Company: Griffiths Energy International Inc.
Property: DOH Block

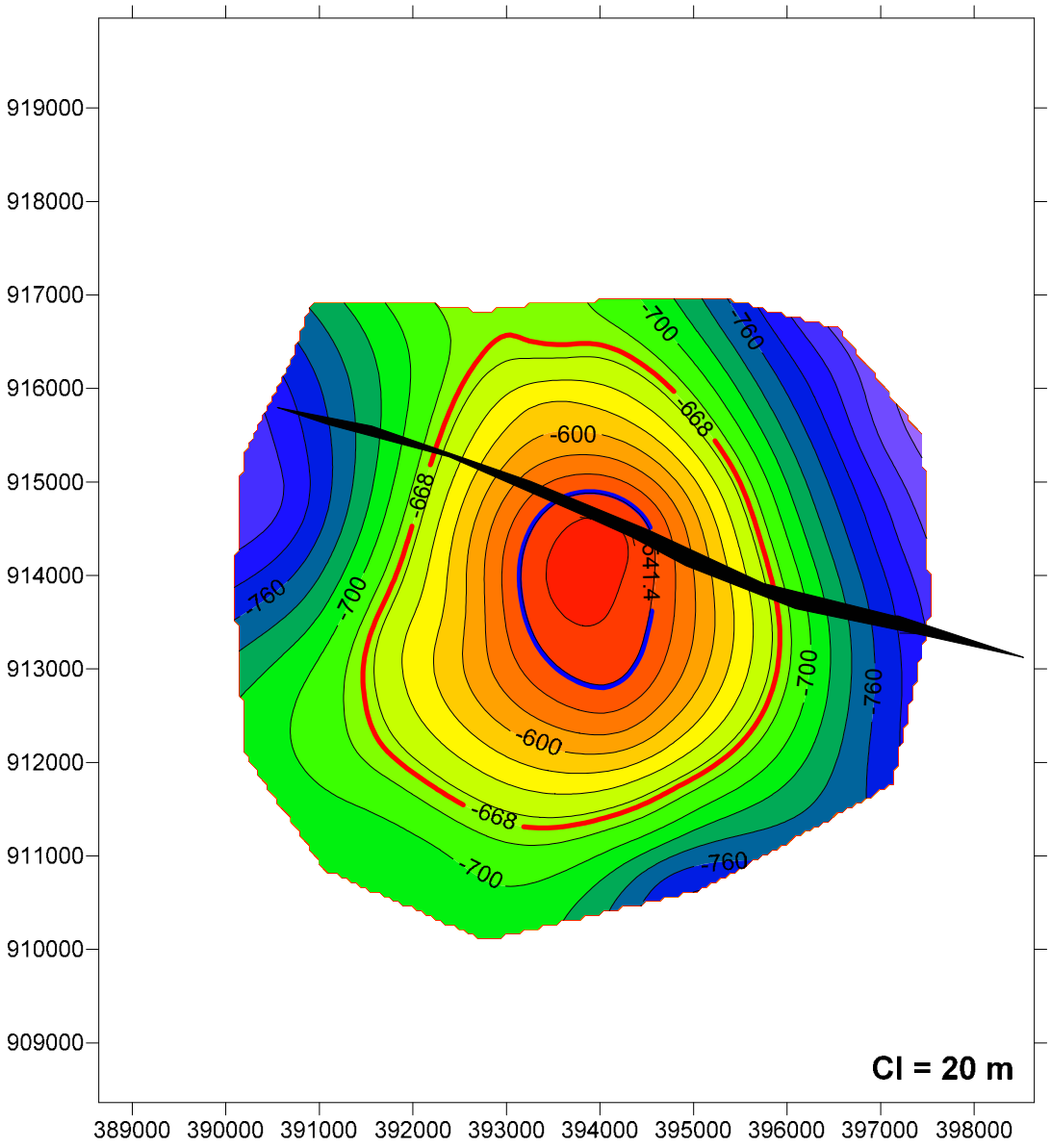
Effective Date: December 31, 2012
Scale: 1:70,000 s1132107



Map 49
Bepara Prospect
Depth Structure Map (metres)
C and D Sands

Company: Griffiths Energy International Inc.
Property: Borogop Block

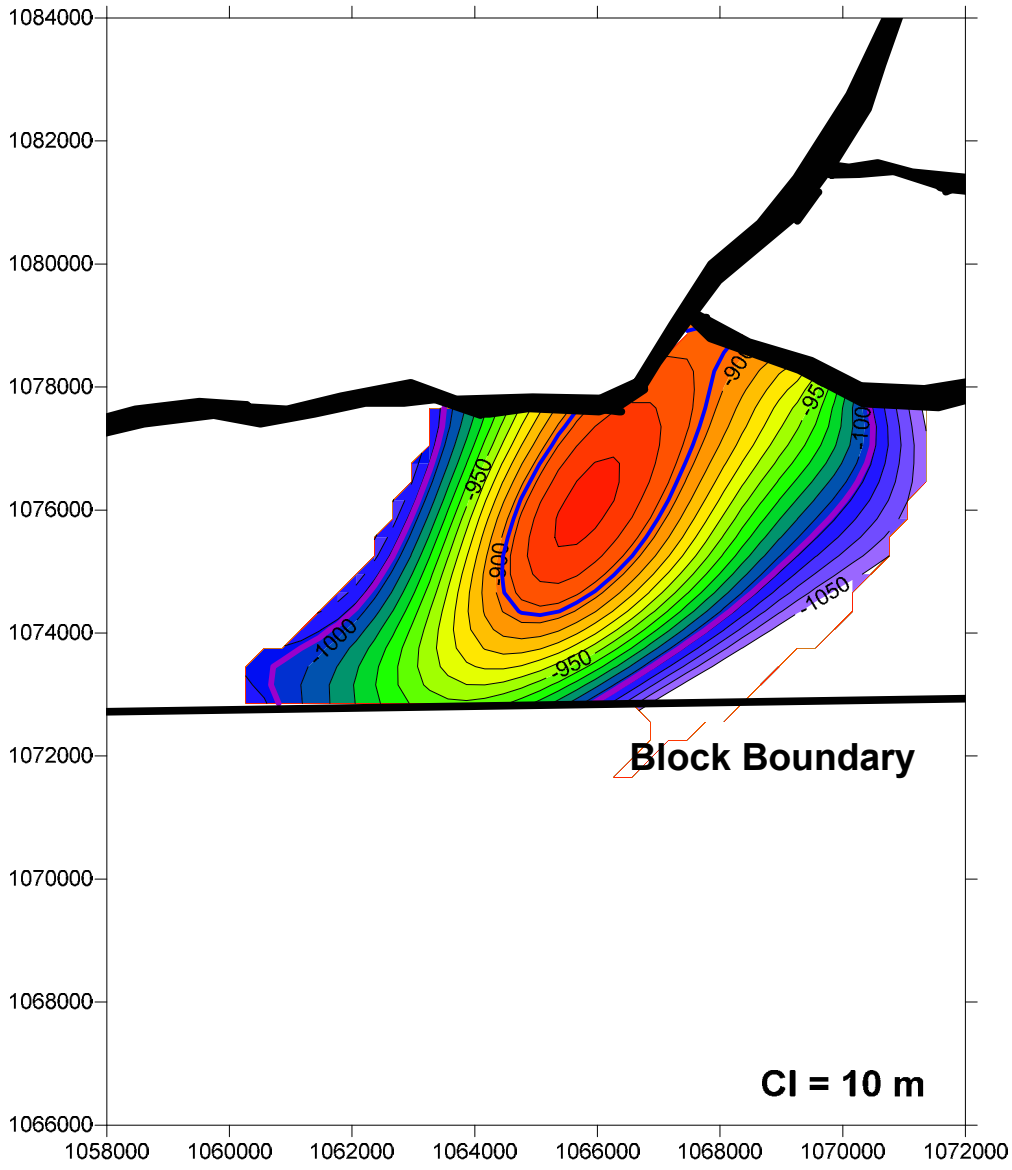
Effective Date: December 31, 2012
Scale: 1:70,000 s1132107



Map 50
Beche Prospect
Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

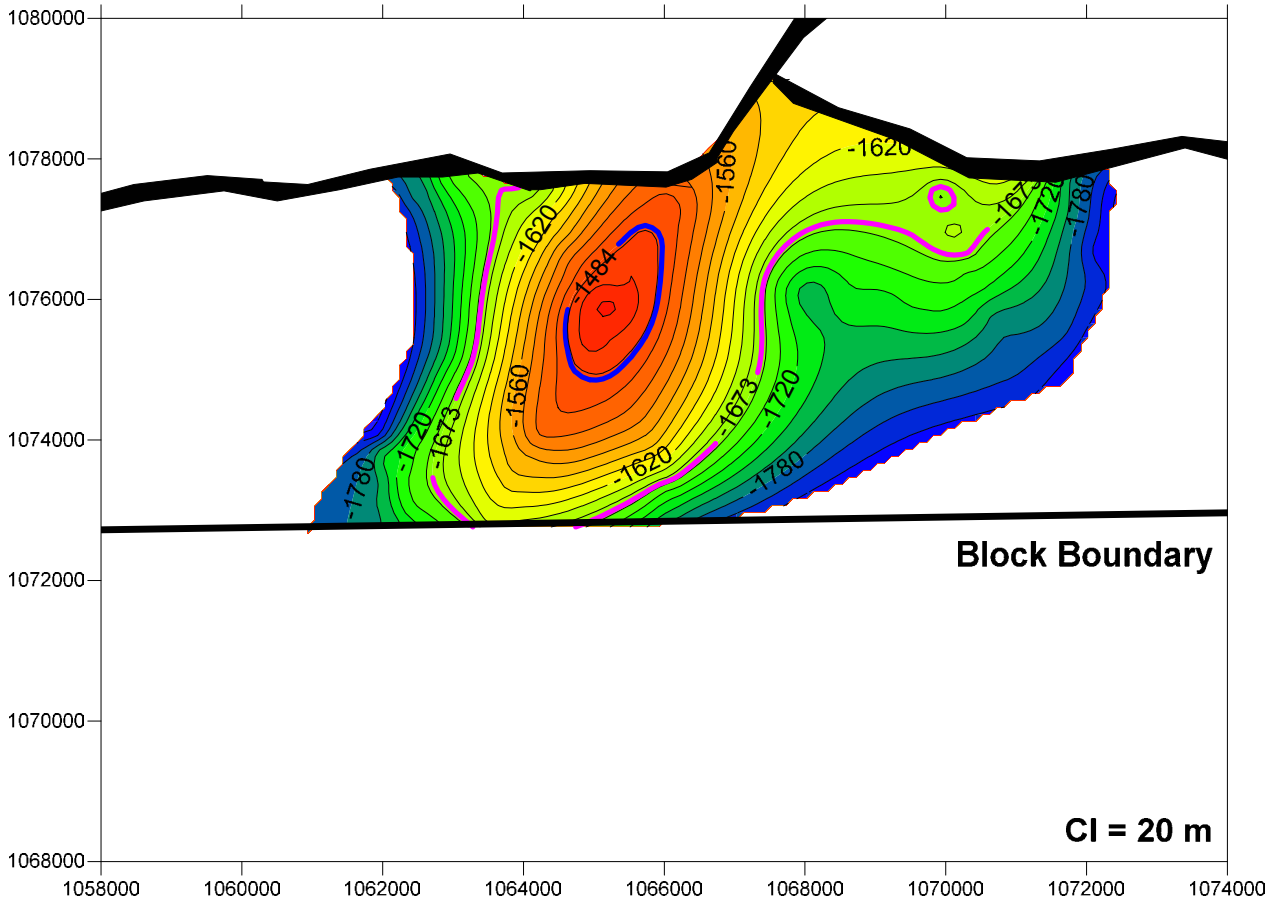
Effective Date: December 31, 2012
Scale: 1:100,000 s1132107



Map 51
Beche Prospect
Depth Structure Map (metres)
D Sand

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

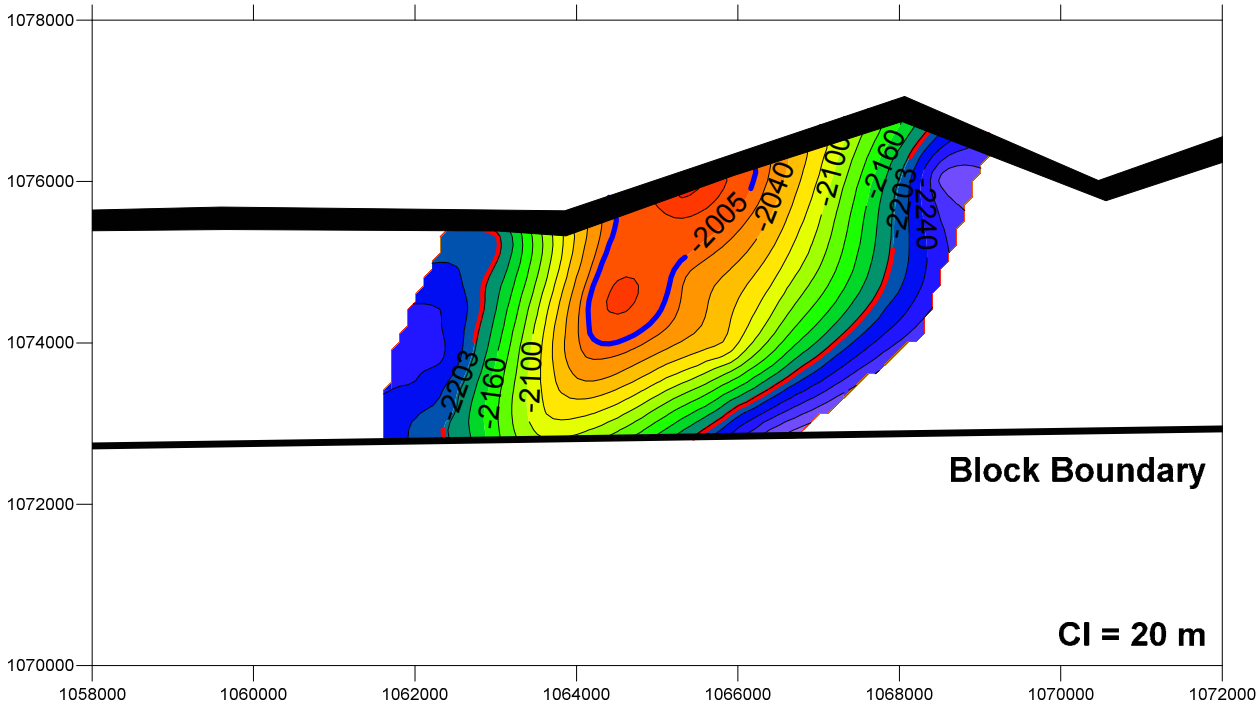
Effective Date: December 31, 2012
Scale: 1:100,000 s1132107



Map 52
Beche Prospect
Depth Structure Map (metres)
E Sand

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

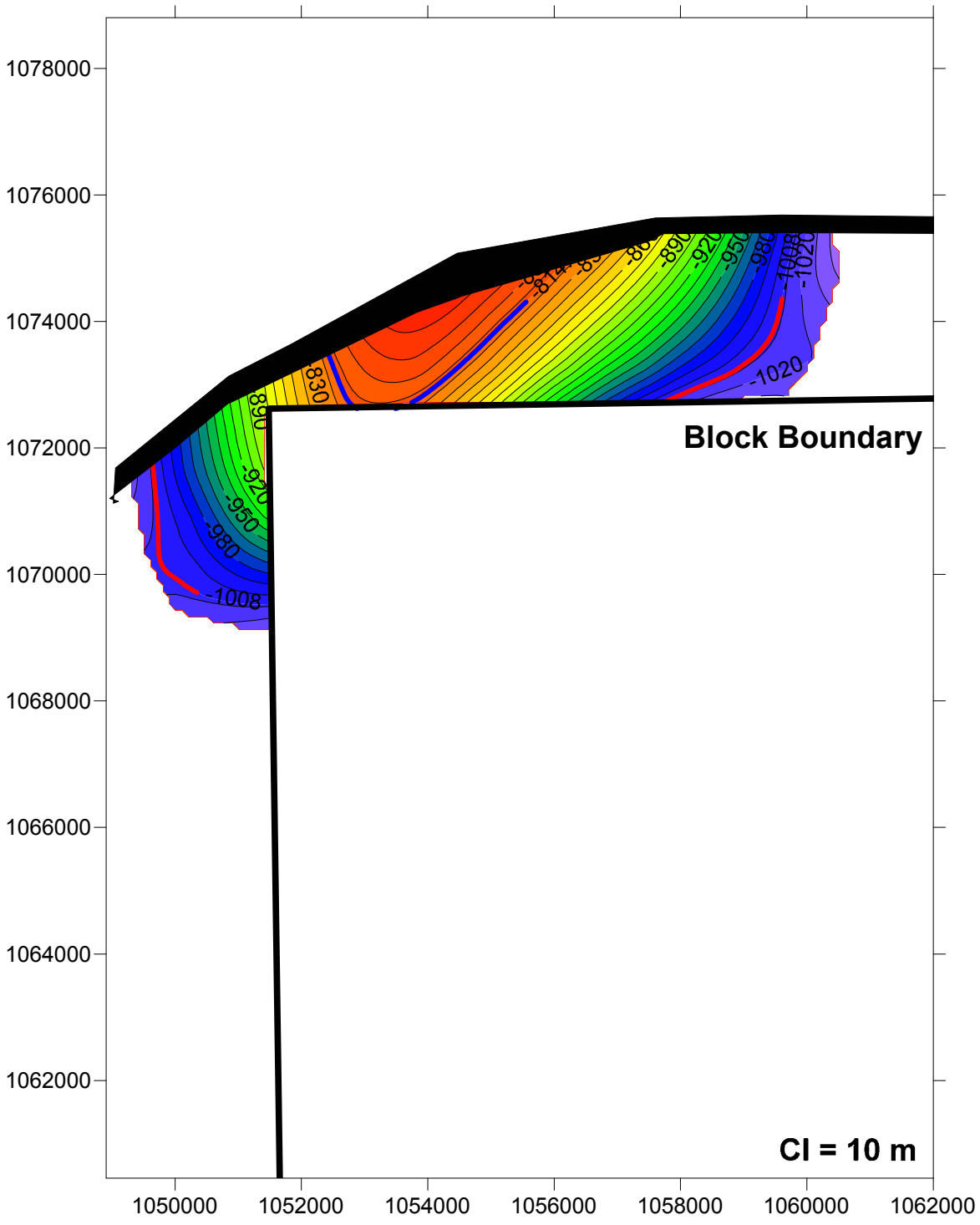
Effective Date: December 31, 2012
Scale: 1:100,000 s1132107



Map 53
Beche B Prospect
Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

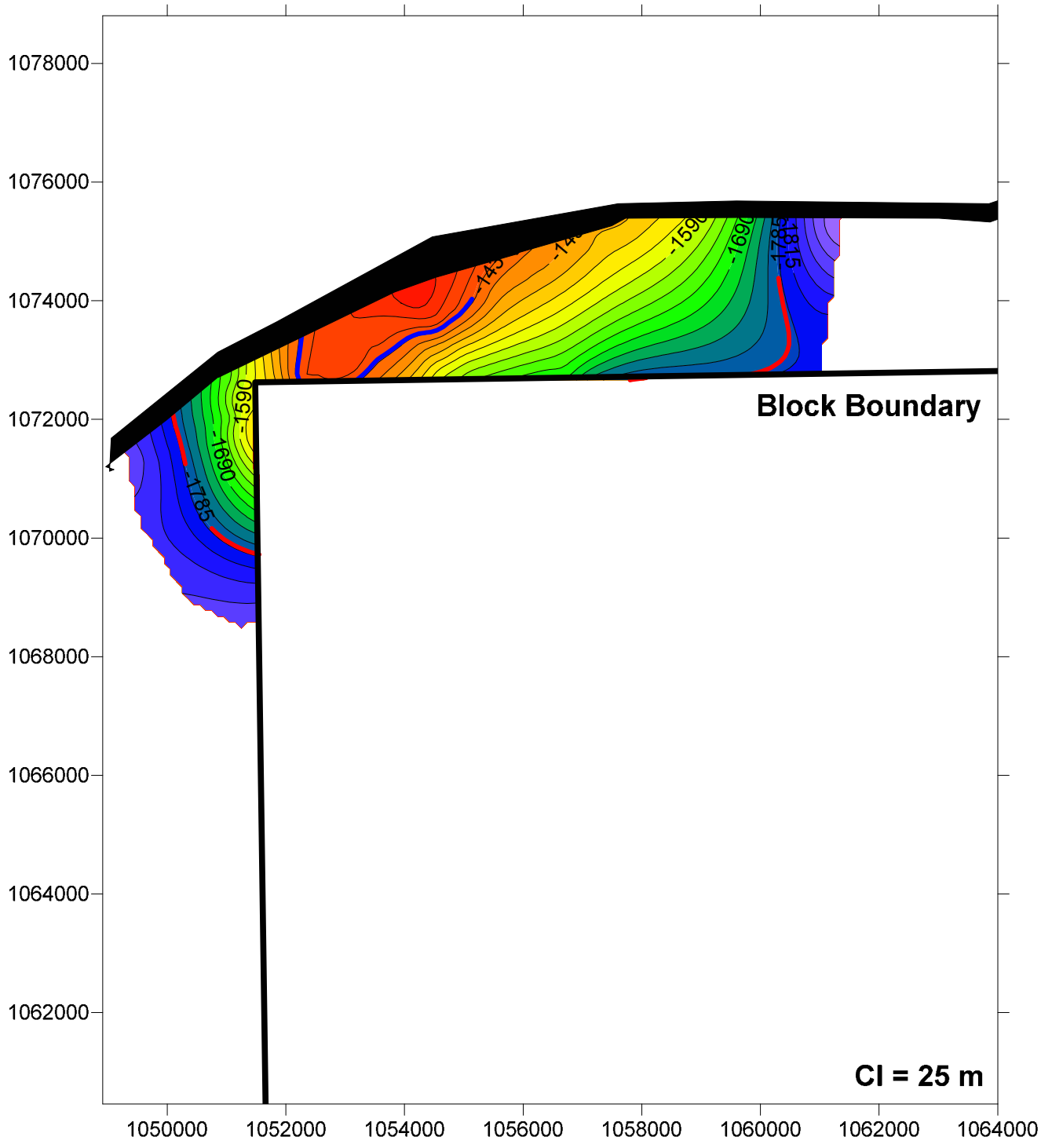
Effective Date: December 31, 2012
Scale: 1:100,000 s1132107



Map 54
Beche B Prospect
Depth Structure Map (metres)
D Sand

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

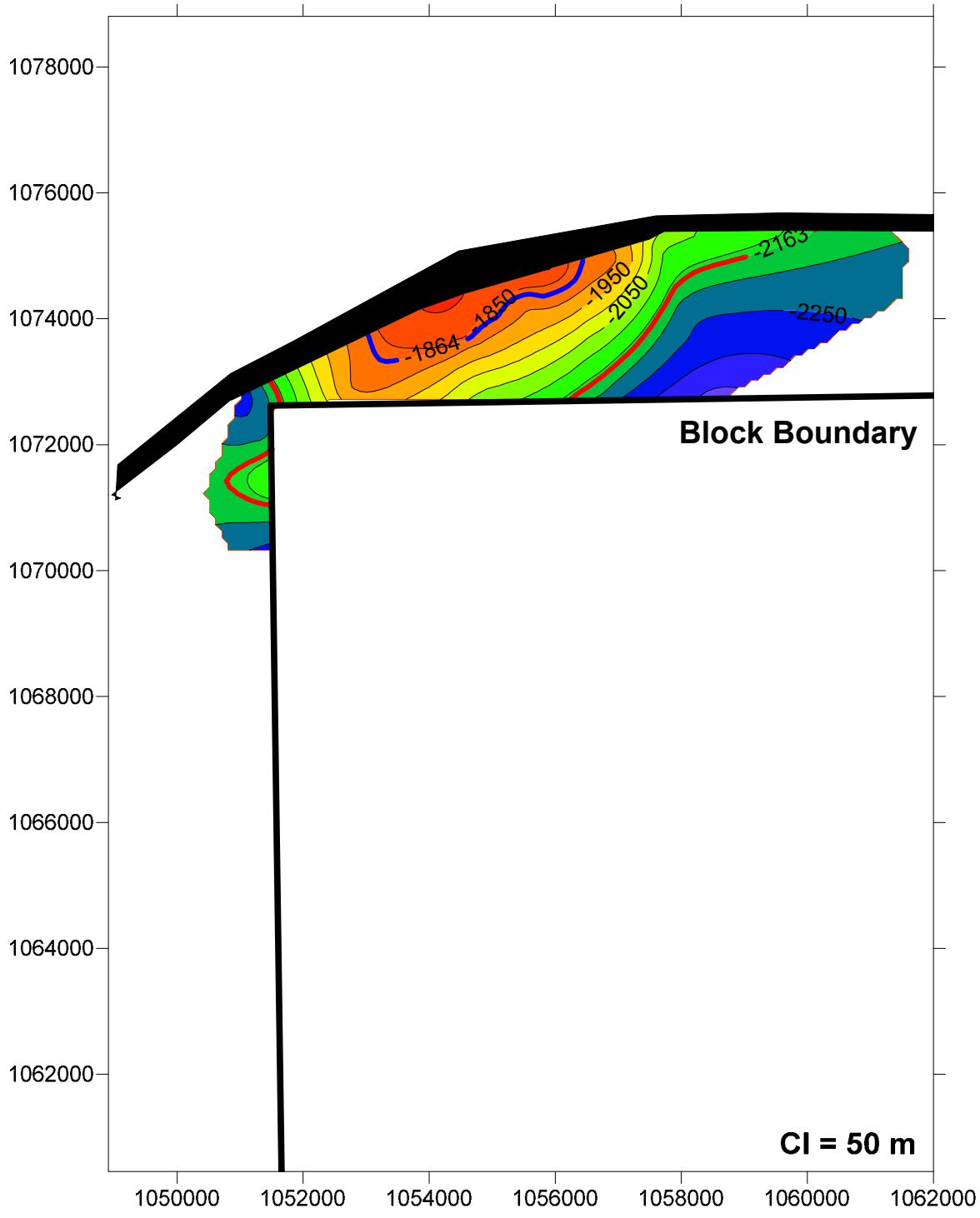
Effective Date: December 31, 2012
Scale: 1:100,000 s1132107



