FRONTERA
RESOURCES

FRONTERA RESOURCES

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The Directors of the Company, whose names appear on page 7, accept responsibility, including individual and collective responsibility, for the information contained in this document and compliance with the AIM Rules. To the best of the knowledge and belief of the Directors, who have taken all reasonable care to ensure that such is the case, the information contained in this document is in accordance with the facts and there is no omission likely to affect the import of such information.

This document is an Admission Document which has been drawn up in accordance with the AIM Rules. This document has been issued in connection with the application for admission to trading of the Common Shares on AIM (the "Admission"). Whilst it contains information equivalent to that required under the Public Offers of Securities Regulations 1995 as amended ("the POS Regulations"), it does not comprise a prospectus for the purposes of the POS Regulations and a copy of it has not been, and will not be, delivered to the Registrar of Companies in England and Wales for registration under regulation 4(2) of the POS Regulations.

Application has been made for all of the Common Shares of the Company in issue and to be issued, pursuant to the placing of Common Shares on behalf of the Company (the "Placing"), to be admitted to trading on the AIM Market operated by London Stock Exchange plc ("AIM"). ***AIM is a market designed primarily for emerging or smaller companies to which a higher investment risk tends to be attached than to larger or more established companies. AIM securities are not admitted to the Official List of the United Kingdom Listing Authority. A prospective investor should be aware of the risks of investing in such companies and should make the decision to invest only after careful consideration and, if appropriate, consultation with an independent financial adviser. Neither London Stock Exchange plc nor the United Kingdom Listing Authority has examined or approved the contents of this document.***

The whole of this document should be read. An investment in the Company involves a significant degree of risk, may result in the loss of the entire investment and may not be suitable for all recipients of this document. Investors should consider carefully the risk factors which are set out in Part III of this document.

Frontera Resources Corporation

Incorporated under the General Corporation Law of the State of Delaware, United States of America

PLACING

of 28,000,000 Common Shares of $0.00004 each at a price of 150 pence per share and

ADMISSION TO TRADING ON AIM

Nominated Adviser
Morgan Stanley & Co. International Limited

Share capital immediately following the Placing

Authorised			Issued and fully paid	
Number	*Amount*		*Number*	*Amount*
200,000,000	*$8000*	*Common Shares of $0.00004 each*	*55,144,368*	*$2,205.77*
10,000,000	*$100*	*Preferred Shares of $0.00001 each*	—	—

All the Common Shares will, on Admission, rank pari passu *in all respects and will rank in full for all the dividends and other distributions declared, paid or made in respect of Common Shares after Admission.*

This document does not constitute an offer to sell or the solicitation of an offer to buy shares in any jurisdiction in which such offer is unlawful. In particular, this document is not for distribution in or into the United States, Canada, Australia, Japan or Georgia or to any national, resident or citizen of the United States, Canada, Australia, Japan or Georgia. In addition, the Placing Shares have not been, and will not be, registered under the US Securities Act or under any state securities laws and may not be offered or sold in the United States or to, or for the account or benefit of, US persons (as defined in Regulation S promulgated under the US Securities Act). The Placing Shares are being offered only to non-US persons outside the United States in transactions exempt from the registration requirements of the US Securities Act in reliance on Regulation S. Purchasers of the Placing Shares may not offer to sell, pledge or otherwise transfer the Placing Shares in the United States or to, or for the benefit of, US persons (other than distributors) unless such offer, sale, pledge or transfer is registered under the US Securities Act or an exemption from registration is available. Further information regarding the significant restrictions on resale and/or transfer that are applicable to the Common Shares is set out in Part VII of this document. Hedging transactions involving the Common Shares may not be conducted, directly or indirectly, unless in compliance with the US Securities Act. The Company does not currently plan to register the Placing Shares under the US Securities Act or the Common Shares under the Securities Exchange Act of 1934, as amended.

The Common Shares have not been and will not be registered under the securities legislation of any province or territory of Canada, Australia, Japan or Georgia. Accordingly, the Common Shares may not, subject to certain exceptions, be offered or sold, directly or indirectly, in or into Canada, Australia, Japan or Georgia or to any national, citizen or resident of Canada, Australia, Japan or Georgia.

Morgan Stanley

Morgan Stanley & Co. International Limited ("MSIL") and Morgan Stanley Securities Limited ("MSSL") are acting for the Company, and no one else, in connection with the Admission and the Placing, and will not be responsible to any other person other than the Company for providing the protections afforded to their respective clients or for providing any advice in relation to the Admission or the Placing. MSIL's responsibilities as the Company's nominated adviser under the AIM Rules are owed solely to London Stock Exchange plc and are not owed to the Company or to any Director or to any other person in respect of his decision to acquire Common Shares in reliance on any part of this document. No representation or warranty, express or implied, is made by MSIL or MSSL as to any of the contents of this document for which the Company and the Directors are solely responsible. Neither MSIL nor MSSL has authorised the contents of, or any part of, this document and, without limiting the statutory rights of any person to whom this document is issued, no liability whatsoever is accepted by MSIL or MSSL for the accuracy of any information or opinions contained in this document or for any omissions of any material information, for which the Company and the Directors are solely responsible. In particular, the information contained in this document has been prepared solely for the purposes of the Placing and the Admission and is not intended to inform or be relied upon by any subsequent purchasers of Common Shares (whether on or off exchange) and accordingly no duty of care is accepted in relation to them.

The Placing is only being made to persons in the United Kingdom whose ordinary activities involve them in acquiring, holding, managing or disposing of investments (as principal or agent) for the purposes of their businesses or otherwise in circumstances which have not resulted and will not result in an offer to the public in the United Kingdom within the meaning of the POS Regulations or FSMA, and the Company and MSIL have only communicated or caused to be communicated and will only communicate or cause to be communicated any invitation or inducement to engage in investment activity (within the meaning of section 21 of FSMA) in connection with the issue or sale of the Common Shares in circumstances in which section 21(1) of FSMA does not apply.

The distribution of this document and the offer of the Common Shares in certain jurisdictions may be restricted by law. No action has been or will be taken by the Group, MSIL or MSSL to permit a public offering of the Common Shares. Other than in the United Kingdom, no action has been or will be taken to permit the possession or distribution of this document (or any other offering or publicity materials or application form(s) relating to the Common Shares) in any jurisdiction where action for that purpose may be required, or doing so is restricted or prohibited by law. Accordingly, neither this document nor any advertisement or any other offering material may be distributed or published in any jurisdiction except in circumstances that will result in compliance with any applicable laws and regulations. Persons into whose possession this document 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.

In connection with the Placing, MSIL as stabilising manager, or any person acting for it, may (but will be under no obligation to) over-allot or effect transactions with a view to supporting the market price of the Common Shares or any options, warrants or rights with respect to, or interests in, the Common Shares, in each case at a level higher than that which might otherwise prevail in the open market for a limited period after the Placing Price is announced. Such transactions, if commenced, may be discontinued at any time and must be brought to an end after a limited period. Save as required by law or regulation, MSIL does not intend to disclose the extent of any over-allotments and/or stabilisation transactions under the Placing.

In connection with the Placing, MSIL, as stabilising manager, or its agent has entered into the Over-allotment Arrangements with the Company, pursuant to which MSIL, or any person acting for it, may subscribe, or procure subscribers for, up to 5,000,000 Over-allotment Shares at the Placing Price, for the purposes of allowing MSIL, or its agent, to meet over-allocations in connection with the Placing and to cover short positions resulting from stabilisation transactions. Any decision to subscribe, or procure subscribers for, any Over-allotment Shares is expected to be taken by no later than 13 April 2005. The Over-allotment Shares made available pursuant to the Over-allotment Arrangements will rank pari passu with all other Common Shares, including for all dividends and other distributions declared, made or paid on the Common Shares after Admission and will form a single class for all purposes with the Common Shares. See paragraph 18 of Part II of this document for further details of these arrangements.

No person has been authorised to give any information or make any representations other than those contained in this document and, if given or made, such information or representations must not be relied on as having been authorised by the Group, MSIL or MSSL. Neither the delivery of this document nor any subscription or acquisition made under it shall, in any circumstances, create any implication that there has been no change in the affairs of the Group since the date of this document or that the information in it is correct as of any subsequent date.

A copy of this document is available to the public, free of charge, at the offices of CMS Cameron McKenna, Mitre House, 160 Aldersgate Street, London EC1A 4DD for one month from the date of Admission.

This document contains forward-looking statements. Words such as "anticipate", "believe", "plan", "expect", "intend", "estimate", "project", "will", "should", "could", "may", "predict" and similar expressions are typically used to identify forward-looking statements. You are cautioned that actual results could differ materially from those anticipated in forward-looking statements. Any forward-looking statements, including statements regarding the intent, belief or current expectations, are not guarantees of future performance and involve risks, uncertainties and assumptions. All forward-looking statements in this document are based on information available on the date of this document. The Company does not intend to update or revise any forward-looking statements made in this document, whether as a result of new information, future events or otherwise.

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CONTENTS

PLACING STATISTICS

Placing Price	150 pence per share
Number of Placing Shares	28,000,000
Number of Common Shares subject to the Over-allotment Arrangements	5,000,000
Number of Common Shares outstanding following the Placing	49,404,513[(1)]
Percentage of the Enlarged Issued Common Share Capital subject to the Placing	56.7 per cent[(1)]
Estimated cash proceeds of the Placing (gross)	£42,000,000
Estimated cash proceeds of the Placing receivable by the Company	£37,300,000
Market capitalisation of the Company at the Placing Price	£74,106,770[(2)]

EXPECTED TIMETABLE OF PRINCIPAL EVENTS[(3)]

Conditional dealings to commence	8.00 a.m. on 10 March 2005
Latest time for payment of the Placing Price in full	14 March 2005
Admission effective and dealings in Common Shares commence on AIM	8.00 a.m. on 14 March 2005
Share certificates despatched to Placees	15 March 2005

Notes:

(1) Assuming that no outstanding options, warrants or convertible loan notes over or in respect of Common Shares are exercised or converted (as applicable) after the date of this document and on or before the Placing. The total number of Common Shares in issue following the Placing would be 75,248,797 if all outstanding warrants, options and convertible loan notes are exercised or converted (as applicable). Further details of the outstanding warrants, options and convertible loan notes are set out in paragraphs 3.4, 3.5 and 3.6 of Part VIII.

(2) Market capitalisation has been calculated based on the number of Common Shares outstanding following the Placing at the Placing Price.

(3) All times are London times and each of the times and dates in the table are subject to change.

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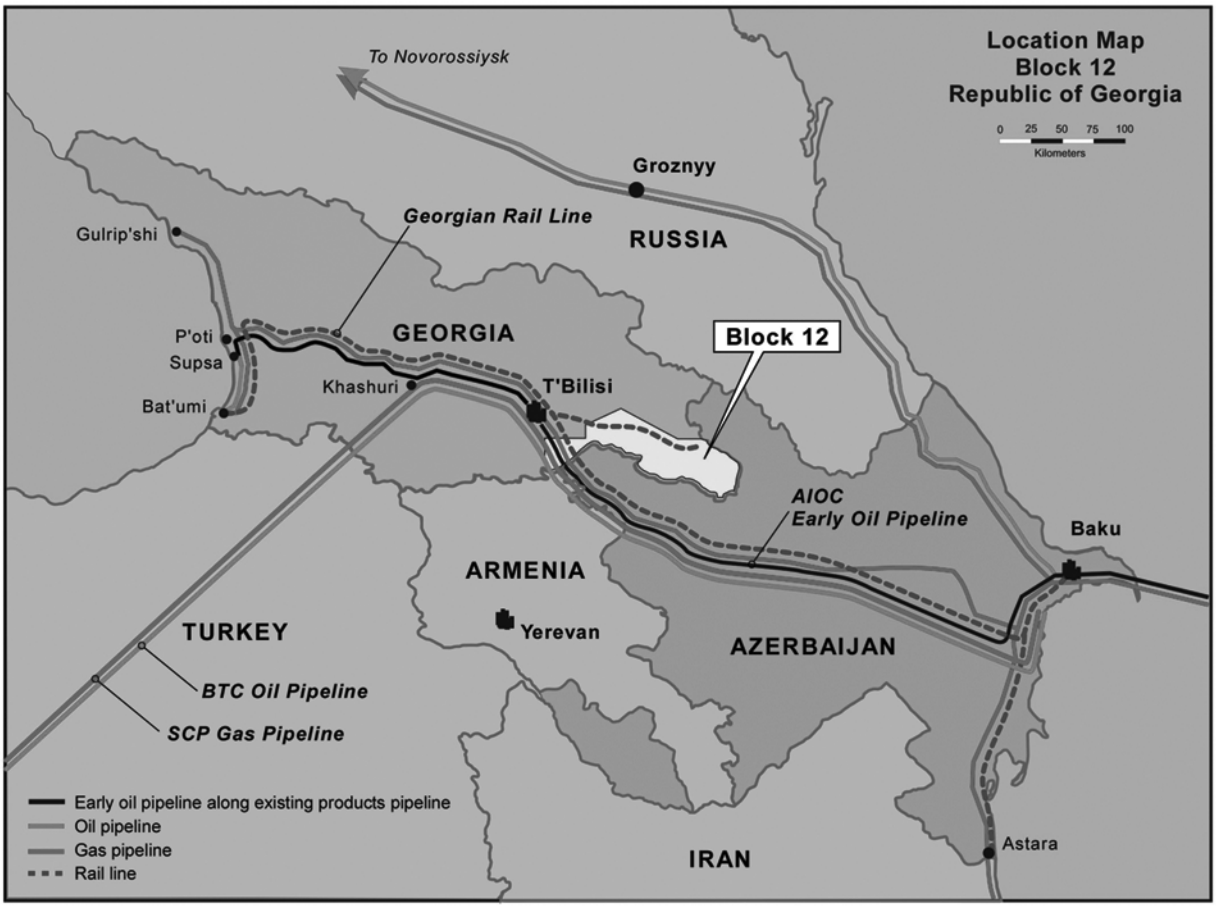


Figure 1: Map of region showing Block 12 and regional transportation infrastructure.

PART I

KEY INFORMATION

The following information is derived from, and should be read in conjunction with, the full text of this document. Prospective investors should read the whole of this document, including the risk factors set out in Part III, and not rely solely on this summarised information.

- Frontera is an independent oil and gas exploration, development and production company which has operated in Georgia since June 1997. The Frontera Group holds a 100 per cent working interest in a production sharing agreement with the government of Georgia that gives the Frontera Group the exclusive right to explore for, develop and produce oil in a 5,060 km^2 area in eastern Georgia known as Block 12.
- Netherland, Sewell & Associates Inc., a leading independent petroleum resources engineering firm, has undertaken a technical evaluation of certain producing properties and exploration prospects associated with Frontera's primary objectives for operations in Block 12. Specifically, Netherland & Sewell reviewed four of twelve oil-bearing horizons in the Taribani Field, two prospects located in the Cretaceous Carbonate Play and various other selected prospects within Block 12. This evaluation concluded that:
  - the four horizons in the Taribani Field contain 118 million barrels of gross (8/8ths) possible (P3) reserves; and
  - the remaining areas of Block 12 covered by the study contain a mean estimated ultimate recovery (EUR) of 657 million barrels and an EUR of as much as 1.417 billion barrels of gross (8/8ths) unrisked prospective oil resources.

  Frontera's management believes that there are additional potential reserves in fields and prospects located in Block 12 outside the scope of the Netherland & Sewell Report, including the other oil-bearing horizons in the Taribani Field. Prospective investors should read the whole of the Netherland & Sewell Report contained in Part IV of this document.
- Frontera's production sharing agreement with the Georgian government provides for full cost recovery from the proceeds of oil produced and allocates Profit Oil in the proportion of 51 per cent to the Georgian state oil company, Saknavtobi, and 49 per cent to Frontera, with almost all taxes being paid out of Saknavtobi's share of oil production. A summary of this agreement is set out in Part VI of this document.
- Frontera has invested approximately $70 million to date on specific scientific studies, drilling and workover operations in Block 12 to develop opportunities for new drilling and commercial production. This investment, which has built on the historical knowledge developed by Saknavtobi and is fully recoverable in accordance with the Block 12 PSA, has resulted in the identification and prioritisation of an extensive inventory of existing fields and prospects.
- The Company's primary objectives for the next three years are to:
  - utilise conventional horizontal drilling techniques to establish commercial production from the Taribani Field;
  - acquire new seismic data and undertake an exploratory drilling programme in identified prospects associated with the previously unexplored Cretaceous Carbonate Play;
  - undertake new drilling in the Mirzaani Field Area; and
  - acquire new seismic data in and around the Company's inventory of known oil fields, prospects and leads in order to further define future drilling locations.
- Frontera's investment and production programme in Block 12 over the past seven years has enabled it to establish the infrastructure to process, store, transport and market the oil produced from Block 12 to date. This infrastructure has the capacity to handle the increased volumes of oil production expected in the near term from operations in Block 12.
- Frontera's management team and Directors have extensive experience in the international oil and gas industry and related oil service industries, having previously held executive, managerial and professional positions with companies including Conoco, Elf, Exxon, Maxus, Mobil, Phillips and Union Texas Petroleum. Frontera's management team also has significant experience in finance and geopolitics, including, in particular, the Georgian political, commercial, operating and regulatory environment.
- Based on a Placing Price of 150 pence per Common Share, the Company will raise approximately £37,300,000 net of expenses from the Placing, which has been fully underwritten by Morgan Stanley & Co. International Limited on the terms of, and subject to the conditions in, the Placing Agreement. The proceeds will be used to fund the Group's capital expenditure programme over the next three years as well as to repay $18.8 million of existing debt and to provide working capital.

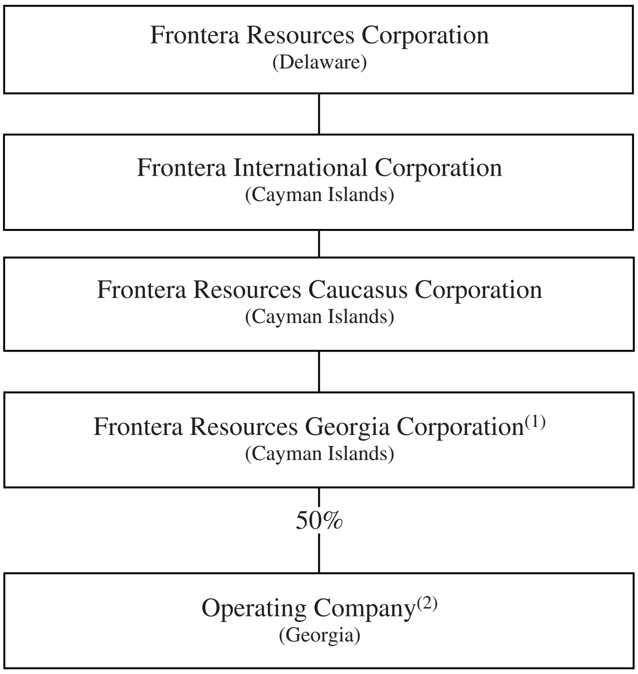
PART II

INFORMATION ON THE COMPANY AND DETAILS OF THE PLACING

1. Overview

Frontera is an independent oil and gas exploration, development and production company, which has operated in Georgia since 1997. It is incorporated with limited liability under the laws of the State of Delaware, U.S.A., with its headquarters in Houston, Texas, U.S.A.

The Company is a holding company and carries out its activities through its subsidiaries. The Group's interest in Block 12 is held through its wholly owned subsidiary Frontera Resources Georgia Corporation ("Frontera Georgia"). Operations in Block 12 are conducted through an operating company, Frontera Eastern Georgia Limited (the "Operating Company"), which is jointly owned by Frontera Georgia and the Georgian state oil company, Saknavtobi. The structure of the Group as it relates to operations in Georgia is set out in the table below.



Notes:

(1) Frontera Georgia is the contracting party to the Block 12 PSA.

(2) Saknavtobi owns the remaining 50 per cent of the shares in the Operating Company, a pass-through entity that exists for operational and execution purposes only and operates on a no profit/no loss basis. Details of the profit sharing arrangements in respect of Block 12 are set out in paragraph 1.6 of Part VI.

The Group holds a 100 per cent working interest in a production sharing agreement entered into with the government of Georgia and Saknavtobi in June 1997 that gives the Group the exclusive right to explore for, develop and produce oil in a 5,060 km^2 area in eastern Georgia known as Block 12 (the "Block 12 PSA"). Further information on the Block 12 PSA is set out in paragraph 7 of this Part II and in Part VI.

2. Netherland & Sewell Report

On behalf of the Company, Netherland, Sewell & Associates Inc. ("Netherland & Sewell"), a leading independent petroleum resources engineering firm, has undertaken a review of the potential hydrocarbon resources associated with Frontera's primary objectives for operations in Block 12. Specifically, Netherland & Sewell reviewed four of the twelve known oil-bearing horizons in the Taribani Field, two prospects located in the Cretaceous Carbonate Play, being the Basin Edge B Prospect and the Basin Edge C Prospect, and various other selected prospects within Block 12.

In conducting its evaluations, Netherland & Sewell reviewed the drilling history, test and production data, regional geology, well logs, seismic data, reports and interpretive data supplied by the Company. Netherland & Sewell also conducted an independent analysis of key well logs and seismic data to define field and prospective areas and to assess the variability in reservoir parameters. A summary of the reserve findings of Netherland & Sewell is set out below[1]:

Taribani Field — Gross Possible (8/8ths) Reserves (P3)
(Millions of barrels)

Zones	Original Oil in Place	Estimated Ultimate Recovery
9, 14, 15 and 19	788	118

Other Exploration Prospects — Unrisked Gross (8/8ths)
Prospective Resources
(Millions of barrels)

	Original Oil in Place			Estimated Ultimate Recovery		
Prospect	**Most likely/mode[2]**	**Mean**	**High side**	**Most likely/mode[2]**	**Mean**	**High side**
Basin Edge B Prospect						
• Cretaceous	632	856	1,810	120	171	376
• Tertiary	799	1,115	2,488	115	168	375
Basin Edge C Prospect						
• Cretaceous	534	703	1,483	100	140	307
• Tertiary	515	675	1,432	74	102	220
Other	448	512	873	66	76	138
Total[3]	2,929	3,861	8,086	475	657	1,417

Notes:

(1) The figures contained in these tables have been extracted from the Netherland & Sewell Report, included in Part IV. Prospective investors should read the whole of that report and should not rely solely on the information summarised in this table. Investors should note that, in accordance with the terms of the Block 12 PSA, a proportion of the oil produced from Block 12 will accrue to Saknavtobi and not the Group and that the Netherland & Sewell Report also includes low side estimates for the prospective resources set out in the second table.

(2) This term is defined in the Netherland & Sewell Report on page 47 of this document.

(3) Totals may not add due to rounding.

Netherland & Sewell has indicated that, provided Frontera can demonstrate the successful application of conventional horizontal drilling and completion techniques, a significant portion of the P3 reserves in the Taribani Field could be recategorised as probable (P2) reserves and a small portion of the P3 reserves could be recategorised as proved (P1) reserves. Frontera's management also believes that there are significant additional potential reserves located in prospects and fields which are outside the scope of the Netherland & Sewell Report, including other oil-bearing horizons in the Taribani Field.

As part of its evaluation of the possible reserves and prospective resources within Block 12, Netherland & Sewell conducted an economic evaluation of a potential development at the Taribani Field, the Basin Edge B Prospect and the Basin Edge C Prospect. Details of the assumptions and parameters used by Netherland & Sewell in undertaking this economic evaluation are set out on pages 64 to 66 and 71 to 79 of this document. Netherland & Sewell indicated in its report that the following net present values may be generated from Frontera's working interest associated with the possible P3 reserves at Zones 9, 14, 15 and 19 of the Taribani Field and the prospective resources for the Cretaceous interval of the Basin Edge B Prospect and the Basin Edge C Prospect[1]:

Field/Prospect	**NPV@8% ($ million)**				**NPV@10% ($ million)**				**NPV@12% ($ million)**			
Crude Pricing (per barrel)	**$30**		**Brent Forward**		**$30**		**Brent Forward**		**$30**		**Brent Forward**	
Taribani Field	383		560		325		482		277		419	
	Mean	**High**	**Mean**	**High**	**Mean**	**High**	**Mean**	**High**	**Mean**	**High**	**Mean**	**High**
Basin Edge B Prospect (Cretaceous)	758	1,660	952	2,059	628	1,369	792	1,700	523	1,138	663	1,415
Basin Edge C Prospect (Cretaceous)	626	1,042	790	1,742	521	1,165	661	1,450	437	976	556	1,216
Total	1,767	3,085	2,302	4,361	1,474	2,859	1,935	3,632	1,237	2,391	1,638	3,050

Note:

(1) The figures contained in this table are unrisked and have been extracted from the Netherland & Sewell Report, included in Part IV, in particular from the tables on pages 76, 77, 78 and 79 of this document. Prospective investors should read the whole of that report and should not rely

solely on the information summarised in this table. Frontera and Netherland & Sewell have assumed $3.25 per barrel transportation costs and a $3.00 per barrel discount to Dated Brent into their long range economic models. Frontera believes that these assumptions are conservative and discounts are likely to be reduced over time as production increases and access to regional pipelines is obtained. Furthermore, Frontera and Netherland & Sewell assumed initial flow rates of 450 bpd from Zones 9, 14 and 15 and 550 bpd from Zone 19 for the Taribani Field. These flow rates are assumed to remain constant for two years, decline 40 per cent annually for years 3 and 4 and then 20 per cent annually thereafter. 132 wells are assumed to be drilled over 10 years to produce the 118 million barrels. For the Basin Edge B Prospect, Frontera and Netherland & Sewell assumed an initial flow rate of 1550 bpd. This flow rate is assumed to decline 12 per cent annually. 42 producing wells are assumed to be drilled over 7 years to produce the reserves in the mean case; 58 producing wells are assumed to be drilled over 9 years to produce the reserves in the high case. Similar assumptions were assumed in the mean and high cases for Basin Edge C prospect.

The value of the resources associated with the other prospects in Block 12 were not specifically estimated by Netherland & Sewell. However, Frontera believes that, due to the similar geological and technical characteristics of the potential resources associated with the other prospects in Block 12, the estimated NPV per barrel for those other prospects is likely to be similar to the values associated with the Taribani Field set out in the table above.

3. Strategy

Based on the Company's exploration work in Block 12 to date, Frontera's strategy is to:

- advance the work already undertaken by the Group in the Taribani Field, utilising conventional horizontal drilling techniques in both the existing wells and newly drilled wells in order to bring on commercial production;
- acquire new seismic data and undertake an exploratory drilling programme in two identified exploration prospects, the Basin Edge B Prospect and the Basin Edge C Prospect, associated with the previously unexplored Cretaceous Carbonate Play;
- undertake new exploratory drilling in the Mirzaani Field Area; and
- acquire new seismic data in and around the Company's inventory of known oil fields, prospects and leads in order to further define future drilling locations.

Following the Placing, Frontera plans to commence its capital expenditure programme in accordance with the planned work programme set out below:

	2005-2006		2007	
Field/Prospect	**Work plan**	**Estimated cost**	**Work plan**	**Estimated cost**
Taribani Field				
Horizons 9, 14, 15 and 19	Re-entry of 7 existing wells	$19 million	1 new well	$6.5 million
	1 new well	$6.5 million		
Basin Edge B Prospect and Basin Edge C Prospect	500 km 2D seismic acquisition	$3 million	1 new well	$4 million
	1 new well	$4 million		
Mirzaani Field Area	1 new well	$3.5 million	1 new well	$3.5 million
Prospect Inventory Development	2D seismic acquisition	$3 million		
Total	—	$39 million	—	$14 million

Further details of the Company's planned programme to identify the resource potential in Block 12 are set out in paragraphs 6.3.1, 6.3.2, 6.4.1 and 6.4.2 of this Part II.

4. History of the Group

Frontera was formed in 1996 by a management team with extensive experience in the international oil and gas industry. The Company's strategy from inception has been to seek early opportunities in known hydrocarbon-bearing basins around the world where historic, political or economic conditions have caused significant oil and gas plays to be underdeveloped. The Company has focused its activities almost exclusively on the onshore Kura Basin situated between the Caspian Sea and the Black Sea in the nations of Azerbaijan and Georgia.

The Group's current activities are exclusively focused on the exploration and development of the large area associated with Block 12 in Georgia. The Group has invested approximately $70 million to date in its research and operations in Block 12, undertaking an extensive series of studies, geologic field work and operational work programmes designed to identify the reserve potential. The Company has attempted to establish commercial production from one of the existing fields in Block 12 and it has identified an extensive inventory of prospects for potential new field discoveries. This work has principally involved the acquisition, processing and interpretation of new 2D and 3D seismic data; reprocessing of historic seismic and well log data; undertaking new and extensive geological field work; carrying out new reservoir engineering studies in some of the existing fields which has entailed workovers of existing wells and the drilling of new wells; other integrated geologic and engineering studies designed to identify prospectivity for new field discoveries within Block 12; and upgrading existing production, transport and export facilities.

This work has resulted in the identification of two major geologic plays within Block 12 that the Company intends to pursue to commercial development: the Tertiary Clastics Reservoir Play (the ‘‘Tertiary Clastics Play’’) and the Cretaceous Carbonate Reservoir Play (the ‘‘Cretaceous Carbonate Play’’). Within each of these plays, Frontera has identified and high-graded an extensive inventory of existing oil fields and generated an inventory of high quality prospects for potential new field discoveries.

Frontera initially targeted the Taribani Field as the basis for attempting to establish the first commercial production from its inventory of opportunities in the Tertiary Clastics Play. The Company worked with a number of leading oil industry service providers and partners to advance its understanding of the Taribani Field. Between 1999 and 2000, assisted by Schlumberger, the Group acquired the first onshore 3D seismic survey over the Taribani Field, and subsequently drilled, tested and completed its first new well on Block 12, the Niko #1 at the Taribani Field. Niko #1 was the first new well drilled into the field using modern drilling practices, reaching a total depth of approximately 3,400 metres. Although the well is not currently producing, Niko #1 did provide important subsurface information enabling Frontera to calibrate field-wide well logs and the new 3D seismic survey that the Company had acquired over the field, and proved to the management team the effectiveness of utilising modern drilling techniques in Block 12.

In addition to its initial work at the Taribani Field, Frontera simultaneously began to identify and develop scientific concepts associated with the Cretaceous Carbonate Play which had not previously been explored but which the Company believes to contain significant hydrocarbon resource potential. Work to date has resulted in the identification and geologic mapping of two significant prospects within intervals of the Cretaceous section of the play as targets for potential new field discoveries. In 2003, CanArgo Energy Corporation, a company listed on the American and Oslo stock exchanges, operating on-trend to the west of Block 12, reported successfully testing an exploration well that had objectives in the intervals of the Cretaceous section. This provided an encouraging new confirmation of this play that extends eastward into Block 12, on-trend with the prospects identified in the Cretaceous Carbonate Play.

In July 2002, the Company entered into agreements with GAC Energy Corporation (‘‘GAC Energy’’), a private oil and gas company affiliated with a subsidiary of the Chinese National Petroleum Company (CNPC) and private investors from China. Frontera obtained important geological, geophysical and engineering information from studies and operations conducted as a result of GAC Energy’s joint work with Frontera in Block 12. This information added to the significant potential that the Company has identified in Block 12. Having invested approximately $8 million, GAC Energy’s interest in Block 12 terminated in September 2004 when it failed to meet its remaining financial and work commitments under the agreements.

Further details of the Company’s operations in Block 12 to date are set out in paragraphs 6.2, 6.3 and 6.4 of this Part II.

At the same time as commencing operations in Georgia, the Group explored opportunities in Azerbaijan, concluding a production sharing agreement with the government of Azerbaijan in 1998. The Company’s interest in Azerbaijan was held through its wholly owned subsidiary, Frontera Resources Azerbaijan Corporation (‘‘Frontera Azerbaijan’’), covering the underdeveloped onshore Kursangi and Karabagli oil fields (the ‘‘K&K Block’’). Frontera Azerbaijan, holding the largest foreign interest in the K&K Block, led successful exploitation programmes in association with Amerada Hess, who held a minority interest in the project, increasing production in the block from approximately 3000 bpd to approximately 6000 bpd in two years, after which time the Group terminated its activities in Azerbaijan. Further details concerning the Group’s activities in Azerbaijan are set out in paragraph 9 of Part VIII.

5. Georgia

Georgia is located on the international waters of the Black Sea bounded by Russia to the North, Turkey and Armenia to the South and Azerbaijan to the East.

Having been incorporated into the Soviet Union in 1921, Georgia declared its independence in April 1991. A new constitution was approved in August 1995, which reinforced a presidential-democratic form of government, providing for a strong executive branch and a unicameral 235-seat parliament. Its current President, Mikhail Saakashvili, was elected by popular vote in January 2004 and succeeded Eduard Shevardnadze who resigned from office in late 2003 under peaceful pressure from reformists. The current government comprises an alliance of the main political parties, which gained almost two-thirds of the vote in the parliamentary elections held in 2004. Since the election of President Saakashvili in 2004, significant progress has been made on law enforcement and economic reform, including collection of taxes, and a comprehensive privatisation policy is being implemented.

Georgia enjoys political and financial support from the United States and the European Union, has been a member of the World Trade Organisation since June 2000, and recently received positive assessment from the International Monetary Fund regarding its economic performance and fiscal position. The country has made substantial economic gains since 1995, achieving GDP growth and controlling inflation. GDP is expected to rise 12 per cent in 2005 and 2006 (*Source: Economist Intelligence Unit, Country Report, November 2004*).

Georgia is situated in a geologically favourable position at the western end of the oil rich geological province known as the Kura Basin. This basin extends eastward from Eastern Georgia into Azerbaijan and the Caspian Sea and is home to some of Azerbaijan's most prolific onshore and offshore oil fields. Fields in offshore Azerbaijan are now producing more than 300,000 bpd. During Soviet times, production of oil and gas in Georgia exceeded 70,000 bpd in 1981.