Map 55
Beche B Prospect
Depth Structure Map (metres)
E Sand

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

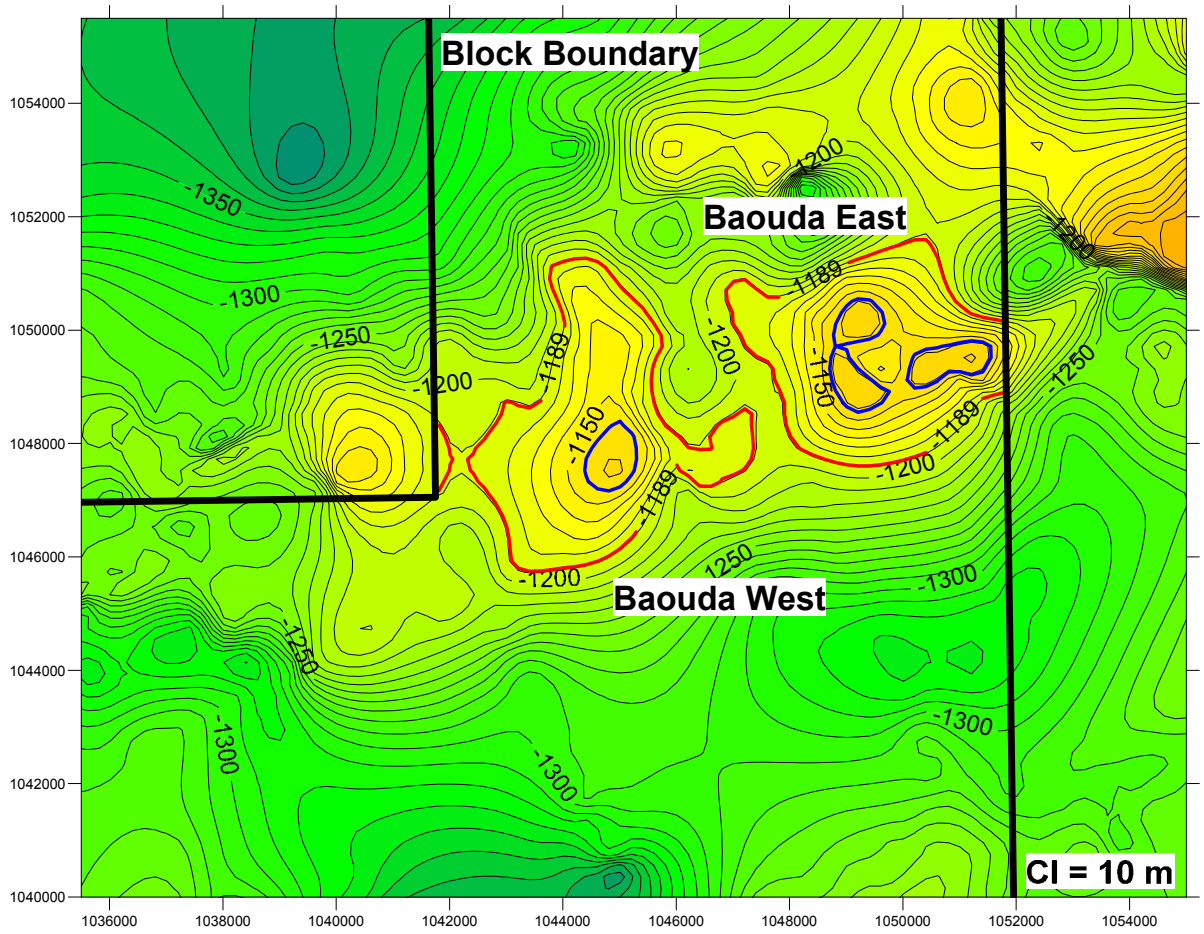
Effective Date: December 31, 2012
Scale: 1:100,000 s1132107



Map 56
Baouda East and Baouda West Prospect
Depth Structure Map (metres)
C, D and E Sands

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

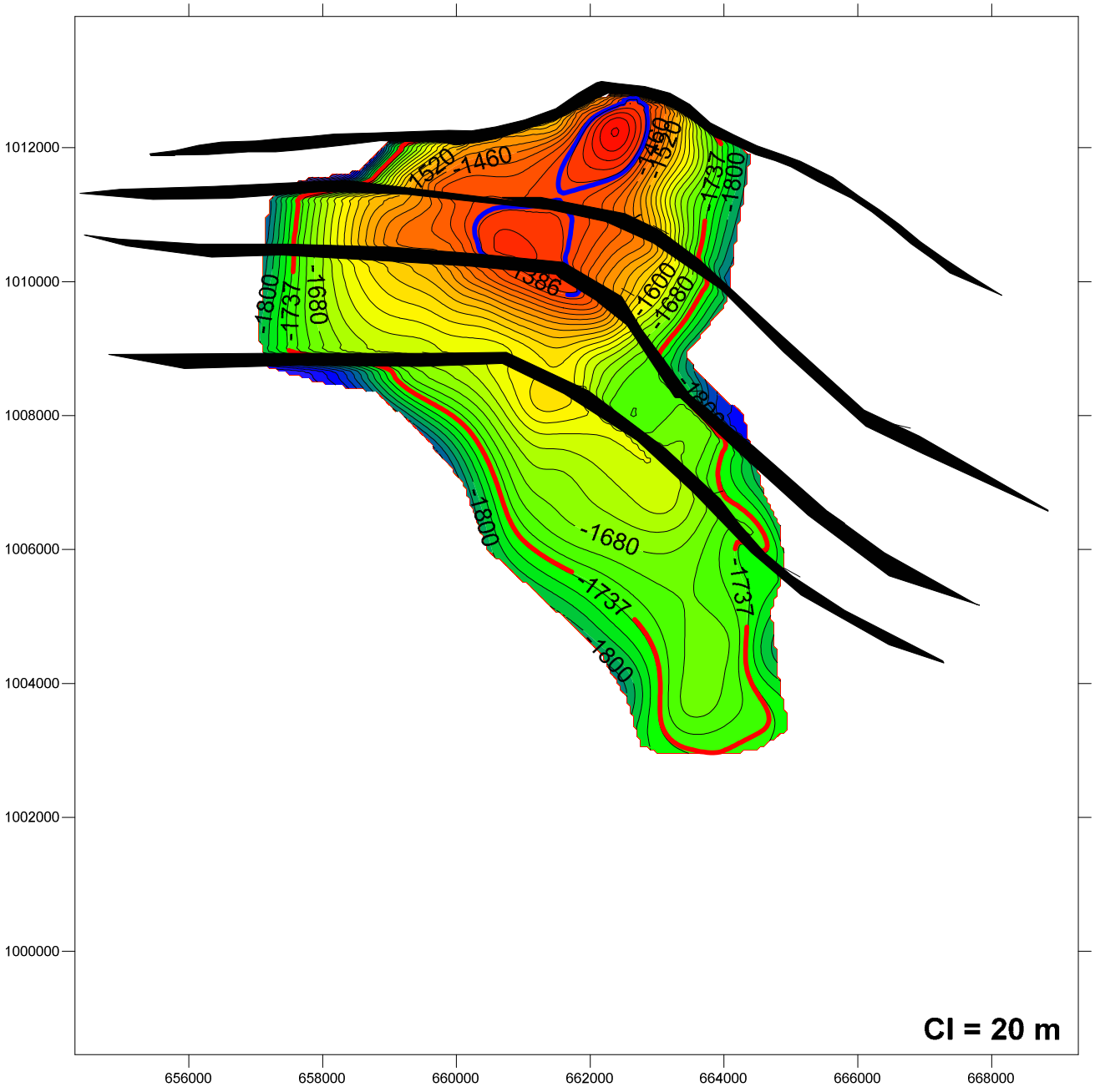
Effective Date: December 31, 2012
Scale: 1:120,000 s1132107



Map 57
Emok Prospect
Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

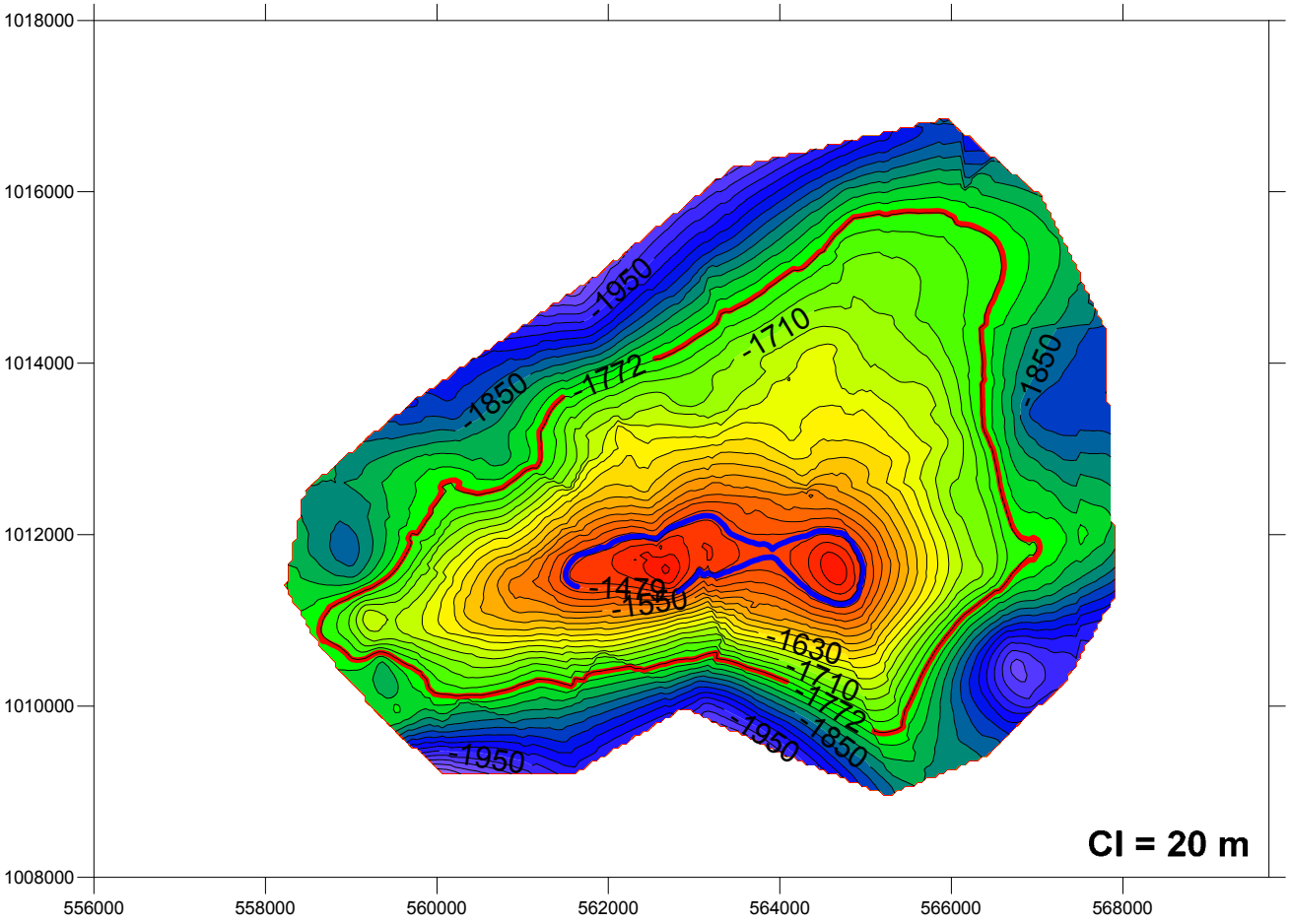
Effective Date: December 31, 2012
Scale: 1:100,000 s1132107



Map 58
Mahimi Prospect
Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

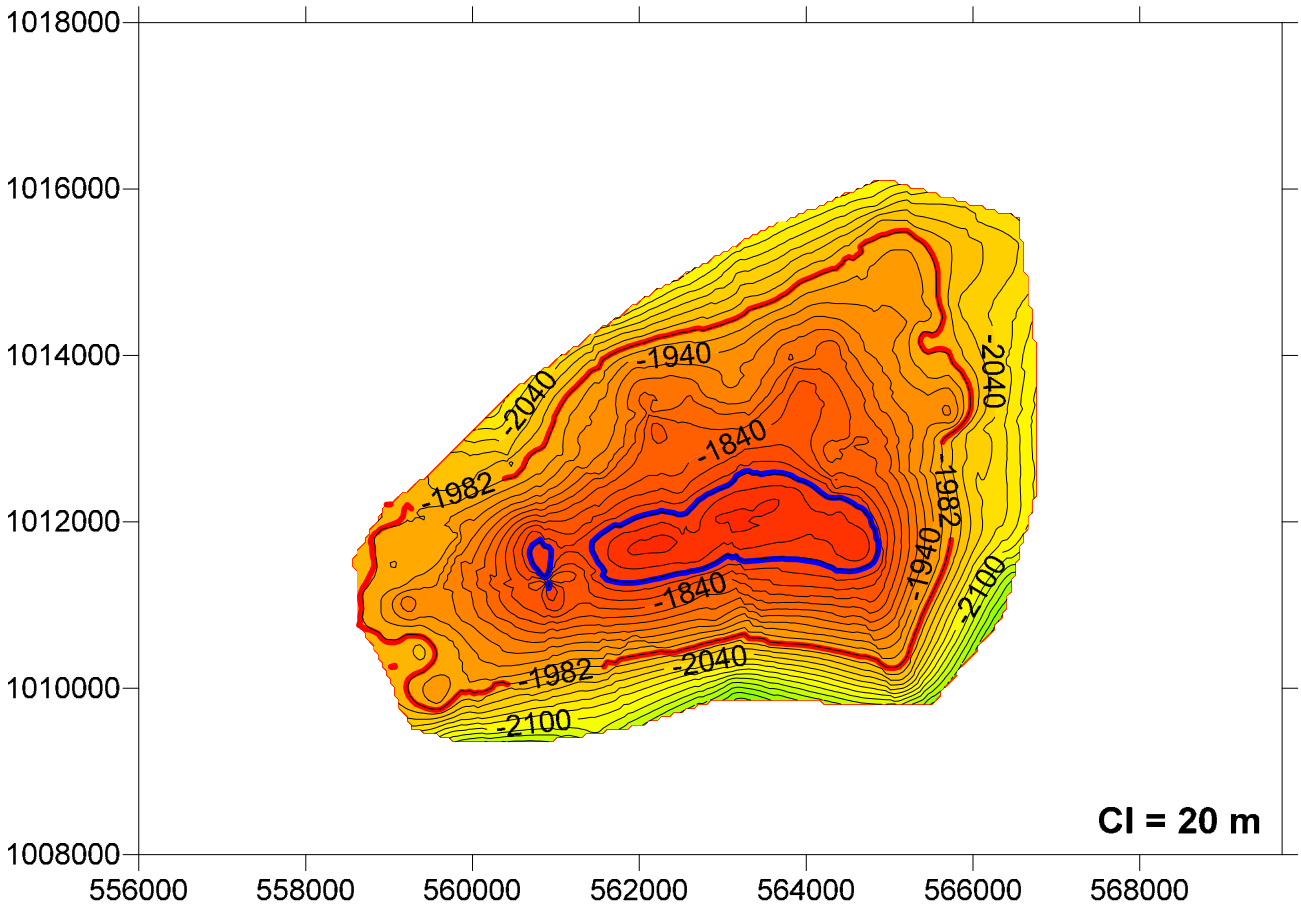
Effective Date: December 31, 2012
Scale: 1:100,000 s1132107



Map 59
Mahimi Prospect
Depth Structure Map (metres)
D Sand

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

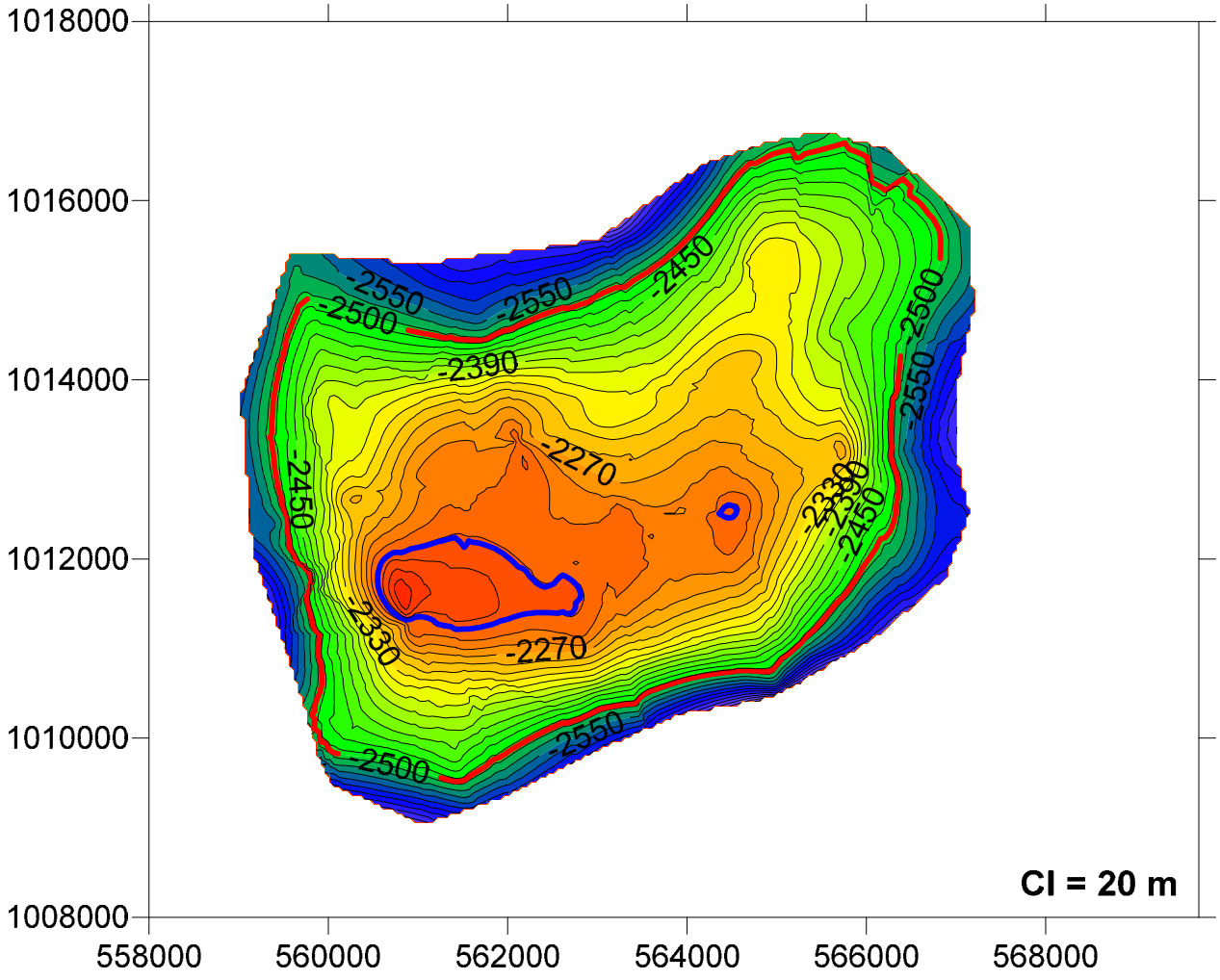
Effective Date: December 31, 2012
Scale: 1:100,000 s1132107



Map 60
Mahimi Prospect
Depth Structure Map (metres)
E Sand

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

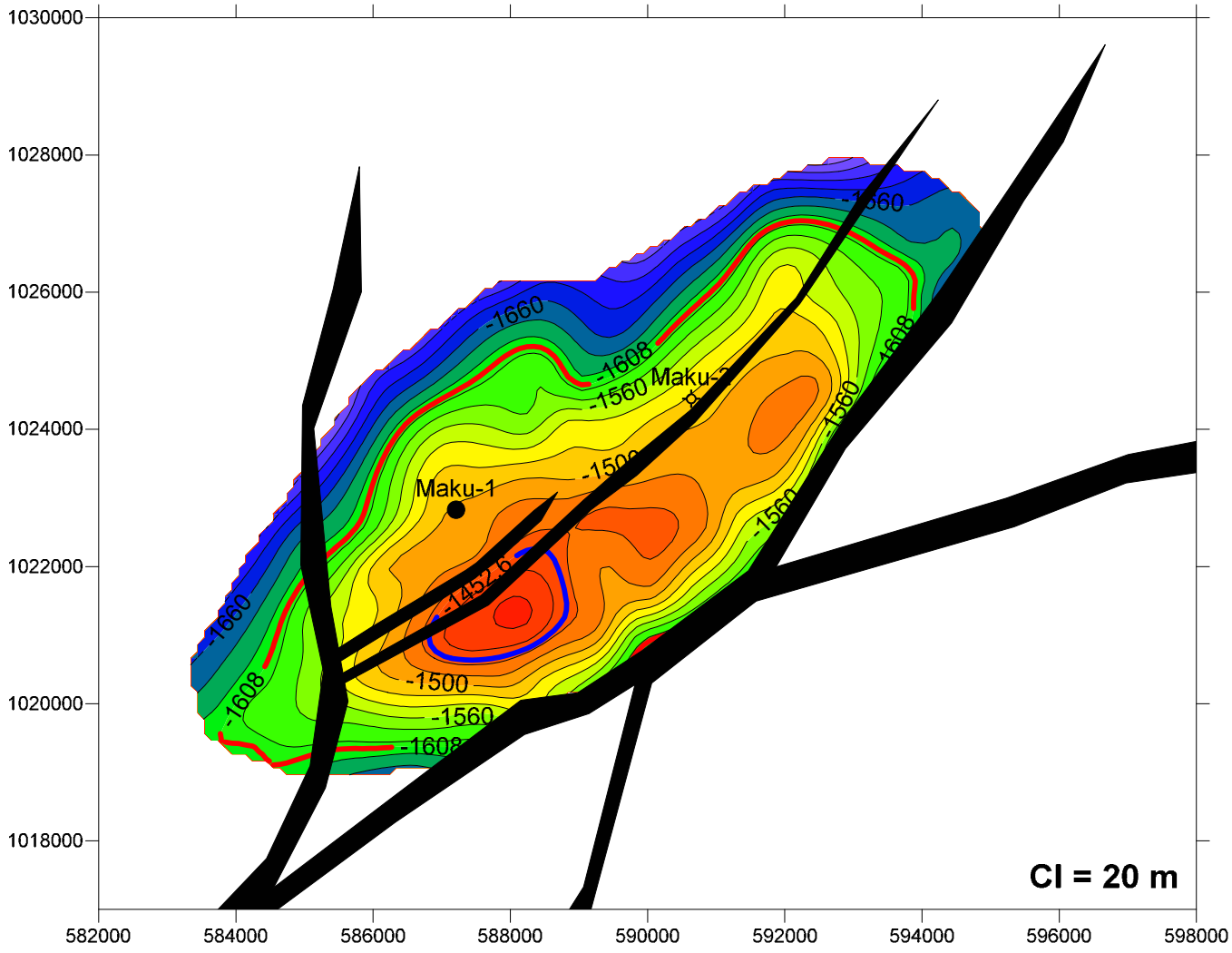
Effective Date: December 31, 2012
Scale: 1:100,000 s1132107



Map 61
Maku Prospect
Depth Structure Map (metres)
D Sand

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

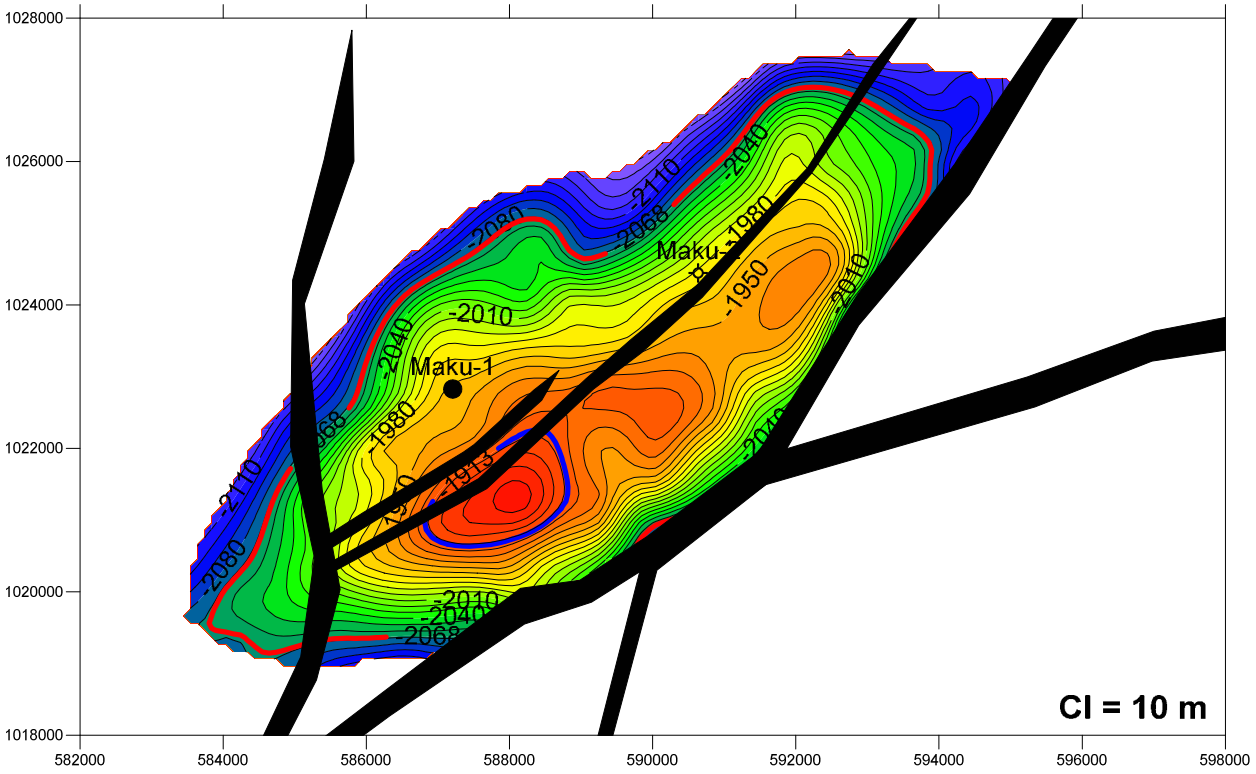
Effective Date: December 31, 2012
Scale: 1:100,000 s1132107



Map 62
Maku Prospect
Depth Structure Map (metres)
E Sand

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

Effective Date: December 31, 2012
Scale: 1:100,000 s1132107

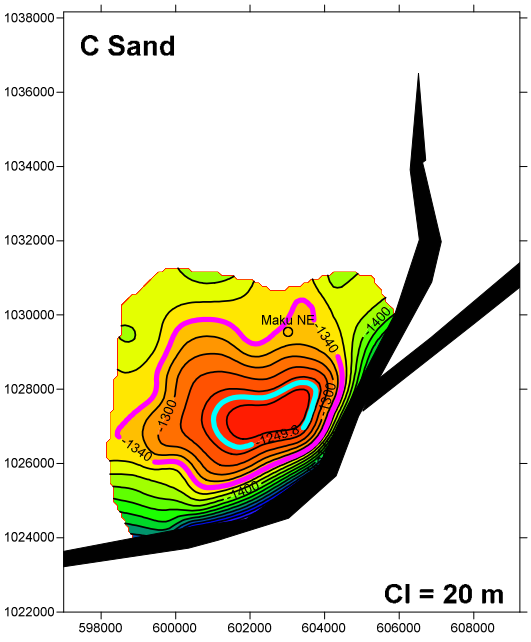


Map 63 a, b, c
Maku Northeast Prospect
Depth Structure Map (metres)
C, D and E Sands

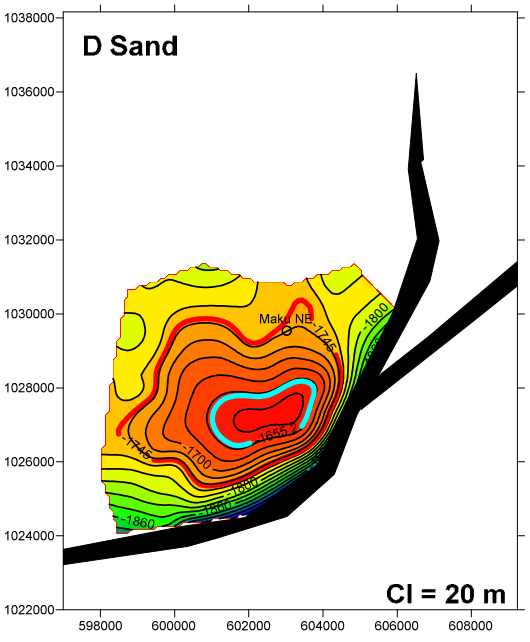
Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

Effective Date: December 31, 2012
Scale: 1:100,000 s1132107

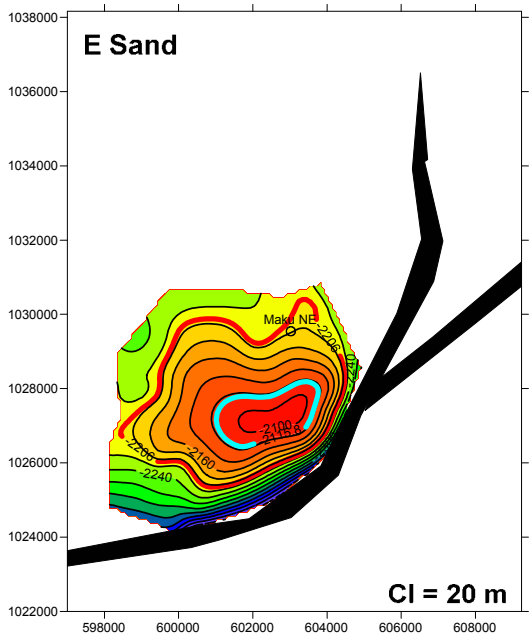
(a)



(b)



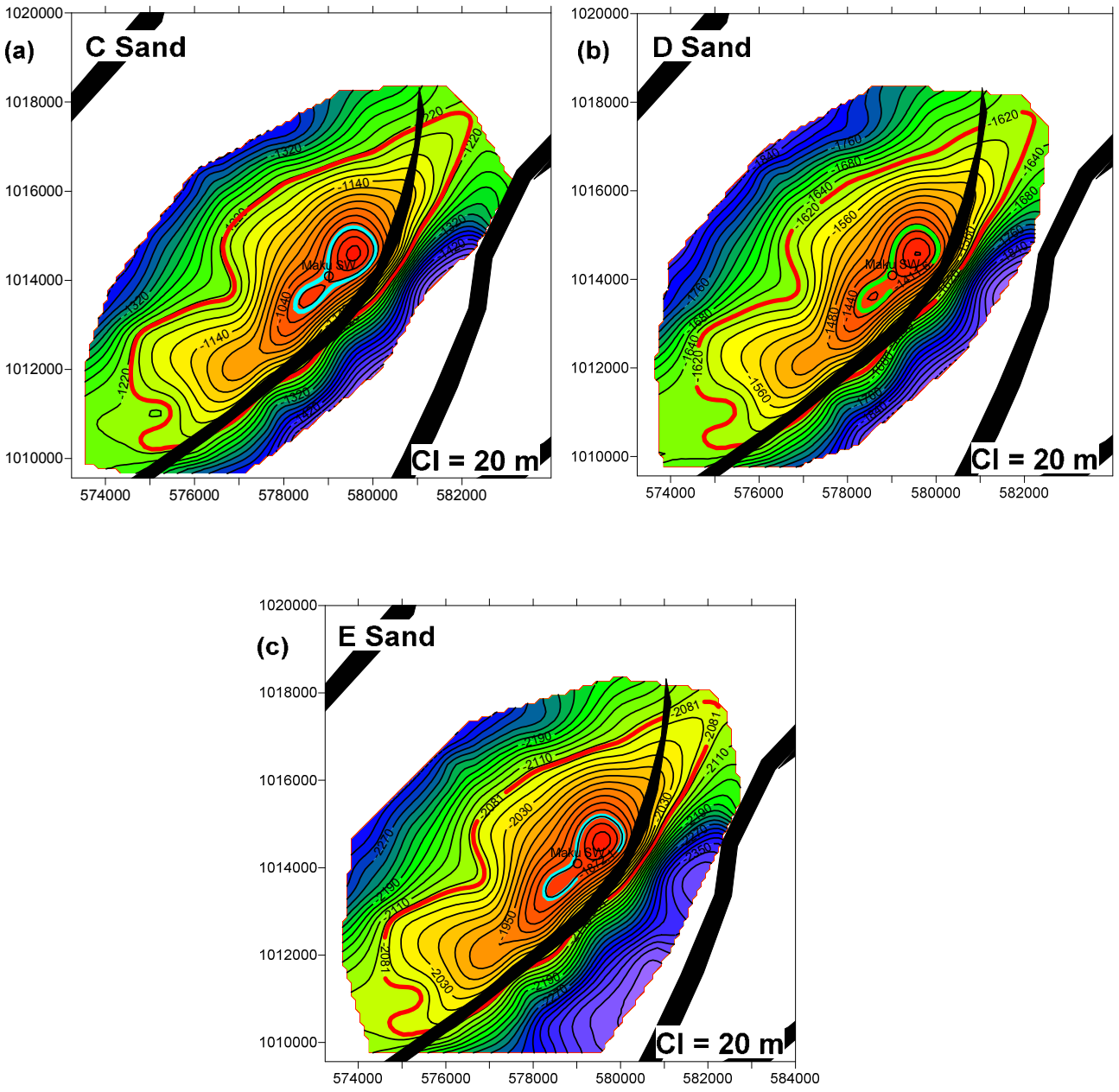
(c)



Map 64 a, b, c
Maku Southwest Prospect
Depth Structure Map (metres)
C, D and E Sands

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

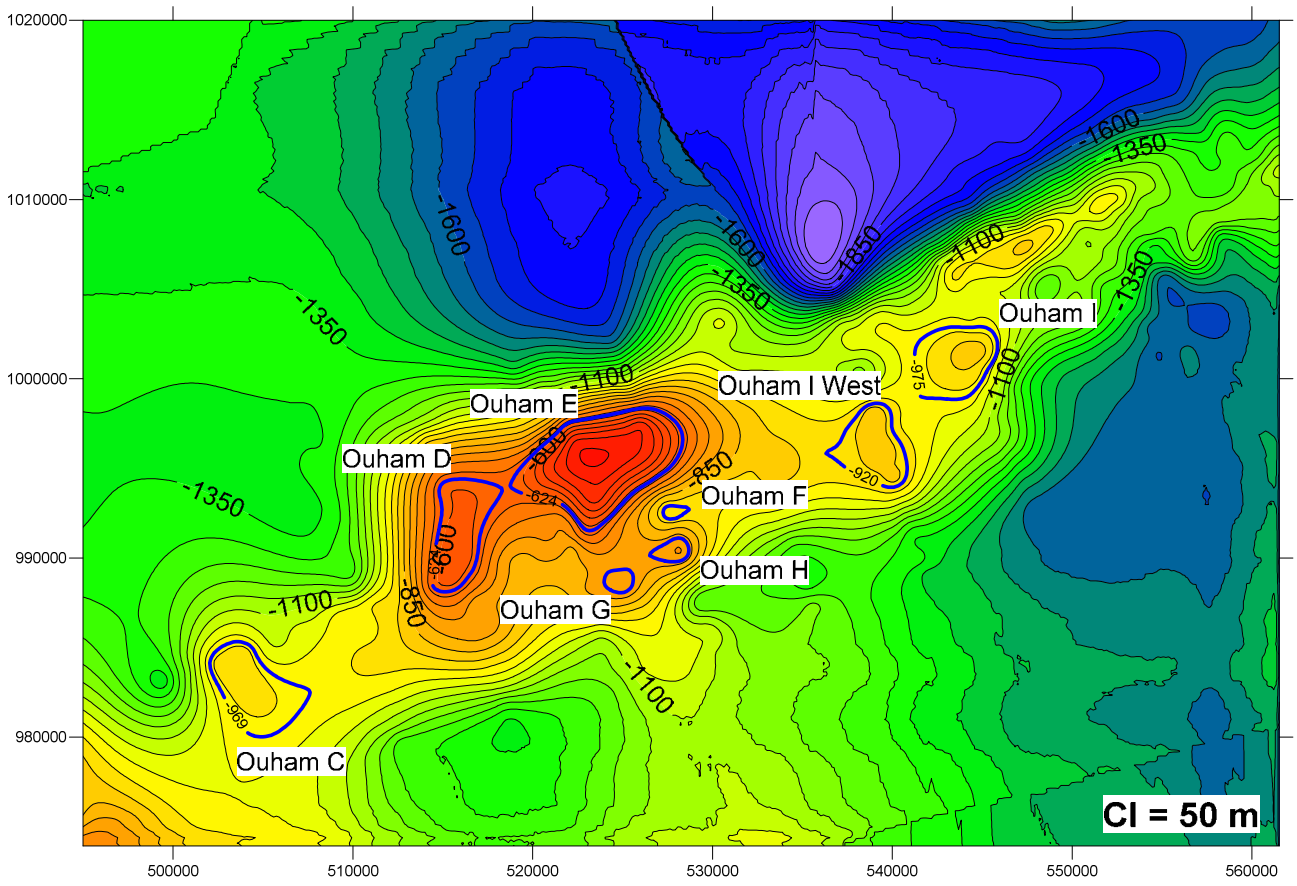
Effective Date: December 31, 2012
Scale: 1:80,000 s1132107



Map 65
Ouham Prospects
Depth Strucutre Map (meters)
Lower Cretaceous Sands

Company: Griffiths Energy International
Property: Chari East-Doseo Block

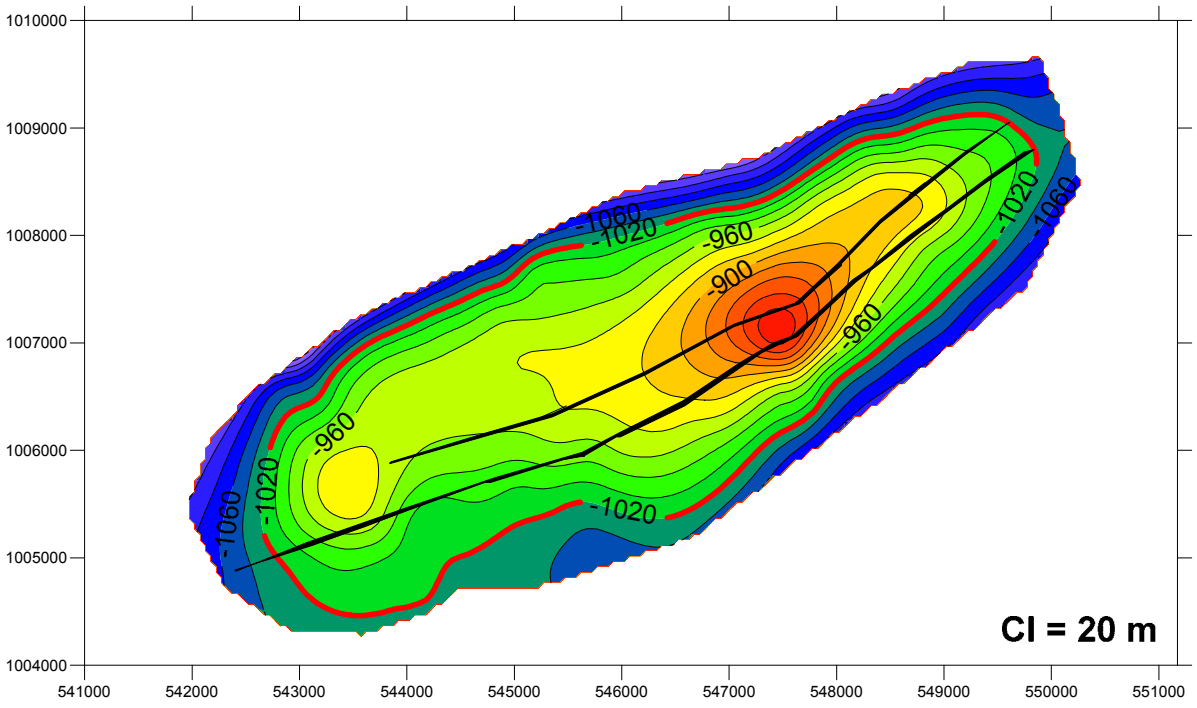
Effective Date: December 31, 2012
Scale: 1:400,000 s1132107



Map 66
Sahr Prospect
Depth Structure Map (metres)
C, D and E Sands

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

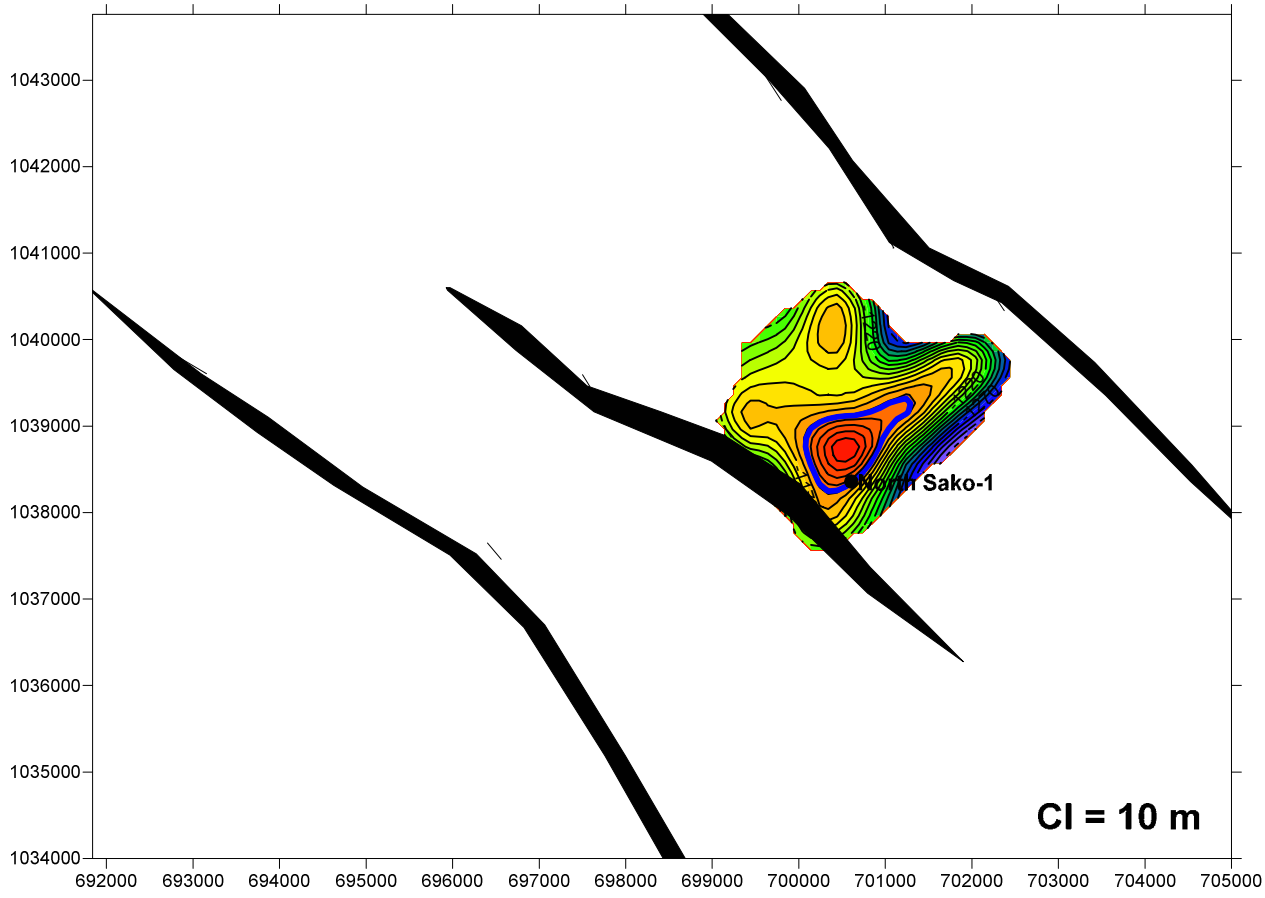
Effective Date: December 31, 2012
Scale: 1:70,000 s1132107



Map 67
Sako North Prospect
Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

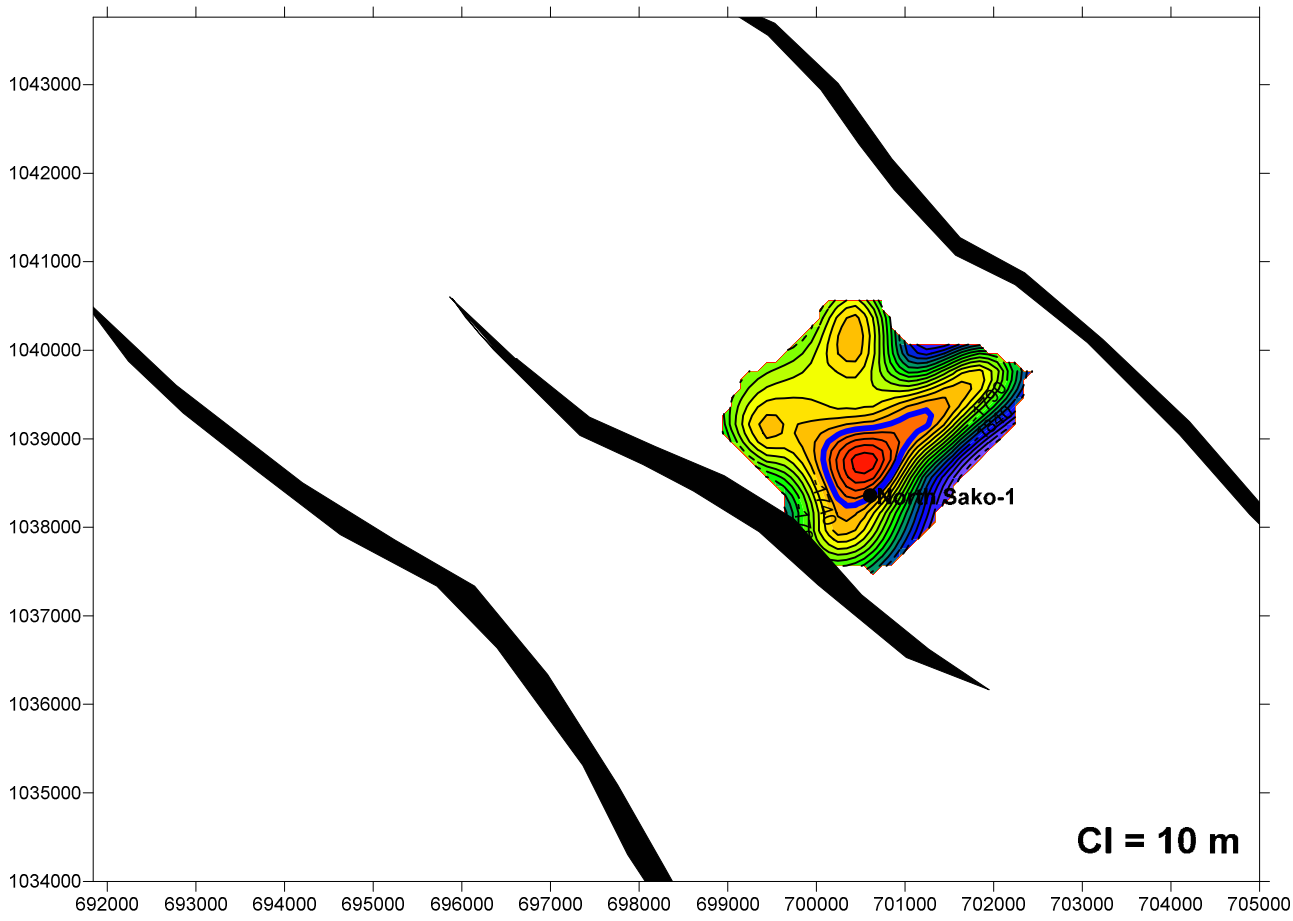
Effective Date: December 31, 2012
Scale: 1:60,000 s1132107



Map 68
Sako North Prospect
Depth Structure Map (metres)
D Sand

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

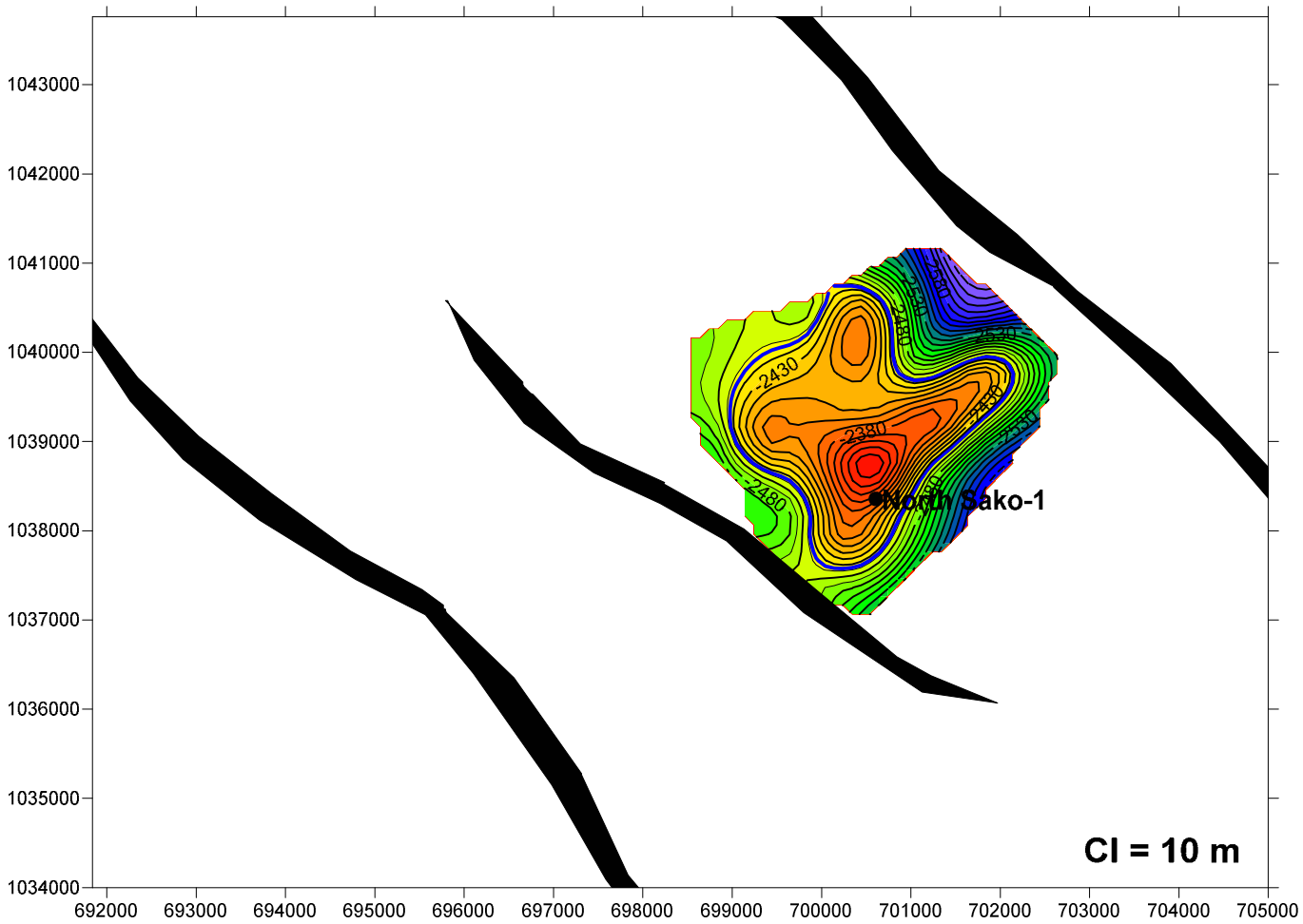
Effective Date: December 31, 2012
Scale: 1:60,000 s1132107



Map 69
Sako North Prospect
Depth Structure Map (metres)
E Sand

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

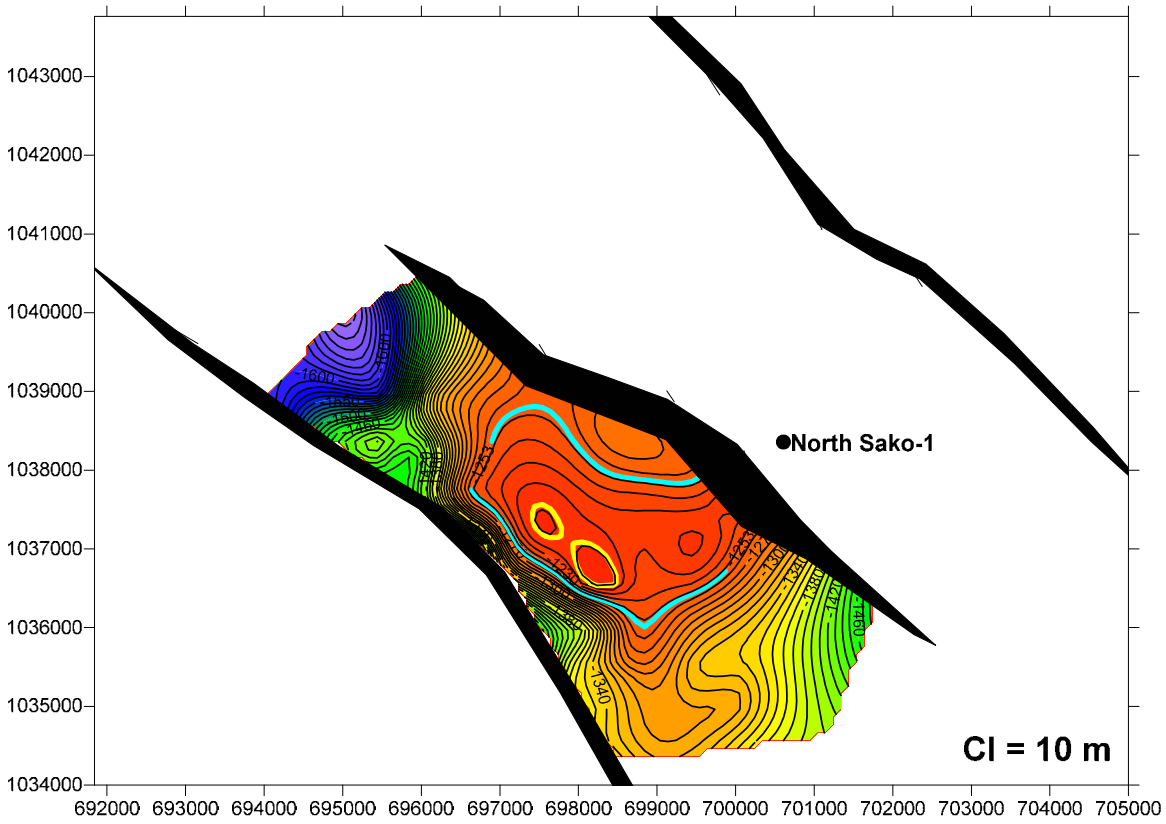
Effective Date: December 31, 2012
Scale: 1:60,000 s1132107



Map 70
Sako North B Prospect
Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