Georgia also holds a strategic position in the region for East-West transportation of oil and gas as it lies on the land bridge connecting Azerbaijan and the countries surrounding the Caspian Sea to the Black Sea and the Mediterranean Sea. Since the break up of the Soviet Union in 1991, western oil companies such as ExxonMobil, BP, Royal Dutch/Shell and others have successfully entered the Caspian Sea region committing billions of dollars of new exploration and production investments.

BP leads an international consortium that has invested in three major oil and gas pipelines passing through Georgia. BP has also made significant investment in an oil and gas terminal on the Black Sea port of Supsa and is pursuing deepwater exploration and production activities adjacent to the southern border of Georgia situated offshore of Turkey. CanArgo Energy is conducting oil and gas operations over an extensive portfolio of prospects in the onshore region of eastern Georgia located close to Block 12. Anadarko Petroleum and JKX Oil and Gas are also pursuing deepwater offshore oil and gas exploration projects in the Georgian waters of the Black Sea. Major international companies, including Baker Hughes, Schlumberger and Weatherford, as well as other regional companies, represent the oil service industry in Georgia.

All of the above factors have combined to create a more economically and politically stable region in which to invest. The development of an extensive transportation infrastructure has also helped the region to become increasingly attractive to foreign oil exploration and production companies by enhancing the economic viability of pursuing exploration and production projects in Georgia.

Details of the regulatory environment of the oil industry in Georgia are contained in paragraph 8 of this Part II below.

6. Block 12

6.1 Geology

Block 12 is situated in the Kura Basin, which is a Late Tertiary back-arc feature located between the predominantly carbonate rocks of the Greater Caucasus Mountains and the volcanic rocks of the Lesser Caucasus Mountains. The basin was created from Alpine and Himalayan compression which began in Early Eocene and peaked 22 million years later in Late Pliocene. The basin has been shaped by the collision, accretion and rotation that took place between the Eastern European Platform, the Arabian Plate and several micro plates. This activity resulted in the development of several structural elements that have provided the basis for oil and gas migration and trapping.

The main productive intervals of the basin are from the Tertiary section, consisting of Upper and Lower Pliocene, Upper Miocene and the Middle Eocene clastic intervals. Newly prospective reservoirs are considered to be the Oligocene clastic section as well as the Mesozoic clastic and carbonates associated with the Cretaceous period. The Oligocene Maykop shales are the principal source for oil and gas in the basin. Further details of the geologic history and characteristics of the subsurface comprising Block 12 are set out in the Netherland & Sewell Report in Part IV of this document.

6.2 Overview

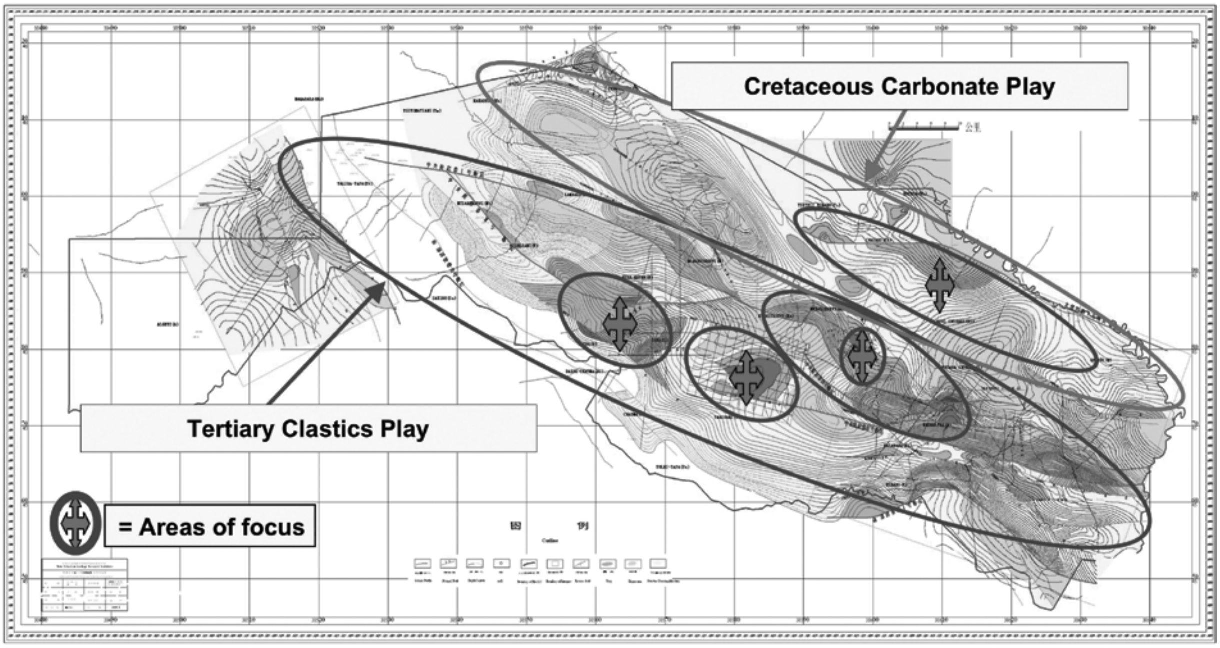


Figure 2: Map of Block 12 showing Tertiary Clastics Play and Cretaceous Carbonate Play areas.

The Group holds a 100 per cent working interest in a production sharing agreement entered into with the government of Georgia and Saknavtobi in June 1997 that gives the Operating Company the exclusive right to explore for, develop and produce oil in a 5,060km^2 area in eastern Georgia known as Block 12. Further details of the Block 12 PSA are set out in paragraph 7 of this Part II and Part VI.

Block 12 covers an extensive, underdeveloped oil and gas province containing seven known oil fields and numerous additional prospects for exploration and developmental exploration drilling. Building on the activities and studies carried out by Saknavtobi prior to the grant of the Block 12 PSA, Frontera has focused its efforts on undertaking specific scientific studies designed to identify and high-grade opportunities for new drilling and potential commercial development.

Frontera's work has resulted in a detailed understanding of the subsurface associated with Block 12 and the significant volumes of oil and gas that have been generated and trapped within it. From this work Frontera has identified two major geological plays within Block 12, the Tertiary Clastics Play and the Cretaceous Carbonate Play (see Figure 2), containing fields and prospects which the Company proposes to pursue to commercial development.

Within the Tertiary Clastics Play, Frontera intends to focus initially on the Taribani Field. Management believes it can begin commercial production within the Tertiary Clastics Play in the near term by using conventional horizontal drilling techniques. Within the Cretaceous Carbonate Play, Frontera intends to focus initially on its two identified prospects, the Basin Edge B Prospect and the Basin Edge C Prospect, by acquiring 500 kilometres of new 2D seismic data over those prospects and the surrounding areas within the play. This will lead to the definition of specific drilling locations on the Basin Edge B Prospect and the Basin Edge C Prospect, as well as an assessment of the potential for other similar prospects. In addition, the Company intends to continue its work throughout its extensive inventory of existing fields and prospects within the Tertiary Clastics Play by drilling new wells in defined prospects and acquiring 700 kilometres of new 2D seismic data over the area in order to better define prospects for future drilling.

6.3 Key Prospects

6.3.1 Tertiary Clastics Play: Taribani Field

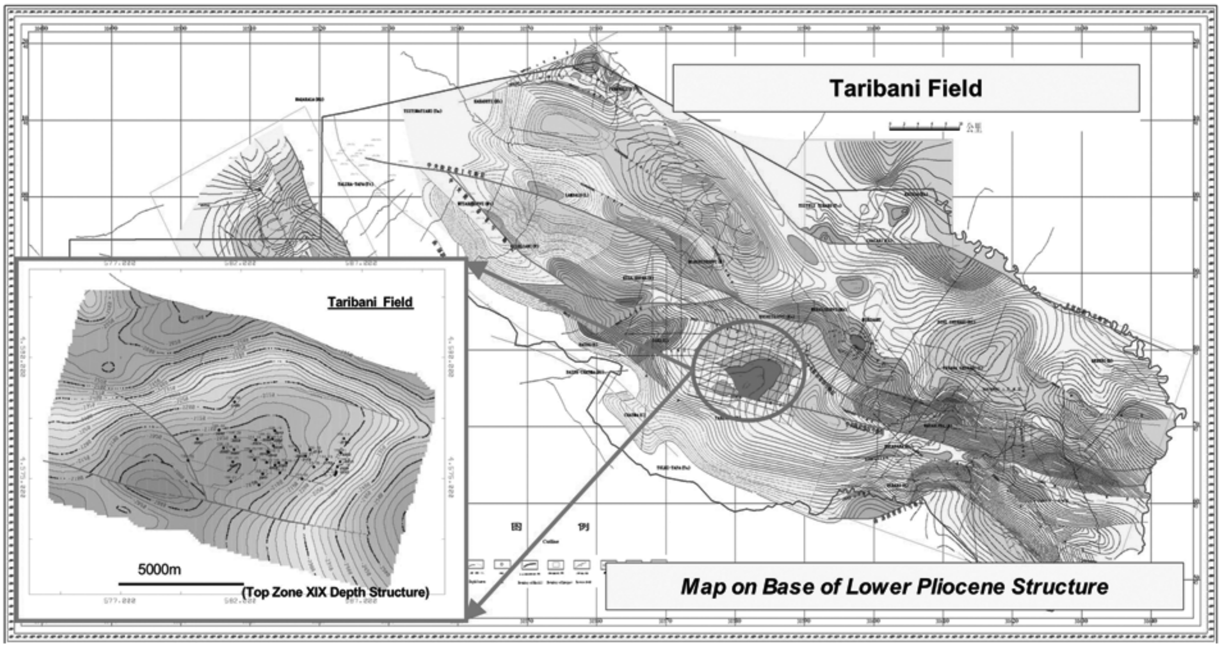


Figure 3: Map of Block 12 showing the Taribani Field.

The Taribani Field is a large over-pressured oil field covering an area of approximately 80 km^2 with productive horizons situated in Miocene and Pliocene age reservoirs that have been deposited in fluvio-deltaic to nearshore marine environments. Reservoir and regional mapping, along with extensive surface geological work, undertaken by the Group indicate that the reservoir facies are well developed and, in some cases, their permeability is enhanced by fracture systems associated with regional strike-slip faulting that is found throughout the Upper Kura Basin. These reservoirs are situated at depths of between 2,200 m and 3,500 m.

The Taribani Field was penetrated by forty-one wells during the Soviet era, drilled between 1962 and 1981 and all clustered in the down-dip portion of the field. The Taribani Field has to date produced a total of approximately 550,000 barrels of oil from eight of the forty-one wells. Oil taken by Frontera from the Taribani Field has been tested and found to be 36 degree API with a low sulphur content (0.23 per cent). Frontera believes that the limited production was due to poor historic drilling and completion practices, and a policy decision taken by the government authorities in the 1970s to focus on the development of the Samgori Field, located close to Block 12. Frontera believes that significant reserves from the Taribani Field are commercially recoverable by utilising conventional technologies, drilling and completion methods.

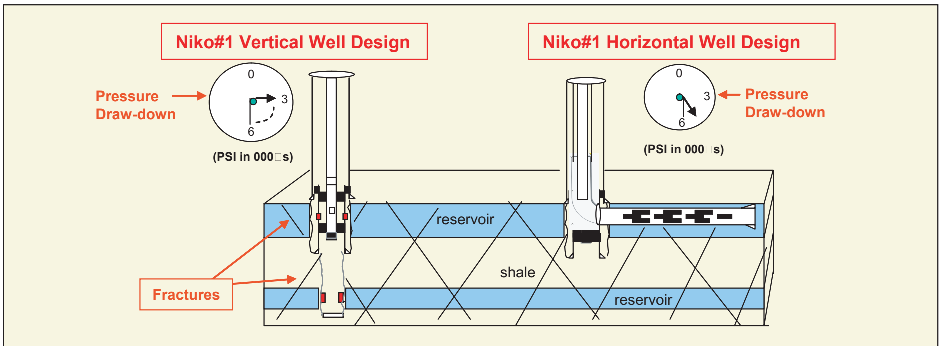
Since acquiring its interest in Block 12 in 1997, Frontera has undertaken detailed field and operational studies at the Taribani Field in order to determine how to bring the field into commercial production. Specifically, Frontera has:

- completed the acquisition, processing and interpretation of a new 3D seismic survey covering 150 km^2;
- digitised and integrated all historical well logs from the Taribani Field;
- created new time and depth structure maps, as well as new associated sand isopach maps, for twelve productive reservoirs;
- conducted static and dynamic reservoir engineering studies;
- conducted fracture and well-bore-hole stability analysis;
- performed new geologic field work that has enabled the integration of surface observations into the subsurface areas of the Taribani Field; and
- commenced new reservoir engineering studies.

In addition to the geological, geophysical and reservoir engineering studies, many of the existing wells were re-entered and checked for casing integrity, mechanical problems and obstructions, with the intention of using them for future workover or sidetrack operations. Workovers were attempted in seven of these wells with limited success due to the previous Soviet era drilling practices that resulted in skin damage to the well-bores. Detailed pore pressure analysis was conducted to prepare for future new well-bore design, mud and completion programmes. Detailed analysis was also undertaken which suggests that the drilling of short radius lateral/horizontal wells are likely to be the key to accessing undamaged portions of the reservoir away from existing well-bores.

Furthermore, in 2000 Frontera drilled, tested and completed the Niko #1 well at the Taribani Field. This well was the first post-Soviet era well drilled into the field using modern drilling practices and provided results that confirmed the effectiveness of modern drilling applications. Specifically, the well provided much needed subsurface information that permitted the Company to calibrate field-wide well logs to conventional core and the reservoirs. It gave critical understanding regarding the fluid properties from the field and established an understanding of the field's depletion drive mechanism.

Niko #1 also provided important velocity information with which to tie the subsurface information to the 3D seismic survey. This information established that most of the structural potential of the field exists west and approximately 200 metres up-dip of the Niko #1 location. Finally, the results from the well established the deeper marine intervals (Zones 18 to 25) as being hydrocarbon bearing with the ability to flow at commercial rates. The well flowed at a peak rate of 960 bpd, producing 5,345 barrels during its forty day production test. However, production was suspended as a result of sediment flow believed to be from the open hole and from behind the casing due to a poor cement job and a failed lower packer. Frontera plans to re-enter Niko #1 to drill and complete a horizontal well as part of its planned near term work programme.



Engineering problems that were encountered in the Niko#1 vertical well will be addressed with new horizontal well-bore design and production engineering solutions

Problem	Solution
1. Washed out hole with no cement behind casing allows sediment to flow	1. Control well bore size with proper mud chemistry and weight, assuring uniform well bore integrity
2. Pressure draw-down too large, causing sediment to be produced and clogged tubing	2. Horizontal well will allow for large volumes of produced oil at smaller pressure draw-down
3. Vertical well encountered few "*fractures*"	3. Horizontal well encounters multiple "fractures" increasing well productivity
4. Lower packer failed	4. Lower packer system not utilized
5. Perforations over too large an interval resulting in shale production above the reservoir	5. Horizontal well is drilled in narrow window reducing shale production from above and below reservoir

Figure 4: Proposed Niko #1 horizontal well design.

Based on its experience with previous production operations, Frontera expects that the previously encountered issues related to the challenges of sediment flow at Niko #1 can be managed and overcome. Through the drilling of horizontal wells instead of vertical wells, Frontera expects to complete the wells in the oil productive reservoirs and avoid intervals more prone to sediment flow. With appropriate completion in the productive reservoir and through controlled pressure drawdown, sediment flow can be managed and individual wells can be brought on production. The issue of sediment flow that was encountered in the Niko #1 well can, therefore, be managed for future wells with new horizontal well-bore design and associated production engineering solutions. At the same time, it should be noted that a lower pressure drawdown in a horizontal well may also yield higher production rates than a higher drawdown in a vertical well (see Figure 4 above for further details).

In addition to the historical subsurface work at the Taribani Field, Frontera also upgraded and installed new production and storage facilities in anticipation of future drilling in the field. Associated railway loading facilities were upgraded at the nearby town of Dedopliskaro (approximately 27 kilometres from the Taribani Field) in anticipation of future production. Further details of these gathering, processing and transportation facilities are set out in paragraph 6.5 of this Part II.

Based on Frontera's work in the Taribani Field, twelve productive horizons have been identified for potential exploitation and development. Frontera's near term strategy is to focus on establishing commercial production from four of these twelve horizons. The Company believes that it can produce approximately 118 million barrels of reserves from these four horizons at commercial rates. These reserves have been independently evaluated by Netherland & Sewell and have been classified as possible (P3) gross (8/8ths) reserves. Netherland & Sewell has indicated that, provided Frontera can demonstrate the successful application of currently planned conventional horizontal drilling and completion techniques, a significant portion of the P3 reserves in the Taribani Field could be recategorised as probable (P2) reserves and a small portion of the P3 reserves could be recategorised as proved (P1) reserves.

Frontera believes that the four targeted horizons can be effectively developed and produced with the use of conventional horizontal drilling and completion techniques tailored for use in that field. This technology is designed to increase the exposure area of the well-bore to the productive face of the reservoirs. It also permits penetration of multiple vertical fracture patterns that enhance reservoir permeability with a single well-bore, and thereby significantly increase individual well productivity. CanArgo Energy has reported that it has successfully employed this practice in a field adjacent to Block 12.

Frontera plans initially to re-enter seven existing wells in the Taribani Field in order to undertake horizontal drilling into the four targeted horizons. This programme is expected to commence in spring 2005 at a total cost of approximately $18.5 million. Existing well re-entries will provide Frontera with an efficient, cost-effective means to test its concepts. After exhausting all existing well-bores from which horizontal drilling operations can be conducted, Frontera plans to drill two new wells at an expected total cost of $13 million. The Company is currently developing its specific execution plans for the work in the Taribani Field and is considering the suitability of a number of leading service providers for drilling and associated operations.

Plans are also underway to continue the assessment of the other eight horizons in the field during 2005. Frontera believes that these other horizons will define additional significant recoverable reserves within the field. In addition, the western portion of the field is believed to contain significant potential that has yet to be exploited. No oil-water contacts have been found in the Taribani Field, which indicates that the field limits have yet to be fully determined.

6.3.2 Cretaceous Carbonate Play: The Basin Edge B Prospect and the Basin Edge C Prospect

The Basin Edge B Prospect and the Basin Edge C Prospect are situated in the Cretaceous Carbonate Play which lies along the northern border of Block 12 and represents one of the newest and potentially most prolific exploration plays in the Upper Kura Basin. Geochemical studies indicate that the Cretaceous Carbonate Play is sourced from the Oligocene aged Maykop shale interval, where thickness can exceed 2,000 metres and total organic carbon can be as high as 11 per cent. The primary reservoir targets are located in the Jurassic and Cretaceous age carbonate rocks and the secondary reservoir targets are in the Miocene and Pliocene age clastic rocks.

Analysis and mapping undertaken by Frontera, based on historic as well as new seismic data acquired by the Company and new geologic outcrop field work, indicates that gross (8/8ths) unrisked potential recoverable resources in the Basin Edge B Prospect and the Basis Edge C Prospect could be in excess of one billion barrels of oil from both the deeper Cretaceous intervals as well as from the shallower Tertiary section. These resources have been independently evaluated by Netherland & Sewell and classified as attractive resource potential.

Many successful exploration wells have been drilled in the upper levels of the Tertiary interval of the Kura Basin over the last 70 years based on the presence of oil seeps and mud volcanoes at the surface. However, Frontera's geologists have identified a new play in the deeper Mesozoic Era, Jurassic and Cretaceous intervals where the reservoirs are principally fractured carbonates. These rock types constitute some of the best reservoirs in the world and production from fractured carbonate rocks is typically characterised by very high flow rates.

Where the Tertiary interval can be as thick as 15,000 metres, and the younger overlying source rock is mature, the Mesozoic Era intervals have typically been beyond drilling depth. However, new 2D and 3D seismic techniques have resulted in companies being able to image prospects in this basin where the deeper Mesozoic carbonate section can be economically reached by conventional drilling.

In 2003, CanArgo Energy completed drilling its Manavi #11 well on trend and to the east of the Basin Edge B Prospect and the Basin Edge C Prospect (see Figure 5). The well reached total depth at 4,500 metres with primary pay zones in the Cretaceous carbonate interval of the Mesozoic Era section, as well as secondary targets in the upper and middle Eocene. CanArgo Energy has reported that the well tested significant volumes of oil and gas and that it is now planning to re-drill the well in order to bring on commercial production.

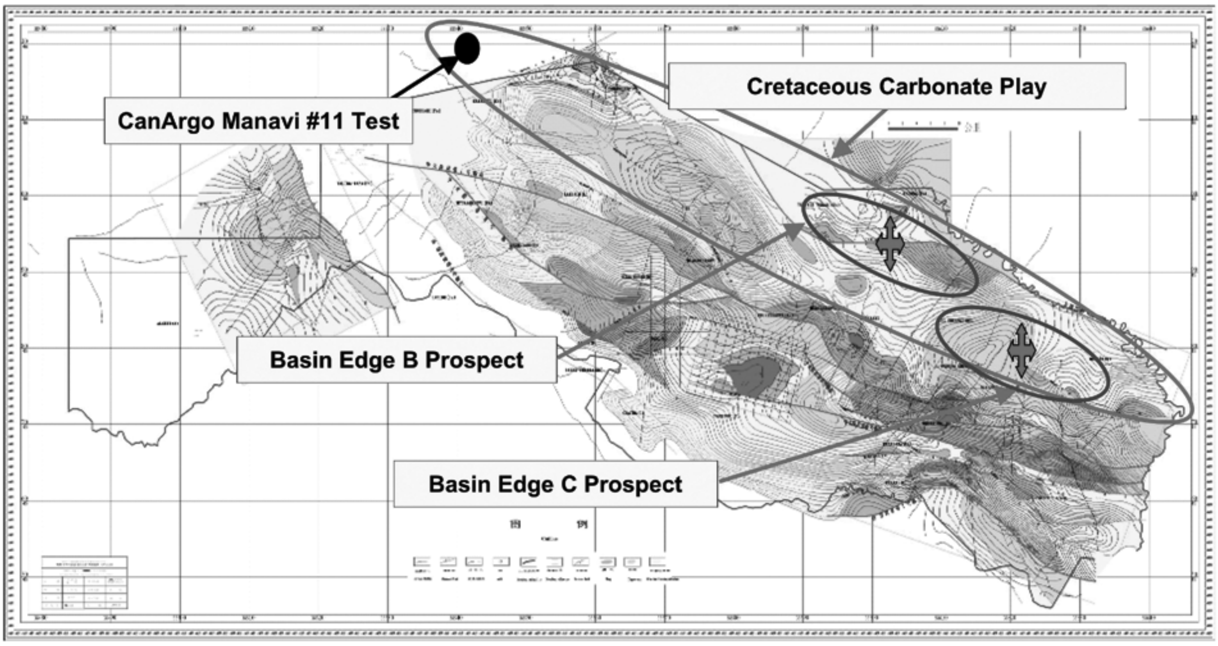


Figure 5: Map of Block 12, showing Basin Edge B Prospect and Basin Edge C Prospect, and the location of the Manavi #11 well.

The Manavi #11 well tested a feature which indicated that the carbonate reservoirs appeared to be fractured in sections previously thought to be too deep as a drilling objective. Frontera has identified the same Cretaceous interval as being prospective throughout the Cretaceous Carbonate Play in the northern portion of Block 12. Within the Cretaceous Carbonate Play, similar structures to those successfully drilled by CanArgo Energy have been identified. Visible on old and newly acquired seismic lines in Block 12, as well as in outcrops, the carbonate rocks appear to overlie and are positioned just above the Maykop source rock. In addition, the section appears to be at a relatively shallower depth in Block 12 of between 2,000 metres and 2,500 metres and should, therefore, be more economic to access.

Over the next three years, Frontera proposes to acquire 500 kilometres of new 2D seismic data over this trend at a cost of approximately $3 million in order to define optimum drilling locations within the Basin Edge B Prospect and the Basin Edge C Prospect. Based on this analysis, Frontera plans to drill and test two new exploratory wells in these two prospects at a total cost of approximately $8 million. In addition to these prospects, the Company's objective is to focus on identifying other drillable prospects within the play.

6.4 Other Prospects in Block 12

In addition to the Taribani Field, the Basin Edge B Prospect and the Basin Edge C Prospect, Frontera has developed an extensive inventory of leads and prospects throughout Block 12. Among the Company's inventory are a series of high-graded prospects and fields that the Company is targeting near-term for new geophysical data acquisition and drilling operations. These targets represent strategic areas such that, if these operations are successful, the Company's scientific work to date indicates that the reserve potential of the Company's inventory of prospects within Block 12 would increase.

Historically, in support of developing the Group's understanding of the Kura Basin, Block 12 and the broader inventory of fields, prospects and leads that could result in future commercial production, Frontera has:

- conducted surface structural and stratigraphic mapping studies over 4,000 km^2 in and around Block 12. This work has been integrated into existing subsurface control resulting in a revised digital geologic map for eastern Georgia;
- performed sequence stratigraphic and biostratigraphic analysis on existing new seismic and outcrops that has yielded the presence of a "paleo deep water" oil play never before explored for in the basin;

- conducted source rock maturation, oil seep typing, depth of burial analysis, soil gas analysis and kerogen studies which indicate where oil and gas generation is occurring;
- reprocessed approximately 2,000 kilometres of existing 2D seismic data;
- acquired 208 kilometres of new 2D seismic across the existing fields, together with 4 shallow well velocity profiles across the Taribani Field that allows the areas to be regionally tied together in a common structural and stratigraphic framework. This work has been extended from known well control to all areas of Block 12, resulting in regional structure and isopach mapping and generating numerous additional prospects and leads; and
- experimented with an eight well workover testing programme from the existing inventory of wells at the Mirzaani Field and Patara Shiraki Field. This work has helped to provide an understanding of the shallow reservoirs in the Mirzaani Field Area.

6.4.1 Mirzaani Field Area

Within the Tertiary Clastics Play, Frontera has identified and high-graded the area associated with the Mirzaani Field, the Patara Shiraki Field and the Nazerlebi Field (the ''Mirzaani Field Area''). The Mirzaani Field Area contains a trend of shallow, Pliocene-age fields that were discovered prior to the grant of the Block 12 PSA. Within this area, oil has extended into and out of the synclinal axis of the trapping folds. This provides a good indication of the significant quantities of oil generated in the Upper Kura Basin where Block 12 is situated. Oil appears to be migrating into these structures both laterally along carrier beds, and vertically along basement related faults, creating what appears to be a very efficient charge system for the area.

The producing reservoirs discovered prior to the grant of the Block 12 PSA are situated at depths of between 900 metres and 1,300 metres. These shallower fields have historically produced approximately seven million barrels and are today producing at a rate of 100 bpd. However, below the existing fields Frontera has identified a new geologic play, characterised by Pliocene-age, Sarmatian reservoirs that are similar to those found in the Taribani Field. These reservoirs are situated at relatively shallow depths of 1,400 metres to 2,000 metres and Frontera believes that this deeper play could open up a new trend of significant potential within Block 12.

Frontera has mapped an anticlinal structure beneath the existing Mirzaani Field and has developed the Mirzaani Deep Prospect. Over the next three years, the Company plans to drill new exploratory wells into the Mirzaani Deep Prospect in order to test this new deep play, as well as access secondary targets in the shallow play potential that exists throughout the area. The Company plans to drill the wells at an approximate cost of $3.5 million each. If these operations are successful, Frontera intends to drill appraisal wells in order to delineate fully the structure and establish plans for development and associated infrastructure upgrades. As the location for the Mirzaani Deep Prospect sits beneath the existing shallow production at the Mirzaani Field, tie-in to existing production facilities will contribute to efficiency in development.

The Company believes that, based on the understanding achieved from its historical work, it can commercially produce as much as 41 million barrels of reserves from the Mirzaani Field Area. These reserves have been independently evaluated by Netherland & Sewell and have been classified as gross (8/8ths) unrisked prospective oil resources.

6.4.2 Development of Block 12 Prospect Inventory

Over the next three years, at a cost of approximately $3 million, Frontera intends to acquire 700 kilometres of additional 2D seismic data over its high-graded inventory of additional fields and prospects in the Tertiary Clastics Play as well as in support of identifying other new plays. After acquiring this new data, the Company plans to complete geologic mapping over the fields and define the limits of the fields' closures, enabling the Company to better develop and define future drilling locations.

This additional seismic will provide the basis for completing geologic mapping over the Kila Kupra Field, Iori Field and Bayda Field Complex, as well as the Mirzaani Field Area and associated potential areas of prospectivity, including the Pkhoveli Prospect, in preparation for future drilling. It will also establish the basis for the next evolution of understanding the surrounding areas in the development and further high-grading of the Block 12 inventory of prospects and leads.

The Kila Kupra Field, Iori Field and Bayda Field Complex is located in the same trend as the Taribani Field, approximately 15 kilometres to the northwest. Situated in a similar geologic setting to the Taribani Field, the complex consists of three fields that were discovered during the Soviet era but were never developed or produced. The geologic trend is characterised by a series of structures that are sub-thrust anticlinal features, located beneath shallow thrust faults which outcrop at the surface. Target reservoirs are situated in Pliocene Era Shiraki sandstones and Upper Miocene Era Sarmatian sandstones at depths of between 2,000 metres and 2,700 metres.

Frontera's work to date has been limited to an analysis of historic seismic and well data. Based on the geological, geophysical and petrophysical work conducted by Frontera, the Company believes the potential recoverable resources from the Kila Kupra Field, Iori Field and Pkhoveli Field to be as much as 97 million barrels. These resources have been independently evaluated by Netherland & Sewell and have been classified as gross (8/8ths) unrisked prospective oil resources.

6.5 Transportation and Sales

6.5.1 Current arrangements

Frontera has significant experience in transporting and marketing its crude oil from Block 12 and Azerbaijan. While Frontera's level of production from Block 12 has been low to date (approximately 100 bpd), this production has allowed the Company to develop reliable, efficient and safe infrastructure and systems to process, gather, store, transport and market its crude oil on an ongoing basis. The development of this infrastructure has been enhanced by experience gained by the management team during the course of the Company's operations in Azerbaijan where the Company was successful in commercially producing, transporting and marketing its crude oil via the existing rail system in Georgia to ports on the Black Sea in volumes of up to 140,000 barrels per month. Furthermore, one of the first projects undertaken by the Company in relation to Block 12 was to invest in the improvement of road, rail and transportation infrastructure situated in Block 12.

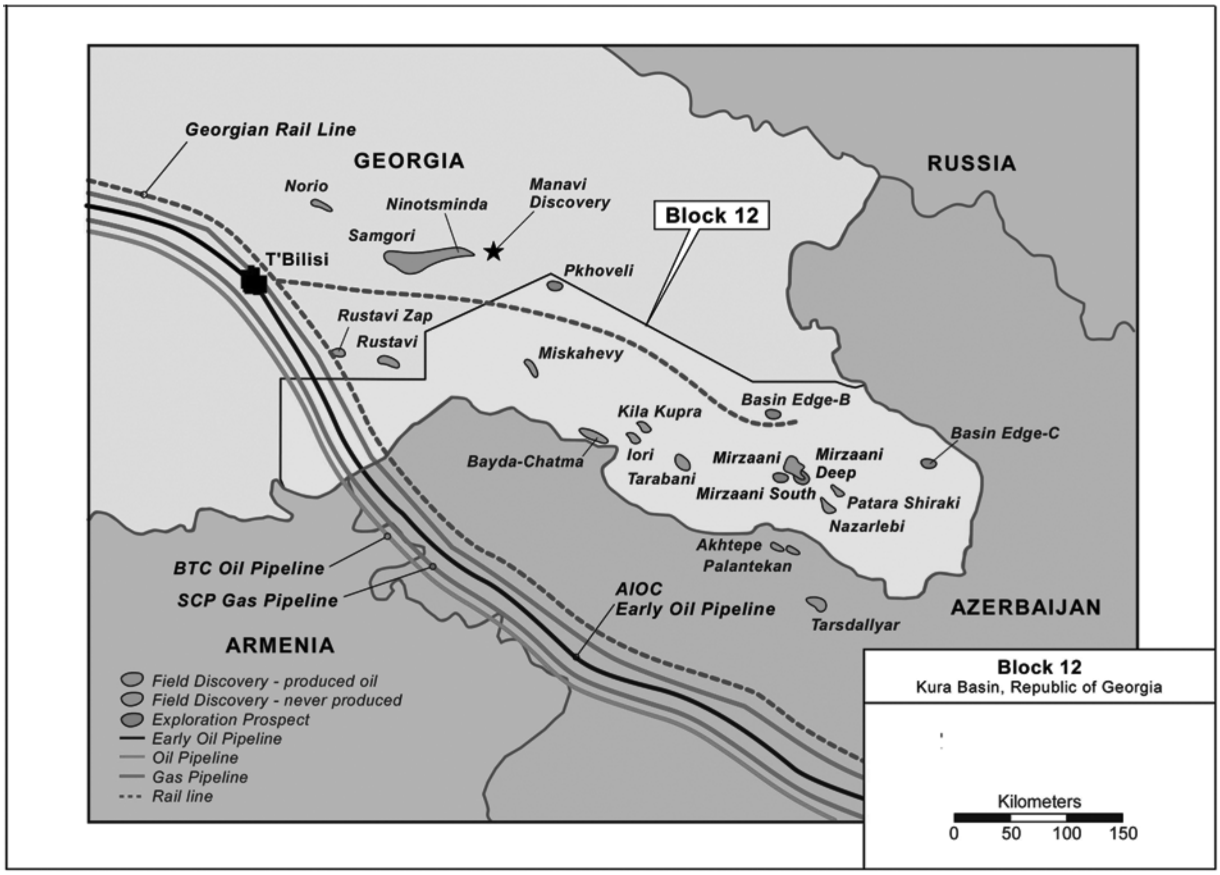


Figure 6: Map of Block 12 showing transportation infrastructure.