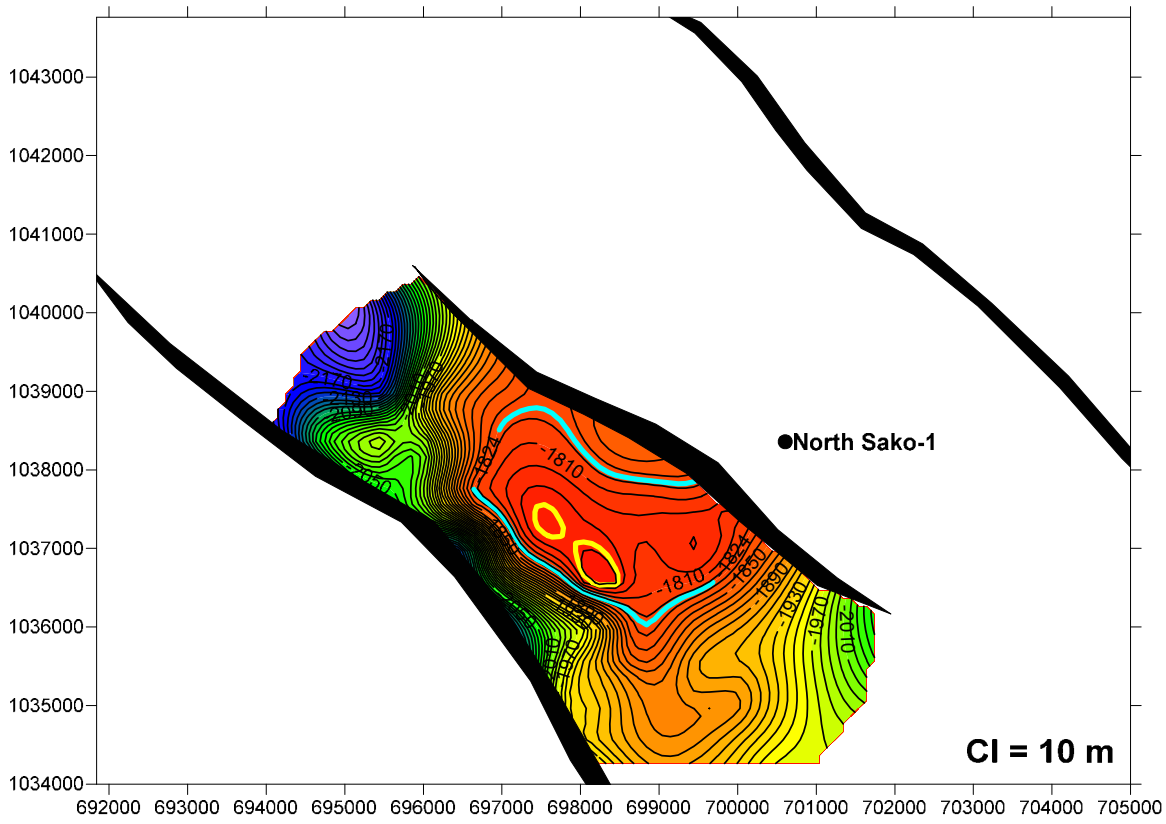
Effective Date: December 31, 2012
Scale: 1:70,000 s1132107



Map 71
Sako North B Prospect
Depth Structure Map (metres)
D Sand

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

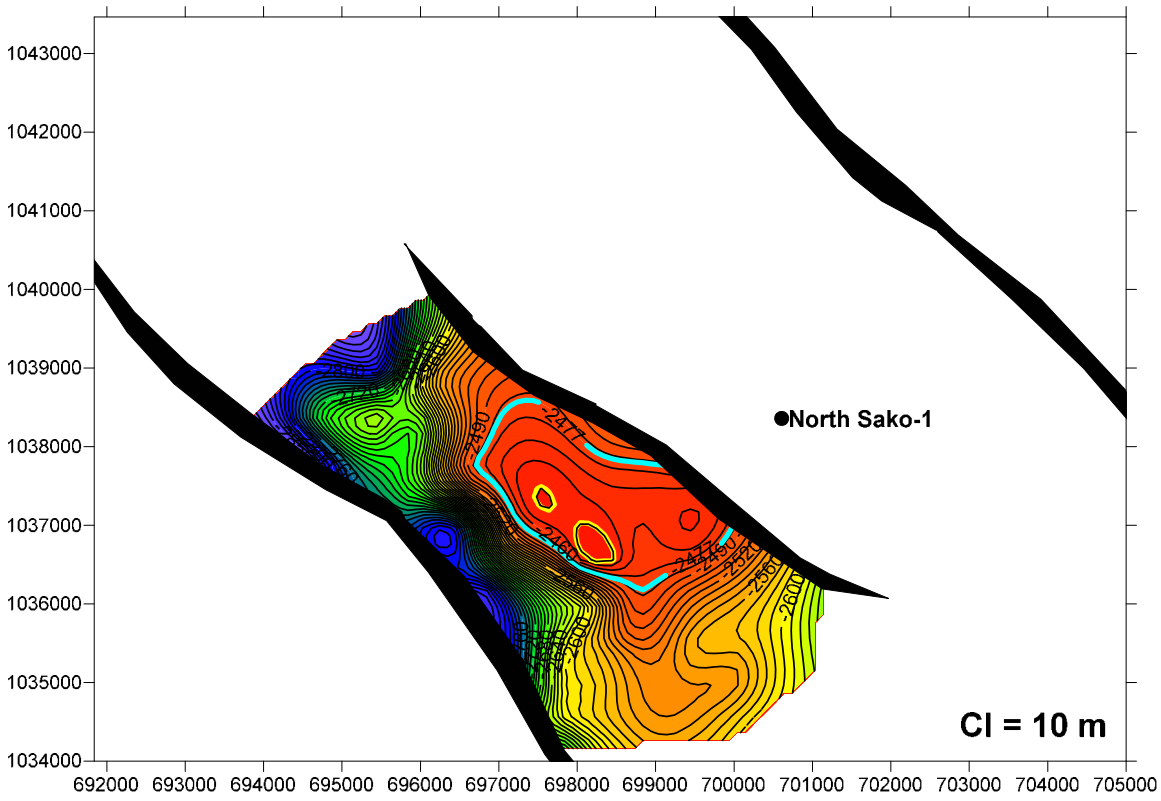
Effective Date: December 31, 2012
Scale: 1:70,000 s1132107



Map 72
Sako North B Prospect
Depth Structure Map (metres)
E Sand

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

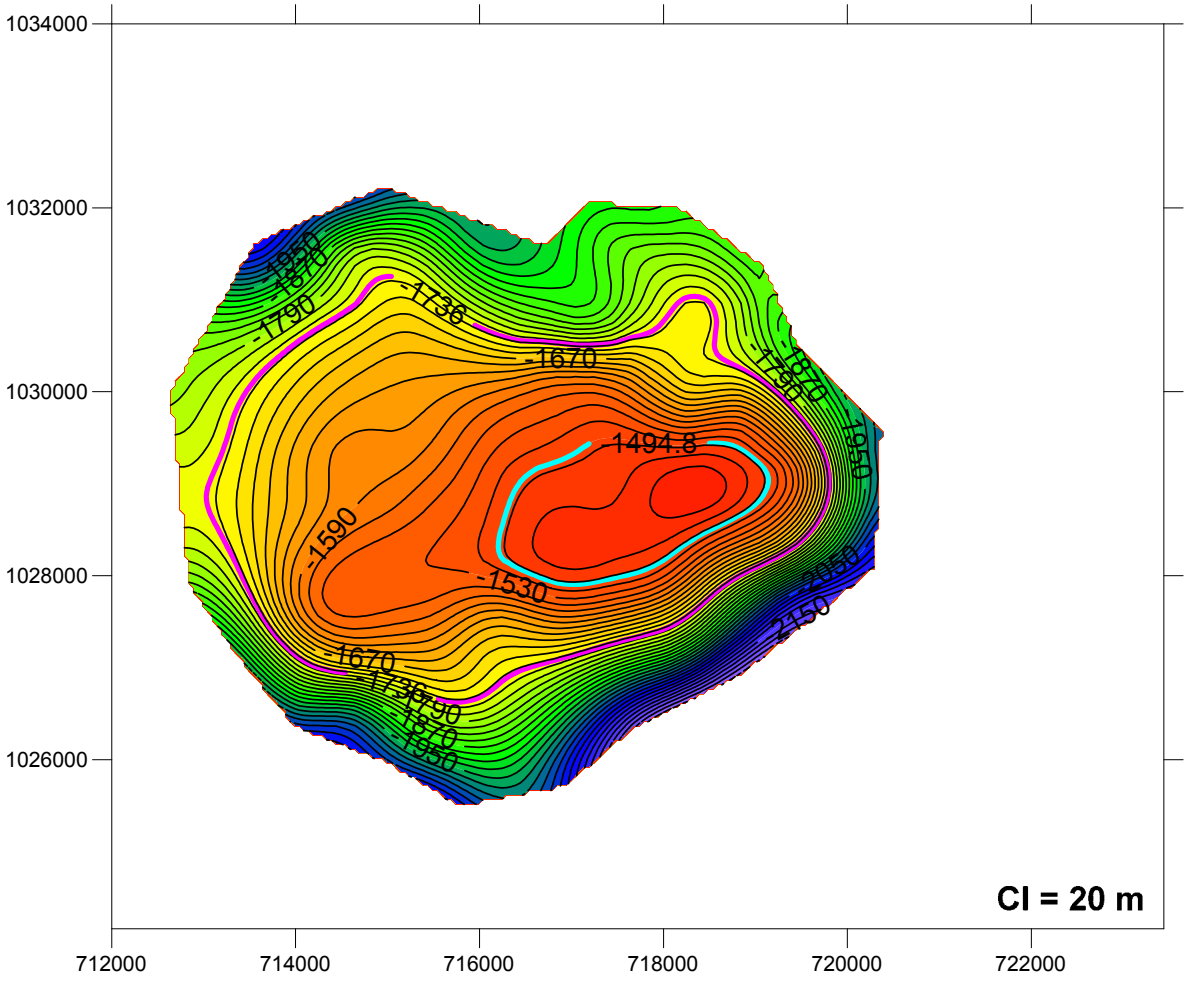
Effective Date: December 31, 2012
Scale: 1:70,000 s1132107



Map 73
Sako Southeast Prospect
Depth Structure Map (metres)
C, D and E Sands

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

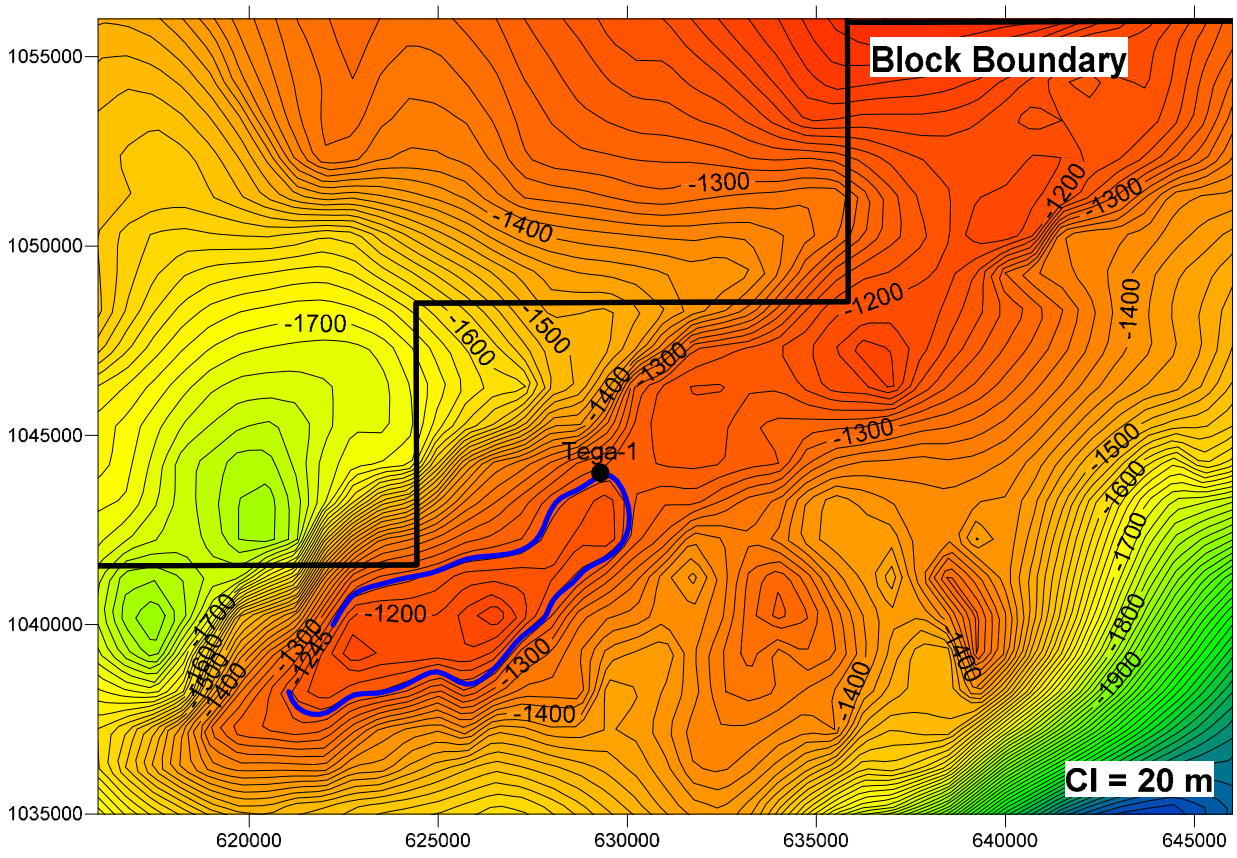
Effective Date: December 31, 2012
Scale: 1:110,000 s1132107



Map 74
Tega Prospect
Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

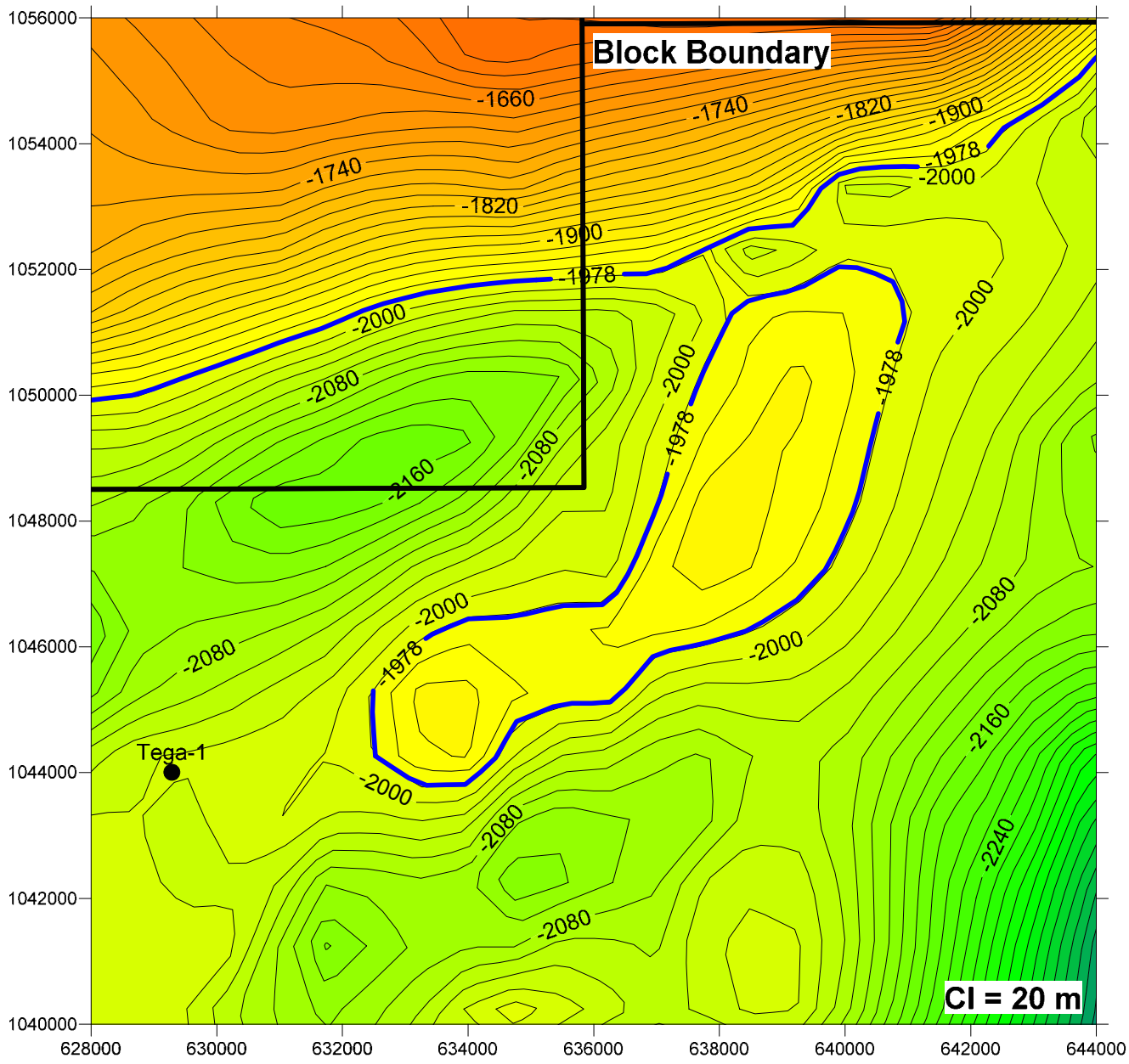
Effective Date: December 31, 2012
Scale: 1:170,000 s1132107



Map 75
Tega Prospect
Depth Structure Map (metres)
D Sand

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

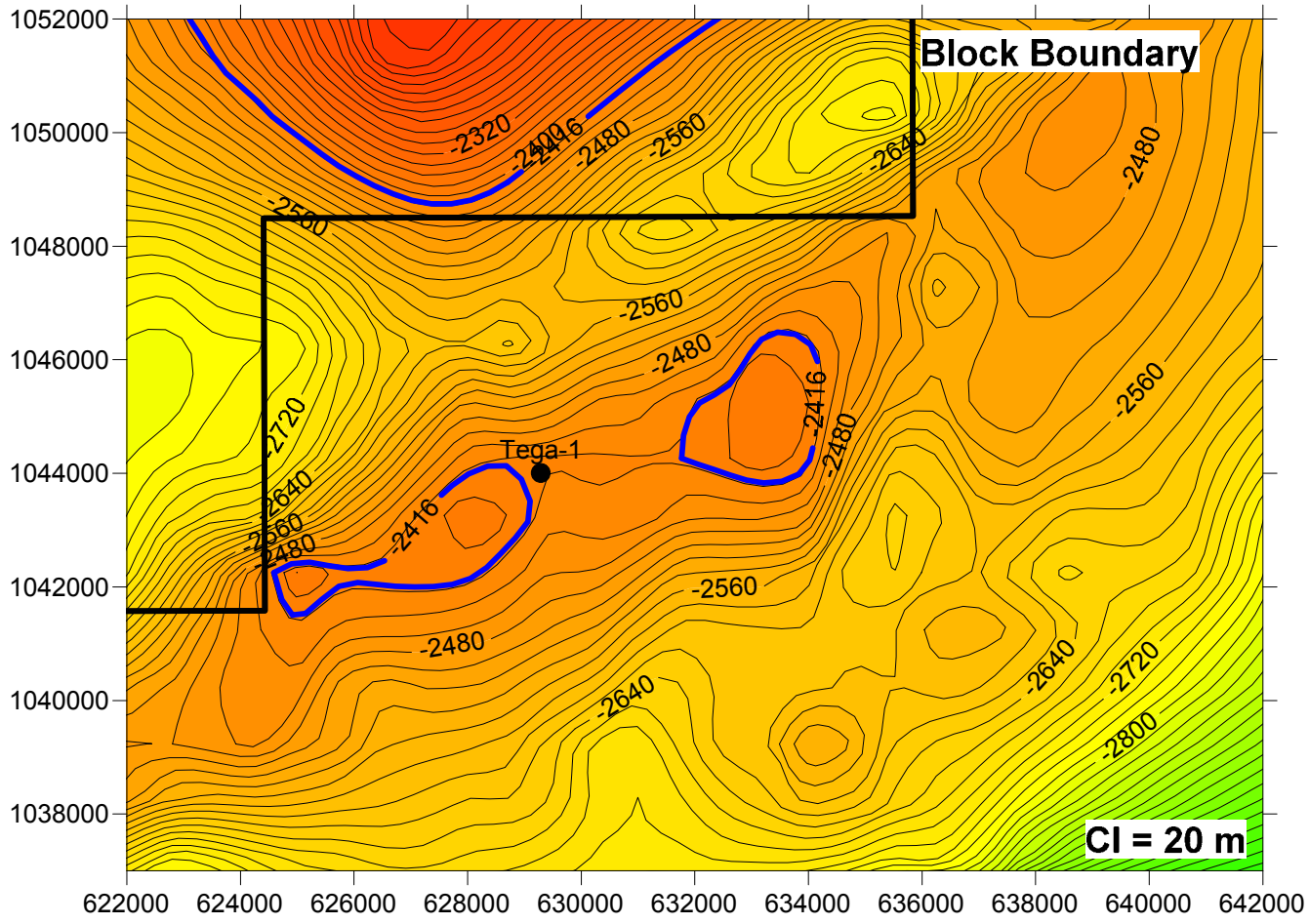
Effective Date: December 31, 2012
Scale: 1:100,000 s1132107



Map 76
Tega Prospect
Depth Structure Map (metres)
E Sand

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

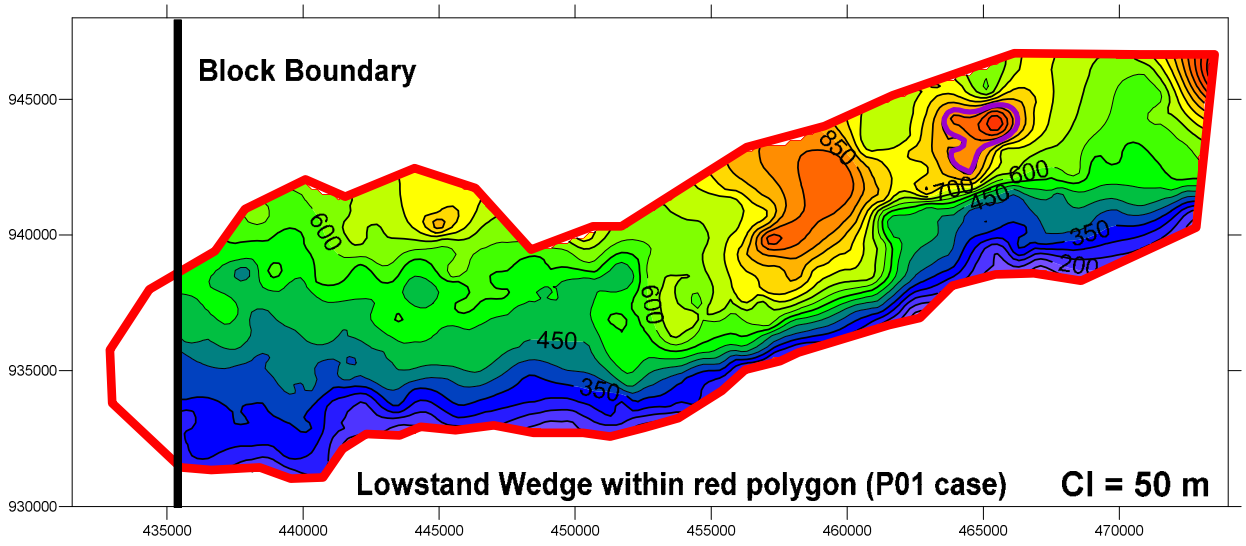
Effective Date: December 31, 2012
Scale: 1:130,000 s1132107



Map 77
Daba Prospect
Isopach Map (metres)
Lower Cretaceous Sands

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo Block

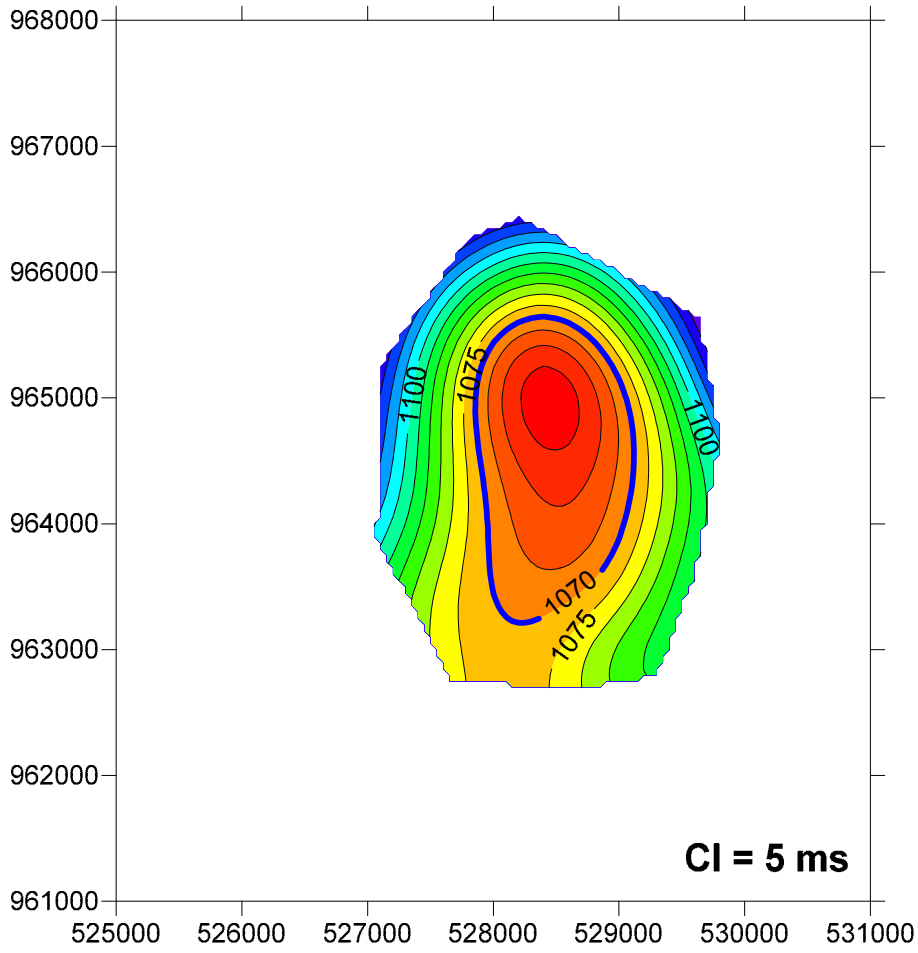
Effective Date: December 31, 2012
Scale: 1:250,000 s1132107



Map 78
Koumogo Prospect
Time Structure Map (milliseconds)
Lower Cretaceous Sands
Low Case

Company: Griffiths Energy International Inc.
Property: Chari East Doseo Block

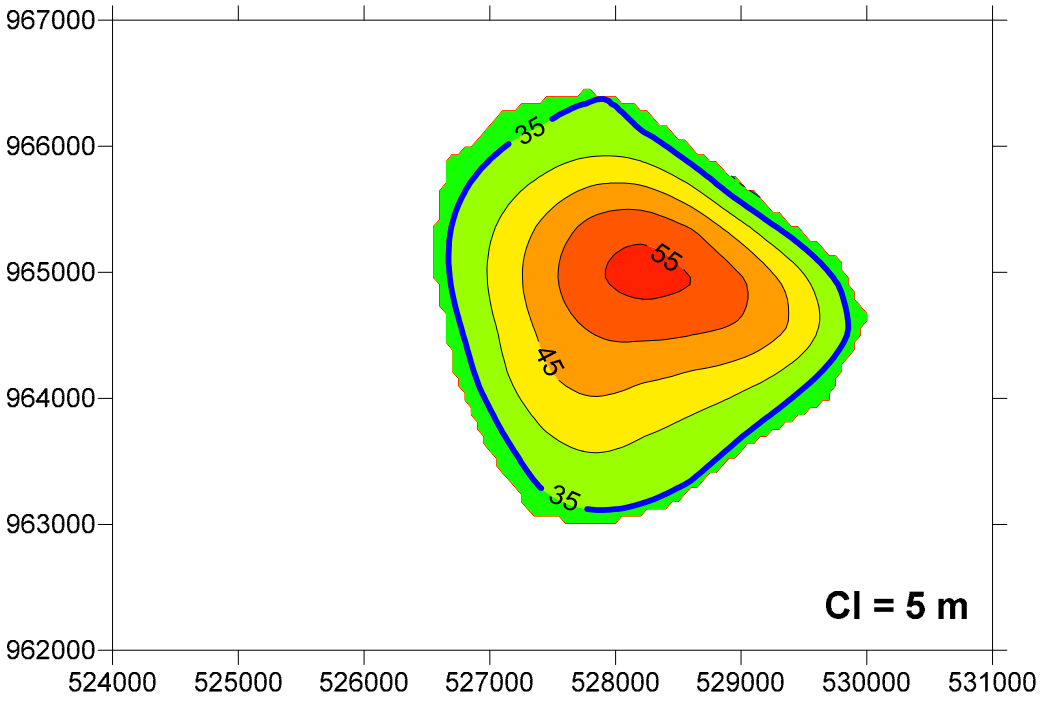
Effective Date: December 31, 2012
Scale: 1:60,000 s1132107



Map 79
Koumogo Prospect
Isochron Map (metres)
Lower Cretaceous Sands
Most Likely Case

Company: Griffiths Energy International Inc.
Property: Chari East Doseo Block

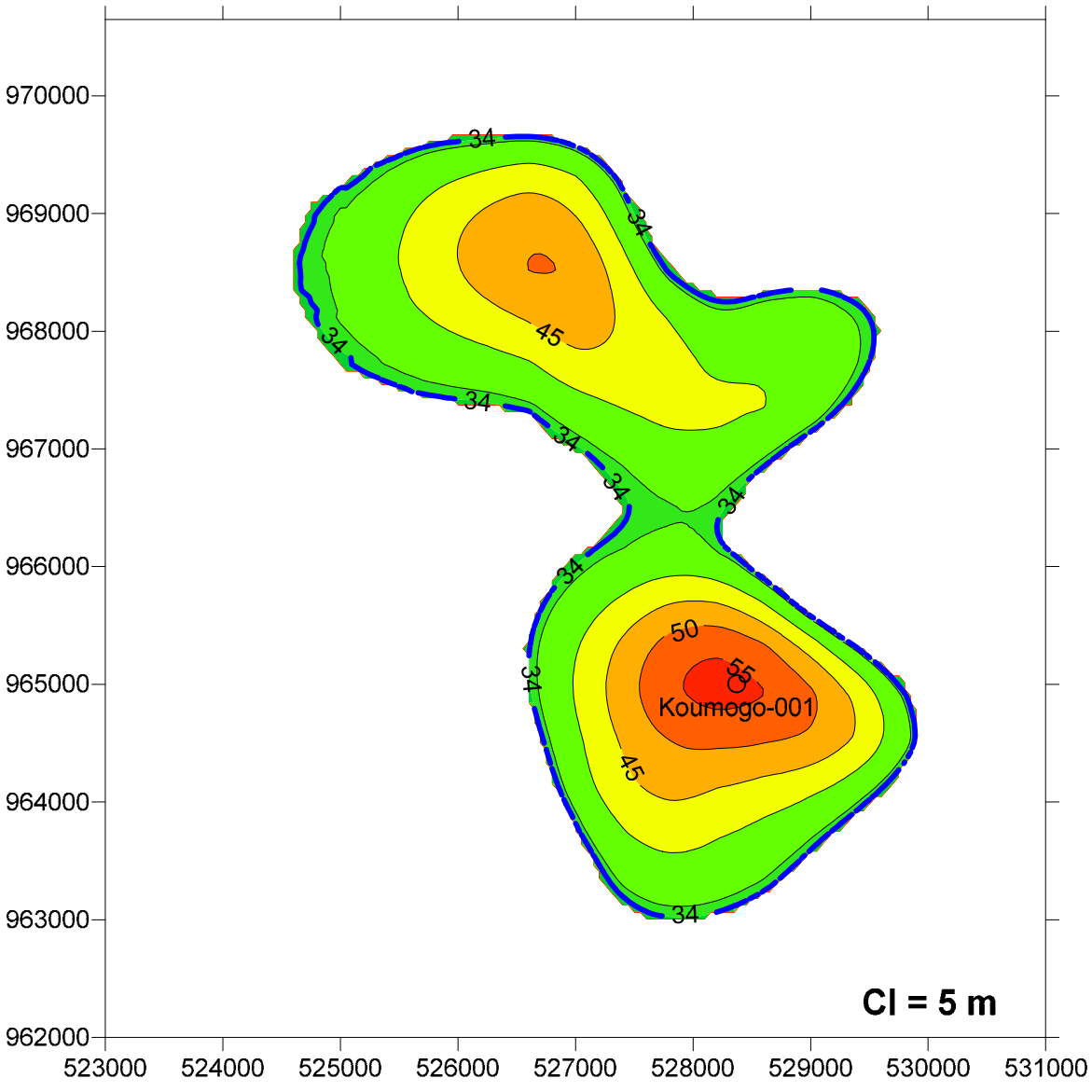
Effective Date: December 31, 2012
Scale: 1:60,000 s1132107



Map 80
Koumogo Prospect
Isochron Map (metres)
Lower Cretaceous Sands
High Case

Company: Griffiths Energy International Inc.
Property: Chari East Doseo Block

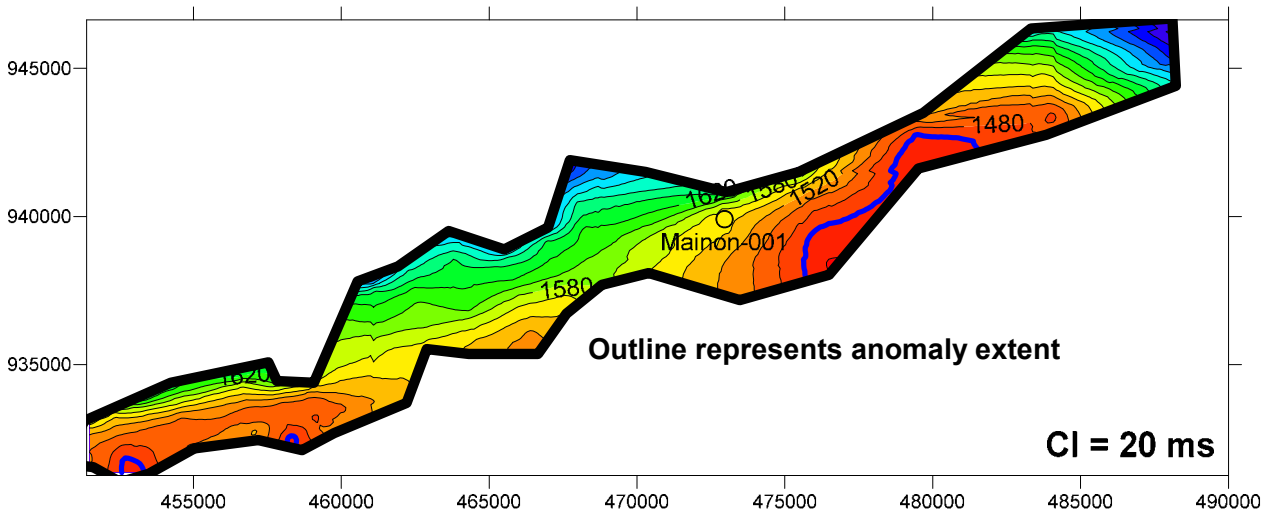
Effective Date: December 31, 2012
Scale: 1:60,000 s1132107



Map 81
Mainon Prospect
Time Structure Map (milliseconds)
Lower Cretaceous Sands

Company: Griffiths Energy International Inc.
Property: Chari East-Doseo and Borogop Block

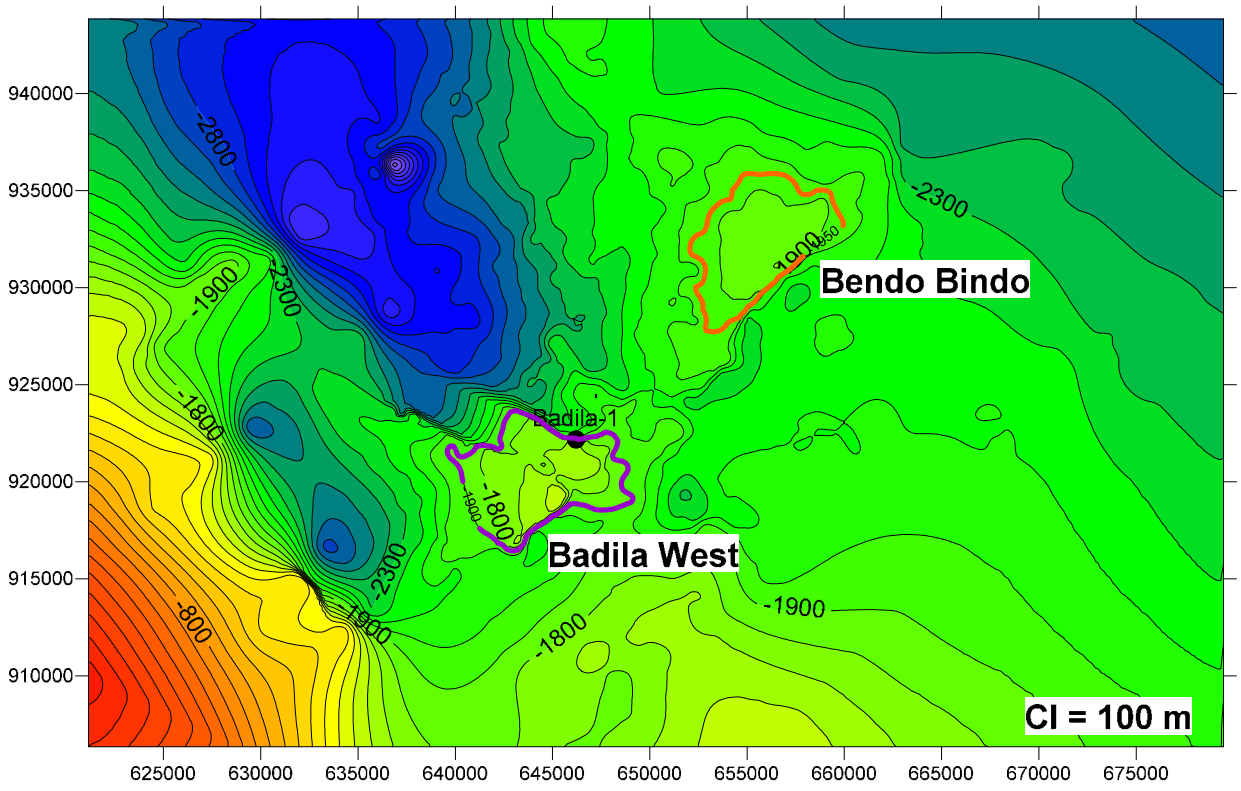
Effective Date: December 31, 2012
Scale: 1:230,000 s1132107



Map 82
Badila West and Bendo Bindo Leads
Depth Structure Map (metres)
Basement Top

Company: Griffiths Energy International Inc.
Property: DOI Block

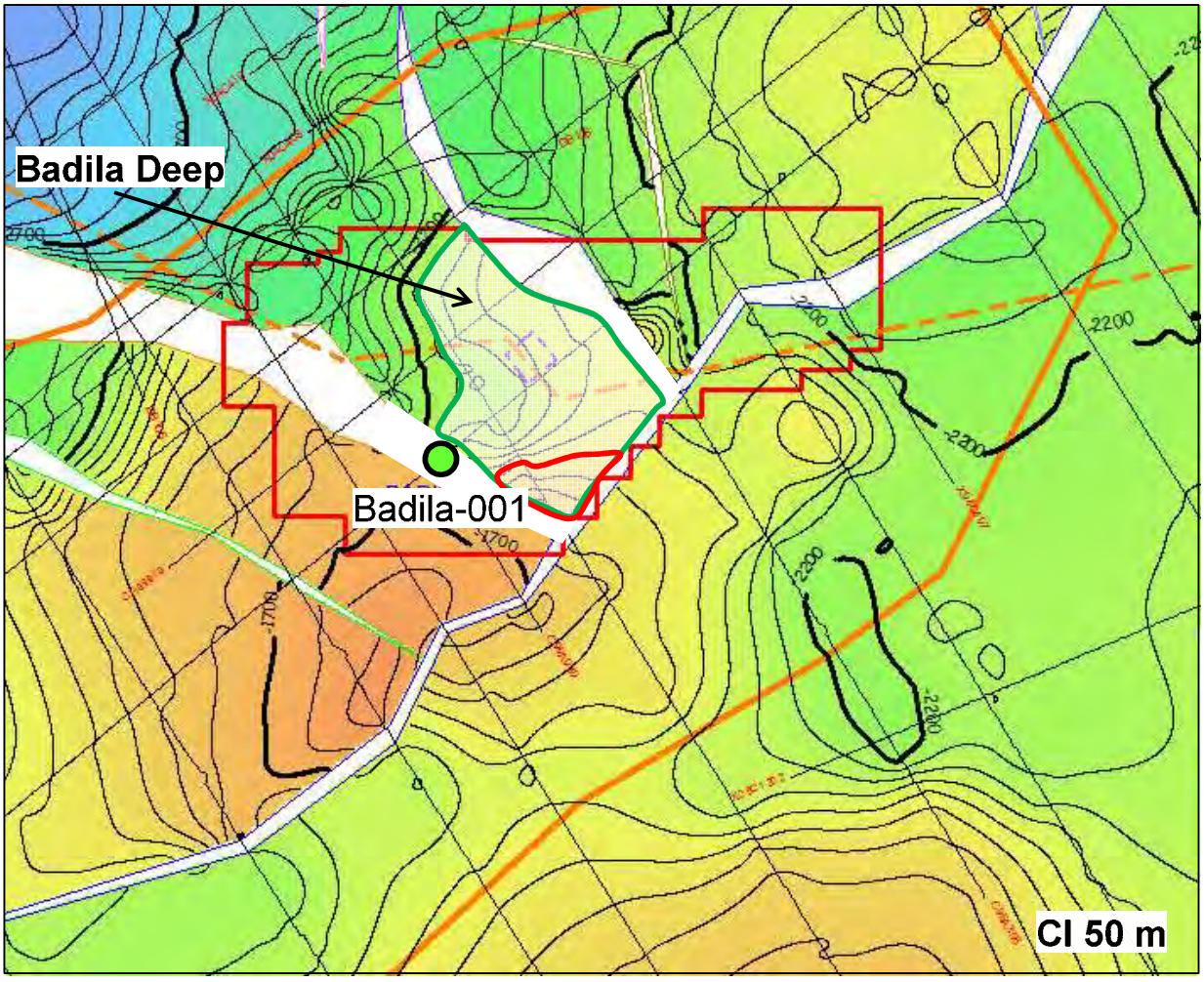
Effective Date: December 31, 2012
Scale: 1:350,000 s1132107



Map 83
Badila Deep Prospect
Griffiths Depth Structure Map (metres)
Top Basement

Company: Griffiths Energy International Inc.
Property: DOI Block

Effective Date: December 31, 2012
s1132107

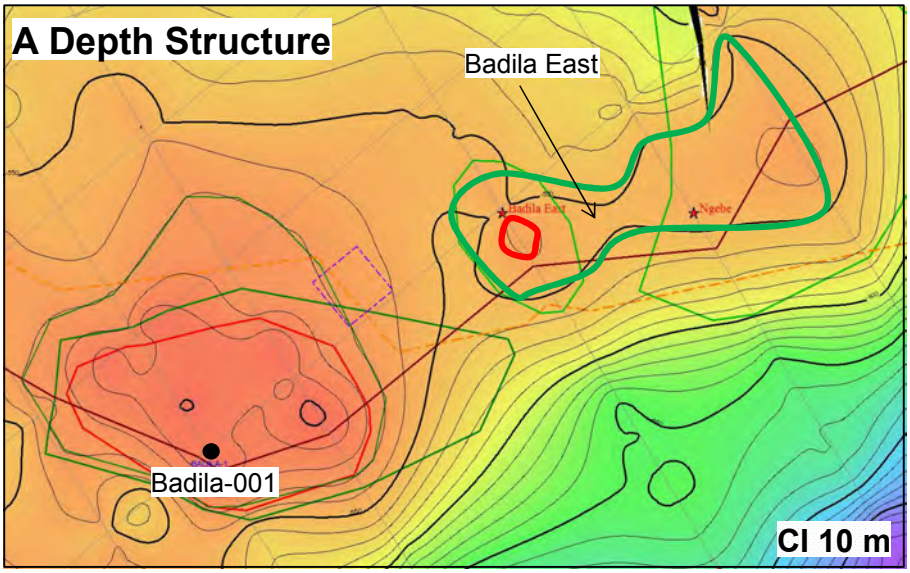


Map 84 a, b
Badila East Prospect
Griffiths Depth Structure Map (metres)
A and D3 Sands

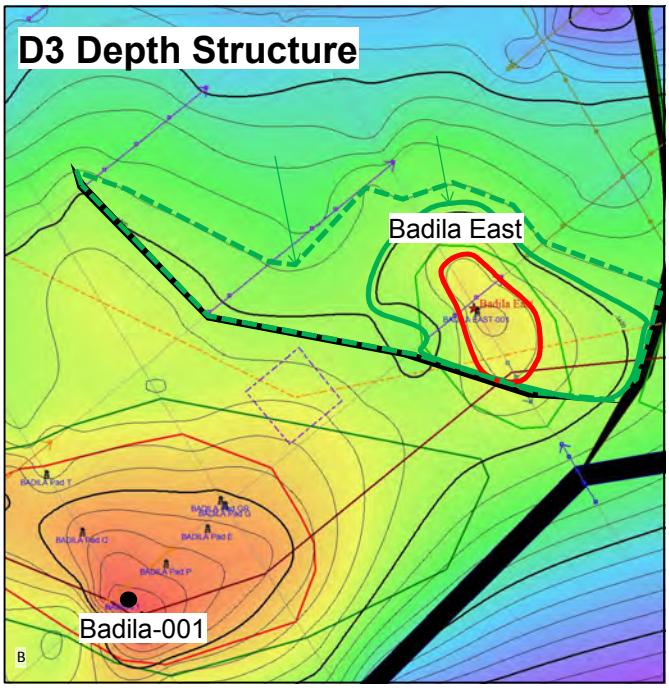
Company: Griffiths Energy International Inc.
Property: DOI Block

Effective Date: December 31, 2012
s1132107

(a)



(b)

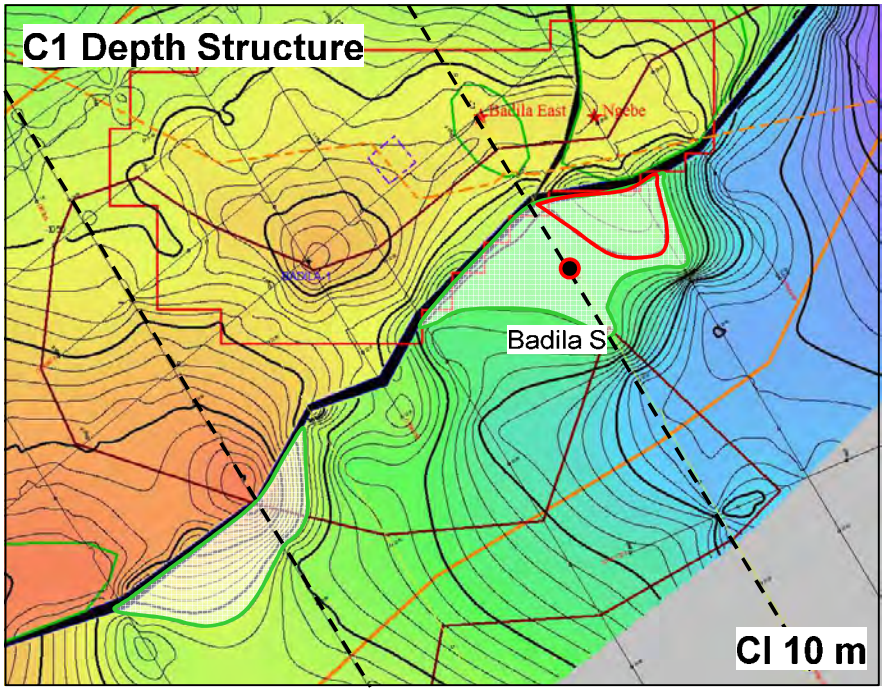


Map 85 a, b
Badila South Prospect
Griffiths Depth Structure Map (metres)
C1 and D3 Sands

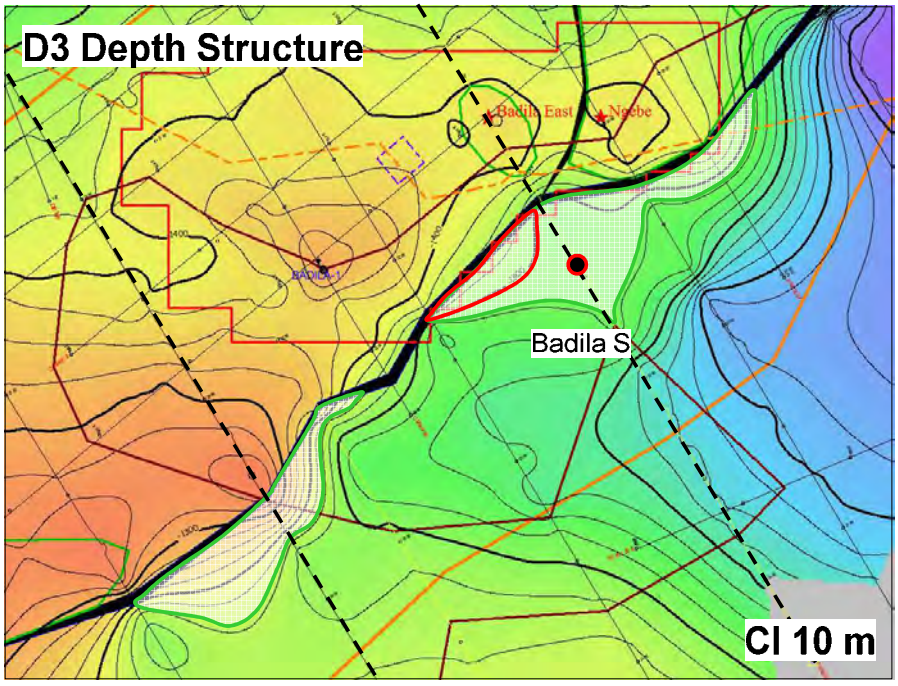
Company: Griffiths Energy International Inc.
Property: DOI Block

Effective Date: December 31, 2012
s1132107

(a)



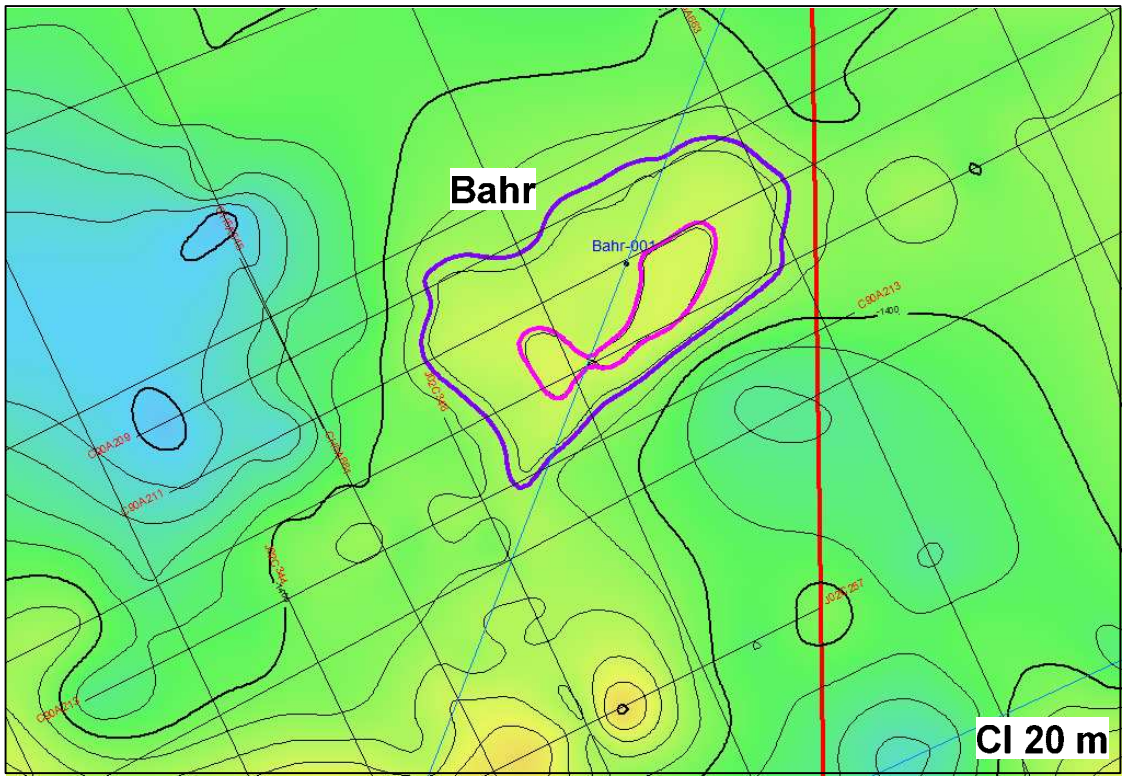
(b)



Map 86
Bahr Prospect
Griffiths Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: Chari East Doseo Block