The Company operates a rail terminal and storage facility at Dedopliskaro, approximately 10 kilometres northwest of the Mirzaani Field, which has a storage capacity of approximately 27,000 barrels and can discharge approximately 10,000 bpd. The Mirzaani Field is connected by a pipeline to Frontera's storage facility at Dedopliskaro. Oil from the Mirzaani Field is processed at the field facility then pumped through the pipeline to Dedopliskaro for storage. This pipeline has the capacity to transport up to 1,500 bpd. Oil produced at the Taribani Field can be taken by truck to the facility at Dedopliskaro or to the Mirzaani Field should processing be required.

Once a sufficient amount of crude oil, usually in the range of 10,000 to 20,000 barrels, has been accumulated at Dedopliskaro and within field storage facilities, Frontera arranges for the oil to be transported by rail to

Batumi, a port on the Black Sea, where it is loaded into crude oil tankers destined for the international markets. The Company has entered into an agency agreement with Trafigura Beheer N.V. pursuant to which Trafigura agrees to market the crude oil from Batumi. Oil sales to date have been transacted F.O.B. Batumi at an average discount to Dated Brent of $3 to $4 per barrel. This discount is attributable to the small volumes and, to a limited extent, a quality differential to Dated Brent. The Company receives payment for its oil in US dollars into its offshore account.

Frontera's costs of transporting and marketing its crude oil from Dedopliskaro, storing at Batumi and loading onto tanker ships has averaged approximately $3.50 per barrel over the past few years. It is anticipated that this cost would decrease as production volume from Block 12 increases. Furthermore, the volume discount to Dated Brent at which the oil is sold would also decrease, and could be eliminated, as production increases.

6.5.2 Future arrangements

Frontera's existing transportation infrastructure is adequate for the volumes of oil currently being produced from Block 12. However, successful development of one or more of the prospects being targeted by the Group will require the current processing and transportation infrastructure within Block 12 to be upgraded. In particular Frontera would seek to construct a pipeline from the Taribani Field to the storage and rail facility at Dedopliskaro, 27 kilometres away, should future production volumes from the Taribani Field make such a project economically viable.

In addition, alternative transportation arrangements from Block 12 may become economically more advantageous as production levels increase. Block 12 is situated in a geographically favourable position for transporting oil to the world markets (see Figure 6) and, while there is no guarantee of availability, the following options are likely to be available to Frontera in the future:

(a) Rail

Depending on production levels from Block 12, Frontera would have the option of continuing to use the railway as its primary source of transportation. Using this rail network, Frontera transported its oil from Azerbaijan to the Black Sea at volumes of up to 6,000 bpd. Georgian Railways, the State owned railway authority, has shipped up to 10 million tons per year in recent years (*Source: Georgian Railways*).

(b) AIOC Early Oil Pipeline

The 830 kilometre AIOC Early Oil Pipeline runs from Baku, a port on the Caspian Sea, in Azerbaijan to the Black Sea port of Supsa in Georgia. The AIOC Early Oil Pipeline passes directly through Block 12. The Company could potentially connect a pipeline from its operations in Block 12 directly into the AIOC Early Oil Pipeline for transport to Supsa for onward sale into the international oil markets of the Black Sea.

(c) BTC Pipeline

A BP led consortium is nearing the completion of the $2.9 billion Baku-Tbilisi-Ceyhan (BTC) oil pipeline connecting the Caspian Sea to the Mediterranean Sea. This pipeline is expected to be ready for operations in early 2005 and passes directly through Block 12. The pipeline stretches for 1,760 kilometres and has the capacity to transport one million bpd. Frontera could potentially access this pipeline for its future production.

7. Production Sharing Agreement

The Group has the exclusive right to explore for, develop and produce oil in Block 12 pursuant to a twenty-five year PSA entered into on 25 June 1997 with the government of Georgia (the "State") and Saknavtobi. The term of the Block 12 PSA comprises an exploration phase during which Frontera Georgia shall designate those areas of Block 12 from which it intends to develop and produce oil. The exploration phase expires on 13 November 2012. Save for any areas within Block 12 that Frontera Georgia has committed to develop and produce pursuant to the Block 12 PSA ("Development Areas"), Frontera Georgia shall relinquish its rights to Block 12 at the end of this exploration phase. The Block 12 PSA can be extended for the producing life of any Development Areas, up to a maximum period of five years.

Under the Block 12 PSA, Frontera Georgia agrees to procure the financing required to conduct the exploration and development operations and is entitled to recover its costs and expenses incurred in doing so from the petroleum produced from Block 12. Subject to approval of those costs by Saknavtobi, Frontera Georgia is currently able to fully recover its cost and expenses from the oil produced from Block 12 ("Cost Recovery Crude Oil") prior to any share of the oil being given to Saknavtobi.

The operational costs incurred by Frontera Georgia on a day-to-day basis, including costs relating to production, processing, transportation, administration, finance and tax, are recoverable in full from oil produced. The proportion of oil produced from Block 12 available for use as Cost Recovery Crude Oil decreases to 80 per cent in respect of costs benefiting Development Areas and further reduces to 60 per cent in respect of costs benefiting areas containing discoveries made prior to the grant of the Block 12 PSA.

Following recovery by Frontera of its costs and expenses from the Cost Recovery Crude Oil, the remaining oil, referred to as Profit Oil, is allocated between Saknavtobi and Frontera Georgia in the proportion of 51 per cent to Saknavtobi and 49 per cent to Frontera Georgia. With limited exceptions, taxes arising in respect of exploration and development operations are ultimately to be borne by Saknavtobi from its share of the Profit Oil.

The State has agreed to provide extensive support and assistance to enable Frontera Georgia and the Operating Company to properly carry out its exploration and development operations, including gaining or granting access to pipelines, infrastructure and export points situated in Georgia. The State has further agreed to maintain the stability of the legal, tax, financial, mining and economic conditions affecting the Block 12 PSA and, if there is a change to the laws and regulations of Georgia which has a material adverse impact on the economic position of Frontera Georgia, to amend the terms of the Block 12 PSA to restore the status quo or indemnify Frontera Georgia for such losses.

The terms of the Block 12 PSA are summarised more fully in Part VI.

8. Regulatory Environment

8.1 Oil and Gas Law

The Law of Georgia on Oil and Gas dated 16 April 1999, as amended (the "Oil and Gas Law") governs matters relating to oil and gas exploration and development operations in Georgia. The Block 12 PSA pre-dated the Oil and Gas Law and was approved and authorised by a specific presidential order, and signed by the Ministry of Fuel and Energy of Georgia ("MoFE") and Saknavtobi by a mechanism of presidential delegation of authority.

The Oil and Gas Law provides for all pre-existing oil and gas agreements, including the Block 12 PSA, to be grandfathered into the Oil and Gas Law and obliges the State to ensure the protection of investors' rights under Georgian law.

8.2 Mineral licensing regime

The exploration and production of oil in Georgia is subject to the requirement to obtain a mineral licence from the State. Pursuant to the law in force at the date of the Block 12 PSA, the 1994 Georgian Law on Entrails (the "Law on Entrails"), the State agency authorised to issue a licence for exploration and production of oil was the Ministry of Environment and Natural Resources Protection (the "Ministry of Environment"). In accordance with the Law on Entrails, the Ministry of Environment issued the licence required to operate oil explorations activities in Block 12 to the Operating Company with effect from 22 August 1997. Details of the terms of the Mineral Licence are set out in paragraph 2 of Part VI.

8.3 Regulatory regime under the Oil and Gas Law

The Oil and Gas Law established a new regulatory framework implementing the State's oil and gas policy and the principles of the licensing regime. The State Agency is the exclusive representative of the State with regard to policy, regulatory and enforcement matters (including licensing). The State Agency is the successor to the MoFE as regards matters relating to oil and gas, including the Block 12 PSA. Although the scope of its regulatory activities was initially limited to oil and gas research, exploration and exploitation, the State Agency's mandate was further extended in 2002 to oil and gas refining and transportation.

The role of the national oil company, Saknavtobi, is to represent the State with regard to the commercial and operational interests of the State, including co-operations with international companies undertaking or seeking to undertake oil and gas projects in Georgia. Pursuant to the Block 12 PSA, Saknavtobi is entitled to 51 per cent of the Profit Oil produced from fields situated within Block 12.

9. Directors

Details of the Directors, their roles and their backgrounds are as follows:

Steve C. Nicandros (age 45), President, Chairman and Chief Executive Officer

Mr. Nicandros has been the President and a director of the Company since it was founded in 1996. He also became its Chief Executive Officer in 1997 and its Chairman in 2002. Mr. Nicandros was President and a member of the board of managers of Frontera Limited from July 1996 until its dissolution and replacement by Frontera Resources Corporation. From 1994 until joining Frontera Limited, Mr. Nicandros was President of Conoco Overseas Oil Company, where he was responsible for Conoco's worldwide development of upstream new business and mergers and acquisitions. Between 1992 and 1994, Mr. Nicandros was Manager of Reserves Acquisitions and Asset Management, following which he became Manager of Upstream Commercial Development for Conoco Inc. He began his career in the oil industry in 1982 with Conoco Inc. Mr. Nicandros graduated from Southern Methodist University, Dallas, Texas in 1982 with a B.S. degree in political science.

Lan Bentsen (age 57), Director, Executive Vice President

Mr. Bentsen is a co-founder of the Company and has served as a director and Executive Vice President since 1996. Prior to Frontera, Mr. Bentsen co-founded and served as Chairman of the board of directors of Security National Bank, Houston, Texas. He founded and operated Lan Bentsen Interests, a national real estate development company, as well as Sovereign National Management, a national real estate asset manager. He has served on the boards of three publicly traded NASDAQ companies: BMA Insurance, Lab Holdings and Seafield Capital. A graduate of Harvard Business School, Mr. Bentsen serves as Georgia's Honorary Consul to the United States. He is a member of the American Leadership Forum and the World Presidents Organisation.

Spyros N. Karnessis (age 65), Director

Mr. Karnessis has been a non-executive director of the Company since 2000. He is currently the chairman of European Navigation Group, an international shipping company that he founded twenty eight years ago, which comprises a large international fleet of tankers. Mr. Karnessis is a former sea captain with half a century of experience in shipping as a seafarer and as a shipping executive for a major international shipping firm. He holds a Masters degree in maritime law from the University of London.

Stephen E. McGregor (age 55), Director

Mr. McGregor has been a non-executive director of the Company since 2002. Mr. McGregor has almost thirty years of experience working in the US and international oil and gas industries. He currently arranges and manages investments in, and provides financial advisory services to, a number of companies, several of which are engaged in oil and gas activities, including certain of the Company's existing shareholders. Previously Mr. McGregor has been Executive Vice-President and CFO of Key Energy Services, Inc., Senior Advisor at James D Wolfensohn, Inc., a global investment banking firm, President and co-founder of Pacific Century Group, L.L.C. and a partner and co-founder of the energy law practice of Skadden, Arps, Slate, Meagher and Flom LLP. Mr. McGregor also served as Deputy Assistant Secretary in the U.S. Department of Energy and as Counsel to the U.S. Senate Commerce Committee. Mr. McGregor earned a B.A. degree from Boston University and a J.D. from the College of William & Mary, U.S.A.

Andrew J. Szescila (age 57), Director

Mr. Szescila has been a non-executive director of the Company since February 1998. He was formerly the Senior Vice President and Chief Operating Officer of Baker Hughes Inc. until retirement in January 2004, having previously served as President of Baker Hughes Oilfield Operations and Senior Vice President of Baker Hughes Inc. since July 1997. Before 1997, Mr. Szescila was Vice President of Baker Hughes Inc. from 1995 and President of Hughes Christensen Company, B.J. Services International and Baker Service Tools. Mr. Szescila earned a B.S. degree from Mississippi State University.

10. Senior Management

Details of senior management, their roles and backgrounds are as follows:

Steve C. Nicandros, President, Chief Executive Officer and Chairman of the Board of Directors

Information about Mr. Nicandros is set out in paragraph 9 of this Part II.

Lan Bentsen, Director, Executive Vice President

Information about Mr. Bentsen is set out in paragraph 9 of this Part II.

Reginal Spiller, Senior Vice President — Exploration and Production (age 51)

Mr. Spiller has been Senior Vice President of the Company since May 1996. He is responsible for the Group's exploration and production activities. Mr. Spiller has over 25 years of experience working in the US and international oil and gas industries. From 1993 until joining the Company, Mr. Spiller was Deputy Assistant Secretary for Gas and Petroleum Technologies at the United States Department of Energy. For five years prior to his service with the Department of Energy, he was the International Exploration Manager for Maxus Energy Corporation, which held properties in Bolivia, Bulgaria, Czechoslovakia and Indonesia. In 2004, Mr. Spiller was appointed to the United States National Academy of Sciences. He also serves as a Director of Osyka Corporation and is an active member of the American Association of Petroleum Geologists and the National Association of Black Geologists and Geophysicists. Mr. Spiller is a graduate of Penn State University with a M.S. degree in geology and a graduate of State University of New York with a B.S. degree in geology.

Randy Theilig, Chief Financial Officer, Company Secretary and Senior Vice President (age 49)

Mr. Theilig became Senior Vice-President of Planning and Finance of the Company in January 1998. He served in various positions with Conoco. Inc and its affiliates between 1979 and 1998. During 1996 and 1997, Mr. Theilig was a senior consultant for Conoco's global business development. From 1994 to 1996, Mr. Theilig served as Vice President of Conoco Overseas Oil Company and from 1990 until 1994 he was Manager of Planning and Analysis for Conoco Norway, Inc. Mr. Theilig is a graduate of University of Wisconsin, Madison with a B.S. degree and a M.B.A. in Operations Research.

William R. Daughtrey, Senior Vice President — Business and Commercial Development (age 51)

Mr. Daughtrey joined Frontera in June 1999 as Senior Vice President — Business and Commercial Development. From 1978 until joining Frontera, Mr. Daughtrey was employed by Conoco Inc. At Conoco, Mr. Daughtrey held various positions within international business development, including assignments in Norway and the UK. Mr. Daughtrey has negotiated numerous exploration and production agreements in Europe, West Africa, the Middle East, the Far East and Australia. In 1996, he became the business development lead for Conoco Latin America's successful efforts to acquire offshore exploration areas in Barbados and Trinidad. Later, Mr. Daughtrey was appointed as President of Conoco Barbados and Conoco Trinidad to develop and manage deepwater exploration operations for these areas. Mr. Daughtrey graduated from Virginia Tech with a B.S. in Business Administration and a M.B.A.

Dr. Mehmet Arif Yukler, Vice President — Worldwide Geosciences (age 57)

Dr. Yukler joined Frontera in 1996 as Vice President of Worldwide Geosciences. He has held a variety of technical positions with Shell Oil Company, Kansas Space Technology Centre, Kansas Geological Survey, Julich Nuclear Research Centre, Phillips Petroleum, Integrated Exploration Systems and Integrated Basin Analysis Inc. He received his B.S. in Petroleum Engineering and M.S. in Petroleum Engineering from Istanbul Technical University and received his M.S. in Geology and PhD in Hydrogeology from the University of Kansas. Dr. Yukler is the author of Quantitative Basin Modelling.

Zaza Mamulaishvili, General Director, Frontera Eastern Georgia Limited; Managing Director, Frontera Georgia; Vice President, Frontera Resources Corporation (age 40)

Mr. Mamulaishvili has been the General Director of the Operating Company since 1998 and Managing Director of Frontera Georgia since 1997. He also serves as a Vice President of the Company. From 1991 until joining Frontera, Mr. Mamulaishvili was President of a privately held company MTA LTD, an exporter of Eastern European crude oil and metals to the international market. Between 2001 and 2003, Mr. Mamulaishvili was the President of the American Chamber of Commerce in Georgia. Mr. Mamulaishvili holds a medical degree from Tbilisi State Medical University.

Necati Demircan, Vice President — Engineering and Operations (age 60)

Mr. Demircan became Vice President of Engineering and Operations in 1997. Mr. Demircan also served on behalf of the Company as the Operations Manager for Salyan Oil Operating Co in Baku, Azerbaijan from 1999 to 2001 and as the General Manager for Frontera's operations in the Caucasus from 1996 until 1999. From 1975 to

1996, Mr. Demircan held a variety of managerial and technical positions with Mobil Exploration Mediterranean Inc. and Mobil Exploration & Production, US. He received a B.S. in Petroleum Engineering and an M.S. in Petroleum Engineering from the Technical University of Istanbul.

Mustafa Corbaci, General Manager — Operations (age 49)

Mr. Corbaci was engaged as a consultant Petroleum Engineer by Frontera in December 2003 and became a permanent employee in 2004. Prior to joining the Company, Mr. Corbaci served as Field Operations Manager of Gobustan Operating Co in Baku, Azerbaijan from October 2003 to December 2003, Operations and Production Manager for Moncreif Oil International from June 2000 to April 2003 and Petroleum Engineering Manager for First International Oil Co in Almaty, Kazakhstan from April 1999 to June 2000. Prior to April 1999, Mr. Corbaci served in various managerial capacities for Union Texas Petroleum, Karakuduk Munai J.V., Opalit, Halliburton and Mobil. He received his B.Sc. in Petroleum Engineering from the Middle East Technical University in Turkey.

Legal Counsel

Haynes and Boone, L.L.P. has served as the Company's primary legal counsel since November 2001. In particular, S. Douglas Stinemetz, a partner in the Houston Office of Haynes and Boone, has served as the Company's General Counsel and Secretary. Mr. Stinemetz, who has B.A. and M.A. degrees from Harvard and a J.D. degree from New York University, speaks Russian and has been active in the former Soviet Union since 1989. As the Company's operations expand, the Company intends to maintain its relationship with Haynes and Boone and may employ other staff in-house to meet a portion of its legal needs.

11. Employees

The majority of the Company's management team is based in Houston, US, along with additional support staff who perform administrative roles. Its local managing director in Georgia, Zaza Mamulaishvili, who is seconded to the Operating Company from the Company, manages the Company's operations in Georgia. Two other members of the management team, Arif Yukler and Mustafa Corbaci, are also seconded to the Operating Company from Frontera.

The Operating Company employs 103 people in Georgia to undertake daily operations relating to Block 12. These employees include geologists, geophysicists, engineers, database managers, exploration and production field workers, accountants and other administrative and logistics employees. These employees report to their respective divisional managers, being either the exploration, operations, finance or logistics managers, who in turn report to Mr. Mamulaishvili. Mr. Mamulaishvili reports to the board of the Operating Company.

The majority of the employees of the Operating Company were previously employed by Saknavtobi and therefore have extensive knowledge and experience of the Georgian oil industry and of Block 12.

12. Frontera Azerbaijan's claim against SOCAR

Following the sale of Frontera's interest in Azerbaijan in March 2002, Frontera Azerbaijan initiated arbitration proceedings against the State Oil Company of the Republic of Azerbaijan ("SOCAR") in October 2003 to recover sums that it claims are due to it under the Azerbaijan PSA for oil deliveries made between 1999 and 2000. Frontera Azerbaijan's claim amounts to approximately $16 million. The arbitration hearing, which is governed by UNCITRAL, is scheduled for the week commencing 7 March 2005.

Further details of this claim are set out in paragraph 9 of Part VIII.

13. Funding arrangements

The Company has historically financed itself through equity fundraisings and third party and related party borrowing. Private placements of the Company's Preferred Stock between 1997 and 2000 raised a total of approximately $50 million from private investors, including Frontera's management team, and institutional investors. In December 2001, the Company raised approximately $500,000 by way of a rights offering to the holders of Common Shares, Series D Preferred Shares and Series E Preferred Shares to subscribe for and purchase in aggregate $500,394 principal amount of loan notes (the "2001 Loan Notes") together with warrants to subscribe for an aggregate of 15,637,329 Common Shares at an exercise price of $0.032 per share (the "2001 Warrants"). Further details of the 2001 Warrants are set out in paragraph 3.4.1 of Part VIII.

In April 2001, the Company entered into a note purchase agreement with DDJ Capital Management LLC ("DDJ"), a shareholder of the Company, for an amount of approximately $4 million, which was subsequently refinanced in September 2002 (the "2002 Amended Note Purchase Agreement"). Pursuant to the 2002 Amended Note Purchase Agreement, the Company issued loan notes bearing interest at 15 per cent per annum (the "Amended 15 per cent Senior Notes") together with warrants to subscribe for an aggregate of 1,950,000 Common Shares at an exercise price of $2.00 per share (the "2002 Warrants"). Further details of the 2002 Amended Note Purchase Agreement, the Amended 15 per cent Senior Notes and the 2002 Warrants are set out in paragraphs 3.4.2 and 8.6 of Part VIII.

In May 2003, the Company entered into a note purchase agreement (the "2003 Note Purchase Agreement") for an amount of approximately $6 million. DDJ provided $5 million of this loan and certain Directors provided $1 million. Pursuant to the 2003 Note Purchase Agreement, the Company issued loan notes bearing interest at 12 per cent per annum (the "12 per cent Senior Notes") together with warrants to subscribe for an aggregate of 3,000,000 Common Shares at an exercise price of $1.00 per share (the "2003 Warrants"). Further details of the 2003 Note Purchase Agreement, the 12 per cent Senior Notes and the 2003 Warrants are set out in paragraphs 3.4.3 and 8.7 of Part VIII.

The Group is currently being financed through a $2.5 million convertible bridge loan provided principally by DDJ in December 2004 (the "2004 Convertible Note Purchase Agreement"). Pursuant to the 2004 Convertible Note Purchase Agreement, the Company issued loan notes bearing interest at 12 per cent per annum which are convertible, at the option of the loan note holder, into Common Shares at a conversion price of 80 per cent of the price of the Common Shares offered pursuant to the Placing (the "2004 Convertible Notes"). The holder's right to convert the 2004 Convertible Notes expires on 15 March 2005, when the principal amount and all accrued interest becomes repayable in full. Further details of the 2004 Convertible Note Purchase Agreement and the 2004 Convertible Notes are set out in paragraphs 3.6 and 8.8 of Part VIII.

Since March 2001, the Company has also issued a number of promissory notes to members of the Company's management team raising an aggregate principal amount of approximately $2.55 million (the "Management Promissory Notes"). Further details of the Management Promissory Notes are set out in paragraph 8.9 of Part VIII.

The facilities made available to the Company under each of the 2002 Amended Note Purchase Agreement, the 2003 Note Purchase Agreement and the 2004 Convertible Note Purchase Agreement are fully drawn. The Company is not obliged to, and does not intend to, repay the 2001 Loan Notes in the period immediately following Admission. The Company is obliged to repay in full the 15 per cent Senior Notes, 12 per cent Senior Notes, the 2004 Convertible Notes and the Management Promissory Notes shortly after Admission. The total amount to be repaid under these arrangements, including accumulated interest, is approximately $18.8 million (assuming the conversion rights are not exercised under the 2004 Convertible Notes). The total amount to be repaid to the Directors pursuant to these arrangements is $1,788,529. The 2002 Warrants and the 2003 Warrants will remain outstanding after repayment by the Company of the amounts outstanding under the 2002 Amended Note Purchase Agreement and the 2003 Note Purchase Agreement.

The Group also received approximately $8 million of investment from GAC Energy during 2002 and 2003 pursuant to the terms of a farm-out arrangement between Frontera Georgia and GAC Energy. The Group has no outstanding obligations to GAC Energy in respect of this investment. Further information on this agreement is set out in paragraph 4 of this Part II.

The Group's largest source of external project finance was from the EBRD between May 2000 and July 2002. This loan was repaid in full in July 2002 from the proceeds of the sale of the Group's assets in Azerbaijan. Further details are set out in paragraph 9 of Part VIII.

14. Equity structure

14.1 Issued share capital

At the date of this document, the Company's authorised share capital consists of 65,000,000 million Common Shares, of which 7,181,808 Common Shares are issued and outstanding, and 10 million Preferred Shares, of which 2,395,099 Preferred Shares are issued and outstanding. Each holder of the issued Preferred Shares has agreed to convert his Preferred Shares into Common Shares immediately prior to the Placing. As a result of these conversions, immediately following the Placing the current Shareholders will own, in aggregate, 21,404,513 Common Shares representing 43.3 per cent of the Enlarged Issued Common Share Capital (assuming that no options, warrants or convertible loan notes over or in respect of Common Shares are exercised or converted (as applicable) after the date of this document and on or before the Placing). There will be no Preferred Shares in issue immediately following the Placing. Full details of the conversion of the Preferred Shares and the Company's share capital following the Placing are set out in paragraph 3.1 of Part VIII.

Holders of Common Shares have no pre-emptive or other subscription or conversion rights. Further details of the rights attaching to the Common Shares are set out in paragraph 3.2 of Part VIII.

14.2 Warrants

As at the date of this document there are an aggregate number of 5,419,710 warrants outstanding giving rights to subscribe in aggregate for 18,636,929 Common Shares. The warrants will remain in place following Admission and the Placing and, accordingly, 19,628,422 Common Shares will be reserved from the authorised share capital of the Company. Further details of these warrants are set out in paragraph 3.4 of Part VIII.

14.3 Options

At the date of this document there are 6,125,513 share options outstanding which grant rights to subscribe, in aggregate, for up to 6,125,513 Common Shares. Further details of the terms of the options and the Company's stock option plans are set out in paragraph 3.5 of Part VIII.

14.4 Convertible loan notes

As referred to in paragraph 13 of this Part II, the Company issued the 2004 Convertible Notes in December 2004. These notes are convertible by the holders, at any time after the closing of a public offering by the Company but prior to repayment of the 2004 Convertible Notes, into Common Shares at a price of 80 per cent of the price per Common Share offered pursuant to the Placing.

15. Dividend Policy

Given the Company's growth strategy, the scale of opportunities which the Directors believe are available to the Group and the capital intensive nature of oil and gas development, any cash generated by the Group's operations in the short to medium term will be invested in the Group's exploration, development and production programmes. Accordingly, the Directors do not expect that the Company will pay a dividend in the initial years following Admission. The Board will review the appropriateness of its dividend policy as the Group develops.

16. Use of Proceeds

The net proceeds of the Placing are expected to be £37,300,000 ($71,900,000). The Company intends to use $18.8 million of the proceeds (assuming that the 2004 Convertible Notes are not converted prior to repayment) to repay existing debt. As described in paragraph 3 of this Part II, the Company plans to use approximately $53,100,000 million to fund the Group's planned work programme for Block 12 for the next three years and for corporate purposes and working capital.

The proceeds will be invested in cash equivalent and short-term interest bearing securities until utilised by the Company.

17. Details of the Placing

MSIL, as agent for the Company, has agreed to procure subscribers for 28,000,000 new Common Shares or, failing which, to subscribe itself for such shares at the Placing Price, on and subject to the terms of the Placing Agreement. The Placing Shares will represent 56.7 per cent of the Enlarged Issued Common Share Capital (assuming that no options, warrants or convertible loan notes over or in respect of the Common Shares are exercised or converted (as applicable) after the date of this document and on or before the Placing). The Placing Shares are being placed by MSIL with institutional and other sophisticated investors and the Placing is conditional, inter alia, on Admission.

Commission is payable to MSIL by the Company in respect of the Placing Shares. Further details of the Placing Agreement are set out in paragraph 8.2.1 of Part VIII.

The Placing Shares will be issued credited as fully paid and will, when issued, rank pari passu with the existing Common Shares, including the right to receive all dividends and other distributions thereafter declared, made or paid. It is expected that the proceeds of the Placing will be received by the Company on 14 March 2005.

Following the Placing, the Directors, together with connected parties, will hold 6,893,503 Common Shares, representing approximately 14 per cent of the Enlarged Issued Common Share Capital (assuming that no warrants, options or convertible loan notes over or in respect of the Common Shares are exercised or converted (as applicable) after the date of this document and on or before the Placing). Certain other shareholders, as referred to in paragraph 3.1 of Part VIII, will together hold 6,279,201 Common Shares, representing approximately 12.7 per cent of the Enlarged Issued Common Share Capital (assuming that no warrants, options or convertible loan notes over or in respect of Common Shares are exercised or converted (as applicable) after the date of this document and on or before the Placing).

18. Over-allotment Arrangements

In connection with the Placing, MSIL, as stabilising manager, or any person acting for it, may (but will be under no obligation to) over-allot or effect transactions with a view to supporting the market price of the Common Shares or any options, warrants or rights with respect to, or interests in, the Common Shares, in each case at a level higher than that which might otherwise prevail in the open market, for a limited time after the Placing Price is announced (the ''Over-allotment Arrangements''). Such transactions, if commenced, may be discontinued at any time and must be brought to an end after a limited period. Save as required by law or regulation, MSIL does not intend to disclose the extent of any over-allotments and/or stabilisation transactions under the Placing.

MSIL, as stabilising manager, or any person acting for it, has entered into the Over-allotment Arrangements with the Company pursuant to which MSIL, or any person acting for it, may subscribe or procure subscribers for up to 5,000,000 Over-allotment Shares to be issued by the Company, at the Placing Price for the purposes of allowing MSIL, or any person acting for it, to meet over-allocations in connection with the Placing and to cover short positions resulting from stabilisation transactions. Any decision to subscribe or procure subscribers for any Over-allotment Shares is expected to be taken by no later than 13 April 2005.

The Over-allotment Shares made available pursuant to the Over-allotment Arrangements will rank pari passu with the Common Shares, including for all dividends and other distributions declared, made or paid on the Common Shares after Admission and will form a single class for all purposes with the Common Shares. MSIL and the Company have also entered into a stock lending agreement (the ''Stock Lending Agreement'') in connection with the Over-allotment Arrangements. Further details of this agreement are set out in paragraph 8.2.2 of Part VIII.

19. CREST, settlement and dealings

CREST is a paperless settlement procedure enabling securities to be evidenced otherwise than by certificate and transferred otherwise than by written instrument. However, due to restrictions on transfer under the US Securities Act, the Placing Shares must be held in certificated form for a period of at least 12 months following the Placing and so the Placing Shares will not be eligible for settlement through CREST during that time. The Placing Shares are not registered in the United States and the certificates will bear a legend to that effect. Accordingly, settlement of transactions in both the existing Common Shares and the Placing Shares following Admission will not take place within the CREST system.

The Company intends to apply for the existing Common Shares and the Placing Shares to be settled in CREST upon the expiry of this 12 month period or sooner if the US Securities Act restrictions on transfers applicable to the Common Shares are relaxed.

It is expected that dealings in the Common Shares will commence on a conditional basis on AIM at 8.00 a.m. on 10 March 2005. All dealings in the Common Shares between the commencement of conditional dealings and unconditional dealings will be on a ''when issued basis'' and at the risk of the parties concerned. If Admission does not take place, these dealings will not be settled and will be of no effect.

Admission is expected to take place and unconditional dealings in the Common Shares are expected to commence on AIM at 8.00 a.m. on 14 March 2005. It is expected that definitive share certificates for the Common Shares will be posted on 15 March 2005.

20. Lock-up and orderly trading arrangements

Lock-up arrangements have been entered into by (i) the Directors and certain senior managers (such Directors and senior managers being referred to as the ''Lock-up Managers'') holding approximately 32 per cent of the Pre-Admission Share Capital, and (ii) certain Shareholders (excluding the Lock-up Managers) holding in aggregate approximately 55 per cent of the Pre-Admission Share Capital (the ''Lock-up Shareholders''), in each case in respect of all of the Common Shares held by all such persons, including any shares which may be acquired in the future through the exercise of any existing options, warrants or other securities convertible into Common Shares. In aggregate, these lock-up arrangements are binding on approximately 87 per cent of all of the Pre-Admission Share Capital.

The Lock-up Managers and Lock-up Shareholders have agreed (subject to certain limited exceptions), for the period up to and including the date 360 days after Admission (the "Lock-up Period"), without the prior written consent of MSIL not to, amongst other things, transfer or encumber any Common Shares, or warrants or options for, or other securities convertible into, Common Shares held by them at any time during the Lock-up Period.

During the period of 180 days immediately following the Lock-up Period, each Director and Lock-up Shareholder has agreed that, if immediately prior to Admission such Director or Lock-up Shareholder holds together with his/its Associates (as such term is defined in section 435 of the Insolvency Act 1986) more than 3 per cent of the Pre-Admission Share Capital, he/it will consult in good faith with MSIL at least 5 business days prior to selling any Common Shares held by that Director or Lock-up Shareholder and his/its Associates, including allowing for representations to be made to that Director and Lock-up Shareholder concerning the timing of any such sale of Common Shares and the possibility of shareholder sales of Common Shares being aggregated. The Directors and Lock-up Shareholders have agreed to take all reasonable steps to ensure that all of their Associates implement these orderly trading arrangements.

After the first 180 days of the Lock-up Period, MSIL may, in its sole discretion, waive in respect of any specifically identified securities, the lock-up and orderly trading arrangements agreed by the Lock-up Shareholders if MSIL concludes that to do so would be appropriate and would not disrupt the orderly trading of the Common Shares. The lock-up and orderly trading arrangements will continue to apply to all other securities which are not the subject of such waiver.

In addition, the Placing Agreement contains certain undertakings given by the Company to MSIL. These include an undertaking not to declare dividends or (subject to certain limited exceptions) make changes to the share capital of the Company without MSIL's consent for the period of 360 days following Admission.

For further details on these arrangements, see paragraph 8.4 of Part VIII.

21. Effects of a US domicile

The Company is a US company incorporated in the State of Delaware. US law and practice relating to companies is not the same as English law applicable to a public limited company incorporated under the Act. The Directors intend to take certain actions when they consider it practicable and appropriate to meet UK standard practice.

Unlike English law, Delaware law does not provide for pre-emption rights under which companies issuing new shares for cash must generally offer them to existing shareholders unless shareholders have given authority for them not to do so. Where circumstances permit and in addition to the undertaking given by the Company to MSIL not to make changes to the share capital of the Company without MSIL's consent for the period of 360 days following Admission, the Directors intend to consult with the Company's nominated adviser and broker at the time of each proposed offering of new Common Shares or Preferred Shares for cash, as to whether non-US shareholders should be provided with the opportunity to participate in such offering (and where it would be customary for a company incorporated in the United Kingdom and admitted to AIM to provide such a right).