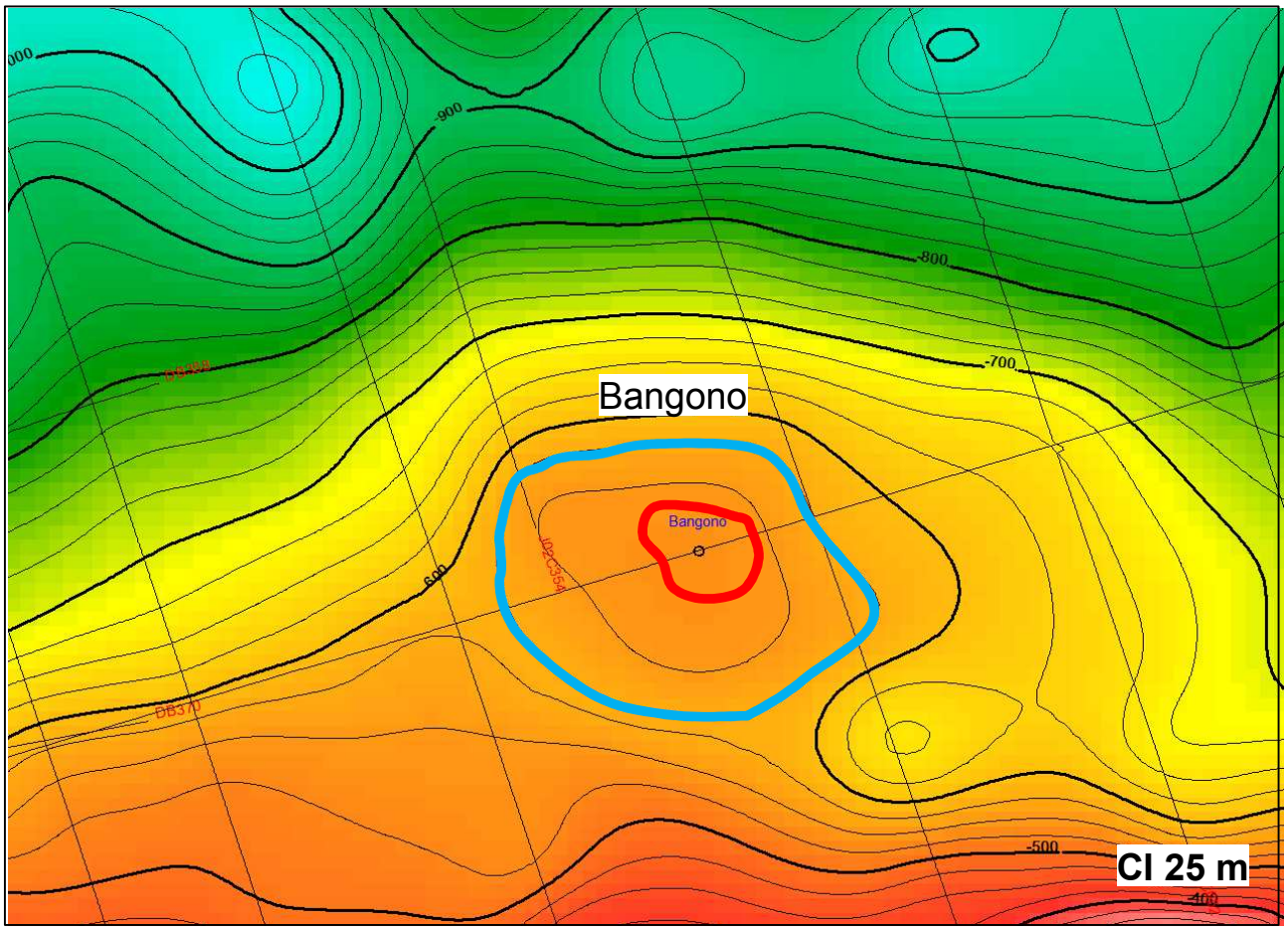
Effective Date: December 31, 2012
s1132107



Map 87
Bangono Prospect
Griffiths Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: Chari East Doseo Block

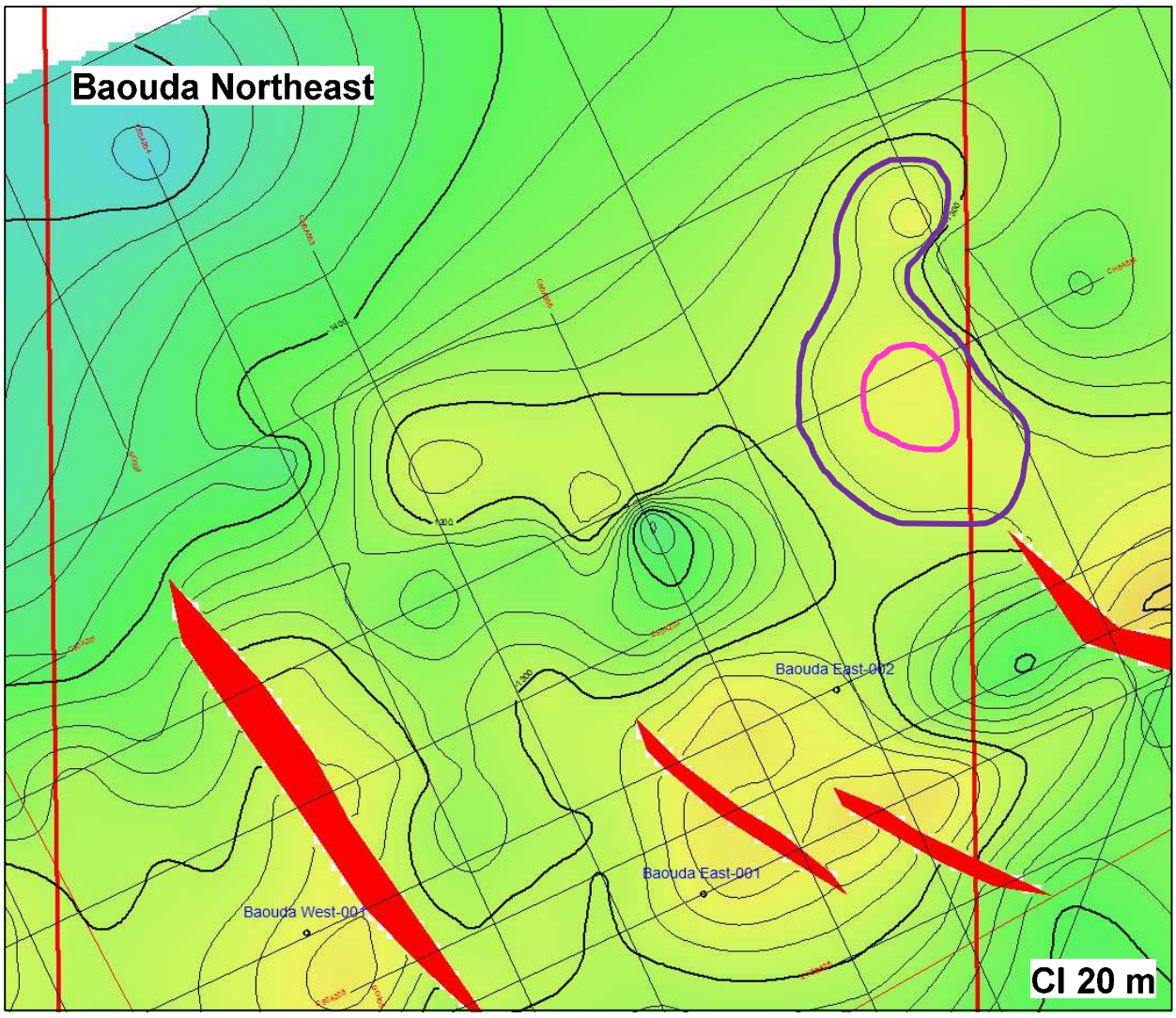
Effective Date: December 31, 2012
s1132107



Map 88
Baouda Northeast Prospect
Griffiths Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: Chari East Doseo Block

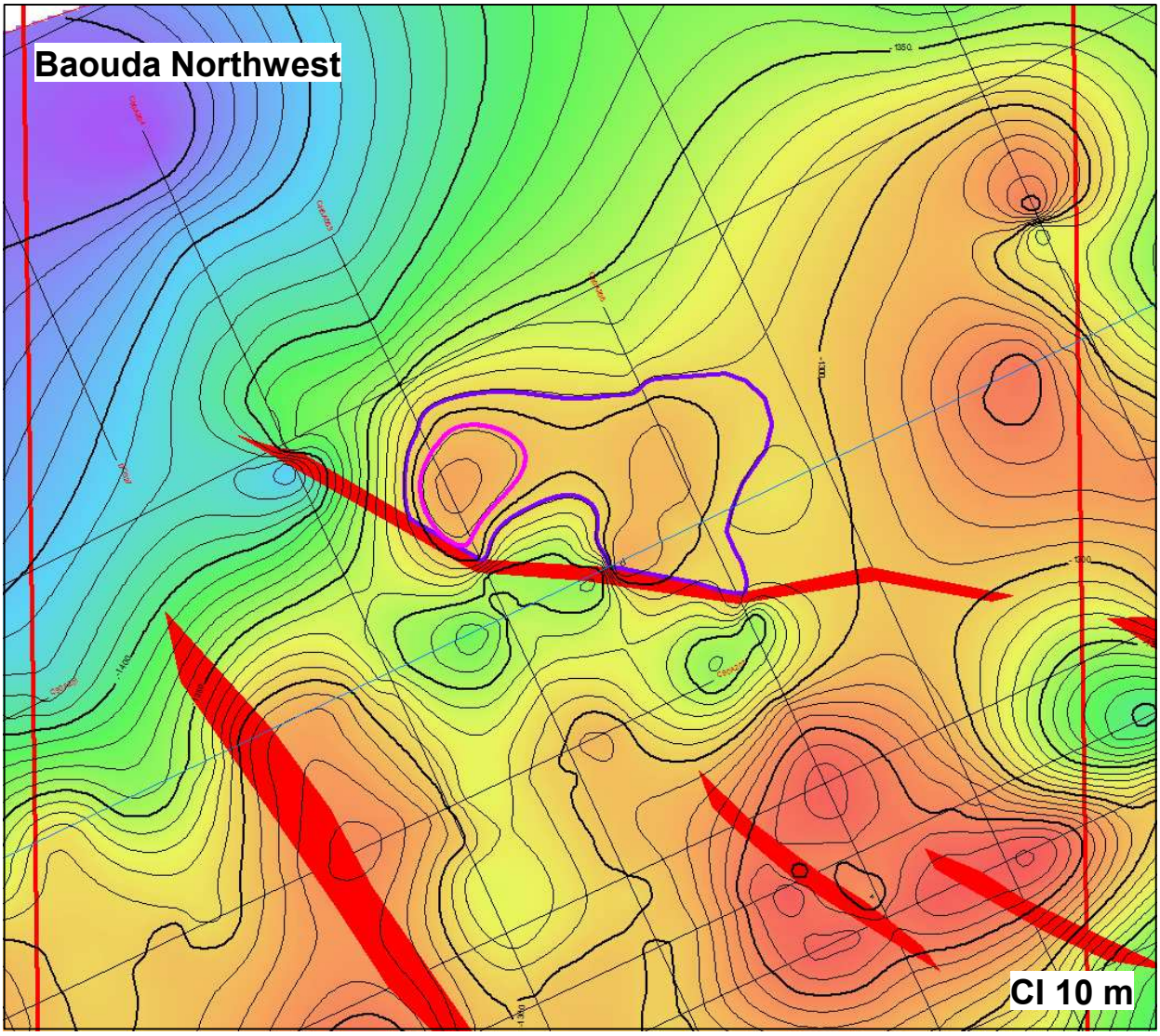
Effective Date: December 31, 2012
s1132107



Map 89
Baouda Northwest Prospect
Griffiths Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: Chari East Doseo Block

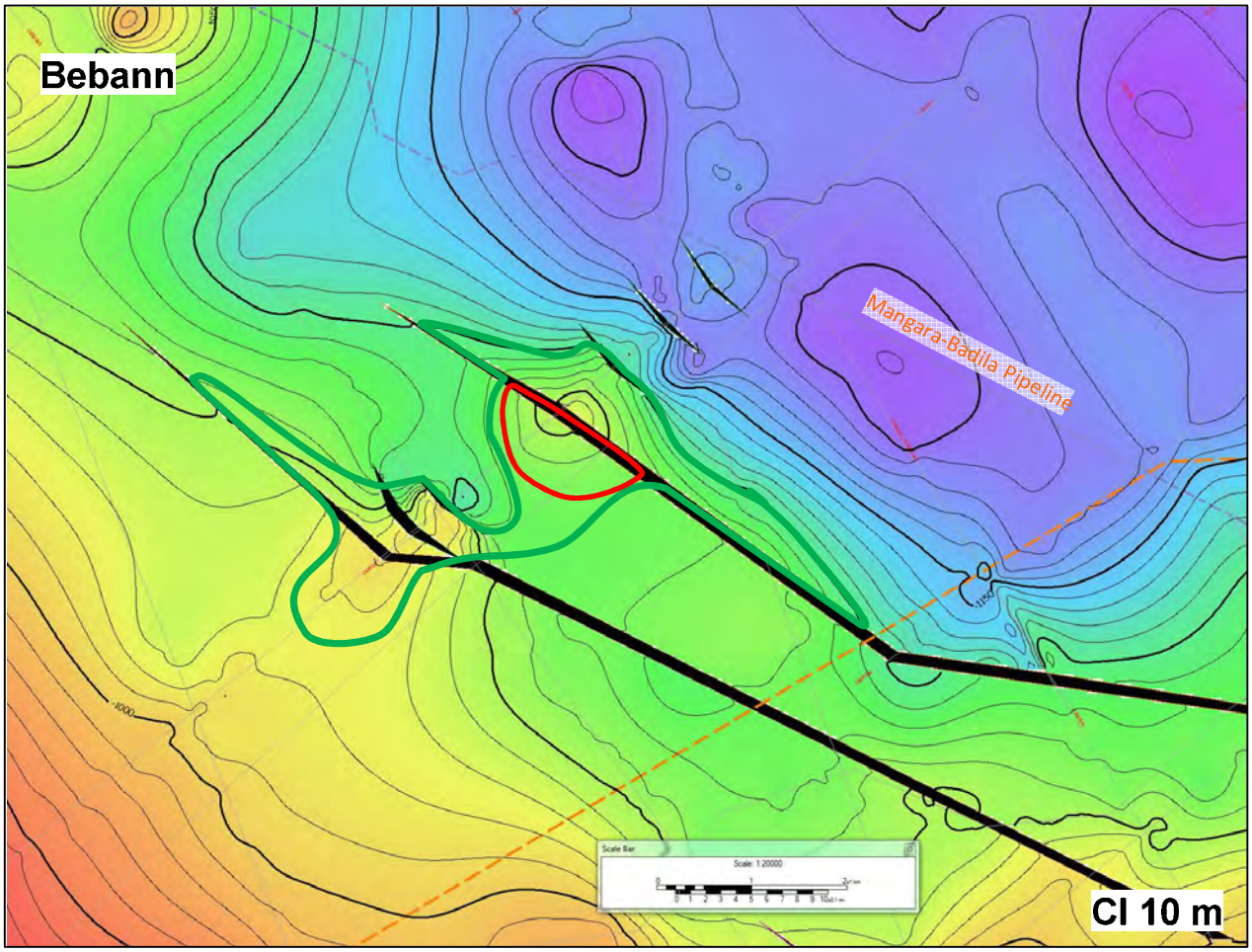
Effective Date: December 31, 2012
s1132107



Map 90
Bebann Prospect
Griffiths Depth Structure Map (metres)
C1 Sand

Company: Griffiths Energy International Inc.
Property: DOI Block

Effective Date: December 31, 2012
Scale: 1:20,000 s1132107

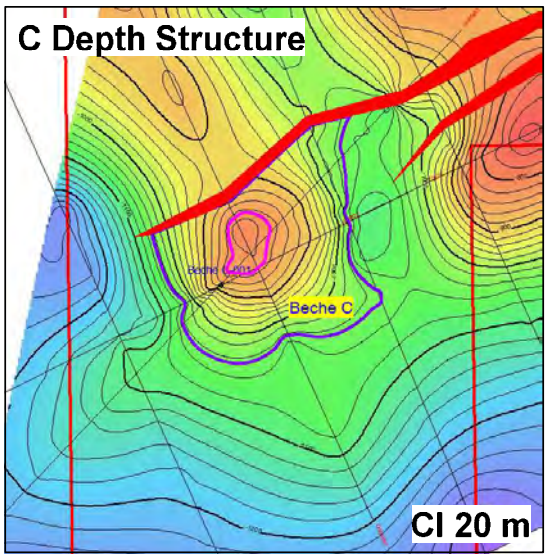


Map 91 a, b, c
Beche C Prospect
Griffiths Depth Structure Map (metres)
C, D and E Sands

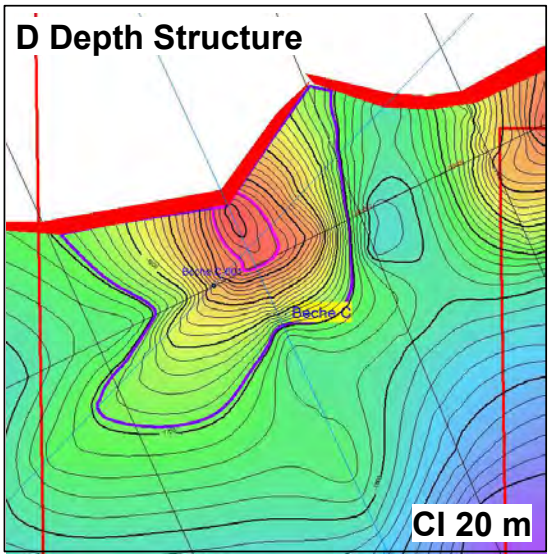
Company: Griffiths Energy International Inc.
Property: Chari East Doseo Block

Effective Date: December 31, 2012
s1132107

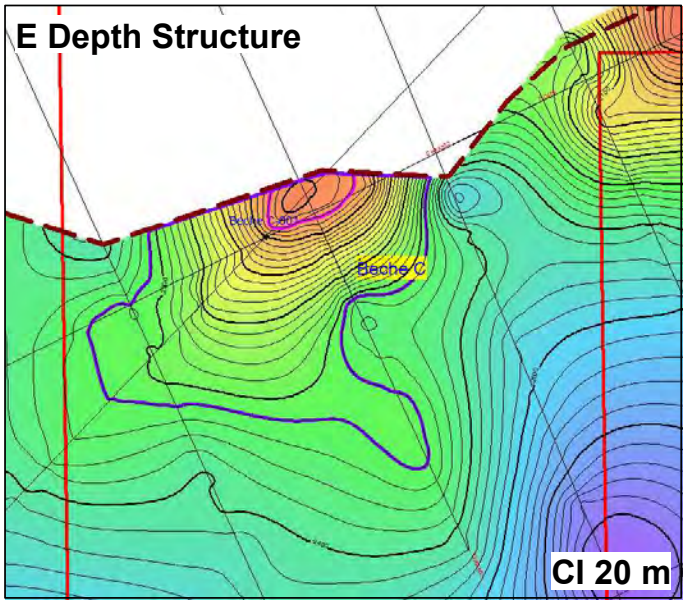
(a)



(b)



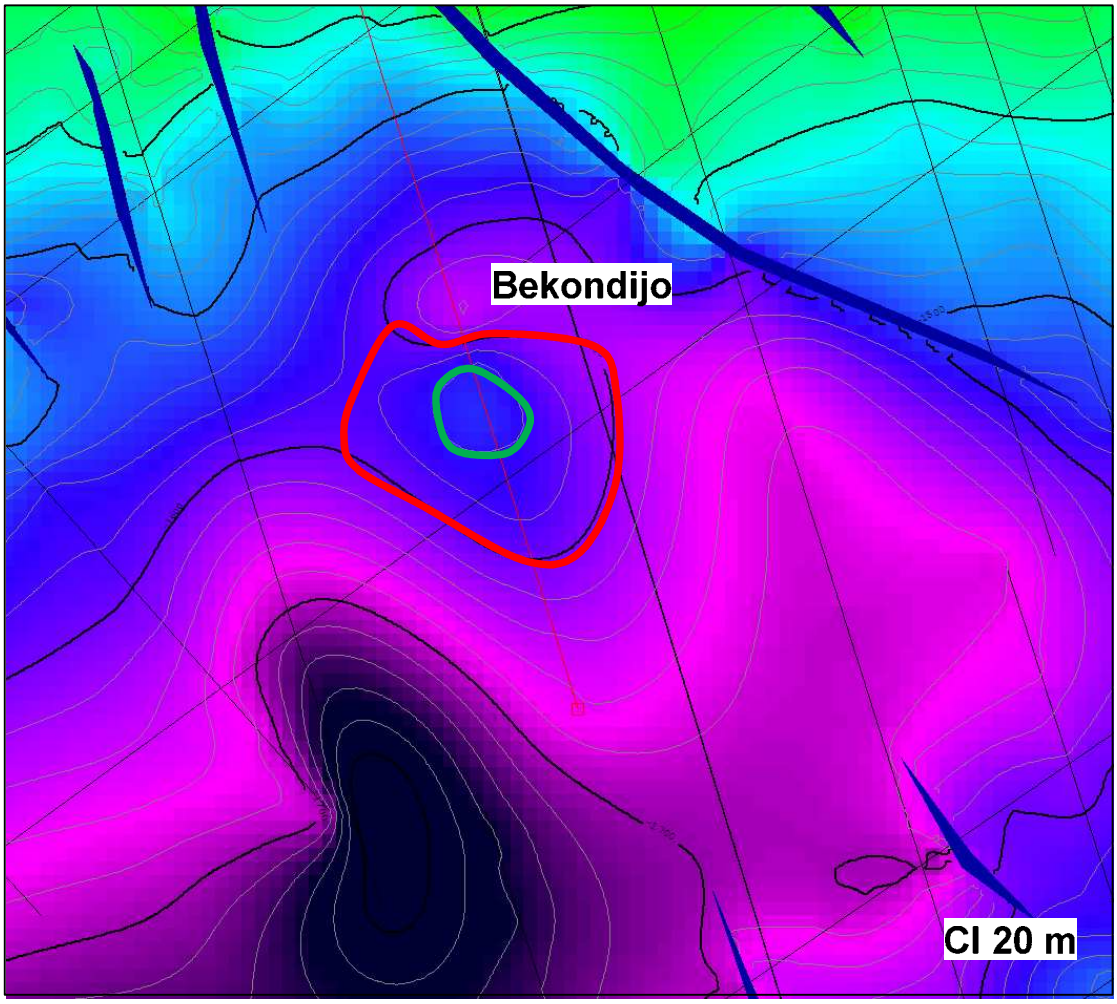
(c)



Map 92
Bekondijo Deep Prospect
Griffiths Depth Structure Map (metres)
A3 Sand

Company: Griffiths Energy International Inc.
Property: DOH Block

Effective Date: December 31, 2012
s1132107

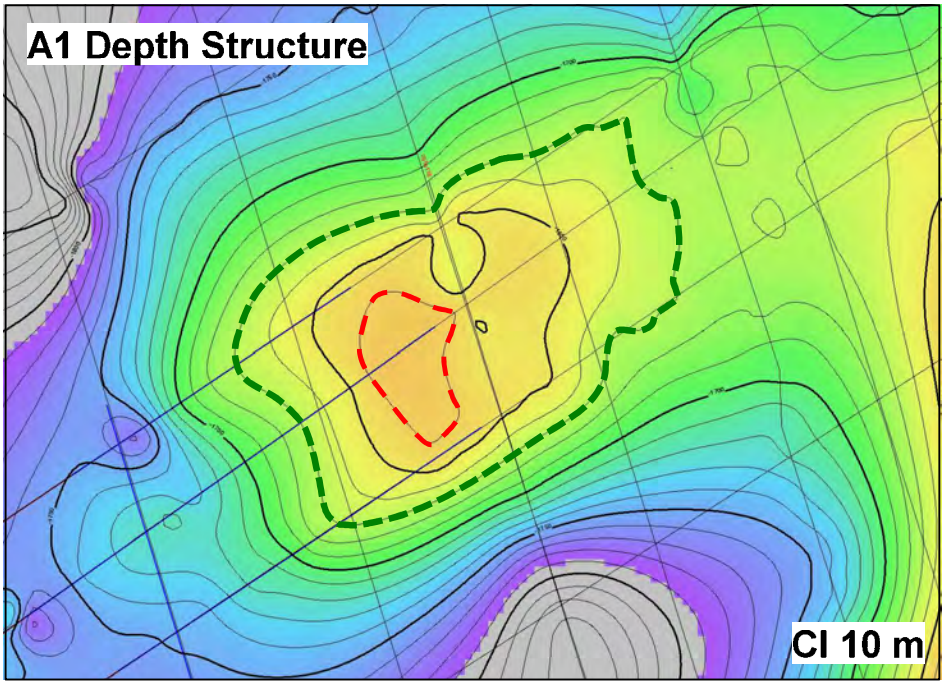


Map 93 a, b
Beongo Prospect
Griffiths Depth Structure Map (metres)
A1 and C Sands

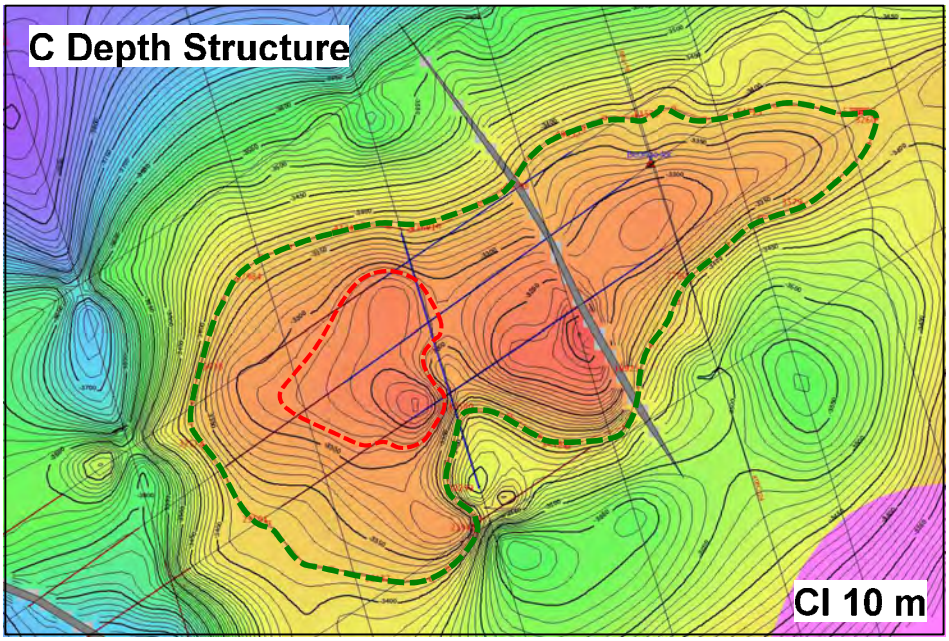
Company: Griffiths Energy International Inc.
Property: DOH Block

Effective Date: December 31, 2012
s1132107

(a)



(b)

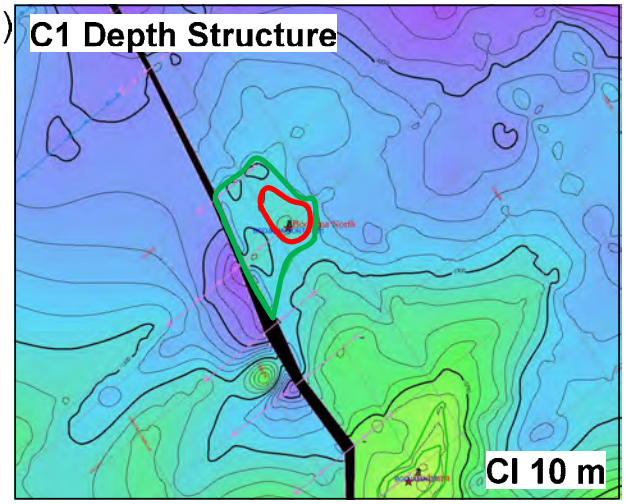


Map 94 a, b, c
Bodjama North Prospect
Griffiths Depth Structure Map (metres)
C1, D3 and E Sand

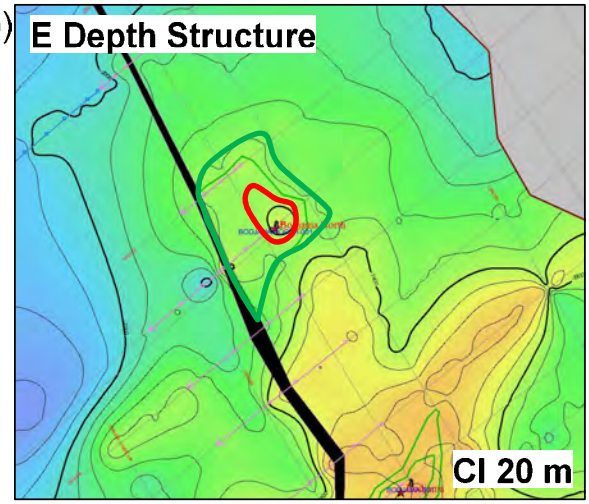
Company: Griffiths Energy International Inc.
Property: DOI Block

Effective Date: December 31, 2012
s1132107

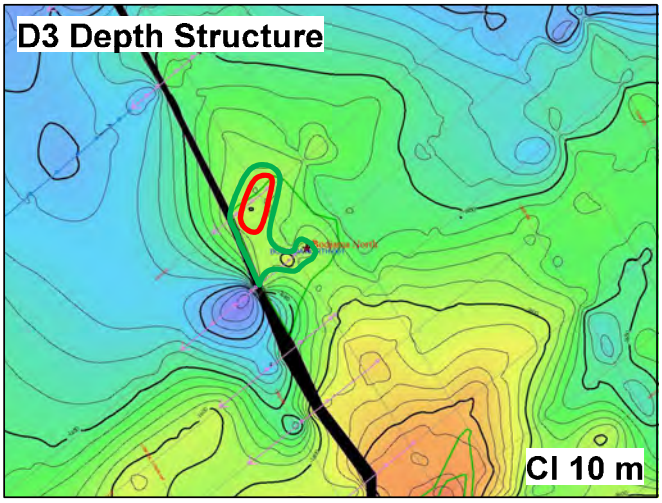
(a)



(b)



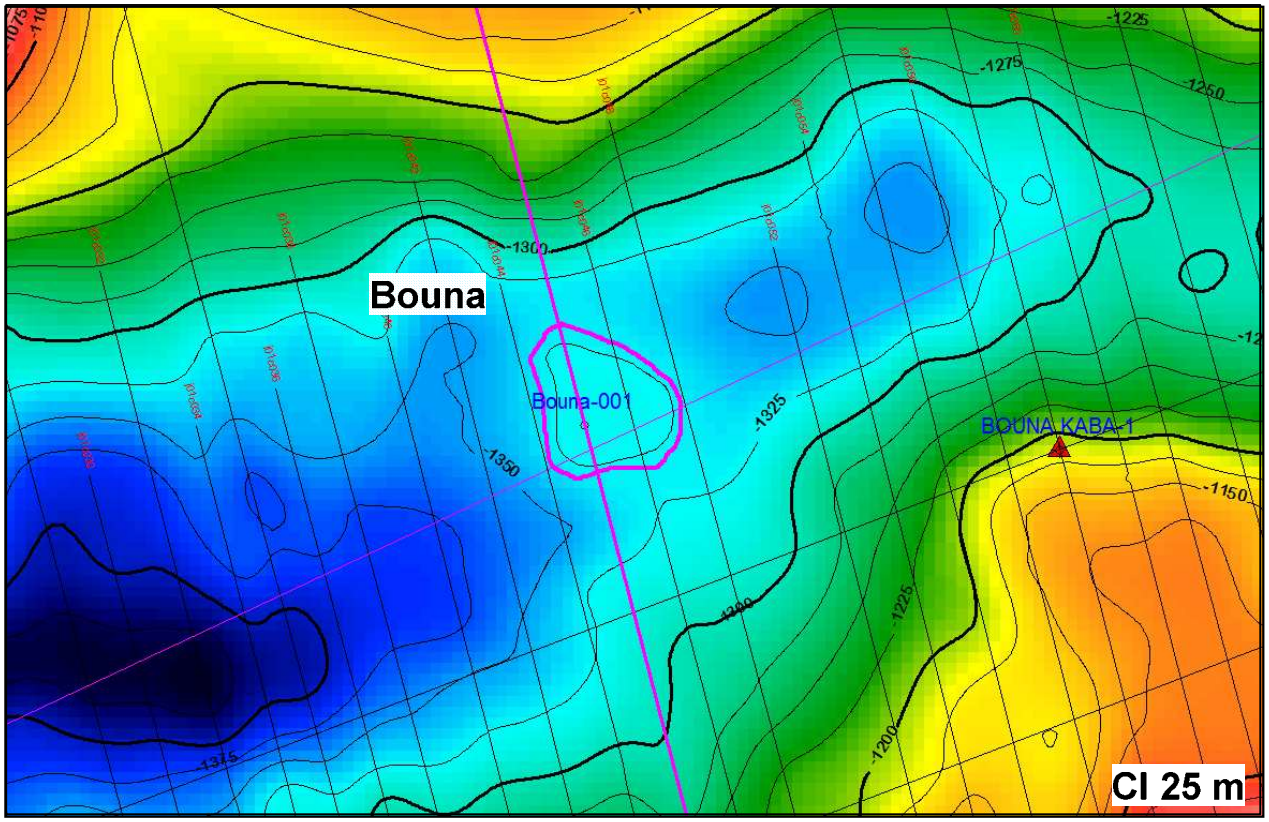
(c)



Map 95
Bouna Prospect
Griffiths Depth Structure Map (metres)
Lower Cretaceous Sand

Company: Griffiths Energy International Inc.
Property: Borogop Block

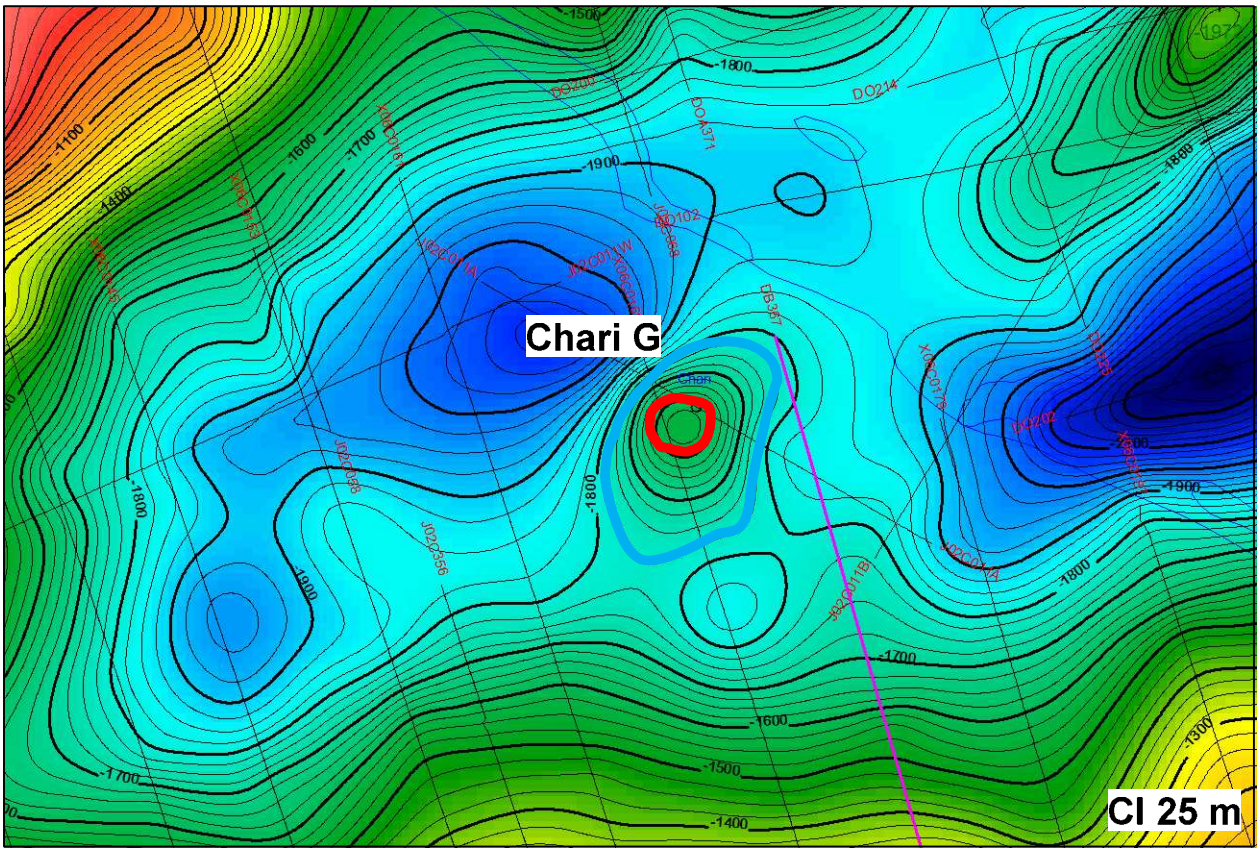
Effective Date: December 31, 2012
s1132107



Map 96
Chari G Prospect
Griffiths Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: Chari East Doseo Block

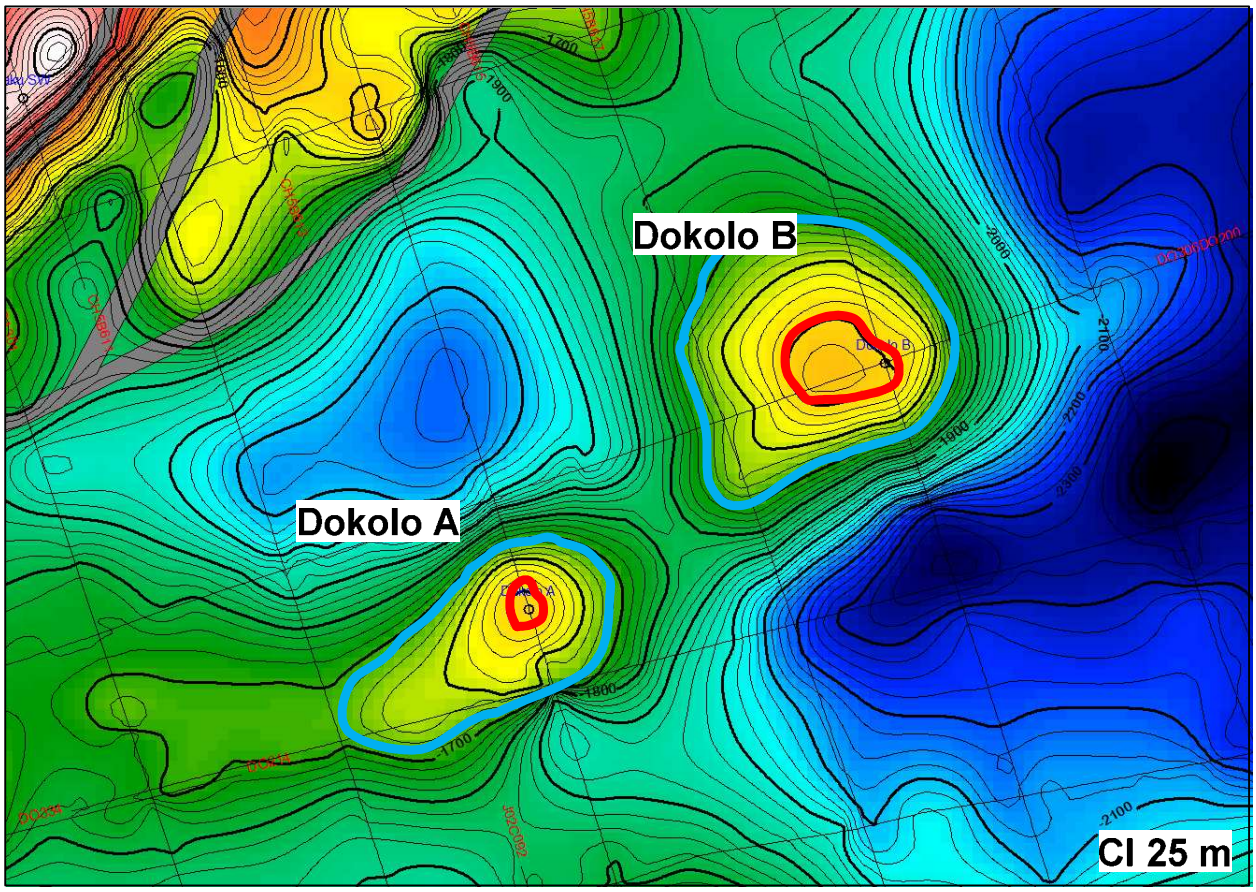
Effective Date: December 31, 2012
s1132107



Map 97
Dokolo A and Dokolo B Prospect
Griffiths Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: Chari East Doseo Block

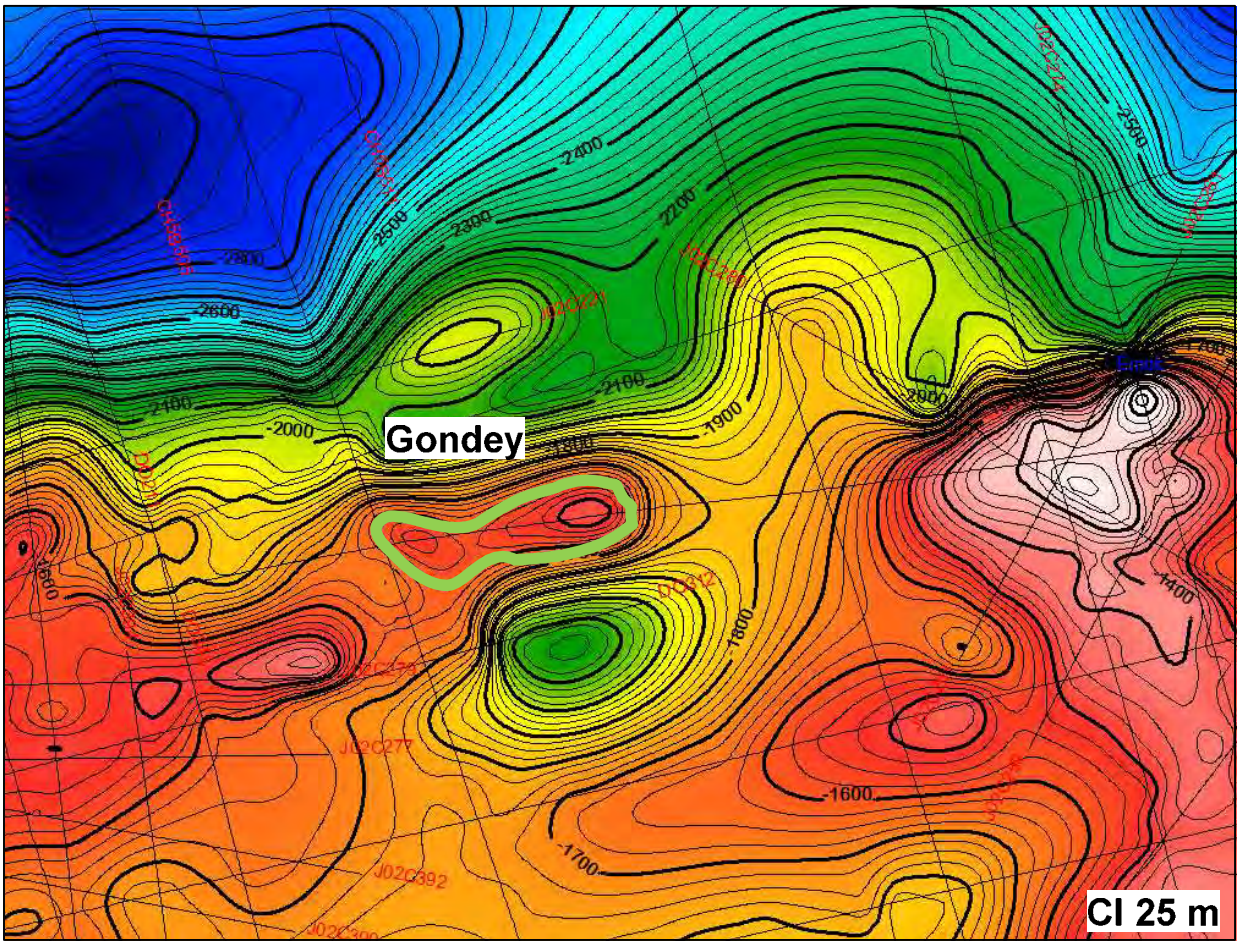
Effective Date: December 31, 2012
s1132107



Map 98
Gondey Prospect
Griffiths Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: Chari East Doseo Block

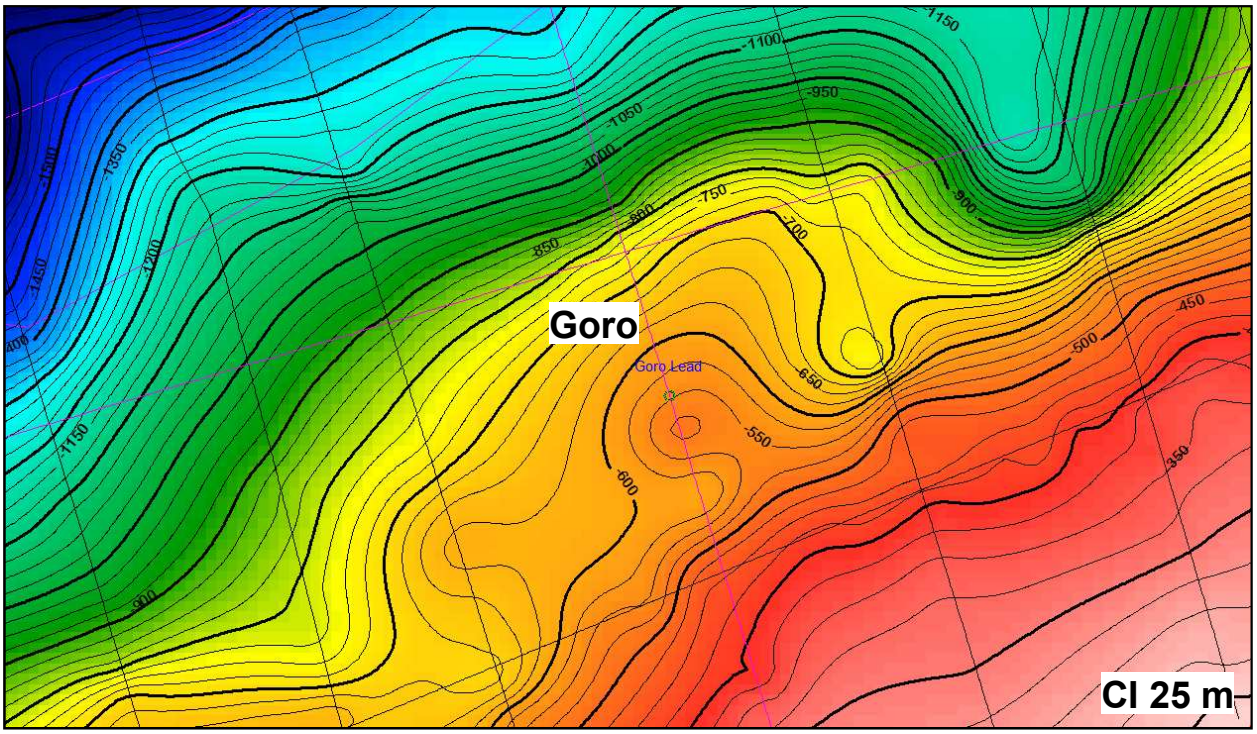
Effective Date: December 31, 2012
s1132107



Map 99
Goro Prospect
Griffiths Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: Chari East Doseo Block

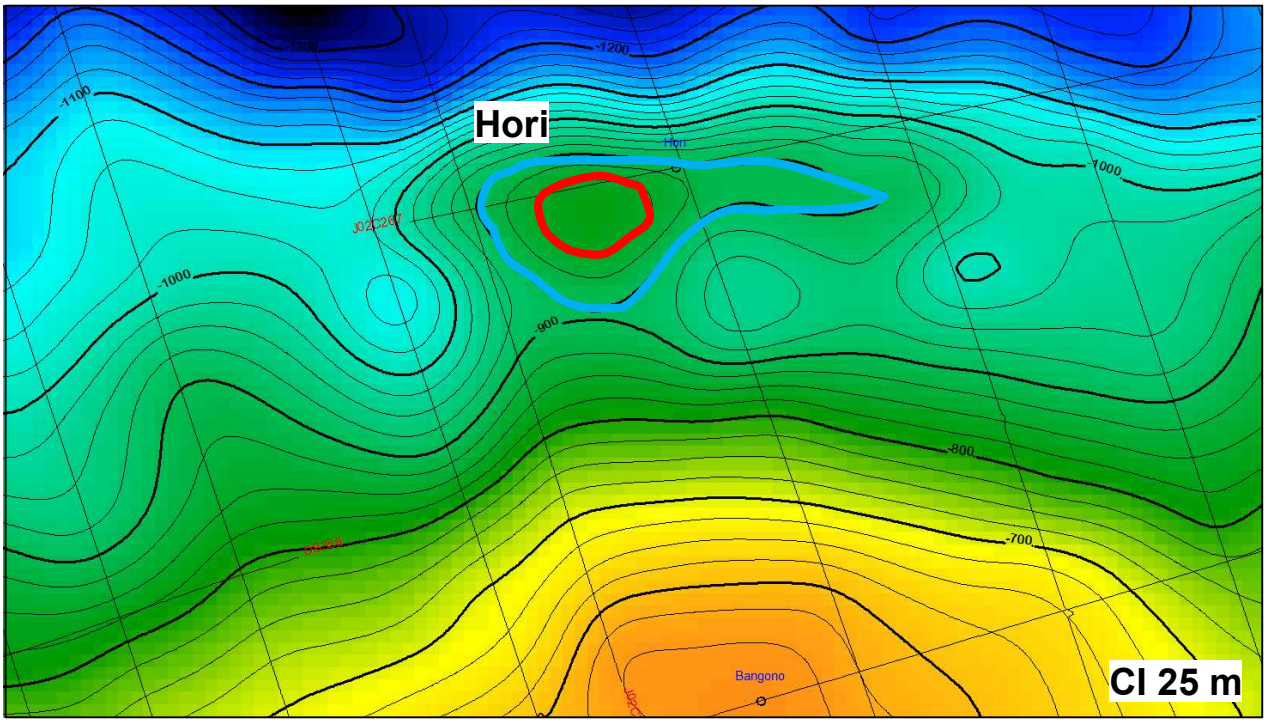
Effective Date: December 31, 2012
s1132107



Map 100
Hori Prospect
Griffiths Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: Chari East Doseo Block

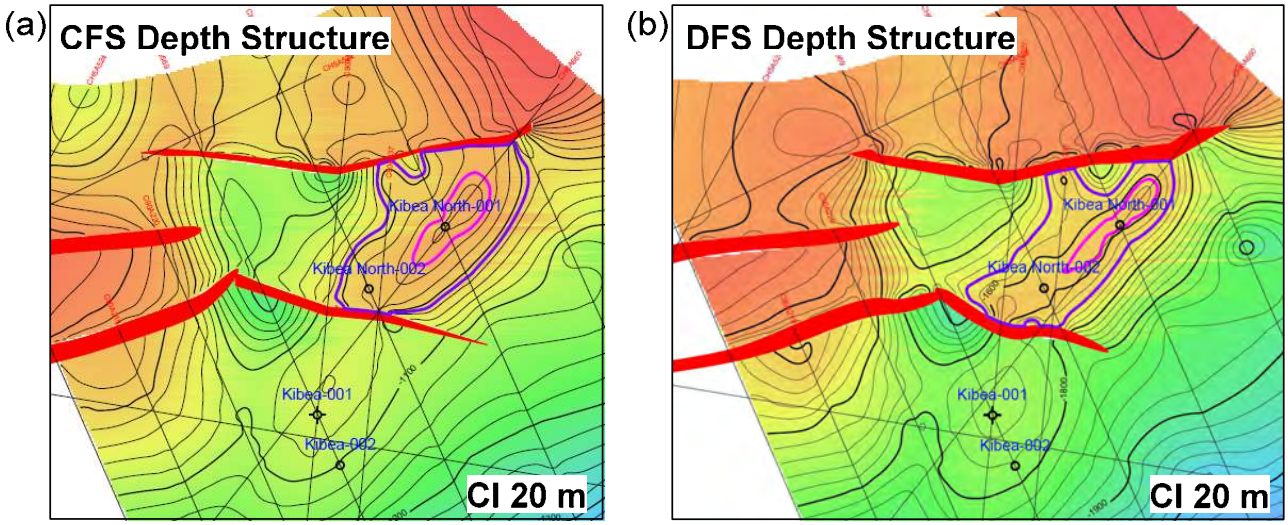
Effective Date: December 31, 2012
s1132107

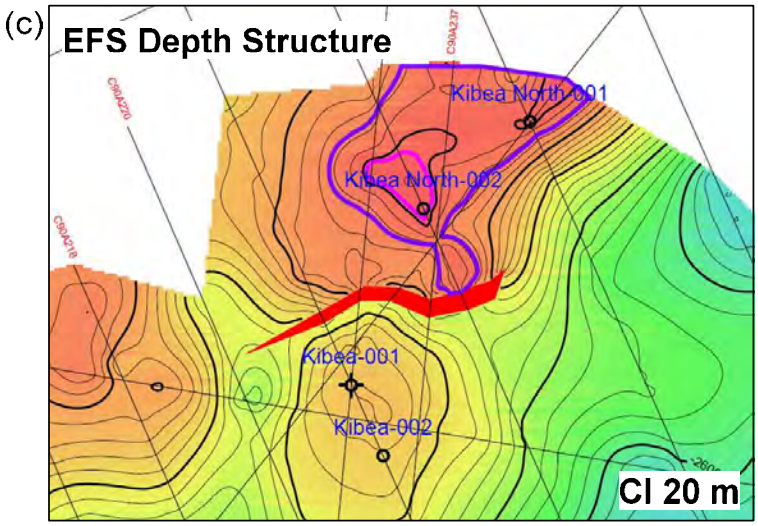


Map 101 a, b, c
Kibea North Prospect
Griffiths Depth Structure Map (metres)
C, D and E Sands

Company: Griffiths Energy International Inc.
Property: Chari East Doseo Block

Effective Date: December 31, 2012
s1132107

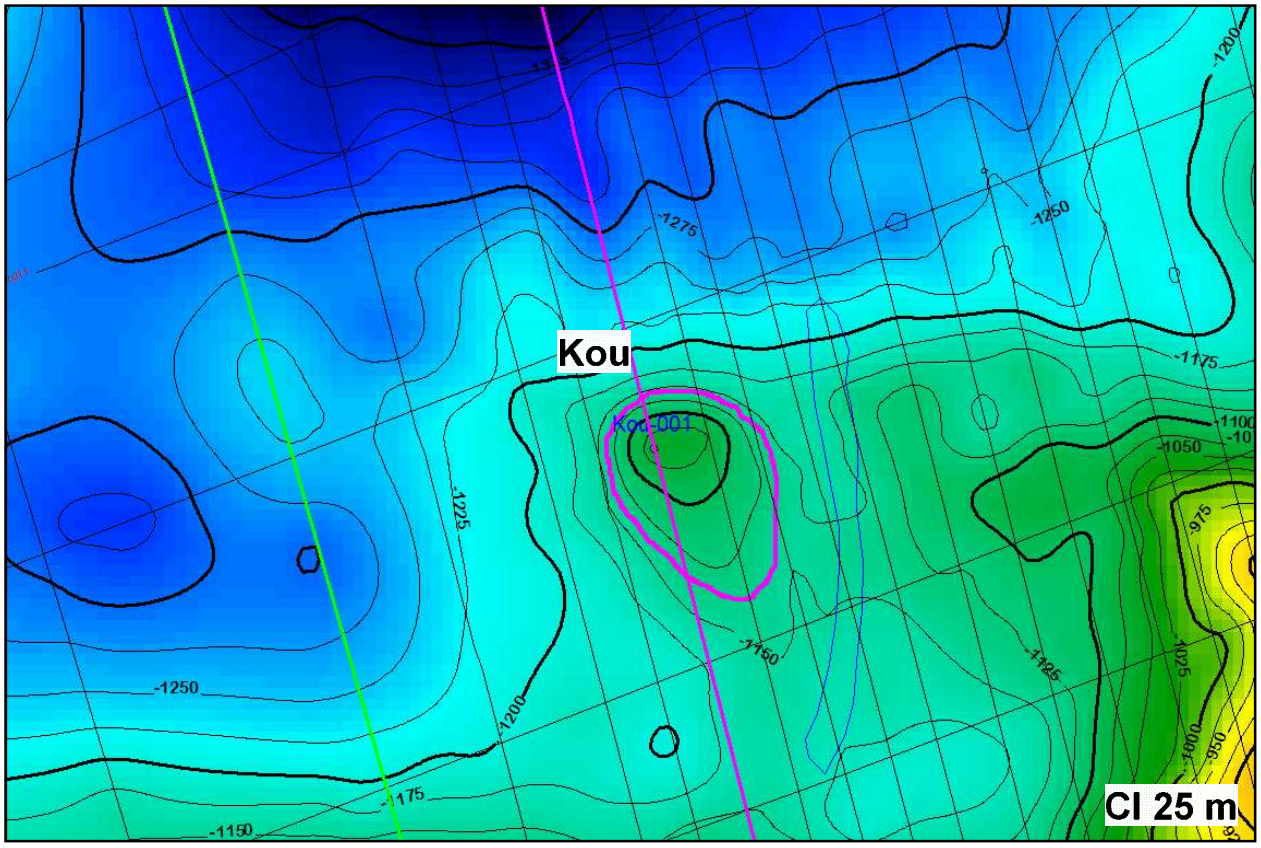




Map 102
Kou Prospect
Griffiths Depth Structure Map (metres)
Lower Cretaceous Sand