22. Takeover Code

A takeover of the Company would not be subject to the City Code on Takeovers and Mergers (the "Code") and certain provisions contained in the Company's articles of incorporation and bylaws may make a hostile takeover of the Company more difficult to achieve.

23. Corporate Governance

The Directors intend to take account of the requirements of the Combined Code to the extent they consider it appropriate having regard to its size, stage of development and resources, and the fact that it is incorporated in the US rather than the UK.

The Company will hold regular board meetings. The Directors will be responsible for formulating, reviewing and approving the Group's strategy, budget, major items of capital expenditure and senior personnel appointments. The Directors have established audit and remuneration committees and will utilise other committees as necessary in order to ensure effective governance.

24. Overseas Shareholders

If you are resident in any jurisdiction other than the United Kingdom, you are advised to consult a professional adviser immediately.

24.1 General

The placing of Placing Shares to persons who are resident in, or citizens of, or which are corporations, partnerships or other entities created or organised under the laws of countries other than the United Kingdom may be affected by the laws and regulations of the relevant jurisdiction. No person receiving a copy of this document in any territory other than the United Kingdom may treat the same as constituting an offer or an invitation to him to subscribe, apply for or purchase Common Shares unless, in the relevant territory, such offer or invitation could lawfully be made without compliance with any registration or other legal requirements other than any such requirements which have been fulfilled. Accordingly, persons (including, without limitation, nominees and trustees) receiving this document should not, in connection with the Placing, distribute or send the same into any jurisdiction where to do so would or might contravene securities laws or regulations. It is the responsibility of any person outside the United Kingdom to satisfy himself as to the full observance of the laws and any regulatory requirements of the relevant territory in connection therewith, including obtaining any governmental or other consent which may be required, and compliance with other necessary formalities including the payment of any issue, transfer or other taxes due in such territory.

24.2 United States

The Placing is not being made in the United States. The Common Shares have not been nor will they be registered under the Securities Act, or under the securities legislation of any state of the United States. Accordingly, the Common Shares may not (other than in certain circumstances, including, in the United States, pursuant to an effective registration statement or an exemption from the registration requirements of the US Securities Act) be offered, sold, transferred, taken up or delivered directly or indirectly in or into the United States, its territories and possession, or any political subdivision thereof, or to, or for the account or benefit of US persons (as defined in Regulation S of the US Securities Act).

Potential investors should also refer to Part VII of this document which describes certain US restrictions applying to the transfer of Common Shares.

24.3 The Netherlands

The Placing Shares may not be offered, sold, transferred or delivered, as part of their initial distribution, or at any time thereafter, directly or indirectly, other than to individuals or legal entities in The Netherlands who or which trade or invest in securities in the conduct of a profession or trade within the meaning of section 2 of the exemption regulation to the Netherlands Securities Market Supervision Act 1995, as amended from time to time, (Vrijstellingsregeling Wet toezicht effectenverkeer 1995), which includes banks, securities firms, insurance companies, pension funds, investment institutions, central governments, large international and supranational organizations, other institutional investors and other parties, including treasury departments of commercial enterprises, which are regularly active in the financial markets in a professional manner.

24.4 Other territories

No document in relation to the Placing Shares has been or will be lodged with or registered by the Australian Securities Commission or the Japanese Ministry of Finance and no steps have been taken to enable the Placing Shares to be offered, sold, transferred or delivered in or into Australia, its states, territories or possessions, or in or into Japan in compliance with applicable laws. Accordingly, neither this document nor the Placing Shares may be offered, sold, transferred or delivered, directly or indirectly, in or into Australia, its states, territories or possessions, or in or into Japan, or to any resident of Australia or Japan, and no offer or invitation to subscribe or acquire Placing Shares is being made by virtue of this document into Australia, its states, territories or possessions, or into Japan.

PART III

RISK FACTORS

AN INVESTMENT IN THE COMPANY IS HIGHLY SPECULATIVE AND INVOLVES A HIGH DEGREE OF RISK. An investment in the Common Shares is suitable only for individuals who are financially able to withstand a complete loss of their investment. The exploration and development of hydrocarbon resources is a highly speculative activity. Therefore, in addition to the other relevant information set out in this document, the following specific factors should be considered carefully in evaluating whether to make an investment in the Company. Any one or more of the risks described below could have a material effect on the value of the Company. Prospective investors should consider carefully whether investment in the Common Shares is suitable for them in light of the risks associated with such investment, including the risks specified in this document, and their personal circumstances. Investors are advised to consult an independent financial adviser authorised under FSMA and who specialises in advising on the acquisition of shares and other securities before making a decision to invest.

The risks described below do not necessarily comprise all those faced by the Group and are not presented in any assumed order of priority.

A. RISK FACTORS RELATING TO GEORGIA

Political and social

The Group's oil and gas projects are located in Georgia.

Georgia is an independent country that was part of the Soviet Union until 1991. Consequently, its legal and tax systems, as well as its economic, political, regulatory and foreign investment policies and programmes, are still developing. As a result, the Company may be subject to material political, social, economic and other risks, including, but not limited to, currency instability or non-convertibility, high rates of inflation, royalty and tax increases, changes in policies or laws governing foreign ownership and the operations of foreign-based companies. Whilst Georgia is actively pursuing a programme of economic reform and inward foreign investment designed to establish a free market economy, there can be no assurance that such reforms and other reforms will continue.

Following a peaceful revolution in December 2003, a new democratic government was elected comprising a coalition of the major political parties. Although these parties gained almost two thirds of the vote in the 2004 parliamentary election, there can be no guarantee that they will continue to work together and agree on material policy decisions. Furthermore, Georgia may experience the effects of existing disturbances or hostilities in surrounding regions such as Abkhazia, South Ossetia and Adzharia, in addition to the effects of regional policies of neighbouring countries such as Russia, Iran, Armenia and Turkey. While the Group's assets are not located on or near to areas within Georgia with ongoing disturbances or hostilities, Georgia could be affected by military action taken in the region and the effect such military action may have on the Georgian economy, political stability of Georgia or the business, operations and prospects of the Group cannot be predicted.

Block 12 PSA and Mineral Licence may be subject to legal uncertainties

The Company's principal business and assets are derived from the Block 12 PSA and the Mineral Licence. The legislative and procedural regimes governing PSAs and mineral use licences in Georgia have undergone a series of changes in recent years, including the introduction in 1999 of a new Oil and Gas Law governing such agreements. As the Block 12 PSA and Mineral Licence pre-dates the new Oil and Gas Law, they were granted to Frontera Georgia pursuant to a presidential decree in accordance with the practice of that time. Despite references in the current legislation grandfathering the terms and conditions of the Block 12 PSA, confirmation from the State Agency that the Block 12 PSA has been grandfathered into the Oil and Gas Law and the stabilisation provisions in the Block 12 PSA, conflicts between the interpretation of the Block 12 PSA and Mineral Licence and then existing, current or future legislation, including, but not limited to, any new Oil and Gas Law and the new tax code effective 1 January 2005, may exist or could arise. Such conflicts, if and to the extent that the Group, the State and/or the State Agency were to dispute them, could adversely affect the Group's rights under the Block 12 PSA.

Other legal uncertainties

In addition, the laws and regulations of Georgia relating to foreign investment, petroleum, sub-soil use, licensing, companies, tax, customs, currency, banking and anti-monopoly are still developing and uncertain.

Many such laws provide substantial discretion in their application, interpretation and enforcement. Accordingly, the best efforts of the Group to comply with applicable laws may not always result in compliance.

The judicial system in Georgia may not be fully immune from outside social, economic and political forces. Court decisions can be difficult to predict and senior officials of the Government of Georgia may not be fully immune from outside economic forces. Given Georgia's relatively recent independence from the Soviet Union, it is not possible to predict the effect of current and future legislation on the business and prospects of the Group. The rights of the Group under the Block 12 PSA, its exploration and production licences and other agreements may be susceptible to revision or cancellation, and legal redress in relation to such revocation or cancellation may be uncertain.

Title to land

There are other land users present on Block 12 who have land rights to the area. To date, the rights of these other land users have not prevented or restricted the Group from operating its business. There can be no guarantee, however, that in the future the rights of other land users will not conflict with the Group's rights which could restrict its ability to carry on its operations and could naturally adversely affect the business and the results of its operations.

Registration of property

Currently existing oil wells located in Block 12 are subject to registration as immovable property under Georgian law. The Company has generally not registered such oil wells because the oil wells, as former State property, need first to be registered by Saknavtobi, which to date has not so registered them. Saknavtobi has advised Frontera that it will register the Block 12 oil wells when and if they are to be used by Frontera. While such administrative problems with the registration of former State property are common in Georgia and throughout the former Soviet Union, they could impact on the Company's ability to drill and register new wells in Block 12.

Currency fluctuation

Whilst the Group has not historically held or been required to hold a substantial amount of Laris, this might not always be the case in the future. To the extent that the Company or any of its subsidiaries or affiliates is required to hold Laris currency positions, there is a risk from foreign exchange fluctuations. Most of the financial obligations of the Group are in US dollars and, consistent with practice in the oil and gas industry, the financial statements of the Group are reported in US dollars. If the exchange rate of the Laris fluctuates substantially, or the rate of inflation in Georgia materially increases, historic financial statements of the Group may not accurately reflect the US dollar value of its assets or operations.

The Group cannot assure prospective investors that the Laris will not depreciate against the US dollar. Further, the Group cannot assure investors that the Laris will continue to be freely exchangeable into US dollars or that the Group will be able to exchange sufficient amounts of Laris into US dollars to meet any foreign currency obligations.

Tax

The reform of the taxation system in Georgia is at an early stage of development and the tax risks and problems with respect to the operations and investment in Georgia of the Group may be more significant than typically found in countries with more developed tax systems.

As noted above, pursuant to the terms of the Block 12 PSA, the Contractor is not required, with certain limited exceptions, to pay taxes in Georgia. However, there is a risk that the tax law is not consistent with the provisions of the Block 12 PSA and that the relevant government bodies may interpret and apply those provisions in the Block 12 PSA differently and apply a new tax regime. The resulting effect on the tax liability of the Group could have a material adverse effect on the financial position of the Group.

B. RISK FACTORS RELATING TO THE BUSINESS OF THE GROUP

Current operations dependent on success of identified fields and prospects

The Group's interests in Block 12 are at an early stage of development. The availability of additional data and the results of the Group's development activities may not lead to the Group developing a sustainable business. The wells the Group has drilled, and plans to drill, on Block 12 may not discover or produce any oil or gas, or may not discover or produce commercially viable quantities of oil or gas to enable the Group to operate profitably or to enable investors to recover their investments.

Frontera has directed substantially all its efforts and most of its available funds to the development of the Tertiary Clastics Play, in particular the Taribani Field. This decision is based on management's assessment of the potential of the Tertiary Clastics Play. However, its focus on the Tertiary Clastics Play, since beginning operations in Georgia, has resulted in overall losses. The Company's exploration and development plans for the Tertiary Clastics Play may not be successful. For example, the fields may not produce sufficient quantities of oil and at sufficient rates to justify the investment made and planned to be made in the fields, and the Company may not be able to produce the oil at a sufficiently low cost or to market the oil produced at a sufficiently high price to generate a positive cash flow and a profit. The Company cannot accurately predict the life or production levels of its wells.

The prospects in the Cretaceous Carbonate Play are also speculative and no producing oil fields have yet been discovered. The availability of data and the results of the Group's development activities may not be an accurate predictor of the Group's success.

Funding requirements for long-term development plans

The Group requires a significant amount of funding in order to maintain its operations (including financing its proposed field development capital expenditure), to pursue its strategy of exploration, to meet its liquidity needs and to service its debt obligations.

It will take several years and substantial capital expenditure to develop fully the Company's prospects in Block 12. Generally the Group has the principal responsibility to provide financing for its programmes under the Block 12 PSA. Accordingly, the Company may need to raise additional funds from outside sources in order to pay for project development costs. The Company may not be able to obtain that additional financing or such funds may only be available on commercially unattractive terms. If adequate funds are not available, or if the Group's operations do not generate sufficient cash flow, the Company will be required to scale back or suspend its operations. The carrying value of the fields and prospects identified in Block 12 may not be realised unless additional capital expenditures are incurred. Furthermore, additional funds will be required to pursue exploration activities on its existing unexplored properties. Without further exploration work and evaluation the funds needed to fully develop all of the Company's oil and gas properties cannot at present be quantified.

The Group may incur significant financial indebtedness in the future. This may affect the operations of the Group and have significant consequences for prospective investors in a number of ways. For example, the Group may be forced to dedicate a substantial portion of its cash flow to repayments of its indebtedness, thereby reducing the cash available to fund working capital, capital expenditure and for other general corporate purposes. It may limit the ability of the Group to borrow additional funds, which in turn may restrict its ability to pursue its business strategy. In addition, it might limit the flexibility of the Group in planning for, or reacting to, change and make it more vulnerable to a downturn in the industry or the economy generally.

Asset concentration

Generally, risk is reduced through diversification. Diversification for an oil and gas exploration and production company can be achieved by operating in a number of countries and drilling a large number of wells over a large area of prospects having different geological characteristics. The Group will, for the time being, continue to focus its activities in Georgia and anticipates drilling a relatively limited number of wells in the area of Block 12. Although successfully identifying and high-grading specific prospects is an important aspect of an effective exploration strategy, the drilling and development programme will have only a relatively limited amount of diversification with a correspondingly higher degree of financial risk for investors.

Dependence on relationships with the State, the State Agency and Saknavtobi

The Group has been operating in Georgia since 1997, during which time it has maintained good relationships with the State, the State Agency and Saknavtobi and each of them share in the benefit of a co-operative relationship in Block 12. The success of the business of the Group and the effective operation of Block 12 is dependent in part on these continued good relationships and co-operation. If the Group and the State, the State Agency and/or Saknavtobi are not able to co-operate with each other, that could have an adverse impact on the business, operations and prospects of the Group.

Dependence on key people

The Group's success depends in large part on the ability of its executive management team to deal effectively with complex risks and relationships and execute the Group's oil exploration development plan. The members of the management team contribute to the Group's ability to obtain, generate and manage opportunities. The prospects of the Group also depend upon the continued service of its technical employees and consultants. In Georgia, the identity and efforts of the local representatives, in particular their relationships with governmental agencies, can be critical factors in its local success. There can be no assurance that the Group's present Directors, advisers, officers, employees, representatives, or consultants will remain with the Group.

Requirement for permits and licences

The operations of the Group require licences, permits and in some cases renewals of existing licences and permits from various governmental authorities. The Board believes that the Group has the benefit of all material licences and permits which are necessary to carry on the activities required under applicable laws and regulations. While the Group may not have the benefit of certain minor licences, this is principally due to the developing nature of the regulatory agencies in Georgia.

The Company believes that the Group is complying in all material respects with the terms of the licences and permits granted to it in order to undertake its activities in Block 12. However, notwithstanding the provisions in the Block 12 PSA obliging the government of Georgia to co-operate fully with Frontera Georgia in obtaining all necessary consents and permits, the Company's ability to obtain, sustain or renew such licences and permits on acceptable terms are subject to change in regulations and policies and to the discretion of the applicable regulatory authorities and governments.

C. RISK FACTORS RELATING TO THE OIL INDUSTRY

Exploration, production and general operational risks

Oil exploration and production is speculative and involves a high degree of risk. In particular, the operations of the Group may be disrupted by risks and hazards which are beyond the control of the Group, including environmental hazards, industrial accidents, occupational and health hazards, technical failures, labour disputes, unusual or unexpected geological formations, flooding, earthquakes and extended interruptions due to weather conditions, explosions and other accidents. These risks and hazards could also result in damage to, or destruction of, wells or production facilities, personal injury, environmental damage, business interruption, financial losses and legal liability.

The Group may never identify commercially exploitable deposits or successfully drill, complete or produce oil reserves. Completed wells may never produce oil, or may not produce sufficient quantities to be profitable or commercially viable. The Company's estimates of oil and gas resources are based on certain material assumptions which may turn out to be incorrect. Furthermore, although the Company's internal resource estimates have been calculated according to the accepted industry practices and corroborated by Netherland & Sewell, they are based, in some cases, on limited technical data and may not reflect actual reserves, which could be significantly less than such estimates.

The nature of reserve quantification studies means that there can be no certainty that estimates of the quantities and quality of oil discovered will be available for extraction. There are numerous uncertainties inherent in estimating quantities of oil and gas reserves. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geologic interpretation and judgment. In evaluating oil and gas properties, and in estimating reserves, the Company has used historic, Soviet seismic data, production data and geologic and geophysical data that may not meet the customary technical quality of data used in the international oil and gas industry. Estimates by different engineers often vary, sometimes significantly. Physical factors, such as the results of drilling, testing and production subsequent to the date of an estimate, as well as economic factors, such as an increase or decrease in product prices that renders production of reserves more or less economic, may justify a revision of reserves estimates.

Delays in the construction and commissioning of projects or other technical difficulties may result in the Company's current or future projected target dates for production being delayed or further capital expenditure being required.

Oil pricing and demand

The price of and demand for oil is dependent on a number of factors, including worldwide supply and demand levels, actions of the Organisation of Petroleum Exporting Countries, energy policies, weather, competitiveness of alternative energy sources, global economic and political developments and the volatile trading patterns of the commodity futures markets. Changes in oil and gas prices can impact the Company's valuation of reserves. International oil prices have fluctuated widely in recent years and may continue to do so in the future. Lower oil prices will adversely affect the Company's revenues, business or financial condition and the valuation of its reserves. In periods of sharply lower commodity prices, the Company may curtail production and capital spending projects and may defer or delay drilling wells because of lower cash flows.

Increase in drilling costs and the availability of drilling equipment

The oil and gas industry historically has experienced periods of rapid cost increases. Increases in the costs of exploration and development would affect the Company's ability to invest in prospects and to purchase or hire equipment, supplies and services. In addition, the availability of drilling rigs and other equipment and services is affected by the level and location of drilling activity around the world. An increase in drilling operations outside of Georgia or in other areas of Georgia may reduce the availability of equipment and services to the Group. The reduced availability of equipment and services may delay its ability to exploit reserves and adversely affect the Group's operations and profitability.

Delays in production, marketing and transportation

Various production, marketing and transportation conditions may cause delays in oil production and adversely affect the Group's business. Drilling wells in areas remote from distribution and production facilities may delay production from those wells until sufficient reserves are established to justify construction of the necessary transportation and production facilities.

Transportation

The Group is reliant on third parties providing access to the necessary infrastructure to transport oil from Block 12 to the international oil markets. While the Group potentially has a number of transportation options available to it, there can be no guarantee that these options will be available or, if available, that the tariffs and taxes charged to use such transportation will be in accordance with the costs assumed by the Group or Netherland & Sewell or at costs that enable the Group's production to be delivered to world markets economically.

Insurance coverage

There are significant exploration and operating risks associated with drilling oil and gas wells, including blowouts, cratering, sour gas releases, uncontrolled flows of oil, natural gas or well fluids, adverse weather conditions, environmental risks and fire, all of which can result in injury to persons as well as damage to or destruction of oil and gas wells, equipment, formations and reserves, production facilities and other property. In addition, the Group will be subject to liability for environmental risks such as pollution and abuse of the environment. Although the Group will exercise due care in the conduct of its business and will maintain customary insurance coverage for companies engaged in similar operations, the Group is not fully insured against all risks in its business. The occurrence of a significant event against which the Group is not fully insured could have a material adverse effect on its operations and financial performance. In addition, in the future some or all of the Group's insurance coverage may not be available at all or on satisfactory terms including pricing, or the amount of coverage may be insufficient to cover all of the losses, damages, costs or liabilities relating to the Group's business and operations.

Environmental exposures and regulation

The requirements or stringency of present or future environmental laws and regulations in Georgia may have a material adverse effect on the Group's business and financial condition. Environmental laws and standards applicable to oil and gas operations in the emerging international marketplace are changing and differ from country to country. The Group's operations are subject to regulatory requirements relating to environmental matters, health and safety, waste management and hydrocarbon and chemical products. In general, environmental legislation and policy throughout the world are evolving in a manner that has resulted in stricter standards and enforcement and in more stringent fines and penalties for non-compliance. Environmental assessments of existing and proposed projects carry a heightened degree of responsibility for companies and their directors, officers and employees.

Oil and gas operations are subject to inherent environmental risk and some of the Group's oil and gas properties have pre-existing environmental damage. Although this pre-existing damage is not the responsibility of the Group under the terms of the Block 12 PSA, the developing nature of Georgia's laws creates ambiguity with regard to responsibility for pre-existing contamination and the costs of complying with environmental regulation in the future could be material and adversely affect the results of the Group.

Decommissioning costs

The Group will be responsible for certain costs associated with abandoning and reclaiming wells, facilities and pipelines which it may use for production of oil. Abandonment and reclamation of facilities and associated costs is often referred to as "decommissioning". Should decommissioning be required, the costs of decommissioning may exceed the value of reserves remaining at any particular time to cover such decommissioning costs. The Company may have to draw on funds from other sources to satisfy such costs. The use of other funds to satisfy such decommissioning costs could have a material adverse effect on the Group's financial position and future results of operations.

D. RISK FACTORS ASSOCIATED WITH THE SHARES

Share price volatility and limited liquidity

The share price of publicly traded emerging companies can be highly volatile. The price at which the Common Shares will be quoted and the price which investors may realise for their Common Shares will be influenced by a large number of factors, some specific to the Company and its operations and some which may affect the Company's quoted sector, or quoted companies generally. These factors could include the performance of the Company's development and production programmes, large purchases or sales of the Common Shares, currency fluctuations, oil prices and general economic conditions.

The admission to AIM should not be taken as implying that there will be a liquid market for the Common Shares. It is likely to be more difficult for an investor to realise its investment on AIM than to realise an investment in a company whose shares are quoted on the Official List of the UKLA.

The market price of the Common Shares may not reflect the underlying value of the Company's net assets. The price at which investors may dispose of their shares in the Company may be influenced by a number of factors, some of which may pertain to the Company, and others of which are extraneous. Investors may realise less than the original amount invested.

Restrictions on transfer under the US Securities Act

The Placing Shares have not been registered under the US Securities Act. The Placing Shares are being offered only to non-US persons outside the United States in transactions exempt from the registration requirements of the US Securities Act in reliance on Regulation S. The Placing Shares may not be offered, sold or delivered in the United States or to, or for the account or benefit of, any US Person, unless the transfer is registered under the US Securities Act or an exemption from the registration requirements is available or under transactions specified by Regulation S promulgated under the US Securities Act.

Only the Company is entitled to register the Placing Shares under the US Securities Act and the Company has no obligation to do so. The Company can give no assurances that an exemption from registration will be available to any subscribers for or purchasers of Placing Shares. The Placing Shares will bear a legend describing restrictions on transfer to US Persons and prohibiting hedging transactions in the Company's Common Shares unless in compliance with the US Securities Act. Each subscriber for Placing Shares, by subscribing for such Placing Shares, agrees to reoffer or resell them only in accordance with the provisions of Regulation S, pursuant to registration under the US Securities Act, or pursuant to an available exemption from registration and agrees not to engage in hedging transactions, directly or indirectly, with regard to such securities unless in compliance with the US Securities Act.

The above restrictions severely restrict purchasers of Placing Shares from reselling the Placing Shares in the United States or to, or for the account or benefit of, a US Person. The Placing Shares will not be admitted for trading on any US securities exchange in connection with the Placing.

Certain shareholders will continue to have substantial control over the Company after the Placing

Upon completion of the Placing, certain shareholders will own a significant proportion of the Enlarged Issued Common Share Capital which proportion may be increased as a result of the exercise of warrants or options or the conversion of the Convertible Notes. As a result, these shareholders will be able to exercise significant control over all matters requiring shareholder approval, which could delay or prevent an outside party from acquiring or merging with the Company. The ability of such shareholders to prevent or delay these transactions could cause the price of Common Shares to decline.

Preferred Shares

The issuance of Preferred Shares could adversely affect the voting power of holders of Common Shares and the likelihood that such holders will receive dividend payments and payments upon liquidation. In addition, the issuance of Preferred Shares could have the effect of delaying, deferring or preventing a change in control of the Company.

PART IV

PETROLEUM CONSULTANT'S REPORT

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

CHAIRMAN EMERITUS
CLARENCE M. NETHERLAND
CHAIRMAN & CEO
FREDERIC D. SEWELL
PRESIDENT & COO
C.H. (SCOTT) REES III

EXECUTIVE COMMITTEE
G. LANCE BINDER - DALLAS
DANNY D. SIMMONS - HOUSTON
P. SCOTT FROST - DALLAS
DAN PAUL SMITH - DALLAS
JOSEPH J. SPELLMAN - DALLAS
THOMAS J. TELLA II - DALLAS

February 15, 2005

The Directors
Frontera Resources Corporation
Suite 730
3040 Post Oak Boulevard
Houston, Texas 77058

Morgan Stanley & Co. International Limited
25 Cabot Square
Canary Wharf
London EI4 4QA

Gentlemen:

In accordance with your request, we have conducted a technical evaluation of certain properties and exploration prospects within Block 12, located onshore in the Republic of Georgia, as of January 1, 2005, for Frontera Resources Corporation (Frontera). A deterministic analysis was performed to derive in-place and recoverable hydrocarbon volumes and possible reserves for Tarabani Field in the Block 12 concession. A probabilistic analysis was conducted to estimate prospective oil resources for the 9 exploration prospects evaluated in Block 12. Our evaluation consisted of a comprehensive reserve and resource assessment for Tarabani Field and selected prospects, as identified by Frontera, with sensitivity analyses on the economics of potential developments. We understand that a development area can only be granted for Tarabani Field after a declaration of commerciality has been made and a development plan has been submitted for approval. Therefore, the reserves estimated in this report are considered technical reserves. The classification of these reserves as possible reserves are therefore contingent upon (1) a declaration of commerciality being made, (2) a development plan being submitted and approved, and (3) granting of a development area for Tarabani Field by the proper authorities.

The following table presents our estimates for the gross (100 percent) unrisked possible oil reserve case, as of January 1, 2005, for Tarabani Field.

	Gross (100 Percent) Unrisked Oil (MMBO)			
Category	Original Oil-in-Place	Estimated Ultimate Recovery	Cumulative Production	Reserves
Technical Possible(1)	788.28	118.24	0.55	117.69

(1) Technically recoverable possible reserves are subject to (1) declaration of commerciality, (2) submission and approval of development plans, and (3) a development area being granted.

The following table sets forth our assessment of mean and high-side gross (100 percent) unrisked prospective oil resources, as of January 1, 2005, for the exploration prospects, as identified by Frontera.

	Gross (100 Percent) Unrisked Oil (MMBO)	
Category/Prospect	Original Oil-in-Place	Prospective Resources
Mean		
Basin Edge B Cretaceous	856	171
Basin Edge C Cretaceous	703	140
Other	2,302	346
Total All Prospects(1)	3,861	657

(1) Totals may not add due to rounding.

Category/Prospect	Gross (100 Percent) Unrisked Oil (MMBO) Original Oil-in-Place	Prospective Resources
High-Side		
Basin Edge B Cretaceous	1,810	376
Basin Edge C Cretaceous	1,483	307
Other	4,793	733
Total All Prospects(1)	8,086	1,417

(1) Totals may not add due to rounding.

Oil volumes are expressed in millions of barrels (MMBO); a barrel is equivalent to 42 United States gallons. The prospective resources have been determined based on probabilistic methods with the low-side, median, mean, and high-side resources corresponding to the P90, P50, mean, and P10 cases, respectively. All prices, costs, and revenue estimates are expressed in United States dollars referred to hereinafter as $.

The estimated reserves shown in this report are for possible reserves only. Our study indicates there are no proved or probable reserves for these properties at this time. It should be understood that the prospective resource volumes discussed and shown herein are defined as those undiscovered, speculative resources estimated beyond proved, probable, and possible reserves where geologic and geophysical data suggest the potential for discovery of reserves but where the level of proof is insufficient for classification as reserves. The prospective oil resources are those volumes that could reasonably be expected to be recovered upon the successful exploration and development of these areas. Possible reserves are not defined by *The Listing Rules* of the United Kingdom Listing Authority; therefore, reserves and resources presented in this report have been prepared in accordance with definitions adopted by the Society of Petroleum Engineers, World Petroleum Congress, and the American Association of Petroleum Geologists in 1997 and 2000. These definitions are presented immediately following this letter.

As shown in the Table of Contents, the Discussion section of this report includes an overview of the contractual terms of the Block 12 concession, a brief review of the database available for this evaluation, a regional geological overview, and a discussion of the technical approach used in our analysis of Tarabani Field and the prospects that were reviewed. Detailed discussion of the economics of the potential full field Tarabani development and the potential full field Basin Edge B development is also presented. Included in the Figures section are summaries of probabilistic input parameters and estimates of the range of potential hydrocarbons for each of the evaluated prospects along with various pertinent maps, tables, and exhibits.

For the purposes of this report, a field inspection of the properties has not been performed. We have not investigated possible environmental liability related to the properties.

The reserves and prospective resources included in this report are estimates only and should not be construed as exact quantities. They may or may not be recovered, and the actual production rates may vary from assumptions included in this report due to governmental policies and uncertainties of supply and demand. Our estimates for these properties are based on calculations of reservoir volumes, well tests, and analogy. Reserve and prospective resource estimates based on these types of methods are subject to greater revision than those based on substantial performance data. Therefore, it may be necessary to revise these estimates as additional performance data become available. Also, estimates of reserves and prospective resources may increase or decrease depending on the actual development plan and results of future operations.

In evaluating the information at our disposal concerning this report, we have excluded from our consideration all matters as to which political, socioeconomic, legal, or accounting, rather than engineering and geological, interpretation may be controlling. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geological data; therefore, our conclusions necessarily represent only informed professional judgments.

The contractual rights to the properties have not been examined by Netherland, Sewell & Associates, Inc., nor has the actual degree or type of interest owned been independently confirmed. The data used in our estimates were obtained from Frontera Resources Corporation and the nonconfidential files of Netherland, Sewell & Associates, Inc. and were accepted as accurate. Supporting geologic, field performance, and work data are on file in our office. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties and are not employed on a contingent basis.

Very truly yours,

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ C.H. (SCOTT) REES III, P.E.
C.H. (Scott) Rees III, P.E.
President and Chief Operating Officer

By: /s/ JOSEPH J. SPELLMAN, P.E.
Joseph J. Spellman, P.E.
Senior Vice President

Date Signed: February 15, 2005

By: /s/ JAY P. MITCHELL, P.G.
Jay P. Mitchell, P.G.
Vice President

Date Signed: February 15, 2005

JPM:RAC

DEFINITIONS OF RESERVES ACCORDING TO THE LISTING RULES OF THE UNITED KINGDOM LISTING AUTHORITY

PROVEN RESERVES

(i) in respect of mineral companies primarily involved in the extraction of oil and gas resources, those reserves which on the available evidence and taking into account technical and economic factors have a better than 90% chance of being produced; and

(ii) in respect of mineral companies other than those primarily involved in the extraction of oil and gas resources, those measured mineral resources of which detailed technical and economic studies have demonstrated that extraction can be justified at the time of the determination and under specified economic conditions;

PROBABLE RESERVES

(i) in respect of mineral companies primarily involved in the extraction of oil and gas resources, those reserves which are not yet "proven" but which on the available evidence and taking into account technical and economic factors have a better than 50% chance of being produced; and

(ii) in respect of mineral companies other than those primarily involved in the extraction of oil and gas resources, those measured and/or indicated mineral resources which are not yet "proven" but of which detailed technical and economic studies have demonstrated that extraction can be justified at the time of the determination and under specified economic conditions;

1997 DEFINITIONS FOR OIL AND GAS RESERVES ADOPTED BY SOCIETY OF PETROLEUM ENGINEERS (SPE) AND WORLD PETROLEUM CONGRESS (WPC)

DEFINITIONS

Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward. All reserves estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability.

The intent of the SPE and WPC in approving additional classifications beyond proved reserves is to facilitate consistency among professionals using such terms. In presenting these definitions, neither organization is recommending public disclosure of reserves classified as unproved. Public disclosure of the quantities classified as unproved reserves is left to the discretion of the countries or companies involved.

Estimation of reserves is done under conditions of uncertainty. The method of estimation is called deterministic if a single best estimate of reserves is made based on known geological, engineering, and economic data. The method of estimation is called probabilistic when the known geological, engineering, and economic data are used to generate a range of estimates and their associated probabilities. Identifying reserves as proved, probable, and possible has been the most frequent classification method and gives an indication of the probability of recovery. Because of potential differences in uncertainty, caution should be exercised when aggregating reserves of different classifications.

Reserves estimates will generally be revised as additional geologic or engineering data become available or as economic conditions change. Reserves do not include quantities of petroleum being held in inventory, and may be reduced for usage or processing losses if required for financial reporting.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

PROVED RESERVES

Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. Proved reserves can be categorized as developed or undeveloped.

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.

Establishment of current economic conditions should include relevant historical petroleum prices and associated costs and may involve an averaging period that is consistent with the purpose of the reserves estimate, appropriate contract obligations, corporate procedures, and government regulations involved in reporting these reserves.

In general, reserves are considered proved if the commercial producibility of the reservoir is supported by actual production or formation tests. In this context, the term proved refers to the actual quantities of petroleum reserves and not just the productivity of the well or reservoir. In certain cases, proved reserves may be assigned on the basis of well logs and/or core analysis that indicate the subject reservoir is hydrocarbon bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

The area of the reservoir considered as proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) the undrilled portions of the reservoir that can reasonably be judged as commercially productive on the basis of available geological and engineering data. In the absence of data on fluid contacts, the lowest known occurrence of hydrocarbons controls the proved limit unless otherwise indicated by definitive geological, engineering, or performance data.

Reserves may be classified as proved if facilities to process and transport those reserves to market are operational at the time of the estimate or there is a reasonable expectation that such facilities will be installed. Reserves in undeveloped locations may be classified as proved undeveloped provided (1) the locations are direct offsets to wells that have indicated commercial production in the objective formation, (2) it is reasonably certain such locations are within the known proved productive limits of the objective formation, (3) the locations conform to existing well spacing regulations where applicable, and (4) it is reasonably certain the locations will be developed. Reserves from other locations are categorized as proved undeveloped only where interpretations of geological and engineering data from wells indicate with reasonable certainty that the objective formation is laterally continuous and contains commercially recoverable petroleum at locations beyond direct offsets.

Reserves which are to be produced through the application of established improved recovery methods are included in the proved classification when (1) successful testing by a pilot project or favorable response of an installed program in the same or an analogous reservoir with similar rock and fluid properties provides support for the analysis on which the project was based, and (2) it is reasonably certain that the project will proceed. Reserves to be recovered by improved recovery methods that have yet to be established through commercially successful applications are included in the proved classification only (1) after a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program where the response provides support for the analysis on which the project is based and (2) it is reasonably certain the project will proceed.

UNPROVED RESERVES

Unproved reserves are based on geologic and/or engineering data similar to that used in estimates of proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves.

Unproved reserves may be estimated assuming future economic conditions different from those prevailing at the time of the estimate. The effect of possible future improvements in economic conditions and technological developments can be expressed by allocating appropriate quantities of reserves to the probable and possible classifications.

PROBABLE RESERVES

Probable reserves are those unproved reserves which analysis of geological and engineering data suggest are more likely than not to be recoverable. In this context, when probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves.

In general, probable reserves may include (1) reserves anticipated to be proved by normal step-out drilling where subsurface control is inadequate to classify these reserves as proved, (2) reserves in formations that appear to be productive based on well log characteristics but lack core data or definitive tests and which are not analogous to producing or proved reservoirs in the area, (3) incremental reserves attributable to infill drilling that could have been classified as proved if closer statutory spacing have been approved at the time of the estimate, (4) reserves attributable to improved recovery methods that have been established by repeated commercially successful applications when (a) a project or pilot is planned but not in operation and (b) rock, fluid, and reservoir characteristics appear favorable for commercial application, (5) reserves in an area of the formation that appears to be separated from the proved area by faulting and the geologic interpretation indicates the subject area is structurally higher than the proved area, (6) reserves attributable to a future workover, treatment, retreatment, change of equipment, or other mechanical procedures, where such procedure has not been proved successful in wells which exhibit similar behavior in analogous reservoirs, and (7) incremental reserves in proved reservoirs where an alternative interpretation of performance or volumetric data indicates more reserves than can be classified as proved.

POSSIBLE RESERVES

Possible reserves are those unproved reserves which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves. In this context, when probabilistic methods are used, there should be at least a 10% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable plus possible reserves.

In general, possible reserves may include (1) reserves which, based on geological interpretations, could possibly exist beyond areas classified as probable, (2) reserves in formations that appear to be petroleum bearing based on log and core analysis but may not be productive at commercial rates, (3) incremental reserves attributed to infill drilling that are subject to technical uncertainty, (4) reserves attributed to improved recovery methods when (a) a project or pilot is planned but not in operation and (b) rock, fluid, and reservoir characteristics are such that a reasonable doubt exists that the project will be commercial, and (5) reserves in an area of the formation that appears to be separated from the proved area by faulting and geological interpretation indicates the subject area is structurally lower than the proved area.

RESERVES STATUS CATEGORIES

Reserves status categories define the development and producing status of wells and reservoirs.

DEVELOPED

Developed reserves are expected to be recovered from existing wells including reserves behind-pipe. Improved recovery reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Developed reserves may be subcategorized as producing or non-producing.

Producing

Reserves subcategorized as producing are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Non-Producing

Reserves subcategorized as non-producing include shut-in and behind-pipe reserves. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future recompletion prior to the start of production.

UNDEVELOPED RESERVES

Undeveloped reserves are expected to be recovered: (1) from new wells on undrilled acreage, (2) from deepening existing wells to a different reservoir, or (3) where a relatively large expenditure is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

2000 DEFINITIONS FOR PETROLEUM RESOURCES
ADOPTED BY SOCIETY OF PETROLEUM ENGINEERS (SPE),
WORLD PETROLEUM CONGRESS (WPC), AND
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)

DEFINITIONS

The resource classification system is summarized in Figure 1 and the relevant definitions are given below. Elsewhere, resources have been defined as including all quantities of petroleum which are estimated to be initially-in-place; however, some users consider only the estimated recoverable portion to constitute a resource. In these definitions, the quantities estimated to be initially-in-place are defined as Total Petroleum-initially-in-place, Discovered Petroleum-initially-in-place and Undiscovered Petroleum-initially-in-place, and the recoverable portions are defined separately as Reserves, Contingent Resources and Prospective Resources. In any event, it should be understood that reserves constitute a subset of resources, being those quantities that are discovered (i.e. in known accumulations), recoverable, commercial and remaining.

TOTAL PETROLEUM-INITIALLY-IN-PLACE

Total Petroleum-initially-in-place is that quantity of petroleum which is estimated to exist originally in naturally occurring accumulations. Total Petroleum-initially-in-place is, therefore, that quantity of petroleum which is estimated, on a given date, to be contained in known accumulations, plus those quantities already produced therefrom, plus those estimated quantities in accumulations yet to be discovered. Total Petroleum-initially-in-place may be subdivided into Discovered Petroleum-initially-in-place and Undiscovered Petroleum-initially-in-place, with Discovered Petroleum-initially-in-place being limited to known accumulations.

It is recognized that all Petroleum-initially-in-place quantities may constitute potentially recoverable resources since the estimation of the proportion which may be recoverable can be subject to significant uncertainty and will change with variations in commercial circumstances, technological developments and data availability. A portion of those quantities classified as Unrecoverable may become recoverable resources in the future as commercial circumstances change, technological developments occur, or additional data are acquired.

DISCOVERED PETROLEUM-INITIALLY-IN-PLACE

Discovered Petroleum-initially-in-place is that quantity of petroleum which is estimated, on a given date, to be contained in known accumulations, plus those quantities already produced therefrom. Discovered Petroleum-initially-in-place may be subdivided into Commercial and Sub-commercial categories, with the estimated potentially recoverable portion being classified as Reserves and Contingent Resources respectively, as defined below.

RESERVES

Reserves are defined as those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward. Reference should be made to the full SPE/WPC Petroleum Reserves Definitions for the complete definitions and guidelines.

Estimated recoverable quantities from known accumulations which do not fulfill the requirement of commerciality should be classified as Contingent Resources, as defined below. The definition of commerciality for an accumulation will vary according to local conditions and circumstances and is left to the discretion of the country or company concerned. However, reserves must still be categorized according to the specific criteria of the SPE/WPC definitions and therefore proved reserves will be limited to those quantities that are commercial under current economic conditions, while probable and possible may be based on future economic conditions. In general, quantities should not be classified as reserves unless there is an expectation that the accumulation will be developed and placed on production within a reasonable timeframe.

In certain circumstances, reserves may be assigned even though development may not occur for some time. An example of this would be where fields are dedicated to a long-term supply contract and will only be developed as and when they are required to satisfy that contract.

CONTINGENT RESOURCES

Contingent Resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from known accumulations, but which are not currently considered to be commercially recoverable.

It is recognized that some ambiguity may exist between the definitions of contingent resources and unproved reserves. This is a reflection of variations in current industry practice. It is recommended that if the degree of commitment is not such that the accumulation is expected to be developed and placed on production within a reasonable timeframe, the estimated recoverable volumes for the accumulation be classified as contingent resources.

Contingent Resources may include, for example, accumulations for which there is currently no viable market, or where commercial recovery is dependent on the development of new technology, or where evaluation of the accumulation is still at an early stage.

UNDISCOVERED PETROLEUM-INITIALLY-IN-PLACE

Undiscovered Petroleum-initially-in-place is that quantity of petroleum which is estimated, on a given date, to be contained in accumulations yet to be discovered. The estimated potentially recoverable portion of Undiscovered Petroleum-initially-in-place is classified as Prospective Resources, as defined below.

PROSPECTIVE RESOURCES

Prospective Resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from undiscovered accumulations.

ESTIMATED ULTIMATE RECOVERY

Estimated Ultimate Recovery (EUR) is not a resource category as such, but a term which may be applied to an individual accumulation of any status/maturity (discovered or undiscovered). Estimated Ultimate Recovery is defined as those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom.

AGGREGATION

Petroleum quantities classified as Reserves, Contingent Resources or Prospective Resources should not be aggregated with each other without due consideration of the significant differences in the criteria associated with their classification. In particular, there may be a significant risk that accumulations containing Contingent Resources or Prospective Resources will not achieve commercial production.

RANGE OF UNCERTAINTY

The Range of Uncertainty, as shown in Figure 1, reflects a reasonable range of estimated potentially recoverable volumes for an individual accumulation. Any estimation of resource quantities for an accumulation is subject to both technical and commercial uncertainties, and should, in general, be quoted as a range. In the case of reserves, and where appropriate, this range of uncertainty can be reflected in estimates for Proved Reserves (1P), Proved plus Probable Reserves (2P) and Proved plus Probable plus Possible Reserves (3P) scenarios. For other resource categories, the terms Low Estimate, Best Estimate and High Estimate are recommended.

The term "Best Estimate" is used here as a generic expression for the estimate considered to be the closest to the quantity that will actually be recovered from the accumulation between the date of the estimate and the time of abandonment. If probabilistic methods are used, this term would generally be a measure of central tendency of the uncertainty distribution (most likely/mode, median/P50 or mean). The terms "Low Estimate" and "High Estimate" should provide a reasonable assessment of the range of uncertainty in the Best Estimate.

For undiscovered accumulations (Prospective Resources) the range will, in general, be substantially greater than the ranges for discovered accumulations. In all cases, however, the actual range will be dependent on the amount and quality of data (both technical and commercial) which is available for that accumulation. As more data become available for a specific accumulation (e.g. additional wells, reservoir performance data) the range of uncertainty in EUR for that accumulation should be reduced.

RESOURCES CLASSIFICATION SYSTEM

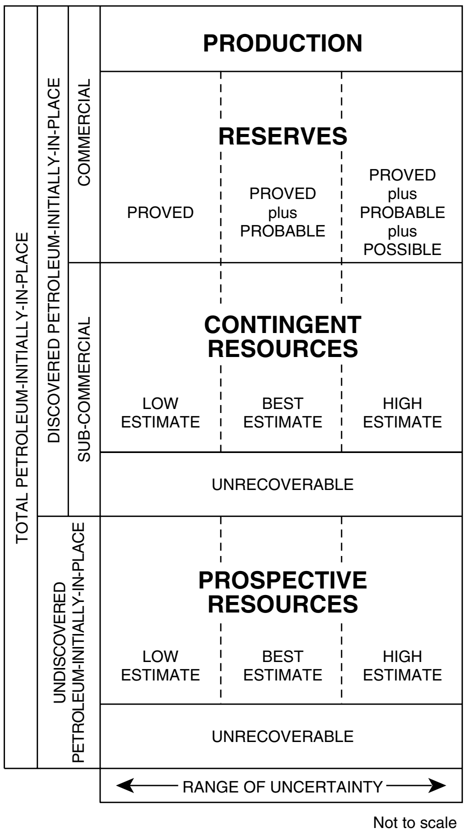
Figure 1 is a graphical representation of the definitions. The horizontal axis represents the range of uncertainty in the estimated potentially recoverable volume for an accumulation, whereas the vertical axis represents the level of status/maturity of the accumulation. Many organizations choose to further sub-divide each resource category using the vertical axis to classify accumulations on the basis of the commercial decisions required to move an accumulation towards production.

As indicated in Figure 1, the Low, Best and High Estimates of potentially recoverable volumes should reflect some comparability with the reserves categories of Proved, Proved plus Probable and Proved plus Probable plus Possible, respectively. While there may be a significant risk that sub-commercial or undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable volumes independently of such a risk.

If probabilistic methods are used, these estimated quantities should be based on methodologies analogous to those applicable to the definitions of reserves; therefore, in general, there should be at least a 90% probability that, assuming the accumulation is developed, the quantities actually recovered will equal or exceed the Low Estimate. In addition, an equivalent probability value of 10% should, in general, be used for the High Estimate. Where deterministic methods are used, a similar analogy to the reserves definitions should be followed.

As one possible example, consider an accumulation that is currently not commercial due solely to the lack of a market. The estimated recoverable volumes are classified as Contingent Resources, with Low, Best and High estimates. Where a market is subsequently developed, and in the absence of any new technical data, the accumulation moves up into the Reserves category and the Proved Reserves estimate would be expected to approximate the previous Low Estimate.

FIGURE 1 - RESOURCES CLASSIFICATION SYSTEM



ABBREVIATIONS

1P	unrisked proved
2P	unrisked proved plus probable
3P	unrisked proved plus probable plus possible
AAPG	American Association of Petroleum Geologists
ac-ft	acre-foot
BOPD	barrels of oil per day
EUR	estimated ultimate recovery
FMI	formation micro imager
Frontera	Frontera Resources Corporation
ft	feet
GAC	Georgia American Chinese Company
Georgia	Republic of Georgia
GRV	gross rock volume
HPV	hydrocarbon pore volume
km	kilometers
km^2	square kilometers
m	meters
M$	thousand United States dollars
MBO	thousand barrels of oil
md	millidarcies
MM$	million United States dollars
MMBO	million barrels of oil
NTG	net-to-gross
OOIP	original oil-in-place
P10	10 percent confidence level
P50	50 percent confidence level
P90	90 percent confidence level
PSA	Production Sharing Agreement
PVT	pressure-volume-temperature
S3	Sarmatian
SPE	Society of Petroleum Engineers
UKLA	United Kingdom Listing Authority
WPC	World Petroleum Congress

NETHERLAND, SEWELL & ASSOCIATES, INC.

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TECHNICAL EVALUATION
BLOCK 12, REPUBLIC OF GEORGIA

1.0 Overview

In accordance with your request, we have conducted a technical evaluation of certain producing properties and exploration prospects within Block 12, located onshore in the Republic of Georgia (Georgia), for Frontera Resources Corporation (Frontera). Block 12 is located within the Kura Basin, an east-west oriented restricted basin which spans from eastern Georgia to central Azerbaijan (Figure 1). The basin is constrained between the Caucasus Mountains, with the Greater range to the north and the Lesser range to the south.

The Kura Basin's western margin is bordered by the Dzirula Massif which separates it from the Rioni Basin to the west. The Western Kura Basin covers an area of approximately 10,000 square kilometers (km^2) and has an elevation of 450 meters (m) above sea level. It slopes southeastward to the Caspian Sea where the eastern shoreline is at an elevation of 28 m below mean sea level. The Block 12 exploration permit area encompasses 5,160 km^2 along Georgia's eastern border with Azerbaijan, and historical exploration activity to date has resulted in 8 field discoveries within the Block (Figure 2). However, only 3 of these fields (Tarabani, Mirzaani, and Patara Shiraki) were actually ever placed on production.

In this study, we have conducted a reserve evaluation of the proved, probable, and possible reserves for Tarabani Field. However, the scope of our evaluation was limited to only 4 of 14 potentially productive zones in the field. A total of 41 wells have been drilled in Tarabani Field, most of which encountered mechanical problems due to high reservoir pressures in combination with substandard drilling practices, materials, completion practices, and sediment influx. The primary reservoir drive mechanism at Tarabani is determined to be pressure depletion. The first few wells in the field were drilled in the 1930s, yet initial production did not commence until 1963 from the Tarabani-9 well. In Tarabani Field there are currently 5 active wells producing at a total rate of approximately 20 barrels of oil per day (BOPD); cumulative field production to date from 11 wells has been approximately 550 thousand barrels of oil (MBO), generally of 36-degree API gravity.

In addition, we also conducted an assessment of the prospective hydrocarbon resources associated with selected prospects identified within Block 12. Frontera has identified a number of prospects or leads thus far, and we were asked to evaluate 9 of these to determine the range of recoverable prospective resources associated with each. Some of these prospects are, in fact, field discoveries that were never placed on production or adequately appraised. In conducting our evaluations we have reviewed the drilling history, test and production data, regional geology, well logs, seismic data, various reports, and interpretive data supplied by Frontera. We conducted an independent analysis of key well logs and seismic data to define field and prospective areas and to assess the variability in reservoir parameters. Original oil-in-place (OOIP) was estimated using a spreadsheet-based Monte Carlo simulation model. The spreadsheet model is based on a range of probability distributions of reservoir variables and gross rock volume (GRV) input to the Monte Carlo simulation. Development plans for Tarabani Field and key prospects were also reviewed so that potential hydrocarbon flowstream projections and estimates of net present worth could be generated for successful case developments. All prices, costs, and revenue estimates are expressed in United States dollars referred to hereinafter as $.

Our analysis of the Block 12 concession consisted of the following steps.

- Data collection, compilation, and formatting.
- Review of the extensive database, reports, and interpretations.
- Independent interpretation of seismic and well log data as necessary.
- Evaluation of pressure-volume-temperature (PVT) properties, test data, and production histories.
- Determination of estimates of in-place and recoverable hydrocarbon volumes by field and prospect.
- Assignment of reserve and resource categories.
- Preparation of an economic model according to the terms of the concession contract.
- Generation of production forecasts and economic projections for possible reserves and selected prospective resources.

This report provides an overview of the contractual terms of the Block 12 concession, a brief review of the database available for this evaluation, a regional geological overview of Kura Basin, and a discussion of the technical approach used in our analysis of Tarabani Field and prospects that were reviewed.

1.1 Overview of PSA Terms

Frontera, as the concession operator, retains Block 12 as an exploration permit and holds a 100 percent working interest. Financial obligations are satisfied and acreage is held by Frontera through 2012. Fields are held until 2022 with an extension to 2027 if the fields are commercially viable. Five existing field discoveries, including Tarabani Field, have been designated as Exploitation Areas under terms of the production sharing agreement (PSA). Agreements with the government of Georgia allow Frontera to maintain 49 percent of all oil and gas profit, and the government pays all taxes on behalf of Frontera and the state oil company.

A summary of the concession terms and work program requirements are provided below.

The Initial Exploration Phase for Block 12 was granted for a 7-year period from June 1997 to June 2004 and encompassed a permit area of 5,160 km^2. The Second Exploration Phase was entered into June 2004 for an additional 8 years. All obligations for these phases have been satisfied through June 2012.

Key PSA terms with the government of Georgia regarding cost recovery are summarized below.

- Operating Costs reimbursed from 100 percent of revenues
- Capital Expenditures
  - Reimbursed 100 percent from 100 percent of annual block revenues during exploration.
  - Reimbursed 100 percent from 80 percent of annual block revenues after commerciality is declared, except on 5 existing fields.
  - Reimbursed 100 percent from 60 percent of annual block revenues after commerciality is declared on 5 existing fields.
  - No amortization of costs (expenditures can be recovered immediately).
  - Fields are held for 25 years.
  - Taxes paid by state oil company.
- Profit oil (revenues remaining after cost recovery)
  - 51 percent to state oil company.
  - 49 percent to Frontera.

2.0 Data Sources

To complete our technical evaluation of Block 12, Frontera allowed complete and open access to its current technical data. These data included several independent reports by Schlumberger, Hellenic Oil, Miller & Lents, PGS Reservoir, ResTech, Object Reservoir, and Ryder Scott. Over 5,000 kilometers (km) of 2-D seismic data of various vintages ranging from 1966 to 1999, as well as a 150-km^2 3-D seismic survey over Tarabani Field that was acquired in 1999, were made available in a digital format for review (Figure 3). Frontera supplied its interpreted seismic time, velocity, and depth structure maps; well log cross sections; and various montages and displays of the drilling, production, and well test history of each field or prospect to review. Well logs and core data from the various reports were available for our review along with post-well drill reports; geochemical source rock evaluations; fracture characterization studies; and well completion, flow test, and production data. Petrophysical analyses conducted by ResTech and Schlumberger were also provided. Object Reservoir was contracted by Frontera to build finite element reservoir models and provide estimates for flow rates on future vertical and horizontal wells.

Well data provided included hardcopy and digital format well logs and interpretations conducted by Frontera and its various consultants. Reservoir objectives for Tertiary clastic play types, such as Tarabani, comprise the Shiraki Productive Series, which extends from the Upper-Miocene to Lower-Pliocene and are commonly referred to, from older to younger strata, as Zones XXV through IX. The scope of our Tarabani Field evaluation in this report covers only the fluvial sands IX and XIV and deltaic marine sands XV and XIX. However, for our prospective resource assessments our analysis considered the range of potential in the entire reservoir interval at each prospect. In addition, 2 prospects that were reviewed also target Cretaceous-aged sandstones and limestones.

A couple of the prospects reviewed were sparsely covered by 2-D seismic data, and analysis in these areas relied upon a combination of surface data and extrapolation of seismic data to estimate the range of prospective area; other prospects generally had good 2-D seismic coverage to define the structures. Seismic data quality is generally fair to good and adequate for imaging gross sequence boundaries, major faults, and trap geometry. However, internal reservoir characteristics and small-scale faulting are below the resolution of the seismic data.

3.0 Geological Overview — Kura Basin

3.1 Tectonic and Sedimentary History

The Western Kura Basin is a Late Tertiary back-arc basin formed as a result of Alpine and Himalayan compression. The basin geometry and its tectonic style have been shaped by multiphase tectonism associated with the collision, accretion, and rotation of the Transcaucasian, Iran-Afghan, Anatolian, and Arabian microcontinents which were caught between the Eastern European Platform and the African Plate. In response to varying stress fields, several structural elements developed, such as thrust belts, normal faults, inverted grabens, strike-slip faults, and associated structures. Within the tectonic setting, basement-related faults provide excellent conduits for short-distance migration of oil and gas from hydrocarbon generation kitchens up into the overlying structural closures. Moreover, decollement surfaces for the overlying thrusts have excellent sealing capabilities.

The following is a summary of the tectonic and sedimentary basin history.

1. During the Late Mesozoic, the Kura Basin comprised the eastern portion of the Tethys Sea, an open seaway connecting the Black Sea on the west and the Caspian Sea to the east.
2. Beginning 150 million years ago, the seaway began to close due to the northward migration of the African and Arabian plates and subduction into the static Eurasian plate.
3. Between 150 and 65 million years ago, the Indian plate also moved north to an eventual collision with Eurasia, producing the Himalaya mountain range and closing off the Tethys Sea.
4. These tectonic events gradually isolated the Black Sea from the Caspian Sea with the impending uplift of the western end of the basin in the vicinity of Tbilisi. The onset of the Cenozoic was marked by a period of worldwide anoxia, and the deposit of fine-grained, organic-rich marine sediments formed the Oligocene-aged source rock of the Maykop Formation.
5. Continued basin restriction due to tectonic movement isolated the seaway and formed a sedimentary basin by the end of the Middle Miocene. The Greater and Lesser Caucasus Mountains were formed, and sediments consisting of fluvial and deltaic forelands were shed off the uplift across a narrow apron into the northern margin of the basin. These sediments include rock fragments and relatively unstable minerals, indicating rapid erosion, transport, and pulses of prograding near-source deposition. Wave and storm activity often reworked the fluvial-deltaic sediments into a series of barrier bars and beaches, which generally paralleled the northern margins of the Kura Basin embayment. With continued infill of the basin, the deltaic complexes were preserved as either reworked or intact deltaic deposits.
6. By the Early Pliocene the basin filling process was marked by the continuing retreat of the shoreline of the Kura-Caspian embayment to the east of the Tarabani Field area. This final depositional event established an integrated fluvial drainage system, with sediments shed off both the Greater Caucasus from the north as well as the Lesser Caucasus from the south. The main drainage channels were oriented parallel to the axis of the Kura Basin, generally west-northwest to east-southeast, similar to the orientation of the present Kura River.

3.2 Trapping Geometry

In general, the trapping geometry for Tarabani Field and for all prospects reviewed are 3-way dip closures coupled with a bounding trapping fault. Tarabani Field provides a good analog to prospects other than the Basin Edge play type, in that the same compressional forces that created uplift within the basin are also the forces that have reactivated, and often inverted, normal faults to now be reverse faults which serve as the bounding trapping fault mechanisms. These faults and forces are also the main conduits of oil migration and source rock juxtaposition with regard to charging potential reservoir rocks. These faults are characterized as having little present-day displacement on them and can internally be normal, reverse, or slip-strike in nature. This type of transpressional system is often conducive to fracturing, which could greatly enhance reservoir productivity. In the fluvial reservoir section, stratigraphy often plays a part in the trapping mechanism.

The Mesozoic Basin Edge prospects differ from the Tertiary clastic play types in that these plays are set up by the thrusting of older Jurassic carbonates and Cretaceous sandstones and limestones over the younger Maykop source rocks and other sediments. The Basin Edge prospects are on the leading edge of a large thrust sheet adjacent to a deep prospective hydrocarbon source basin where light oil and gas are likely generated. This sourcing potential is demonstrated by shows in the Kirsa-1 well, located downdip of the Basin Edge B Prospect, as well as in methane gas that bubbles freely from nearby water wells. The Basin Edge plays are associated with inversion of the Greater Caucasus Mountains, and their reservoir targets can be found in outcrop at various locales along the basin margins. Fractured sandstone and carbonates are thought to constitute good quality reservoir rocks analogous to those found in the recent Manavi-11 well drilled by CanArgo Energy Corporation, which tested and flowed 35-degree API oil at high rates some 50 km to the northwest on trend with this basin edge play.

3.3 Reservoir Properties

The Western Kura Basin is asymmetric, with its axis located closer to the Greater Caucasus Mountains to the north. Figure 4 is a regional stratigraphic column showing the major lithologic sequences in the basin. The basin fill consists of 10 to 15 km of Mesozoic and Cenozoic sediments underlain by a crystalline basement. This thick sediment cover was derived from both the Greater and Lesser Caucasus Mountains, with locally thick sediment input from the Dzirula Massif. The basin developed as a northwest-trending embayment where both fluvial and marine sediments are aligned in a predominant northwest-southeast trend and are stacked vertically. This has resulted in the development of multiple reservoir objectives over each structure, reducing the reservoir risk of each play.

The principal reservoir objective in Tarabani Field is the Miocene-Pliocene interval which consists of approximately 2,700 m of clastic sandstones and shales divided into 3 major sequences. These 3 major sequences are a shallow fluvial and transitional facies between 2,300 and 2,600 m, a deltaic nearshore marine facies between 2,600 and 3,500 m, and a deep marine sequence (Middle Sarmatian shale and Middle Miocene deepwater fan sediments) between 3,500 and 5,000 m. Production in the basin has been established between 2,000 and 2,600 m, with oil shows down to 3,500 m. Total net pay per well ranges from 25 to 90 m, or 80 to 275 feet (ft), with individual reservoirs ranging in thickness from 3 to 36 m (10 to 120 ft).

Sandstone porosities in the Shiraki productive interval in Tarabani Field range from 14 to 22 percent with an average of 19 percent. Porosities have been more favorable locally west of Tarabani with regard to high-end values; however, porosities lower than 14 percent have also been noted in areas such as the Kila Kupra and Iori Field Complex. Net-to-gross (NTG) ratios in Tarabani Field fluctuate from 6 to 25 percent with an average of 11 percent, although NTG ratios as high as 35 percent have been encountered in some wells. Average water saturation is 53 percent for all zones.

Permeability in most of the reservoirs has been very low and provides the greatest risk to commercial production rates being achieved. However, potential fracture enhancement near major faults as a result of the tectonic reactivation in the basin may provide enhanced permeability and better reservoir quality.

3.4 Source Rock

The primary hydrocarbon source in the Kura Basin is the Oligocene-Miocene age Maykop shale. It was deposited during a worldwide anoxic (oxygen-starved) event within a restricted basin environment. Basin modeling performed by Frontera suggests that, within the Western Kura Basin oil-generation kitchen, the Maykop shales are characterized by marine Type II kerogen (with local concentrations of Type III kerogen near the basin edges) and total organic carbon content between 1.0 and 10.0 percent. Oil generation and expulsion have occurred since the Pliocene (2.2 Ma) with most of the Maykop shales currently within the peak oil generation window (4,000 and 5,200 m).

3.5 Seal

As a result of intermittent pulses of sedimentation, each of the Shiraki Series sands are separated by thick, laterally continuous shale and siltstone overbank, splay, and marine deposits which isolate each reservoir sand. These fine-grained sediments act as seals and vertical barriers between zones in Tarabani Field as well as in prospects of the Tertiary clastic play types.

3.6 Production Characteristics

Only 3 fields have been placed on production within the Block 12 permit area. However, other fields to the west have produced or are currently producing. Shallow reservoirs, like those producing at Mirzaani, have produced oils with a range of 34- to 38-degree API gravity. Pliocene and older reservoirs, below 1,500 m, tend to yield slightly lighter oils with API gravities in the high 30s and ranging as high as 45 degrees in some reservoirs. The high pressures encountered in many of the reservoirs, coupled with the high shale and siltstone content of the reservoir section, often results in flowing shale sediments into the wellbores, limiting the productive capacity and duration of producing wells to date.

4.0 Tarabani Field

4.1 Exploration and Development History

The concepts of exploiting possible oil accumulations in Kura Basin were facilitated by the presence of apparently favorable geologic structures in the region in combination with the numerous oil and gas seeps throughout the area. The first well drilled in Tarabani Field was the Tarabani-1 well in 1933. During the 1930s a total of 5 wells were drilled. Drilling in the field was then put on hiatus until the 1950s when an additional 2 wells were drilled. Main Tarabani Field development occurred between 1962 and 1982, over which time 34 additional wells were drilled. Objective formations include the Pliocene Shiraki Formation (Zones IX through XIII) and the mid-to-upper Miocene Sarmatian Formation (Zones XIV through XXV). Production of oil commenced in 1963 with the successful completion of the Tarabani-9 well.

Prior to Frontera's own drilling activity, a total of 41 wells were drilled in the field, of which only 10 wells ever produced oil. Only 7 wells have been drilled below Zone XXII due to drilling and well control problems. Wells were typically drilled overbalanced with 17- to 20-pound-per-gallon mud. Poor completion techniques, which included the practice of perforating across shales with the sands, greatly contributed to production of solids, clogging of perforations, and lack of initial pressure information as well as uncertainty as to which zones actually contributed to overall production. Prior to the drilling of the Niko-1 well by Frontera in 2000, 5 wells were still on production. Those presently producing include the Tarabani-22, 23, 25, 32, and 34 wells with nearly half of the total field cumulative oil coming from the 23 well. This high yield has likely come at the expense of nearby wells, 32 and 34, which are downdip and have never reached the production levels of the Tarabani-23 well. These 3 wells are separated by just 540 m.

Total field production to date for Tarabani Field is approximately 550 MBO. Oil gravity is generally between 35 and 41 degrees API with an oil saturation range between 30 and 65 percent. Recovery efficiency is thought to be as high as 20 percent with a depletion drive mechanism. Effective permeability is between 1 and 100 millidarcies (md), although localized fracturing could enhance communication. Porosity averages are approximately 20 percent field wide and consistent throughout the various zones.

Frontera assumed an ownership role of Block 12 in 1997. Its staff has performed the necessary, yet resource-consuming, steps of acquiring new 2-D and 3-D seismic data to tie to older vintage 2-D regional seismic data and has reprocessed a significant volume of the older 2-D seismic data. In addition they did extensive regional mapping in combination with outcrop studies, fracture analysis, source rock evaluation, and prospect generation to evaluate many of the opportunities and plays within the block. Their outcrop studies have also led to new concepts for potential deepwater marine deposits that have yet to be explored.

Frontera's first well, the Niko-1 well was spud in November 1999 and was completed as an oil well in May 2000 after reaching a total depth of 3,410 m (11,224 ft). The well was originally designed to test the marine interval with main objectives in Zones XXIII and XXIV. Due to mechanical difficulty a 7-inch liner was set early, and the well was open-hole-tested in those main objectives. The well flowed during cleanup at approximately 100 BOPD from Zones XXIII through XXV. These zones were later commingled on a long-term production test, with a cased-hole interval at Zone XIX, and flowed at a combined rate of 960 BOPD. Niko-1 production rates were cut back to 460 BOPD for fear of sediment production. For the first 10 days of testing, the flow rate dropped to 300 BOPD. Wellhead pressure fell, by design, from around 6,000 to 5,000 pounds per square inch during the first couple of days and was maintained around 5,000 pounds per square inch for the remainder of the test period. The well flowed for 40 days until it eventually became clogged with sediment. Later analysis of production history suggested that as much as 40 percent of the production was attributed to Zone XIX with the remainder coming from the open hole. The well produced 5,345 barrels during the 40-day test, and it represents the eleventh well to have produced oil in the field.

Georgia American Chinese Company (GAC) farmed into Block 12 for a brief period with a 50 percent working interest and took over the role of Operator. GAC drilled a second well, Dino-2, and it was spud on October 31, 2003, and is located north of the Tarabani-23 well and immediately south of Tarabani-9. The well was targeting the Shiraki and Upper Sarmatian sands with a proposed total depth of 2,744 m. This well reached a total depth of only 1,760 m and was temporarily suspended after setting intermediate casing and before reaching any of the objective reservoirs in March 2004 when GAC encountered financial difficulty. Frontera has now resumed full ownership and again serves as operator of the block. It is important to note that no well drilled within Tarabani Field to date has encountered an oil-water contact, and our reserve estimates for the field utilize only the lowest known perforation of the deepest well that tested oil for any given zone.

Future scheduled completion practices such as drilling lateral extensions from existing wells could have a favorable impact on production rates while lowering drilling costs. Multiple laterals would target specific sands and reduce the adverse effects of perforating into areas that are prone to sediment influx. Workovers performed by Frontera have had little success in the past at reestablishing initial production rates, whereas elsewhere in the basin, drilling of lateral extensions from existing wells has demonstrated that such horizontal extensions can outperform the original vertical wells, in some cases reportedly as high as 15:1. Performing successful workovers in horizontal wellbores using conventional equipment to maintain flow rates is difficult. Coiled tubing and underbalanced lateral drilling technology now available may provide a more efficient and cost-effective solution to managing sediment influx and increasing production rates.