Company: Griffiths Energy International Inc.
Property: Borogop Block

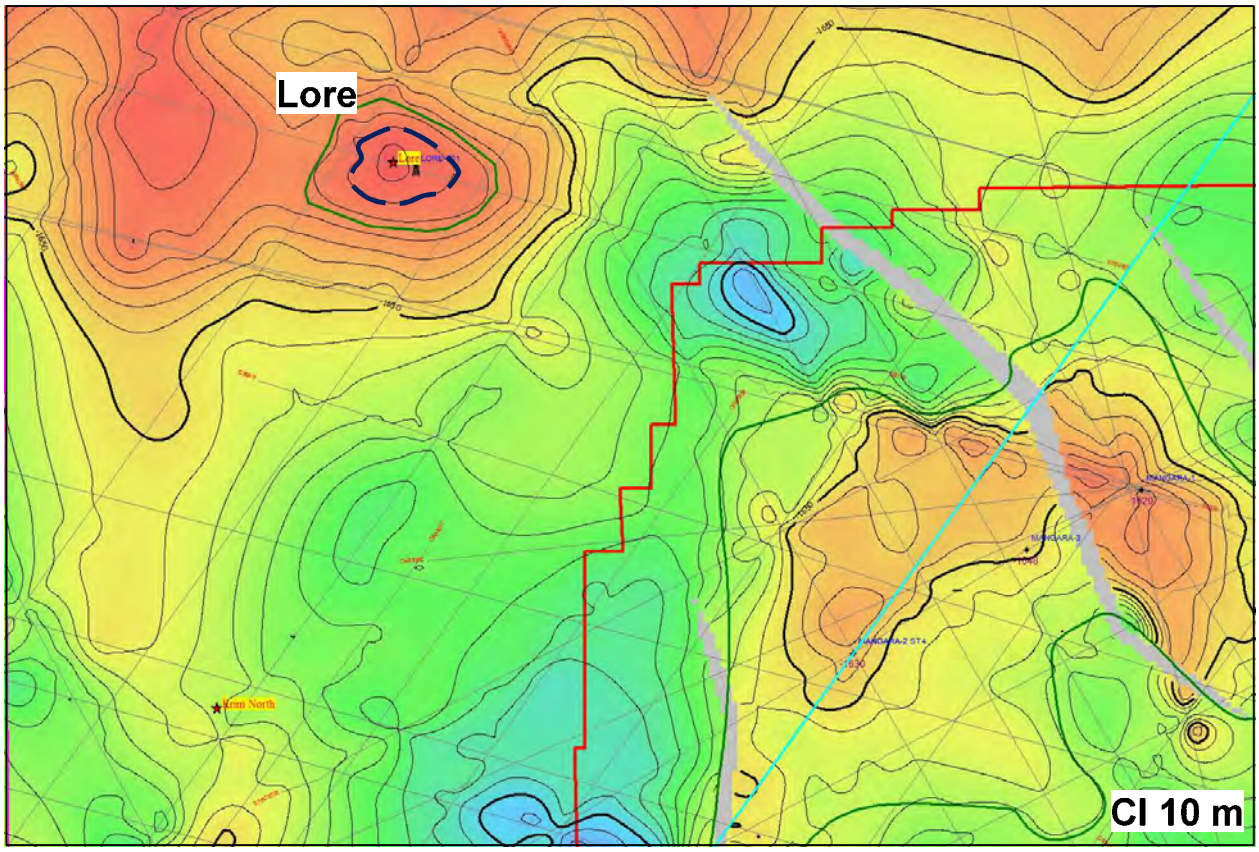
Effective Date: December 31, 2012
s1132107



Map 103
Lore Prospect
Griffiths Depth Structure Map (metres)
C2 Sand

Company: Griffiths Energy International Inc.
Property: DOB Block

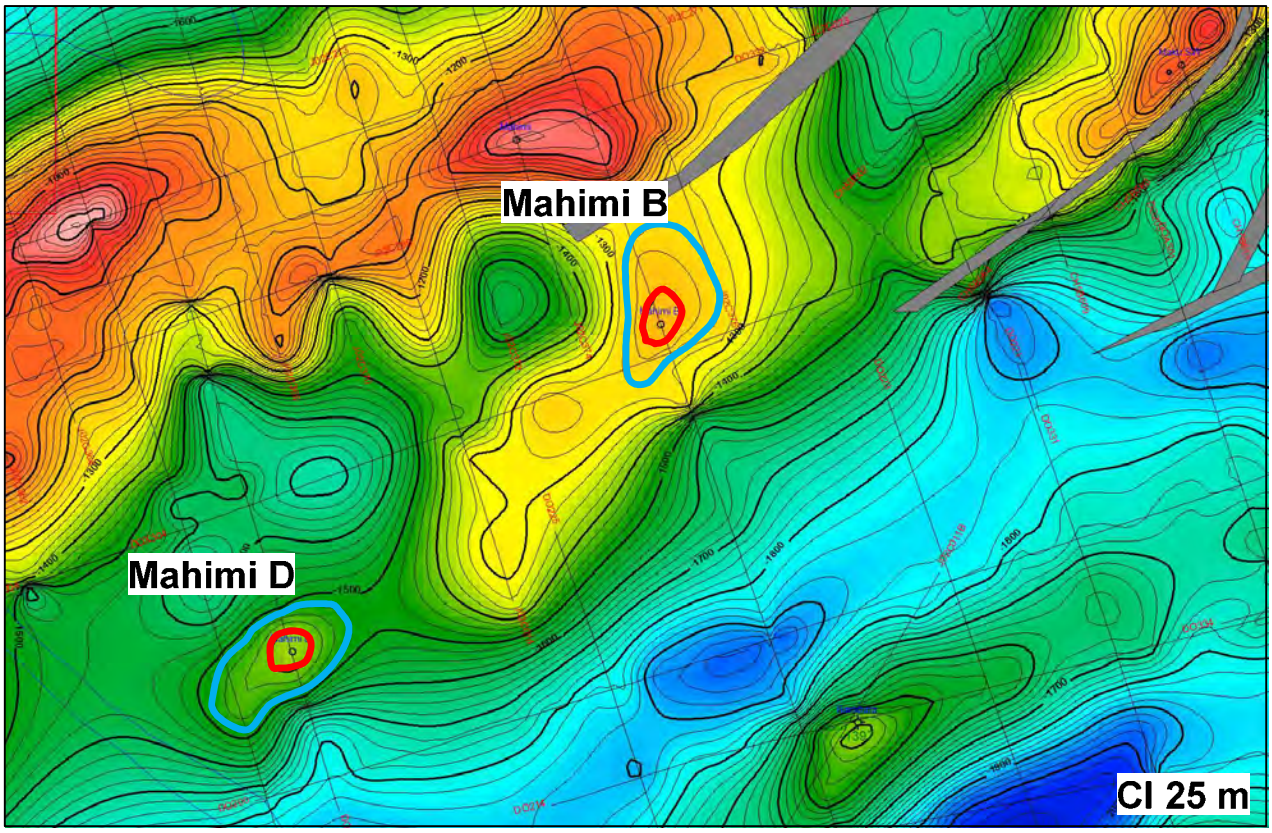
Effective Date: December 31, 2012
s1132107



Map 104
Mahimi B & Mahimi D Prospect
Griffiths Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: Chari East Doseo Block

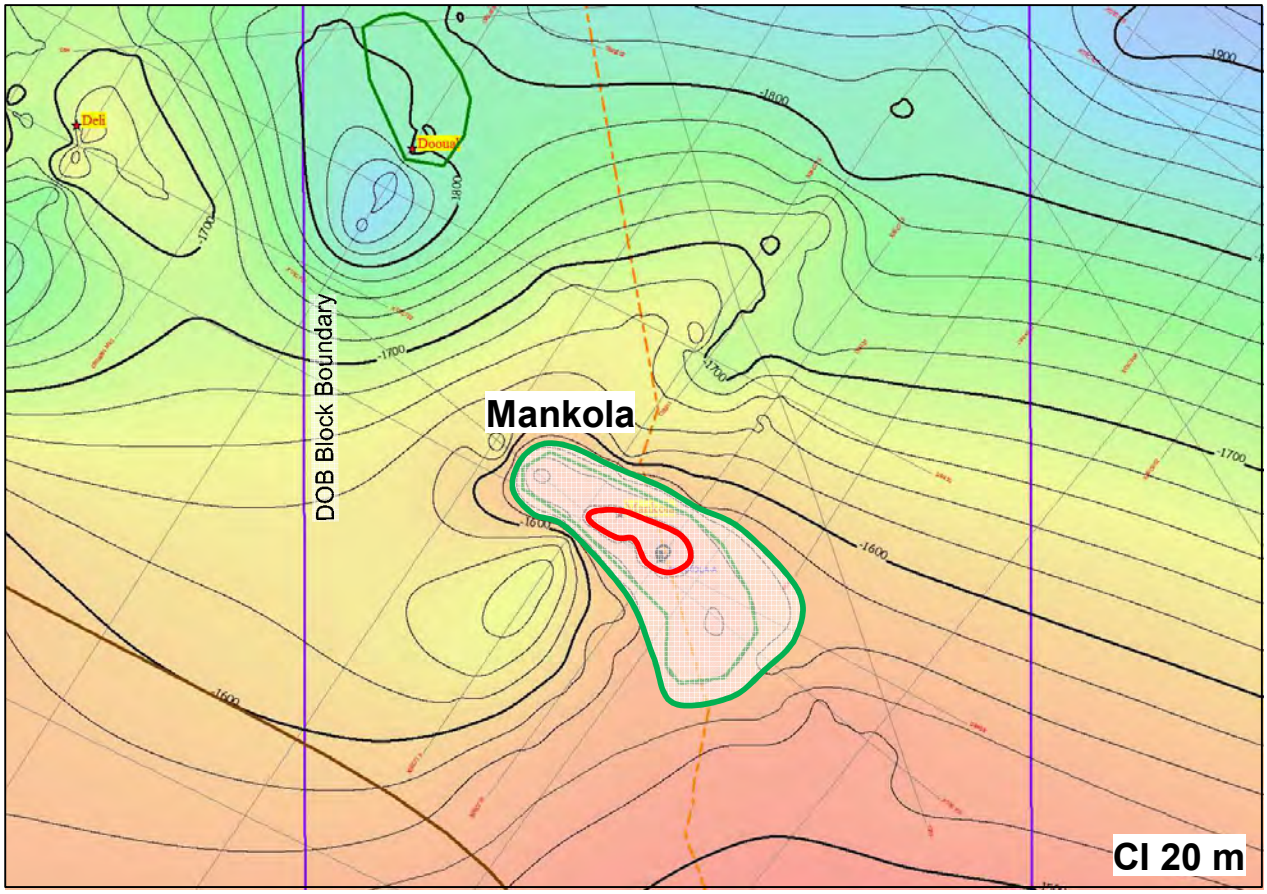
Effective Date: December 31, 2012
s1132107



Map 105
Mankola Prospect
Griffiths Depth Structure Map (metres)
C2 Sand

Company: Griffiths Energy International Inc.
Property: DOB Block

Effective Date: December 31, 2012
s1132107

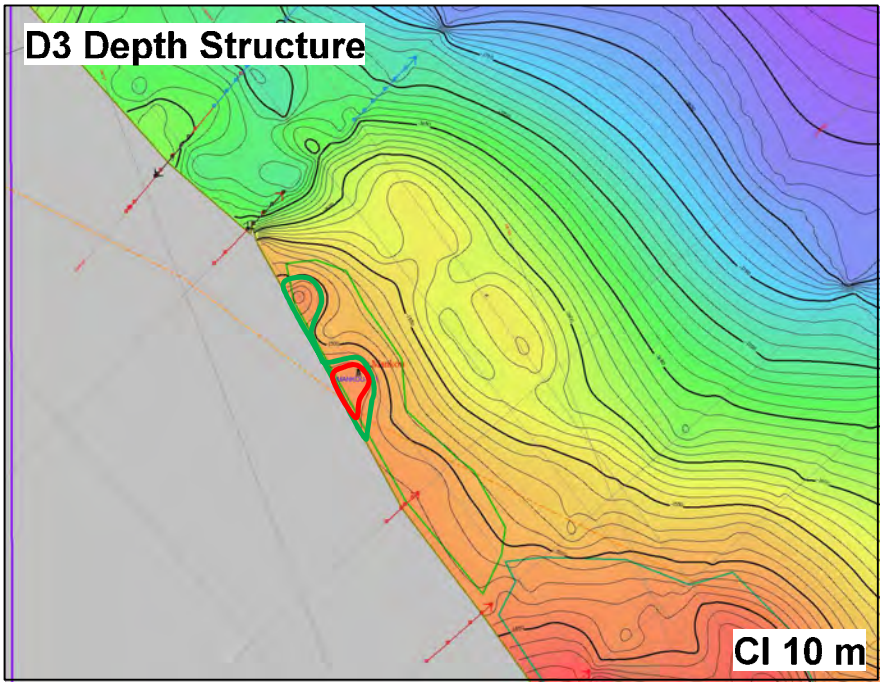


Map 106 a, b
Mankou Prospect
Griffiths Depth Structure Map (metres)
D3 and E Sands

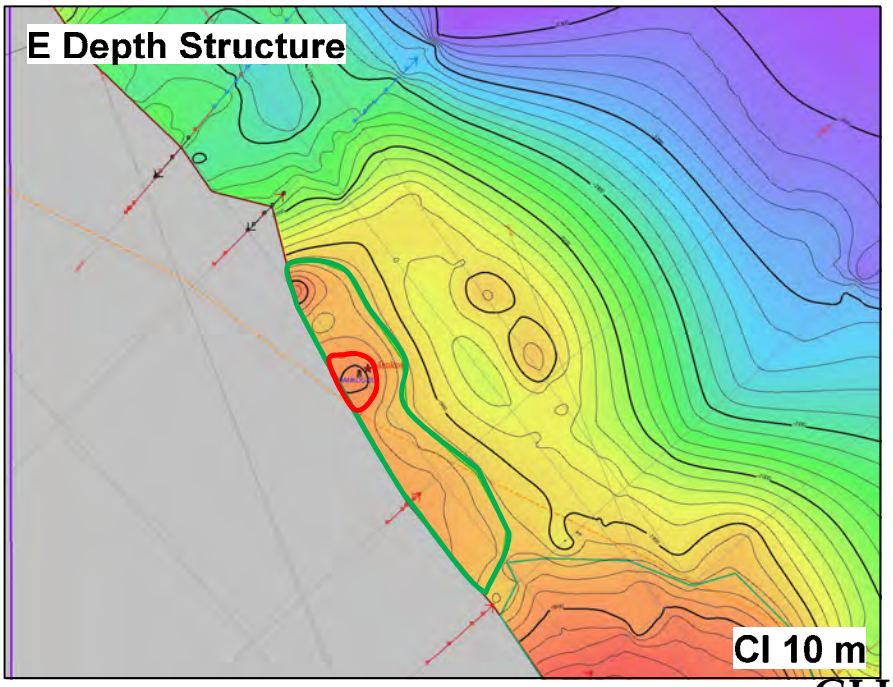
Company: Griffiths Energy International Inc.
Property: DOI Block

Effective Date: December 31, 2012
s1132107

(a)



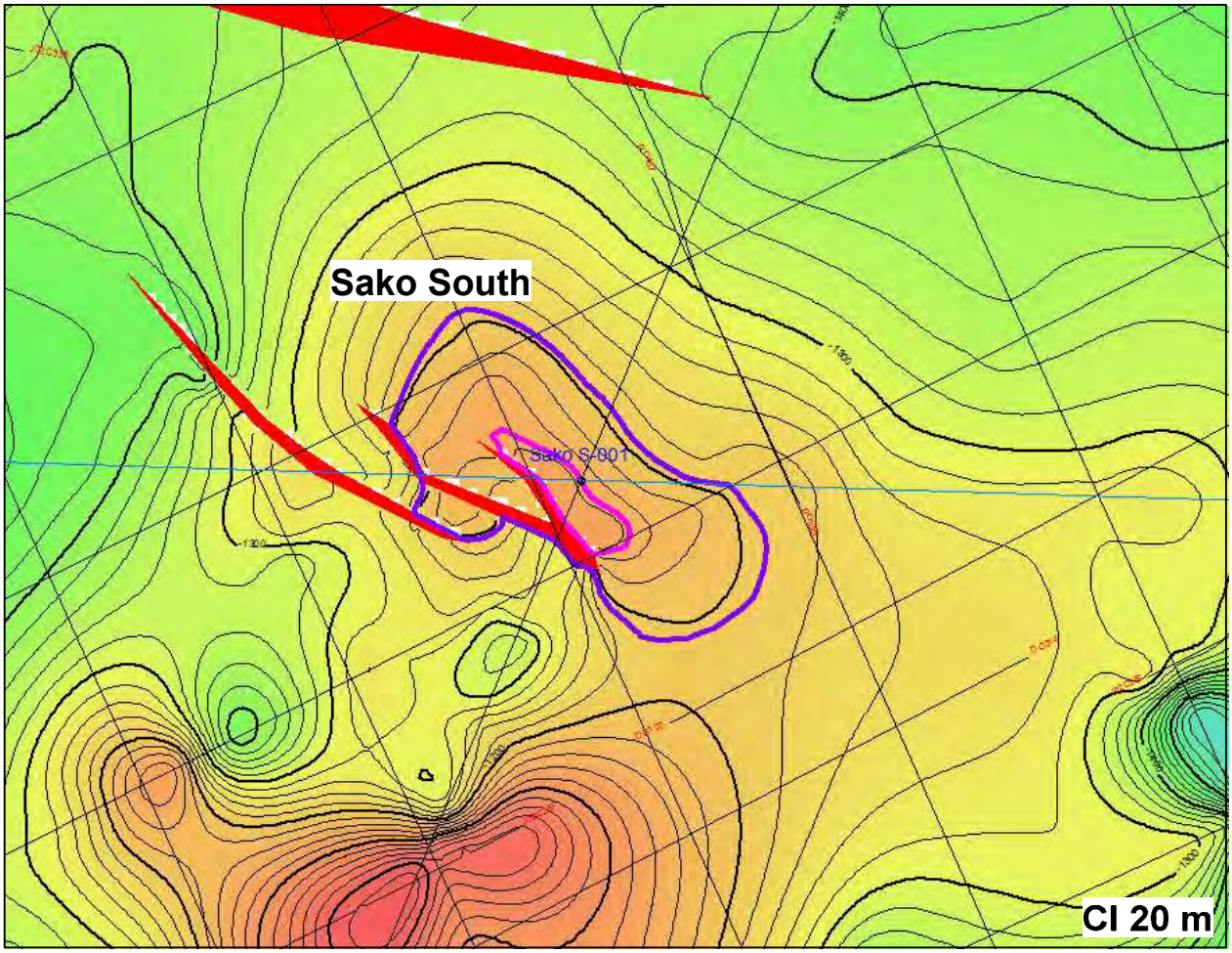
(b)



Map 107
Sako South Prospect
Griffiths Depth Structure Map (metres)
C Sand

Company: Griffiths Energy International Inc.
Property: Chari East Doseo Block

Effective Date: December 31, 2012
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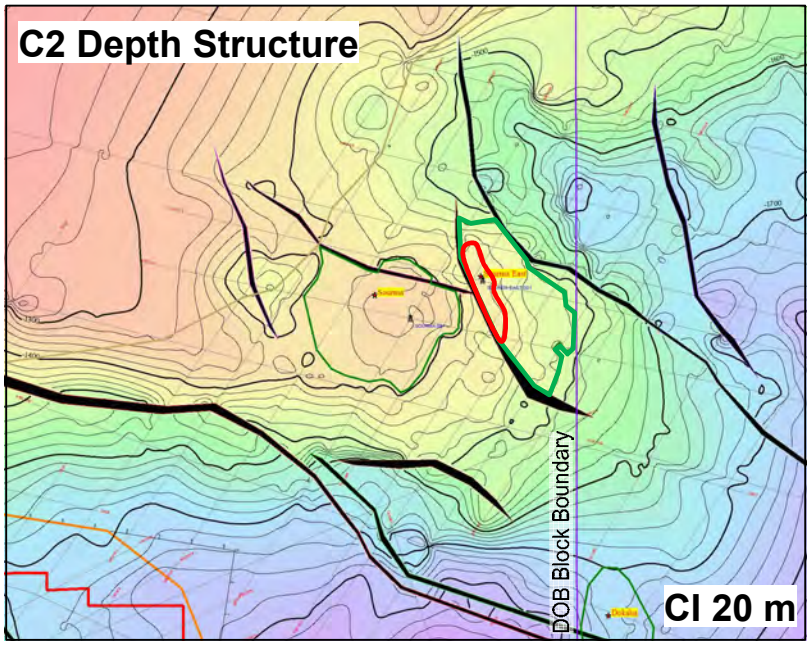


Map 108 a, b
Sourma East Prospect
Griffiths Depth Structure Map (metres)
C2 and E Sands

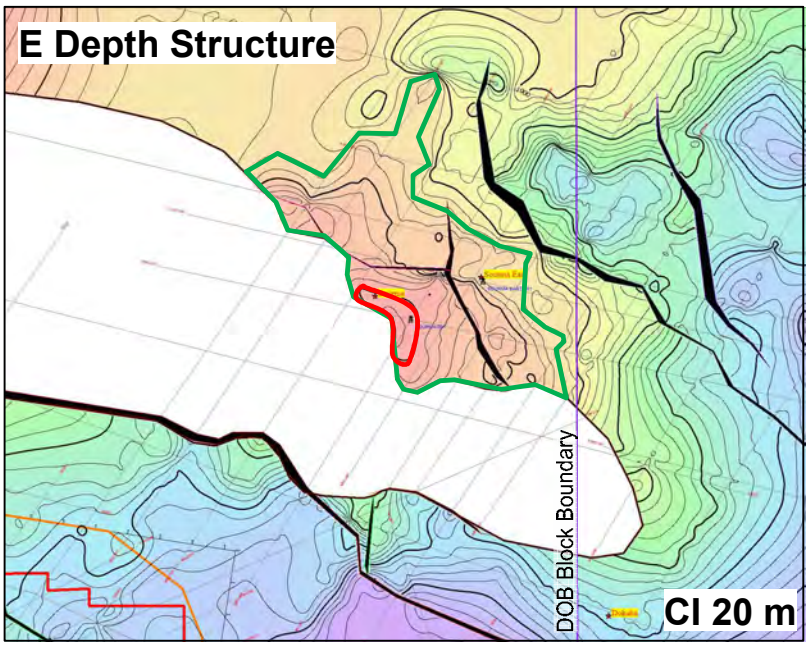
Company: Griffiths Energy International Inc.
Property: DOB Block

Effective Date: December 31, 2012
s1132107

(a)



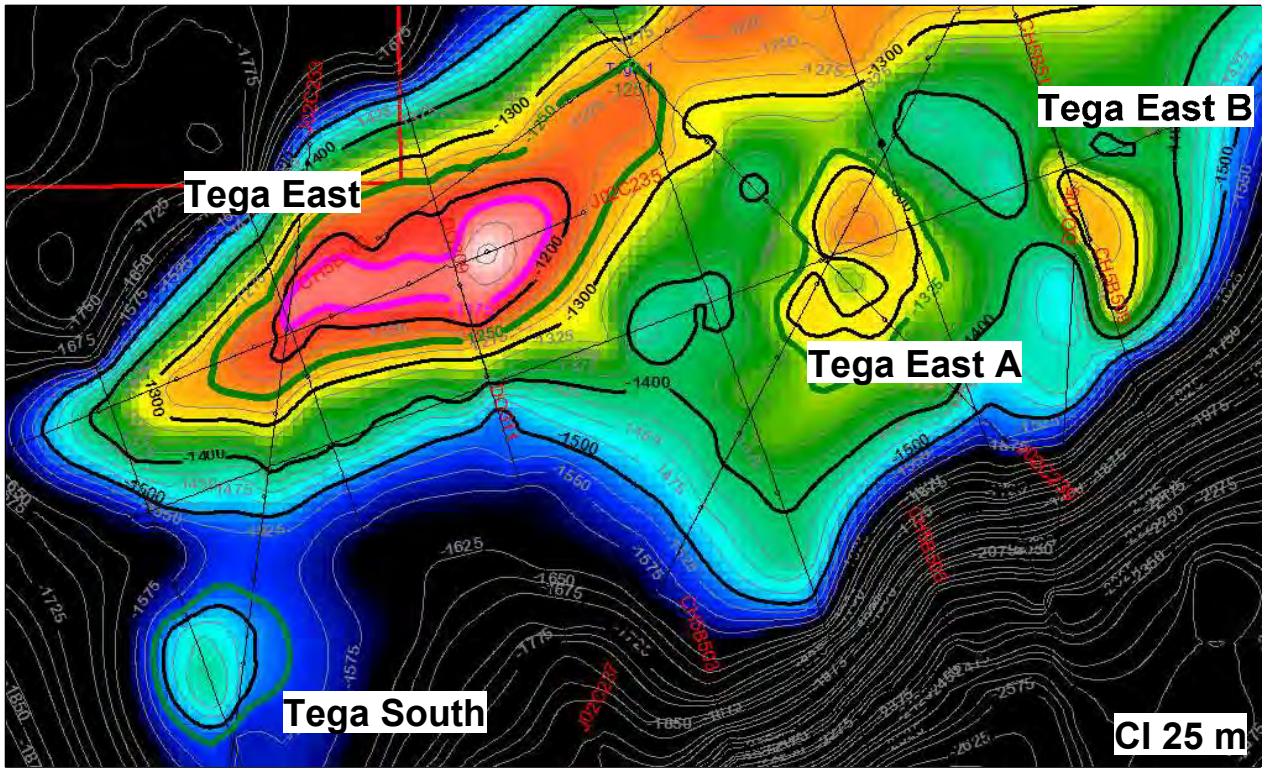
(b)



Map 109
Tega East A, Tega East B and Tega South Prospect
Griffiths Depth Structure Map (metres)
C, D and E Sands

Company: Griffiths Energy International Inc.
Property: Chari East Doseo Block

Effective Date: December 31, 2012
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13ZBN76901