4.2 Reservoirs

For the purposes of this report and at the request of Frontera, only Zones IX, XIV, XV, and XIX have been evaluated at Tarabani Field. Each of these zones have similar crude characteristics of low solution gas-oil ratio of 200 standard cubic feet per stock tank barrel, approximately 35-degree API oil, an oil formation volume factor of 1.1 reservoir barrels per stock tank barrel, and a bubblepoint pressure of 1,200 pounds per square inch gauge. Net reservoir sand mapping is based upon a shale volume cutoff of 40 percent, minimum porosity of 8 percent, and a maximum water saturation of 65 percent. A total of 10 wells have produced measured volumes of approximately 550 MBO from Tarabani Field.

4.2.1 *Zone IX*

Zone IX is composed of shale and siltstones deposited as overbank and splays capped by a fluvial sandstone representing channel features of a braided floodplain. The channels are oriented parallel to the basin axis where alluvial streams were oriented west-northwest to east-southeast and transporting sediments from the west-northwest toward the Caspian Sea. Gross thicknesses of the total unit range from 47 m at Tarabani-18 well to 62 m in the north of the field encompassing the Tarabani-44, 20, and 38 wells. Net sand mapping reveals thicknesses of up to 18 m generally oriented west to east with an accumulation at the westernmost control point, Tarabani-12, that suggests that the depositional mechanism persists to the west of Tarabani Field. Hydrocarbon pore thickness for Zone IX reaches a maximum of 1.9 m at the Tarabani-31 well and recorded 1.2 m at both Tarabani-22 and 23 wells.

Twelve wells had evidence of oil when perforated in Zone IX. Tarabani-16, 23, and 34 had the largest volume of oil produced from Zone IX with accumulations from the 23 well exceeding 700 BOPD during initial production. Five wells had no flow and 4 either produced only water or an oil-water mixture. Tarabani-14 is the deepest Zone IX perforation that produced any oil, and the deepest Zone IX perforation in this well is considered the low known oil for the zone. Due to the commingled nature of completion practices in Tarabani Field, it is unknown exactly which zone is contributing to the oil production or how to quantify that amount when other zones have also been perforated and demonstrate hydrocarbons.

4.2.2 *Zone XIV*

Zone XIV is composed of shale and siltstones deposited as pro-delta fronts capped by sandstones representing distributary channels within a lobate delta fanning relatively to the south. The base of the sand unit as it appears in the Niko-1 core is erosive to the underlying fine-grained portion of Zone XIV. Even within the underlying siltier sections of core, angular rip-up clasts are noted and suggest rapid deposition and preservation. Net sand distribution demonstrates that the greater accumulations of sand are located in the center of the field in the area between the Tarabani-20 and Tarabani-23 wells as well as an isolated lobe in the vicinity of the Tarabani-21 well. Gross unit thickness varies from 101 m at the northernmost well, Tarabani-40, to 87 m at the southeasternmost well, Tarabani-6. Hydrocarbon pore volumes (HPV) generally parallel high values of sandstone distribution with the exception of the northern portion of the field. The westernmost control point, the Tarabani-12 well, has sand accumulations that suggest deltaic deposits exist to the west of Tarabani Field within Zone XIV. Maximum HPV thickness is found near the Tarabani-20 (1.8 m) and the Tarabani-21 (1.9 m) wells where the reservoir is of high quality. This is likely a result of reworking of sediments and the removal of silty materials.

Five wells had evidence of oil when perforated in Zone XIV. The largest tests have come from the Tarabani-18 and 21 wells in the east and in the center of the field from Tarabani-21 to Tarabani-31. The largest producer of Zone XIV is the Tarabani-9 well which produced some 75 MBO from 1963 until 1966 and initially flowed at a peak rate of 875 BOPD. Four wells had evidence of water and are spread throughout the field in wells 8, 10, 20, and 24. Six other wells recorded no flow for this interval. Tarabani-21 is the deepest Zone XIV perforation that produced any oil, and its deepest perforation is considered the low known oil for the zone. As mentioned previously, due to the commingled nature of completion practices in Tarabani Field, it is unknown exactly which zone is contributing to the oil production or how to quantify that amount when other zones have also been perforated and demonstrate hydrocarbons.

4.2.3 *Zone XV*

Zone XV is composed of shale and siltstones capped by sandstone in what is interpreted as a fluvial-deltaic depositional setting generally correlative to outcrop exposures of this unit at Lake Tarabani. The gross interval thickness trend for the field is roughly parallel to the basin axis. Net sand trends differ from the gross trend in that several wells recorded little or no pay mainly to the north in the Tarabani-40 and Tarabani-19 wells. Large accumulations of sand in the Tarabani-40 do not translate into large net sand accumulations at this site due to negligible reservoir quality. This mapped thickness of poor quality sand is thought to represent either overbank deposits, a silty sand-filled channel, or could imply that the northern section of the field was subjected to less sediment reworking, thus causing it to be siltier than those sands to the south. Thick net sand values at the Tarabani-12 well again suggest further deposition on the west side of the Tarabani structure. Gross interval thickness for Zone XV range from 87 m in the northernmost well, Tarabani-40, to 67 m in the east recorded at the Tarabani-8 well.

Five wells had evidence of oil when perforated in Zone XV. The largest initial rates came from the Tarabani-31 well which tested at 730 BOPD, though it never contributed to total accumulations from this zone. Contributions to total production of Zone XV came solely from the 32 and 34 wells. The Tarabani-12 well is the only well in the zone to have tested water. Two other wells, the 13 and 14, had no flow recorded. Tarabani-8 is the deepest Zone XV perforation that tested any oil, and its deepest Zone XV perforation is considered the low known oil for the zone even though this well was never a producer for the zone. Again, due to the commingled nature of completion practices in Tarabani Field, it is difficult to determine exactly which zone is contributing to the oil production or quantify that amount when other zones have also been perforated and demonstrate hydrocarbons.

4.2.4 *Zone XIX*

Zone XIX is comprised of interbedded siltstones and sandstone derived from a combination of fluvial channels and shallow marine littoral sands of the Upper Sarmatian Eldari Formation. The interconnectivity of sands for this zone is probably low, and they are considered to be a secondary objective in most cases. Gross interval isopach mapping for Zone XIX demonstrates a thick deposit in the vicinity of the newly drilled and centrally located Niko-1 well. Thickness values range from 51 m at the Niko-1 well to 34 m in Tarabani-12, the westernmost well, and 43 m in the easternmost well, Tarabani-21. Net sand thickness reaches its maximum at the Tarabani-39 well where it reaches 13 m with a field-wide average of 5 m.

Three wells, including Niko-1, have tested oil with water in Zone XIX. One well, the Tarabani-10, had no flow for this horizon. Of the 3 wells testing oil, only the Niko-1 well has ever produced any oil from this zone. It produced nearly 10 MBO over a 5-month testing period from July through November 2000. This was from the cased-hole section of the Niko-1 well. Tarabani-21 has the deepest Zone XIX perforation that produced any oil, and its deepest Zone XIX perforation is considered the low known oil for the zone. Due to the commingled nature of completion practices in Tarabani Field, it is unclear as to exactly which zone is contributing to the oil production; however, for the Niko-1 well it has been calculated that 40 percent of all production comes from Zone XIX.

4.3 Technical Evaluation

Our technical evaluation of Tarabani Field involved independent analyses of the geological, geophysical, petrophysical, and engineering data available to derive estimates of the OOIP and estimated ultimate recovery (EUR) as classified under the definitions of the United Kingdom Listing Authority (UKLA), Society of Petroleum Engineers (SPE), World Petroleum Congress (WPC), and the American Association of Petroleum Geologists (AAPG). We also assessed the development plans, along with estimated capital expenditures and operating costs provided by Frontera, to derive estimates of the flowstreams and future net revenue attributable to the Frontera interest.

4.3.1 Geology

An independent review of all pertinent geologic aspects of Tarabani Field and Block 12 prospects, with regard to hydrocarbon resources, was conducted for the purposes of this report. Frontera supplied data and documents regarding geology, petrophysics, geophysics, and production histories available under the terms of this agreement.

Well logs, perforation information, and 3-D seismic data were loaded into our geologic database, and an independent analysis was performed initially over the Tarabani Field area. Stratigraphic tops provided by Frontera were verified and in some cases modified in the initial phase of analysis. Correlation was conducted for top of Zone IX to top of Zone XX to capture the entire requested stratigraphic sequence of the Shiraki productive series. An interpreted well log depicting typical log response for Zone IX through XXI at Tarabani is provided (Figure 5). A viewing of the Niko-1 core was utilized for conceptual development regarding facies for Zone XIV and below.

Upon completion of the stratigraphic correlations of all Tarabani Field wells with available petrophysical logs, equivalent time-interpreted horizons to those correlated events from the seismic data were examined for reasonable depth conversion results. Upon validation of realistic velocity measures field wide, structure mapping commenced from the top down. Tarabani Field on its own has enough well control to afford good structure mapping results; however, it is often useful to examine the velocity fields for possible anomalies and fault detection. Faults within Tarabani Field often have little throw (less than 20 m) yet can act as barriers in reservoir sands less than 10 m thick. Such small offsets along faults are below seismic tuning thickness in these data. To address this, a common seismic attribute known as coherency was applied to the seismic data set in an effort to improve small-scale fault detection. Observed faults were interpreted and positioned for purposes of structural mapping integration. Faults in Tarabani Field are high angle and can be slip-strike, normal, or reverse in nature.

Seismically, Tarabani Field was interpreted for top of Zones IX, XIV through XV, and XIX. Structure mapping originated with Zone IX, and all subsequent zone tops are mapped based on isopach thicknesses from one horizon to the next. Isopach grids were not allowed to go beyond or below isopach values from zone well values. This procedure produced extremely conformable structure maps throughout the productive series as seen in the cross section in Figure 6. A seismic line extracted from the 3-D seismic survey which mimics the path of the cross section and demonstrates the continuity of Zones IX, XV, and XIX in the seismic data is shown in Figure 7. Upon depth mapping of Zones XIV through XV and XIX, additional velocity analysis was performed to validate time interpretations of the various horizons from the seismic data.

Tarabani Field is composed of a western fault block which contains no well penetrations and an eastern block that has 41 well penetrations. It is speculated that the presence of a low-velocity localized conglomerate directly overlying the western portion of the field has produced distortion in seismic travel time, commonly referred to as a "push-down" feature. Frontera attempted to estimate this velocity anomaly and adjust the depth structure to reflect this condition. This adjustment was adopted with consideration that volumetrically it would have little impact on reserves in that block.

Petrophysical analysis was performed on each Tarabani well with appropriate log suites in order to obtain porosity, NTG, and water saturation values at the wellbores. These values were subsequently mapped for each zone, and HPV maps were generated by multiplying the input grids shown in the formula below.

GRV x NTG x porosity x (1-water saturation) = HPV

The units for GRV are in acre-feet, and those for NTG, porosity, and hydrocarbon saturation (1-water saturation) are in decimal percent.

An HPV map was produced for each zone and volumetrics were calculated. Structure maps, as well as gross rock, net rock, and HPV maps for each of the objective zones of Tarabani Field are provided in Figures 8 through 23. Red polygon outlines on the maps delineate regions inside which volumes were calculated. Volumes from the HPV maps were used in determining estimates of the original in-place hydrocarbons.

The procedures described here facilitated the integration of Tarabani Field parameters to analogous prospects throughout the Block 12 area. In summary, these procedures included the stratigraphic correlation of all Tarabani wells; 3-D seismic interpretation of horizons and faults within Tarabani Field; velocity validation and structure mapping; petrophysical analysis and mapping; interpretation of 2-D lines intersecting 3-D volume to provide continuity; velocity validation for mapped prospects; and applying analogous petrophysical parameters and gross rock thickness to prospects.

4.3.2 *Geophysics*

Frontera supplied 2-D seismic data, and in the case of Tarabani Field, 3-D seismic data were available. Please refer to Figure 3 for a base map showing the seismic data coverage over Block 12 (seismic lines are shown in black). All the seismic data have a 750-m datum correction applied to accurately tie well control. At Tarabani, we reviewed depth conversion methodology and accuracy of depth structure maps provided for the 4 horizons of interest (IX, XIV, XV, and XIX). Synthetics, developed by Frontera, were reviewed and tied to seismic data. We created a coherency cube, which is a seismic trace attribute, so as to further investigate structural and reservoir components with particular emphasis on potential for additional faulting that might enhance fracture development and well placement. Our results from interpreting the coherency attributes were inconclusive in the confirmation of smaller faults. From our analysis we have concluded that Frontera adequately depth-converted its seismic time maps of Tarabani Field to depth.

4.3.3 *Petrophysics*

The data available for the evaluation consisted of a set of Western well logs from the Niko-1 well drilled in 2000, core analysis data from sidewall and conventional cores taken in Niko-1, Russian well logs from 31 wells drilled between 1953 and 1982, and petrophysical data gathered from the analysis of outcrops of the formations productive in Tarabani Field. Reports concerning previous petrophysical evaluations by Schlumberger and ResTech were also available for review.

The basic methodology employed in the petrophysical evaluation involved the following processes.

- Calibration of the modern Western log data from Niko-1 to the available core measurements.
- Selection of a water saturation model consistent with the observed reservoir lithology and clay/shale distribution.
- Interpretation of the sparse Russian log data set under constraints established with the modern log and core data.

Because of the difficult drilling environment, the overall quality of the petrophysical data available for this evaluation is poor. As a result, considerable uncertainty exists in the interpretation results. The petrophysical evaluation was confined to Zones IX, XIV, XV, and XIX.

In calibrating the log measurement data recorded in Niko-1, it was necessary to shift the bulk density log data in order to bring the log measurements into agreement with the available conventional core grain density and porosity measurements. It is not clear whether the original bulk density measurements were too high as the result of errors in field calibration or as the result of the very high levels of barite in the drilling mud system. A uniform shift was applied over the entire logging interval.

A gamma ray-based shale volume model was developed based on analysis of the available conventional core data, the formation micro imager (FMI) data, and the analysis of neutron-density log separation in cored shale-bearing intervals. A standard nonlinear gamma ray scaling (Stieber relationship) was found to provide the best match to the available independent shale volume estimates. In intervals with incomplete or questionable gamma ray measurements, shale volume was estimated from the bulk density, neutron, and deep resistivity measurements.

In intervals with good log quality, porosity was calculated from shale-corrected bulk density measurements. In washed-out intervals and in an interval where the density tool was not properly decentralized, porosity was calculated from sonic log measurements. The density log interpretation parameters were selected to bring the log-calculated porosities into agreement with the conventional core porosity measurements. Sonic interpretation parameters were selected to bring the sonic and bulk density-based porosity estimates into reasonable agreement in non-washed-out intervals.

Comparison of percussion sidewall core porosity and permeability measurements with conventional core measurements in intervals where both were collected indicated that the sidewall porosity and permeability estimates were too high. This is likely the result of plug damage during percussion sidewall acquisition. Oil saturation estimates from the sidewall cores were used to identify nonpay intervals for the purposes of calibrating the water saturation model.

A modified dual water model (standard Juhasz implementation) was used to make the water saturation estimates. This model assumes that the conductivity associated with authigenic clays and the clays associated with shale inclusions within the productive sands operate in a laminar geometry. This is consistent with the clay and shale geometry observed in the cores, FMI images, and surface outcrops of the formations that are productive in Tarabani Field. Clay conductivity was estimated from the deep resistivity measurements in thick shales bounding the reservoir sands. Formation water resistivity was derived from Tarabani produced water measurements.

Permeability was estimated from the log-derived porosity and shale volume estimates using a model developed by Core Laboratories for Miocene age rocks. Adjustments were made to the model parameters to bring the permeability estimates into agreement with conventional core measurements.

For the Russian well logs, slight revisions were made to the resistivity, shale volume, and porosity modeling approaches originally proposed by ResTech. These modifications were necessary to bring the original ResTech interpretation into better alignment with the interpretation results from Niko-1. Shale volume, porosity, and permeability constraints were defined for Zones IX, XIV, XV, and XIX based on the core and log interpretation results from Niko-1. A nonlinear scaling was applied to the ResTech shale volume estimates to bring the predicted shale volumes into better agreement with the core and FMI-based estimates derived for each zone. Modifications were made to the shale volume-based porosity model to bring the porosities from the analysis of the Russian logs into agreement with the levels observed at Niko-1. Water saturation estimates were made using the revised shale volume and porosity estimates with the deep resistivity estimates from the BKZ resistivity processing originally carried out by ResTech. The modified dual water model discussed above was used for the water saturation calculations.

Permeability estimates for the Russian well logs were made using the modified Core Laboratories model discussed above. As the result of the likelihood of a natural fracture component in Taribani Field, significant oil production from low-permeability rock (less than 1 md) is possible. Review of the available core data indicates that a significant drop in permeability (to less than 0.01 md) consistently occurs when the porosity falls below 8 percent. Economic production from 0.01 md rock is unlikely; therefore, an 8 percent porosity cutoff was applied. Relative permeability modeling indicates that oil will likely become immobile as water saturations exceed 65 percent. Visual analysis of the cores using log-calculated shale volume estimates indicates that reservoir quality significantly diminishes when the shale volume approaches 40 percent. As a result of these analyses, net pay was defined using a porosity cutoff of 8 percent, a water saturation cutoff of 65 percent, and a shale volume cutoff of 40 percent.

4.3.4 *Engineering*

Tarabani Field is defined by 41 wells drilled to date. Cumulative field production from the 11 producers has been approximately 550 MBO, and the 5 currently active wells produce approximately 20 BOPD. The field is located close to some existing infrastructure as production is transported by truck and rail for export via the Black Sea.

The Niko-1 well is the most recent well and was drilled in 2000. The nearly vertical well penetrated down through Zone XXV and was subsequently tested in Zone XIX. The well tested at short-term rates as high as 450 BOPD. The well is currently shut-in due to sediment production problems.

In the Frontera development plan, the development wells are forecast to be dual short-radius horizontal wells. For this analysis, each well is expected to be dedicated to only 1 zone. Recovery factors of 15 percent have been estimated to calculate recoverable possible reserves. This recovery factor reflects the uncertainties of drive mechanism, fracture intensity, fracture extent, and drainage areas for the wells. Associated gas production has not been considered in this analysis.

4.3.5 *Original Oil-in-Place and Recoverable Oil Reserves*

Deterministic mapping of the net pay and other petrophysical parameters for the 4 reservoirs studied in this evaluation resulted in a total OOIP estimate of 788.3 millions of barrels of oil (MMBO) and an EUR of 118.2 MMBO as shown below and in the table in Figure 24.

	Gross Unrisked (100 Percent) Oil (MMBO)			
Horizon	**OOIP**	**EUR**	**Cumulative Production**	**Possible Reserves**
Zone IX	134.01	020.10	N/A	N/A
Zone XIV	221.94	033.29	N/A	N/A
Zone XV	334.07	050.11	N/A	N/A
Zone XIX	098.26	014.74	N/A	N/A
Total	788.28	118.24	0.55(1)	117.69(1)

(1) Cumulative production figures by zone are not well documented.

These reserves are classified as possible reserves; it should be noted that the listing rules of the UKLA do not include possible reserves. The possible reserves shown in this report follow the definitions for reserves adopted by the SPE/WPC/AAPG. These definitions, for both the UKLA and the SPE/WPC/AAPG, are included after the cover letter of this report.

As stated earlier, cumulative production to date at Tarabani Field is approximately 550 MBO, and the field actively produces oil at very low rates from 5 wells. However, the current production rates are uneconomic under existing economic and operating conditions, and thus no proved reserves exist in this field. Moreover, there are several significant technical challenges that must be overcome to demonstrate that these 4 reservoirs can be produced at sustained economical rates of production. Due to the multiple technical risks and production histories to date, we categorize all the estimated recoverable reserves at Tarabani Field as possible reserves with no proved or probable reserves. However, if Frontera demonstrates the success of planned potential new drilling and completion techniques, we would envision that a small portion of these possible reserves would move to the proved (1P) reserve category and a significant portion would move up to the proved plus probable (2P) reserve category.

4.3.6 *Technical Challenges*

There are numerous technical challenges that must be overcome before the likelihood of commercial production meets the risk threshold needed under the reserve definitions of the UKLA to be classified as 1P or 2P reserves. The following technical challenges are of both geologic and mechanical nature.

- Successfully drill laterals and control costs on sidetrack of existing wells.

- Demonstrated success with the proposed casing and completion program controlling sediment production to allow wells to produce continuously.
- Encounter sufficient fracturing to improve well productivity.
- Encounter sufficient fracturing extent to establish sufficient drainage area of horizontal wells.
- Confirm sufficient hydrocarbon storage in matrix and fractures to support production.
- Establish long-term economic production to support models and interpretations.
- Successfully and economically drill new wells with horizontals.
- Realize upper range of estimated recovery efficiencies via reservoir performance and drive mechanism.
- Demonstrate ability to move large volumes of oil to market.

4.4 Economic Evaluation

4.4.1 *Economic Input Parameters*

As part of the evaluation of the possible reserves at Tarabani Field, we conducted an economic evaluation of a potential Tarabani development. Because Tarabani is at a very early stage of potential development, these development plans are very preliminary and therefore are subject to revision as new data become available. The technical challenges described above in Section 4.3.6 will need to be overcome for the Tarabani development to proceed.

An economic model was created using the following parameters.

- PSA terms (see Section 1.1 for a description of the terms).
- Netherland, Sewell & Associates, Inc. estimates of recoverable reserves.
- Estimated production flowstreams based on analogy and Object Reservoir simulation results.
- Capital costs and operating costs prepared by Frontera.

Well Costs	
Zones 9 – 15	
Reentry	2.5 MM$
New Well	6.5 MM$
Zone 19	
Reentry	3.0 MM$
New Well	8.0 MM$
Facility Costs	70 MM$
Annual Operating Costs	
Fixed	60 M$
Variable per well	48 to 60 M$
Variable per barrel	$2.00

- Development timing estimates prepared by Frontera.
- Brent pricing differential prepared by Frontera marketing.

Transportation Costs	$3.25 per barrel
Sales Differential	Brent minus $3.00
Total Adjustments (netback to well)	Brent minus $6.25

- Two Brent pricing cases: $30.00 flat and a Brent Forward estimate before adjustments.

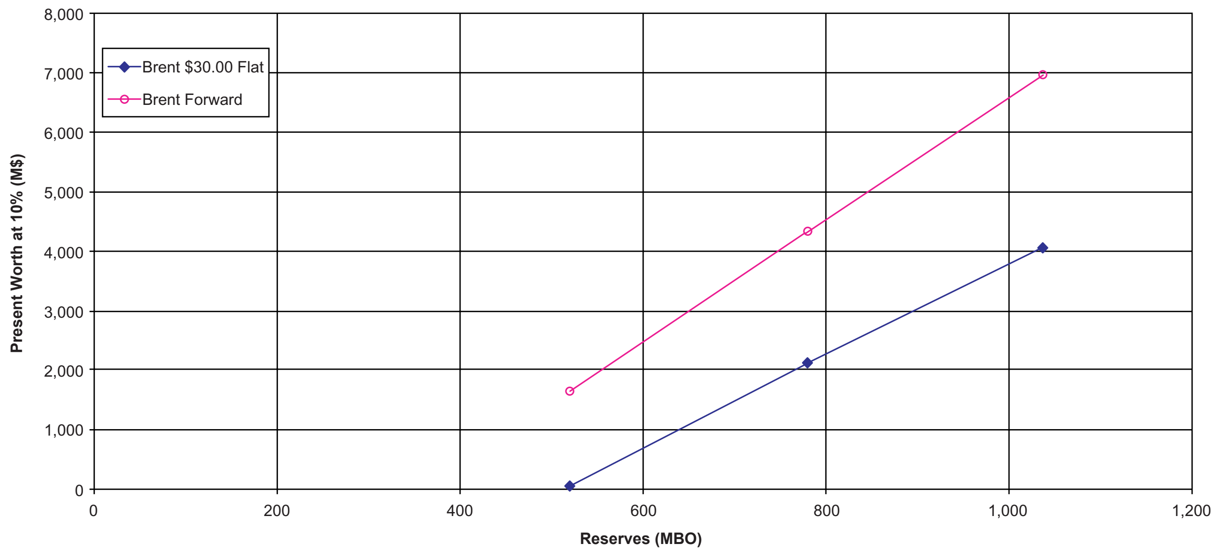
Year	Brent $30.00 Flat ($/BBL)	Brent Forward ($/BBL)
2005	30.00	42.00
2006	30.00	38.50
2007	30.00	37.50
Thereafter	30.00	35.00

4.4.2 *Single Well Model*

As the first step in the economic evaluation of a potential Tarabani development, we constructed a single well model to test the sensitivity to well production rates and recoverable reserves. The present worth discounted at 10 percent net to Frontera's interest for the 6 cases, i.e., 3 production rate cases using 2 different pricing scenarios, is shown in the following table and graph.

		Present Worth at 10% (M$)	
Initial Well Rates (BOPD)	**EUR (MBO)**	**Brent $30.00 Flat**	**Brent Forward**
300	519	51	1,648
450	779	2,125	4,340
600	1,036	4,057	6,969

Potential Tarabani Single Well Economics (Net to Frontera's Interest)



4.4.3 *Tarabani Full Field Model*

A full field development for Tarabani Field was modeled with the following parameters.

- Possible reserves of 118 MMBO are produced.
- Reserves are produced from the 4 key zones at Tarabani: Zones IX, XIV, XV and XIX.
- Each well is drilled as a bilateral and is completed in only 1 zone.
- Frontera's unrecovered costs of $81.5 million in Block 12 at year-end 2004 are recovered from field revenues per the PSA terms.
- Development drilling program timing requiring a peak rig count of 6 rigs.

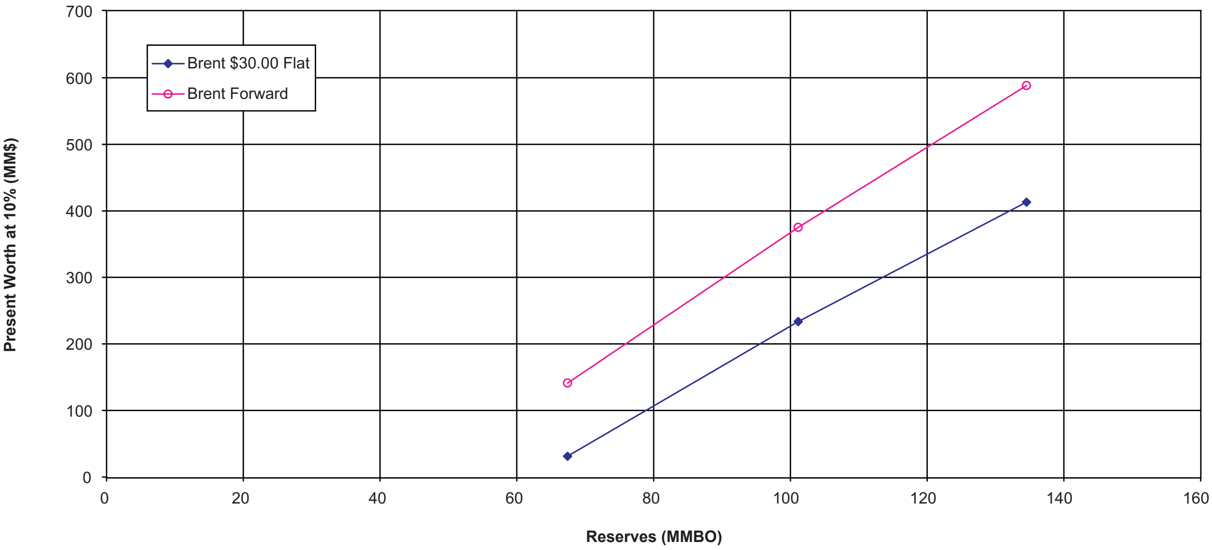
Shown in the following table is the present worth discounted at 10 percent net to Frontera's interest for the 2 pricing scenarios.

Initial Well Rates (BOPD)	EUR/Well (MBO)	EUR (MMBO)	Present Worth at 10% (MM$) Brent $30.00 Flat	Brent Forward
450 to 550	890	118	325	482

Production rates are a key uncertainty in the Tarabani development. To illustrate the impact of production rates on the full field economics, we constructed 3 sensitivities by varying only the production rates for each of the zones. Note that these sensitivities have not been optimized for the potential development options of commingling dual completions or recompleting to other zones after the existing zone has been depleted. The results of the production rate sensitivities are shown in the following table and graph.

Initial Well Rates (BOPD)	EUR/Well (MBO)	EUR (MMBO)	Present Worth at 10% (MM$) Brent $30.00 Flat	Brent Forward
300	500	67	31	141
450	770	101	233	375
600	1,020	135	413	588

Potential Tarabani Full Field Development
Zones IX, XIV, XV, and XIX
(Net to Frontera's Interest)



5.0 Prospect Evaluation

5.1 Exploration History

Exploration of the block began as early as 1930, whereas discoveries in the prospective areas commenced from 1940 and continued on into the 1960s. All drilling was based primarily on surface geologic mapping, topographic features, and oil and gas seeps. Like most exploration of its time, shallow, normally pressured surface wells were drilled (generally to 200 m deep) to delineate the subsurface. Logs and lithologic descriptions of drill cuttings established the presence of oil in these structures years before any seismic data were acquired in the region. The subsurface mapping encountered both the lower Shiraki section (Pliocene) and the Upper Sarmatian sections (Miocene) as being hydrocarbon-bearing with crude oils ranging from 34 to 36 degrees API.

The first 2-D reflective seismic (CDP lines) data were not acquired until the late 1960s to reconfirm the existence of closures/structures. Most of the 5,000 km of 2-D seismic were acquired using the Vibroseis method. In limited areas, some dynamite was used in acquisition. While the quality of the data was not very good, the data establish reflectors that could be correlated between previously drilled wells. After reprocessing over 2,000 km of the existing seismic data, in 1999 Frontera acquired 210 km of new 2-D and 150 km^2 of 3-D seismic data in and around the eastern portion of the block. These additional new seismic and reprocessed seismic data have further delineated new areas for exploration within the Tertiary clastic interval. Some prospects/fields like the Iori, Kila Kupra, and Bayda complex were further delineated with the new 2-D seismic data and show good potential in the Upper Sarmatian (Upper Miocene) sandstones in the overriding thrust sheets. Mirzaani is the only prospect area covered in this report that has established production.

New areas of focus have been defined with reprocessed 2-D seismic and the new seismic data acquired in 1999 in the Mesozoic interval along the northern portions of the block. The Basin Edge play in this area of the block targets fractured Cretaceous limestone and sandstones in an area that is thrust over the younger Maykop source rock. The Basin Edge play is believed to be on trend with the recent Manavi-11 Cretaceous oil discovery drilled by CanArgo Energy Corporation in 2003. Seismic data coverage over the prospects reviewed (highlighted in red text) is shown on the seismic base map in Figure 3.

5.2 Play Types

The most prevalent play type for prospects is a fault-bounded structure with 3-way closure, characterized as foot wall and hanging wall anticlinal closures. In other areas the structures appear as ‘‘pop-up features.’’ Many of these structures can be seen on seismic data located beneath what appears to be shallow, younger thrust faulting. Because most of these structures can be tied directly to outcrop at the surface, stratigraphic calibration can be performed between the subsurface well control, existing seismic data, and the outcrop. Faulting in the region is numerous and multiphased. Frontera has studied the timing of faulting relative to regional tectonic events and has determined from studying outcrops at the surface that much of what appears to be conventional thrusting in the subsurface is actually a component of strike-slip faulting. This would seem to account for the varied nature of features seen in the subsurface.

Generally, with the seismic data, large faults are evident, but in some cases, the fault image is beneath the resolution of the seismic data. Numerous structural closures associated with faulting are present throughout the Tertiary clastic play which is composed of prospects which are analogs to Tarabani Field. At places like the Mirzaani Deep Prospect, the fault is easily recognized along with corresponding dip reversals at the mapping levels. The main targets there are the lower Pliocene Shiraki interval and the Upper Miocene Sarmatian interval. Other places like the Iori Prospect appear to be plunging noses associated with an overall ‘‘pop-up feature.’’ All these prospects have some indication of independent closure. However, as we consider the areas associated with larger fill-up, faulting becomes a key component in the trapping mechanism. The Basin Edge prospects are also associated with what appears to be 3-way closures associated with strike-slip faulting and inversion of the Greater Caucasus Mountains. Cretaceous fractured limestones and sandstones are considered to be the principal reservoirs for this play type. In addition to these plays, Frontera has identified a deepwater sandstone play associated with the Middle Sarmatian intervals. Based on field work, lithofacies analysis, and micropaleontology, Frontera believes that a large portion of the area east and downdip of Tarabani Field is prospective for these reservoirs. No attempt was made to evaluate this play type in this report.

5.3 Risks

Most of the prospects reviewed are considered Tarabani Field analogs and are assumed to have the same risk components. There are favorable components of source rock, maturity, and trapping geometry, and as seen in Tarabani, the primary risk for each prospect is assumed to be reservoir quality. As noted in the petrophysical analysis, log measurements recorded in most wells to date are poor due to an overpressured environment, and results were inconclusive at best. Many of the prospects we reviewed, such as Kila Kupra and Iori, are actually undeveloped fields that appear to have logged oil pay, and thus these represent lower risk opportunities than conventional frontier exploration. The technical challenges discussed above for Tarabani highlight many of the risks likely associated with these features. The Mirzaani Deep Prospect targets deeper potential reservoirs in the producing Mirzaani Prospect and thus also represents a lower risk prospect.

5.4 Technical Evaluation

Volumetric estimates of OOIP and EUR oil are calculated probabilistically using a Monte Carlo simulation of input variables for each of the evaluated prospects in Block 12. Probability distributions are assigned to describe the range of uncertainty in reservoir parameters, reservoir volumes, and recovery factor for calculation of in-place oil and estimated recoverable oil.

Volumetric parameters used include GRV, average NTG ratio, porosity, hydrocarbon saturation, formation volume factor, and recovery factor. As shown in Figure 25, appropriate ranges of GRV, average NTG ratio, and oil-in-place per acre-foot (ac-ft) are used as input variables to the Monte Carlo simulation to generate probability distributions of OOIP. The 3 input variables for oil-in-place per ac-ft are based on minimum or maximum values of porosity, hydrocarbon saturation, and formation volume factor. Recovery factor is another variable used in the Monte Carlo simulation to derive probabilistic estimates of ultimate oil recovery. Each input variable is assigned a triangular or lognormal probability distribution. An output probability distribution of OOIP and recoverable oil is calculated using the input distributions. The input parameters used are summarized by prospect on Figures 25 and 26.

The Monte Carlo simulation was performed using Decisioneering's Crystal Ball software program (a Microsoft Excel add-in). The Monte Carlo simulation is an iterative technique that randomly samples each parameter within the prescribed uncertainty range and distribution. Crystal Ball then combines these random values in the formulas to create a cumulative probability distribution curve. As described above, following are the formulas used.

GRV * Average NTG Ratio * Barrels per Ac-Ft
= OOIP

and

GRV * Average NTG Ratio * Barrels per Ac-Ft * Recovery Factor
= Recoverable Resources

where

7,758 * Porosity * Hydrocarbon Saturation * (1/formation volume factor)
= Barrels per Ac-Ft for oil resources

The cumulative probability distribution curve indicates the likelihood that the hydrocarbons-in-place or recoverable hydrocarbons will be greater than the value shown on the graphs. The P90 estimate indicates a 90 percent likelihood that actual results will be greater than the low-side estimate, and so on for the P50 (most likely) and P10 (high-side) estimates. In our probabilistic resource assessment, the range and distribution of the independent variables is discussed in the following sections 5.4.1 through 5.4.5.

5.4.1 *Geological and Geophysical Evaluation*

Tarabani Field has been used as an analog to all prospects whose play type targets the Shiraki productive series. Frontera, when designing 2-D regional seismic lines, appropriately tied some of those lines into its 3-D survey in order to propagate dense seismic control into areas of sparse control. The Basin Edge prospects, which mainly target formations other than the Shiraki, had the benefit of interpreting a rather strong seismic reflector. Each prospect was mapped in time and depth-converted using average velocities relative to overlying sediment types. Derived depth maps were further scrutinized by calculating average velocity maps for each prospect. In cases other than the Kila Kupra-Iori Field Complex, no wells existed in the prospect area and no definitive isopach values could be established or mapped. In these instances, constant isopach thicknesses were used to generate a base structure. Petrophysical ranges from Zones IX, XIV, XV, and XIX within Tarabani Field, which interestingly are quite similar to cumulative zone ranges, were used to populate petrophysical parameters for the prospects.

For most prospects, seismic data coverage was sparse (refer to Figure 3) but fair to good in quality. We reviewed 2-D seismic data to confirm size ranges appropriate for probabilistic ranges of GRV distribution in low-side, most likely, and high-side cases. Topographic data and dip information from surface geology were used where appropriate to confirm poorly imaged dips in seismic data, and regional gravity data confirmed the presence of potential highs in the area. However, in our view, acquisition of additional seismic data is needed to further delineate the structures with consideration given to the depth of the zones of interest and the potential velocity challenges. We understand that Frontera has included plans for additional seismic acquisition over key prospects in its future work programs.

5.4.2 *Area and Gross Rock Volume*

The maximum areas for each of the prospects reviewed in Block 12 were determined from the data supplied by Frontera. We reviewed the representative seismic lines, well control, and surface geology at outcrop to investigate the interpretation and depth conversion of the seismic data and thus develop a better understanding of the potential trap areas and play types of each prospect. Based on our review of the data, we found the structure maps provided by Frontera to be reasonable interpretations of the data and accepted the structural closures as currently interpreted to the spill point as the high-side case. Due to data coverage, data quality, and potential for velocity distortions, we risked the GRV downward to 60 percent and 80 percent of the high-side case, for the low-side and most likely cases, respectively. Maps at the base of the prospective interval were derived from Frontera's interpretations or by adding an appropriate gross reservoir thickness so that depth volume curves could be derived for each prospect from the structural crest down to its structural spill point.

5.4.3 *Net-to-Gross Ratio*

NTG is defined as the ratio of net reservoir thickness to gross interval thickness. Typical petrophysical thresholds defining net reservoir characteristics include porosity, water saturation, shale proportion, and permeability calculations from well logs. These threshold values, commonly referred to as cutoff values, are typically established from petrophysical analysis or experience from producing reservoirs as to what constitutes a productive interval.

In Tarabani Field, as described in Section 4.3.3, cutoff values were established for porosity (greater than or equal to 8 percent), shale volume (less than or equal to 40 percent), and water saturation (less than or equal to 65 percent). In any given interval, net pay will be measured if the calculated log responses meet each of these criterions. Due to the lack of capillary pressure data at Tarabani, no permeability cutoff was used to define net pay, although estimates of permeability were made by Core Laboratories for the Niko-1 well. NTG ratios for Tarabani Field ranged from 6 to 35 percent with an average of 15 percent net reservoir to gross interval thickness. Several wells at Tarabani Field and the Kila Kupra-Iori Field Complex were analyzed from the top of the prospective interval to the total depth of the wells to determine reasonable ranges to apply to the entire prospective interval in each prospect. High-side NTG estimates appropriate for the Cretaceous targets in the Basin Edge play are based on press releases from CanArgo Energy Corporation about its recent Manavi discovery.

5.4.4 *Yield*

The yield or "barrels per ac-ft" factor is defined by the equations indicated above in Section 5.4 for oil resources that combine variables of porosity, hydrocarbon saturation, and formation volume factor. Parameters were assigned based on properties seen at Tarabani. Parameter ranges for the reservoirs and yield factor are displayed in the following table.

	Tarabani Analogs	Upper Cretaceous
Porosity (%)	19 to 22	19 to 22
Hydrocarbon Saturation (%)	44 to 50	44 to 50
Formation Volume Factor	1.10	1.10
In-Place Barrels per Ac-Ft	590 to 776	590 to 776

5.4.5 *Recovery Factor*

For the prospects, we defined the P90, or minimum values, of recovery factor to reflect a high degree of certainty the reservoirs could produce that amount of the OOIP, and defined P10, or high-side, values to reflect maximum efficient recovery of OOIP by either depletion or strong water drive as appropriate. We assigned a triangular distribution for recovery factor values as shown below.

	Tarabani Analogs	Upper Cretaceous
Recovery Factor (%)	5 to 25	5 to 35

5.5 Tertiary Clastic Plays

We reviewed 5 prospects that are analogs to Tarabani Field for the Tertiary clastic section. As shown in the location map on Figure 2, these are the undeveloped Kila Kupra Field, the undeveloped Iori Field (collectively termed the Kila Kupra-Iori Field Complex), and undrilled exploration prospects: Mirzaani South, Mirzaani Deep, and Pkhoveli. As the near-term work program envisaged by Frontera is likely to focus in the Mirzaani area, only the 2 prospects for this play type in that area are highlighted here.

Mirzaani Field was discovered in 1932 and has been penetrated by 297 wells. The deepest penetration is the Mirzaani-271 well which was drilled to a total depth of 2,080 m in Pliocene sandstones. Mirzaani Field is located on one of a series of east-trending ridges in the eastern part of Block 12. The field structure is a northeast-dipping limb on an eroded anticline in the hanging wall of the Mirzaani thrust. In the Mirzaani Field area, there are 2 opportunities to explore for additional resources: Mirzaani South, a shallow fault-bounded, 4-way dip footwall closure; and Mirzaani Deep, targeting deeper, upper Sarmatian sandstones within the productive limits of the shallower Mirzaani Prospect.

5.5.1 *Mirzaani South Prospect*

This shallow fault-bounded, 3-way closure has multiple reservoir targets identified in the fluvial sandstones (Zones X to XVI) of the Pliocene age Shiraki Formation (refer to Figure 4). This prospect is located immediately south of the producing Mirzaani Field and is trapped against the same thrust sheet as the actively producing Patara Shiraki Field. Although a small feature, the opportunity to test an undrilled fault closure on trend with an active producing field is attractive since there is ample infrastructure in the immediate area. Our mean and high-side estimates for gross unrisked potential recoverable resources are 8.5 and 14.0 MMBO, respectively.

The range of probabilistic input parameters for this prospect is shown in the table in Figure 25, and the range of OOIP and recoverable resources is shown in the table in Figure 26. A depth structure map for Mirzaani South is shown in Figure 27.

5.5.2 *Mirzaani Deep Prospect*

This deep, untested, faulted hangingwall structure targets the deeper Sarmatian reservoirs which are productive at Tarabani Field and underlie the shallow producing reservoirs of the active Mirzaani Prospect. Although the imaging is relatively poor for some of the 2-D seismic data over this structure, the trapping nature of this fault has already been established for the shallower reservoirs. The seismic expression of the shallow producing reservoirs and the deeper reservoir interval targeted in this prospect is shown in Figure 28 which is a dip-oriented seismic line across the structure. As seismic quality and coverage is only fair, Frontera plans to acquire additional seismic data to further delineate the true potential and size of this structure. Obviously, infrastructure already exists to produce the shallower reservoirs, so a deep well is warranted to test the potential of the deeper targets. Our mean and high-side estimates for gross unrisked potential recoverable resources are 16.6 and 27.3 MMBO, respectively.

A depth structure map for Mirzaani Deep is shown in Figure 29. The range of probabilistic input parameters for this prospect is shown in the table in Figure 25, and the range of OOIP and recoverable resources is shown in the table in Figure 26.

5.5.3 *Kila Kupra-Iori Field Complex and Other Prospects*

Although relatively small features, the Kila Kupra and Iori structures have already been drilled and discovered hydrocarbons in the prospective reservoir intervals. However, these field discoveries were never developed and represent attractive future appraisal drilling opportunities. A structure map showing these 2 fields is shown in Figure 30. The Pkhoveli Prospect lies along the northwest border of Block 12 in an area of active oil seeps and is currently poorly defined by 2-D seismic data and shallow well control. Additional seismic control is needed to better define this feature. A structure map for Pkhoveli is shown in Figure 31. The prospective resources estimated for each of these other prospects is shown in Figure 26.

5.6 Basin Edge Plays

The Basin Edge play lies along the northern border of Block 12 where the Tertiary sedimentary sequence pinches out beneath the Greater Caucasus frontal reverse thrust faults and fractured carbonates. Oil could be trapped in structural traps within faulted, 3-way hangingwall or 4-way dip closures. Any trap located along this edge is the first to trap oil migrating out of the Western Kura Basin oil-generating kitchen, which is believed to be sourced by the Oligocene-Miocene Maykop shales. There are 2 prospects in this play currently identified on trend, separated by the Didi Shiraqi Syncline (Figure 2), where the primary reservoir target is the Cretaceous carbonate rocks, and a secondary target is the Sarmatian (S3) sandstones. Seismic coverage is sparse; resolution is poor, but faulted anticlinal features are supported by dips seen in outcrop. Additional seismic data are needed to adequately delineate the structural extent of the reservoir and further discern dips and faulting. The high-side NTG parameter for this play is based on well data reported at the recent CanArgo Energy Corporation Manavi discovery as reported in the press for the 11 well that indicates a NTG of 50 percent. Other petrophysical parameters are assumed to be similar to those seen at Tarabani.

5.6.1 *Basin Edge B Prospect*

This prospect has 2 reservoir objectives. The carbonate objective has been studied in outcrop, but few penetrations exist within the block or within the basin. The Kirsa-1 well was drilled significantly downdip but did penetrate some Cretaceous and Jurassic limestones. The limited seismic control indicates that a significant wedge of sediments, unpenetrated in that well, exists updip at the prospect location. This may be another thrust sheet or may represent a thickening of the carbonate interval. Both the Cretaceous and S3 reservoir objectives are trapped in 3-way hangingwall closures. Our mean and high-side estimates for gross unrisked potential recoverable resources for the Cretaceous reservoir target are 171.1 and 376.4 MMBO, respectively. Mean and high-side estimates for gross unrisked potential recoverable resources for the S3 reservoir target are 167.6 and 374.7 MMBO, respectively.

A depth structure map for Basin Edge B Cretaceous is shown in Figure 32. The range of probabilistic input parameters for this prospect is shown in the table in Figure 25, and the range of OOIP and recoverable resources is shown in the table in Figure 26.

A depth structure map for Basin Edge B S3 is shown in Figure 33. Again, the range of probabilistic input parameters for this prospect is shown in the table in Figure 25, and the range of OOIP and recoverable resources is shown in the table in Figure 26.

5.6.2 *Basin Edge C Prospect*

This prospect lies to the southeast of the Basin Edge B prospect along the identified play trend near the border with Azerbaijan. Depth structure maps for this prospect at the 2 reservoir objectives, the Cretaceous and the S3, are shown in Figures 34 and 35, respectively. The probabilistic input parameters used and the resulting estimated ranges of OOIP and recoverable resources are shown in the tables in Figures 25 and 26, respectively.

5.7 Probabilistic Input Parameters

The table in Figure 25 sets forth the input parameters of GRV, NTG ratio, porosity, hydrocarbon saturation, formation volume factor, and recovery factor used in the Monte Carlo simulation for all prospects and leads. Note that, as described above in Section 5.4, the combination of ranges in porosity, hydrocarbon saturation, and formation volume factor values actually determines the range in stock tank barrels used in the simulation. Please refer to the discussion in Sections 5.4.1 through 5.4.5 for more detail on how these parameters were derived.

5.8 Prospective Original In-Place and Recoverable Resources

The table in Figure 26 sets forth our assessment of the gross (100 percent) unrisked OOIP and unrisked prospective oil resources for the prospects and leads calculated from the input parameters. The large range seen in these estimates is typical for an exploration portfolio, and the mean value is often used to best quantify or capture this range. Obviously, high-side values demonstrate the potential upside in the portfolio of prospects evaluated. Additional upside potential may yet exist in prospects not yet identified or included in this report.

5.9 Prospect Economic Evaluation

5.9.1 *Prospect Economic Input Parameters*

As part of the evaluation of the prospective resources in Block 12, we conducted an economic evaluation of potential developments of two of the prospective resources, the Basin Edge B and C Cretaceous reservoirs.

Because these properties are in a very early stage of exploration, these development plans are very preliminary and therefore are subject to revision as new data become available. The technical challenges described in Section 4.3.6 will need to be overcome for the Tarabani play prospect developments to proceed, and the Basin Edge B exploration program will need success for the Basin Edge development to proceed.

An economic model was created using the following parameters.

- PSA terms (see Section 1.1 for a description of the terms).
- Netherland, Sewell & Associates, Inc. estimates of recoverable resources.
- Estimated production flowstreams based on analogy and Frontera estimates.
- Capital costs and operating costs prepared by Frontera.

Well Costs	
Exploration	4.0 MM$
Development	2.5 MM$
Facility Costs	
Mean Case	95 MM$
High-Side Case	125 MM$
Annual Operating Costs	
Fixed	120 M$
Variable per well	120 M$
Variable per barrel	$1.00

- Development timing estimates prepared by Frontera.
- Brent pricing differential prepared by Frontera marketing.

Transportation Costs	$3.25 per barrel
Sales Differential	Brent minus $3.00
Total Adjustments (netback to well)	Brent minus $6.25

- Two Brent pricing cases: $30.00 flat and a Brent Forward estimate before adjustments.

Year	Brent $30.00 Flat ($/BBL)	Brent Forward ($/BBL)
2005	30.00	42.00
2006	30.00	38.50
2007	30.00	37.50
Thereafter	30.00	35.00

5.9.2 *Basin Edge B Cretaceous Model — Mean Estimate*

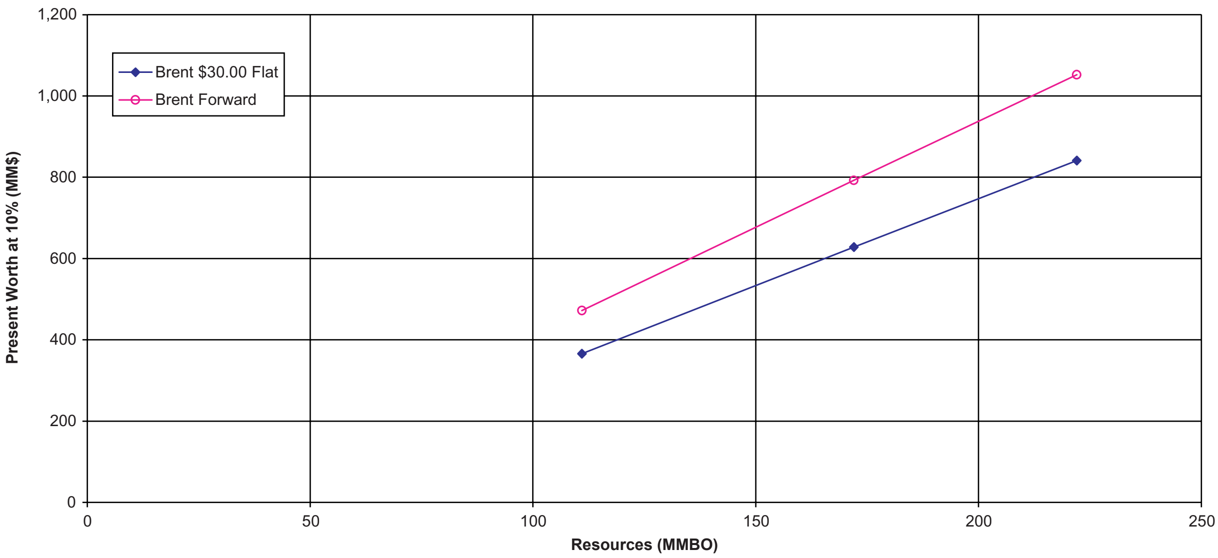
The Basin Edge B Cretaceous full field development was modeled for the mean resource estimate, resulting in the following present worth discounted at 10 percent net to Frontera's interest for the 2 pricing cases.

			Present Worth at 10% (MM$)	
Initial Well Rates (BOPD)	EUR/Well (MBO)	EUR (MMBO)	Brent $30.00 Flat	Brent Forward
1,550	4,090	172	628	792

To illustrate the impact of production rates on the full field economics, we constructed 3 sensitivities by varying only the production rates for the development. The results of the production rate sensitivities are shown in the following table and graph.

			Present Worth at 10% (MM$)	
Initial Well Rates (BOPD)	**EUR/Well (MBO)**	**EUR (MMBO)**	**Brent $30.00 Flat**	**Brent Forward**
1,000	2,640	111	366	472
1,550	4,090	172	628	792
2,000	5,290	222	841	1,052

Potential Basin Edge B Cretaceous Development
Mean Case Sensitivities
(Net to Frontera's Interest)



5.9.3 *Basin Edge B Cretaceous Model — High-Side Estimate*

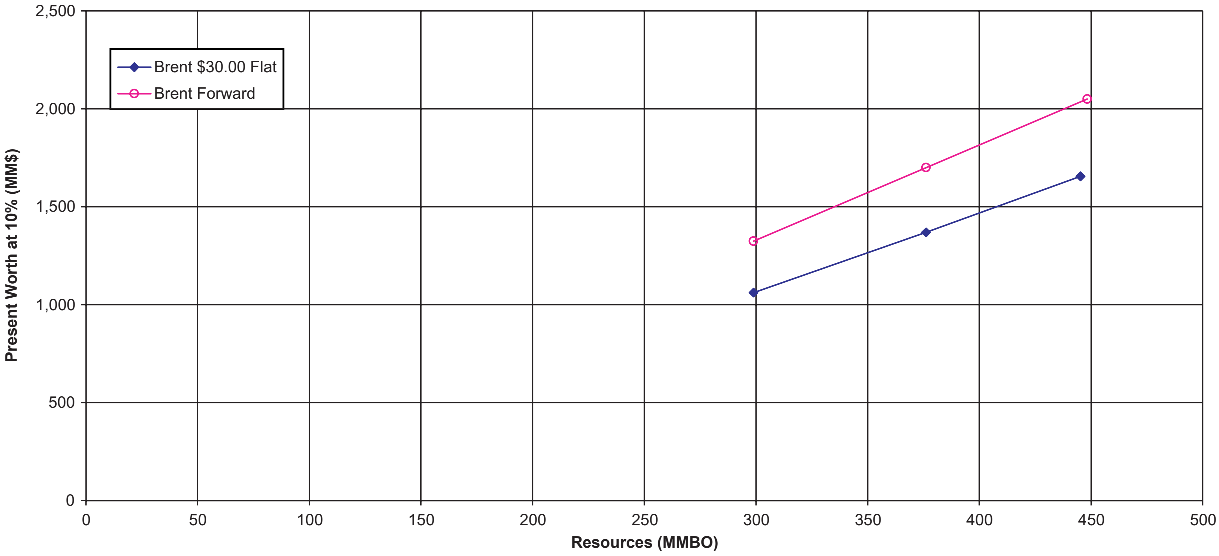
The Basin Edge B Cretaceous full field development was modeled for the high-side resource estimate, resulting in the following present worth discounted at 10 percent net to Frontera's interest for the 2 pricing cases.

			Present Worth at 10% (MM$)	
Initial Well Rates (BOPD)	**EUR/Well (MBO)**	**EUR (MMBO)**	**Brent $30.00 Flat**	**Brent Forward**
2,500	6,480	376	1,369	1,700

To illustrate the impact of production rates on the full field economics, we constructed 3 sensitivities by varying only the production rates for the high-side estimate development. The results of the production rate sensitivities are shown in the following table and graph.

			Present Worth at 10% (MM$)	
Initial Well Rates (BOPD)	**EUR/Well (MBO)**	**EUR (MMBO)**	**Brent $30.00 Flat**	**Brent Forward**
2,000	5,160	299	1,062	1,325
2,500	6,480	376	1,369	1,700
3,000	7,720	448	1,655	2,050

**Potential Basin Edge B Cretaceous Development
High-Side Sensitivities
(Net to Frontera's Interest)**



5.9.4 *Basin Edge C Cretaceous Model — Mean Estimate*

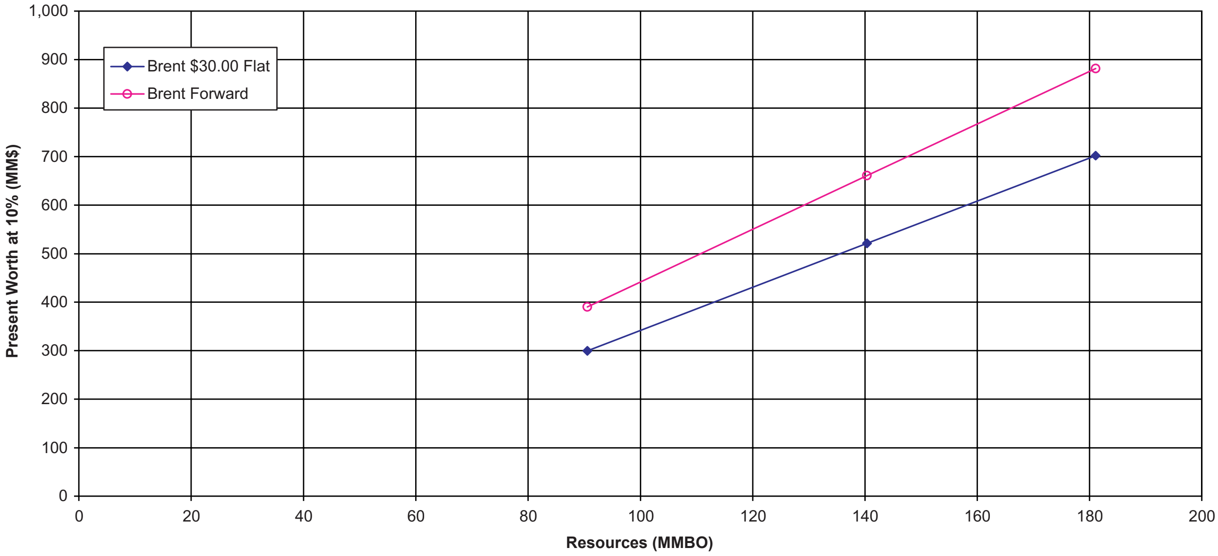
The Basin Edge C Cretaceous full field development was modeled for the mean resource estimate, resulting in the following present worth discounted at 10 percent net to Frontera's interest for the 2 pricing cases.

			Present Worth at 10% (MM$)	
Initial Well Rates (BOPD)	**EUR/Well (MBO)**	**EUR (MMBO)**	**Brent $30.00 Flat**	**Brent Forward**
1,550	4,118	140	521	661

To illustrate the impact of production rates on the full field economics, we constructed 3 sensitivities by varying only the production rates for the development. The results of the production rate sensitivities are shown in the following table and graph.

			Present Worth at 10% (MM$)	
Initial Well Rates (BOPD)	**EUR/Well (MBO)**	**EUR (MMBO)**	**Brent $30.00 Flat**	**Brent Forward**
1,000	2,676	91	300	390
1,550	4,118	140	521	661
2,000	5,324	181	702	881

Potential Basin Edge C Cretaceous Development
Mean Case Sensitivities
(Net to Frontera's Interest)



5.9.5 *Basin Edge C Cretaceous Model — High-Side Estimate*

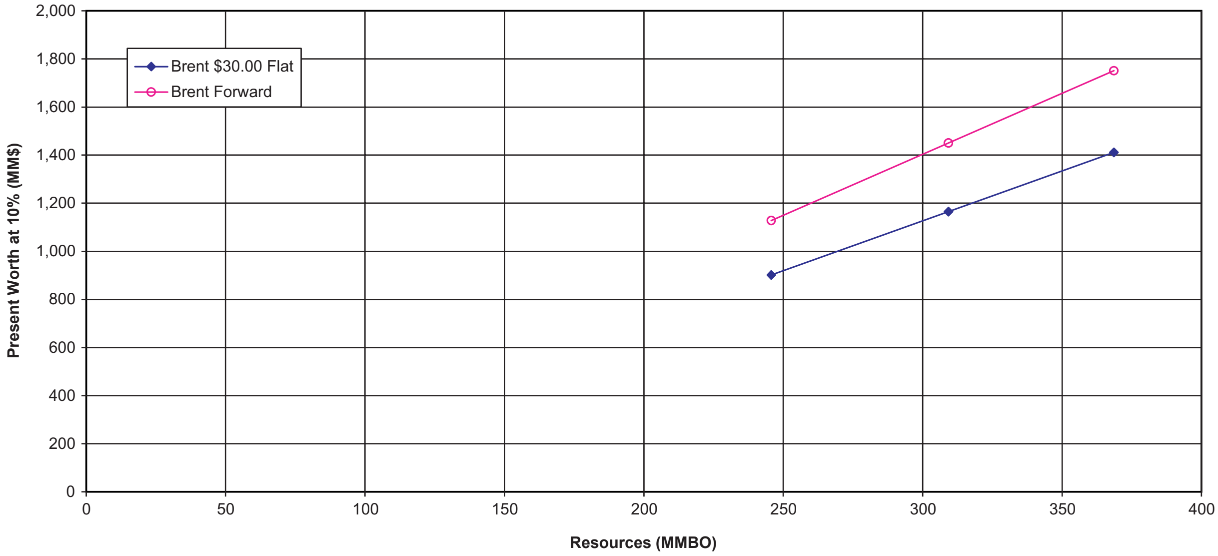
The Basin Edge C Cretaceous full field development was modeled for the high-side resource estimate, resulting in the following present worth discounted at 10 percent net to Frontera's interest for the 2 pricing cases.

			Present Worth at 10% (MM$)	
Initial Well Rates (BOPD)	**EUR/Well (MBO)**	**EUR (MMBO)**	**Brent $30.00 Flat**	**Brent Forward**
2,500	6,574	309	1,165	1,450

To illustrate the impact of production rates on the full field economics, we constructed 3 sensitivities by varying only the production rates for the high-side estimate development. The results of the production rate sensitivities are shown in the following table and graph.

			Present Worth at 10% (MM$)	
Initial Well Rates (BOPD)	**EUR/Well (MBO)**	**EUR (MMBO)**	**Brent $30.00 Flat**	**Brent Forward**
2,000	5,234	246	902	1,128
2,500	6,574	309	1,165	1,450
3,000	7,851	369	1,411	1,751

Potential Basin Edge C Cretaceous Development
High-Side Sensitivities
(Net to Frontera's Interest



6.0 Economic Discount Rate Sensitivities

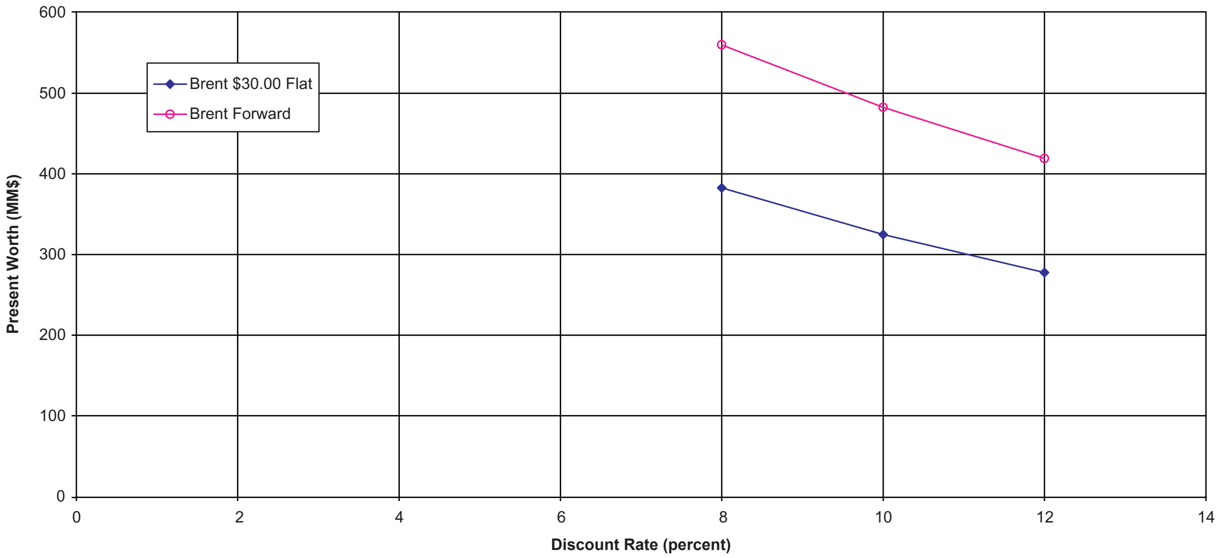
We evaluated the discount rate sensitivity for the economic cases presented in this report by evaluating the economics at discount rates of 8, 10, and 12 percent. The results are outlined in the following sections.

6.1 Tarabani Full Field Development

Refer to Section 4.4.3.

	Present Worth (MM$)	
Discount Rate (Percent)	Brent $30.00 Flat	Brent Forward
8	383	560
10	325	482
12	277	419

Discount Rate Sensitivity
Potential Tarabani Full Field Development
Zones IX, XIV, XV, and XIX
(Net to Frontera's Interest)

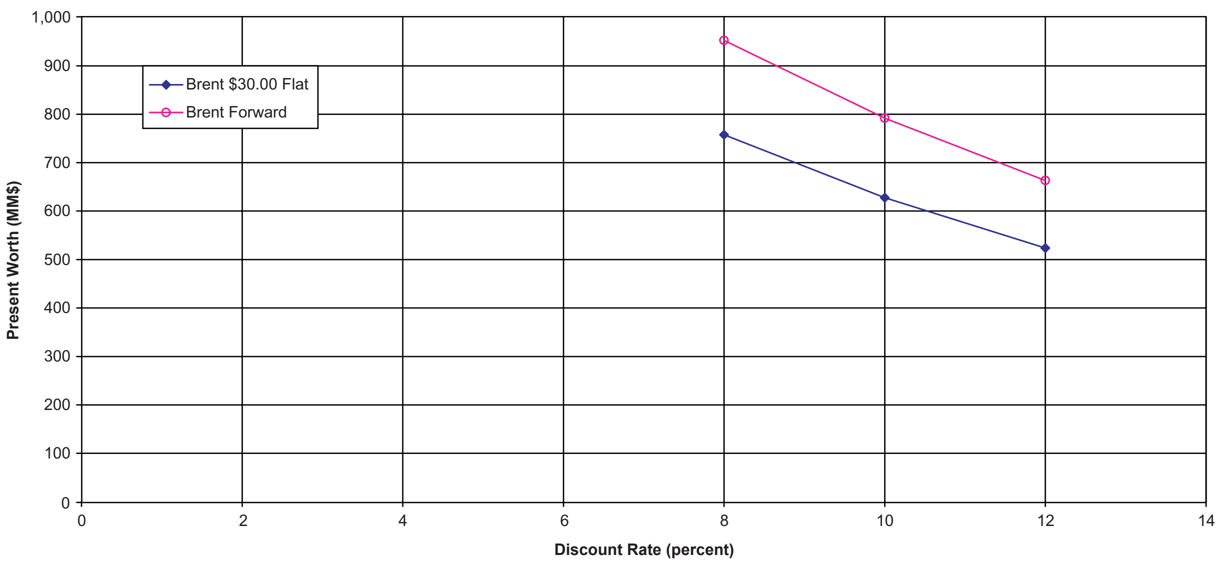


6.2 Basin Edge B Cretaceous — Mean Estimate

Refer to Section 5.9.2.

Discount Rate (Percent)	Present Worth (MM$) Brent $30.00 Flat	Brent Forward
8	758	952
10	628	792
12	523	663

Discount Rate Sensitivity
Potential Basin Edge B Cretaceous Development
Mean Case Sensitivities
(Net to Frontera's Interest)

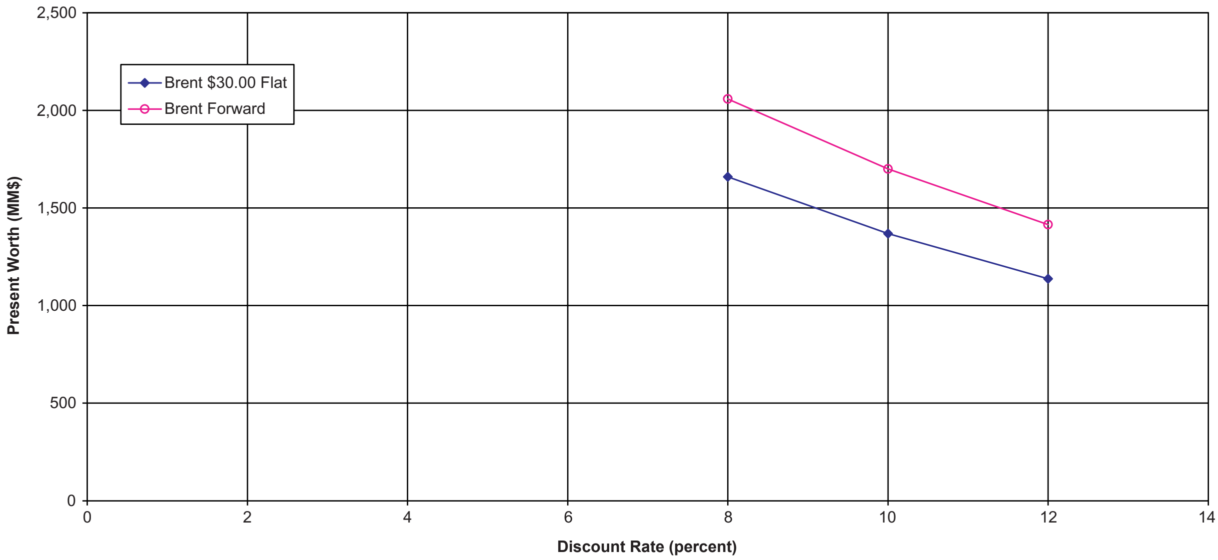


6.3 Basin Edge B Cretaceous — High-Side Estimate

Refer to Section 5.9.3.

Discount Rate (Percent)	Present Worth (MM$) Brent $30.00 Flat	Present Worth (MM$) Brent Forward
8	1,660	2,059
10	1,369	1,700
12	1,138	1,415

Discount Rate Sensitivity
Potential Basin Edge B Cretaceous Development
High-Side Sensitivities
(Net to Frontera's Interest)

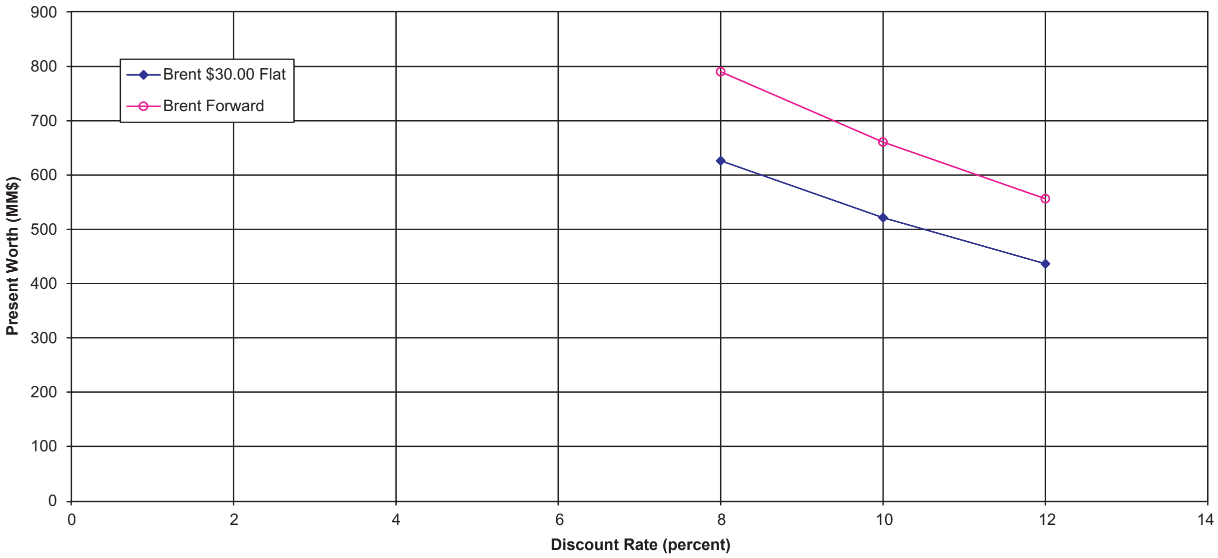


6.4 Basin Edge C Cretaceous — Mean Estimate

Refer to Section 5.9.4.

Discount Rate (Percent)	Present Worth (MM$) Brent $30.00 Flat	Present Worth (MM$) Brent Forward
8	626	790
10	521	661
12	437	556

Discount Rate Sensitivity
Potential Basin Edge C Cretaceous Development
Mean Case Sensitivities
(Net to Frontera's Interest)

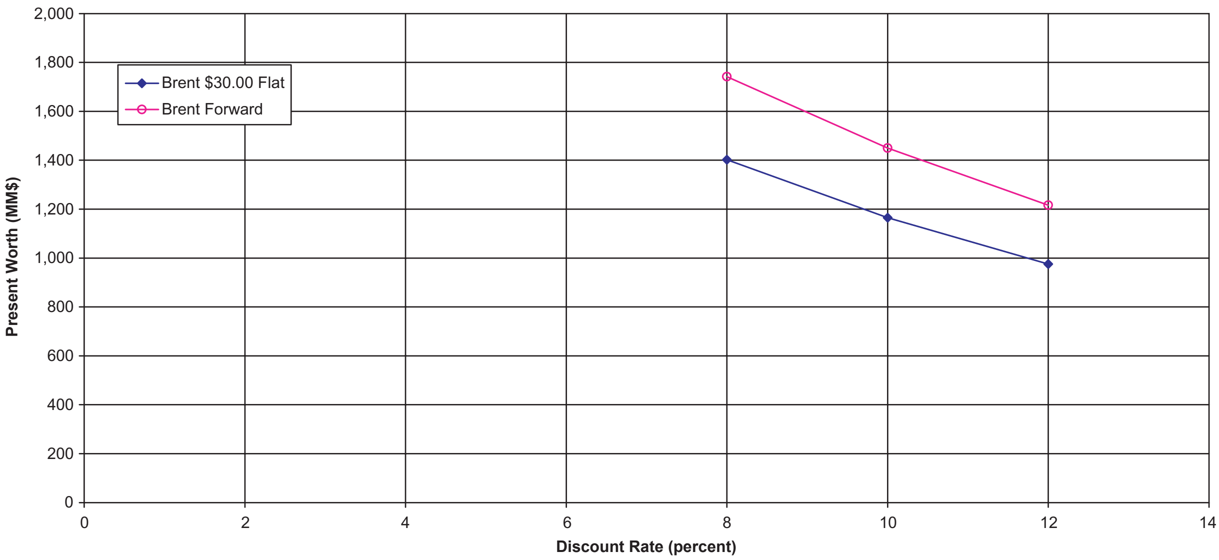


6.5 Basin Edge C Cretaceous — High-Side Estimate

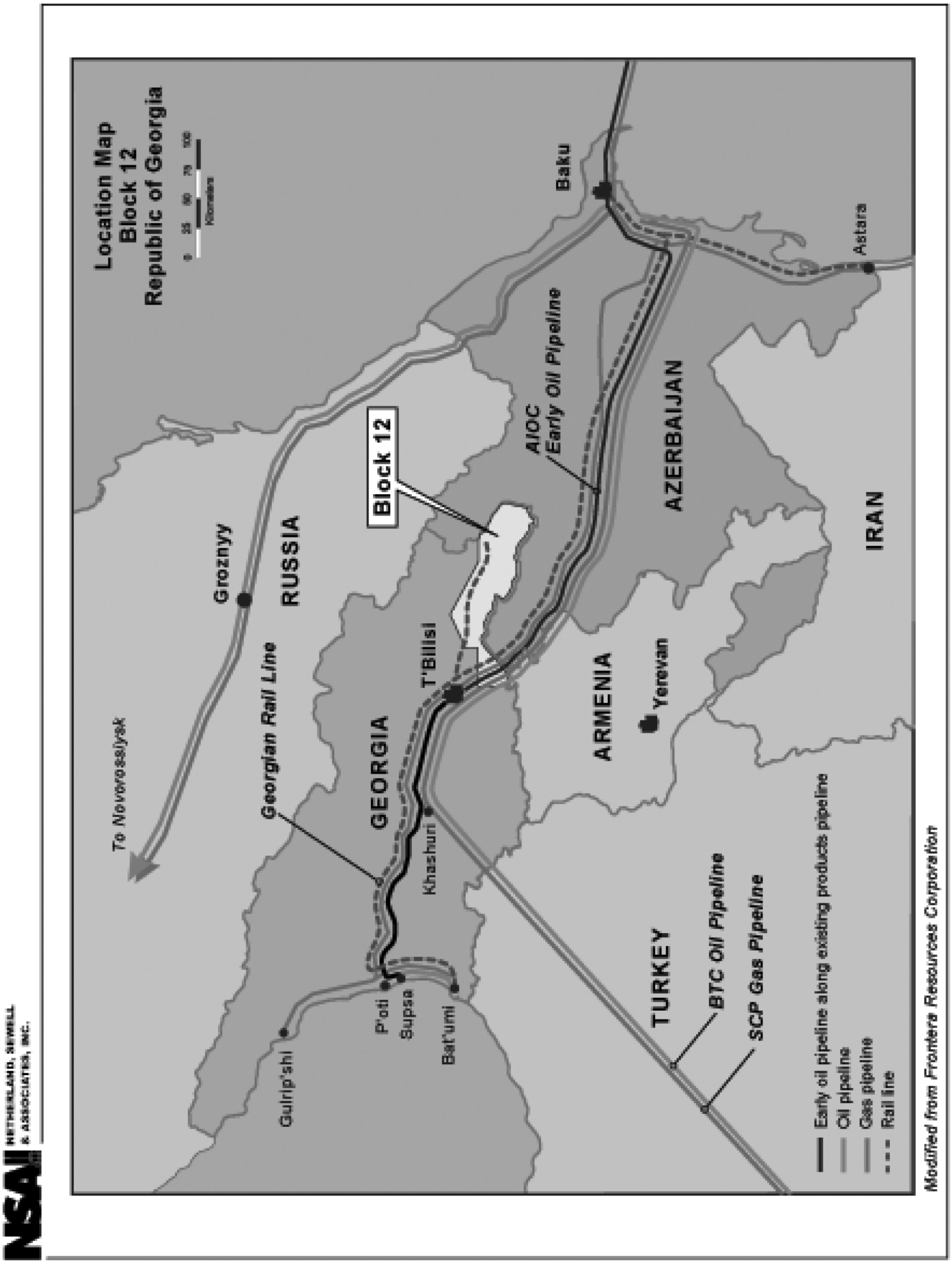
Refer to Section 5.9.5.

	Present Worth (MM$)	
Discount Rate (Percent)	**Brent $30.00 Flat**	**Brent Forward**
8	1,042	1,742
10	1,165	1,450
12	976	1,216

Discount Rate Sensitivity
Potential Basin Edge C Cretaceous Development
High-Side Sensitivities
(Net to Frontera's Interest)



FIGURES



Modified from Frontera Resources Corporation

Figure 1

NETHERLAND, SEWELL & ASSOCIATES, INC.

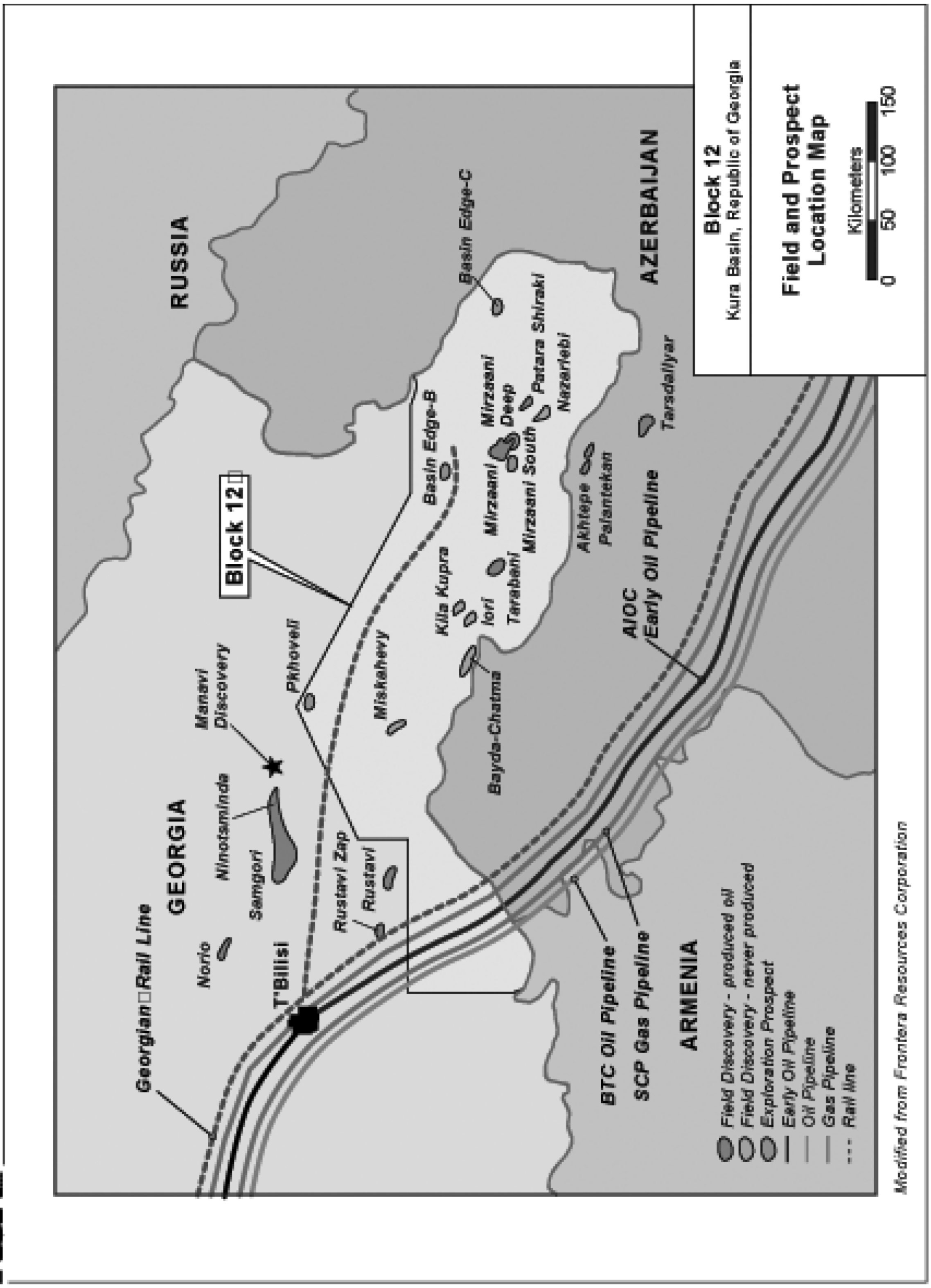


Figure 2

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

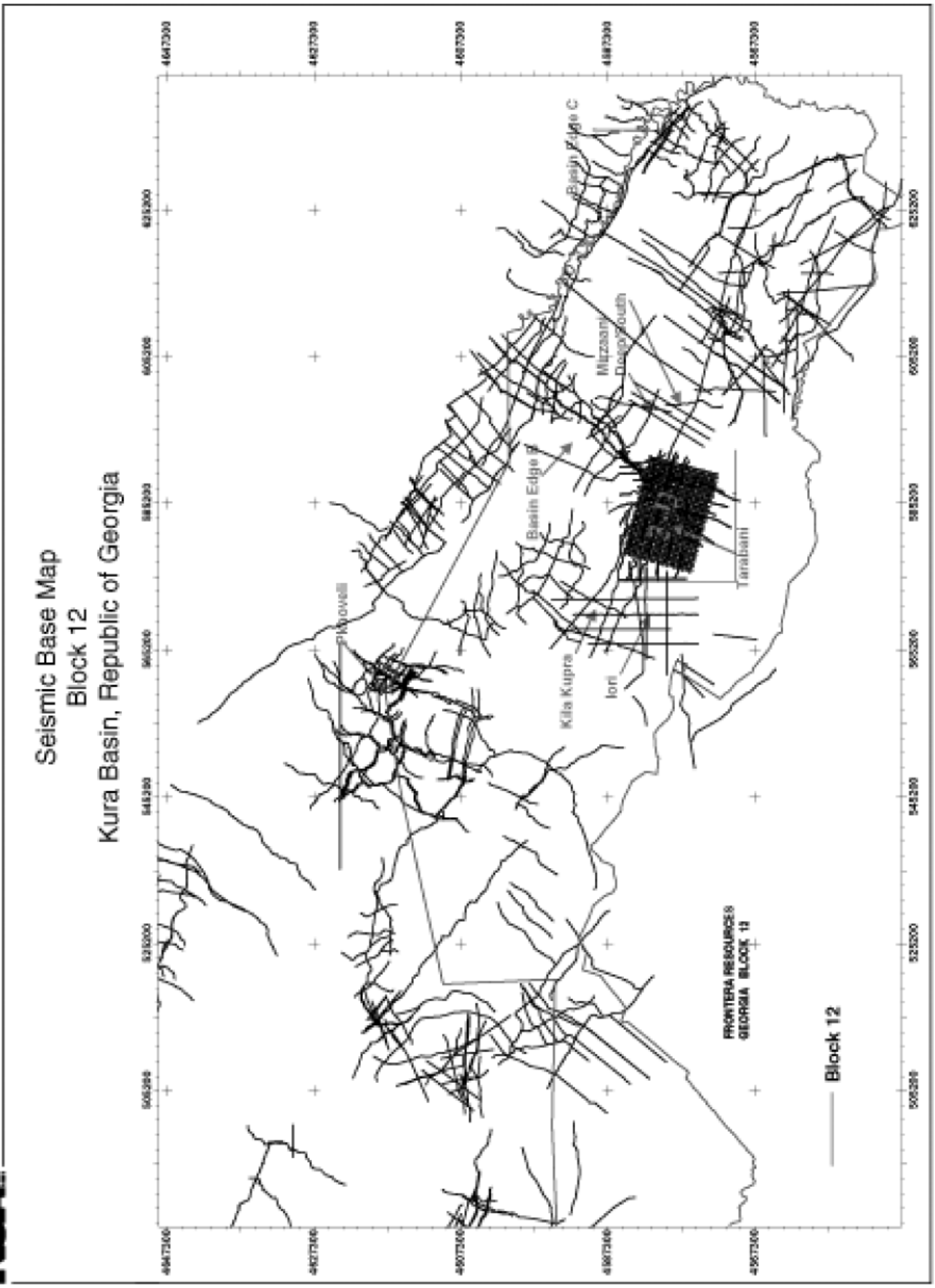
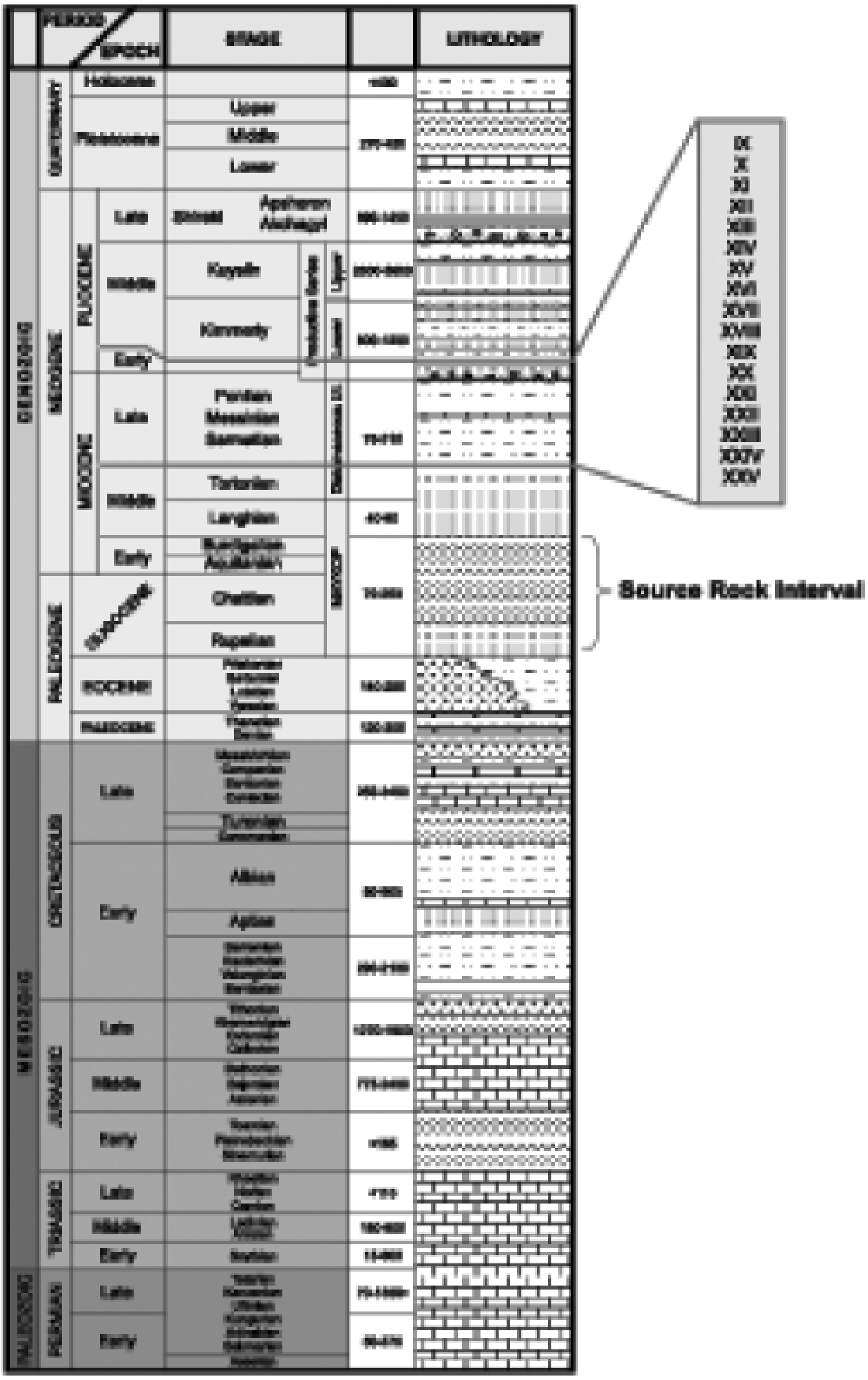


Figure 3

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

Kura Basin Stratigraphic Column
Caucasus Region



Modified from Frontera Resources Corporation

Figure 4

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

Interpreted Log
Tarabani-38 Well, Tarabani Field
Kura Basin, Republic of Georgia

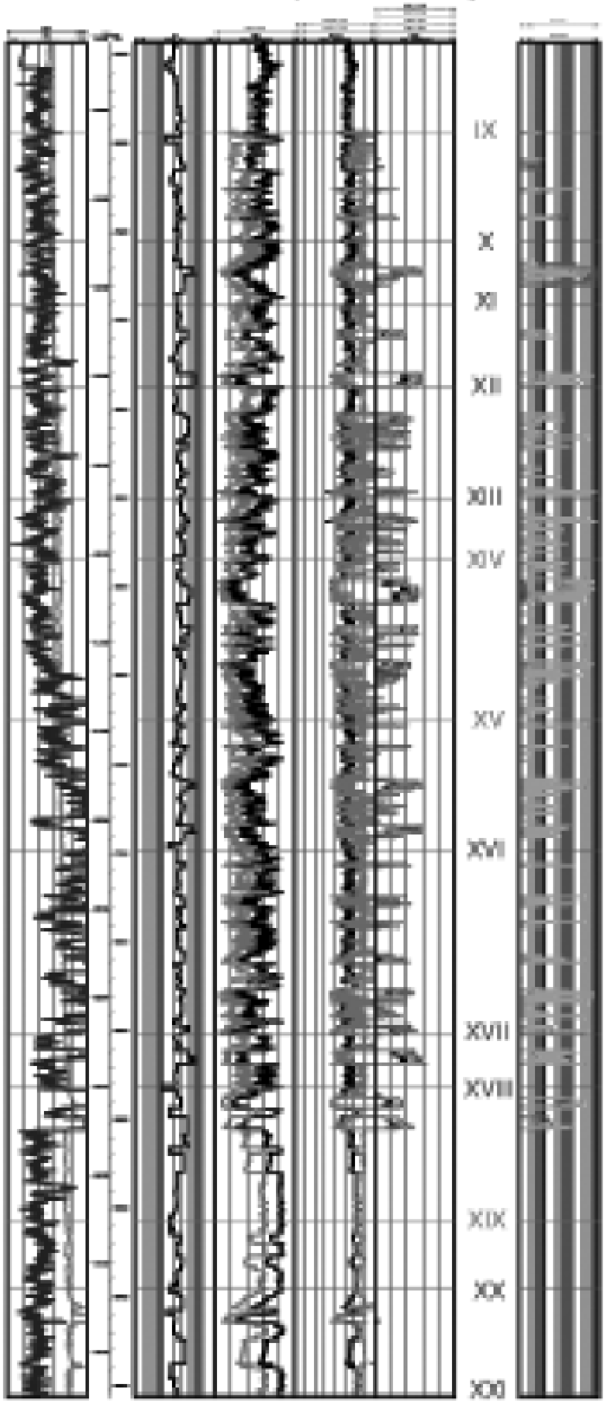


Figure 5

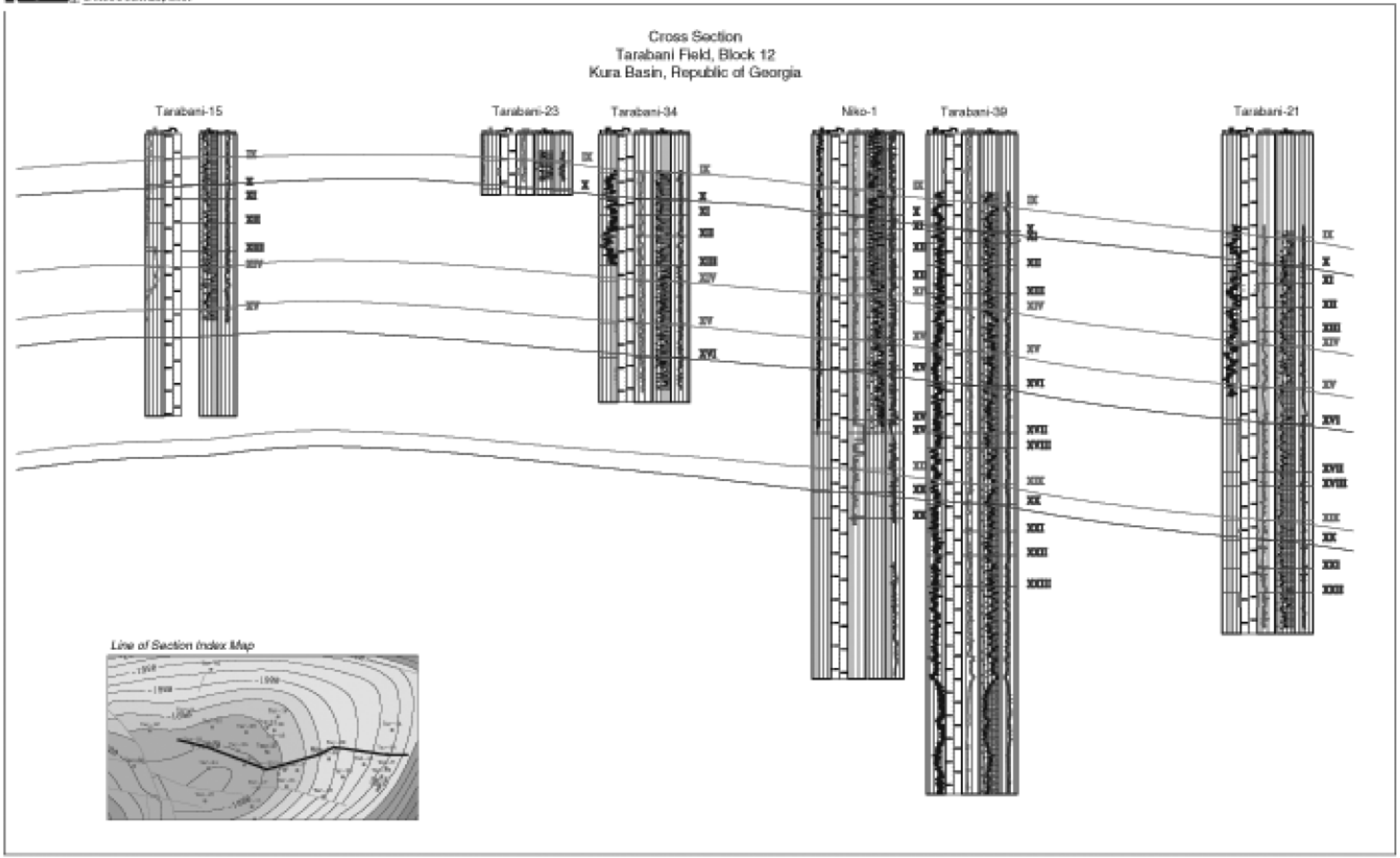

Cross Section
Tarabani Field, Block 12
Kura Basin, Republic of Georgia
Tarabani-15
Tarabani-23
Tarabani-34
Niko-1
Tarabani-39
Tarabani-21
Line of Section Index Map

Figure 6

NETHERLAND, SEWELL
& ASSOCIATES, INC.

Seismic Cross Section
Tarabani Field
Kura Basin, Republic of Georgia

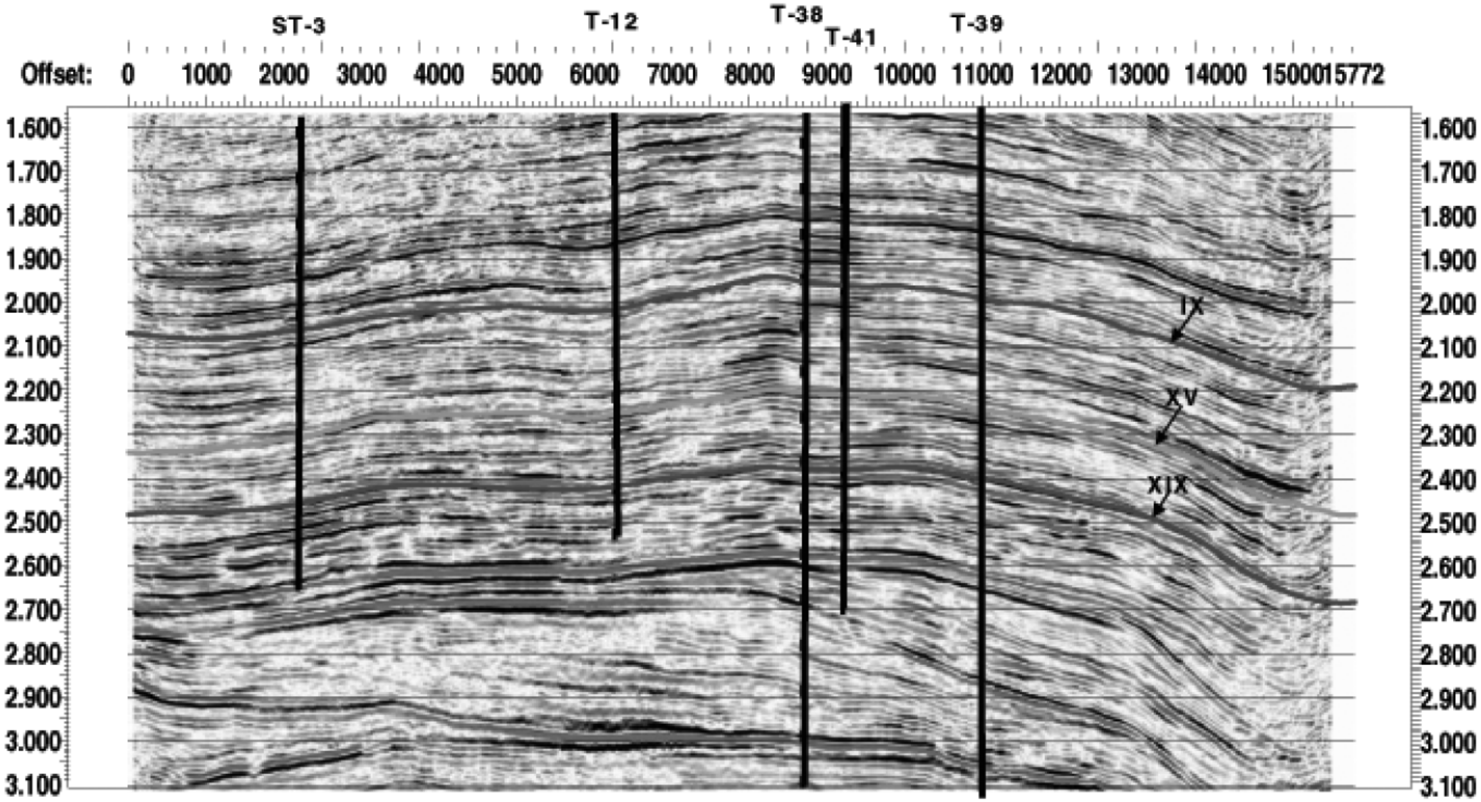


Figure 7

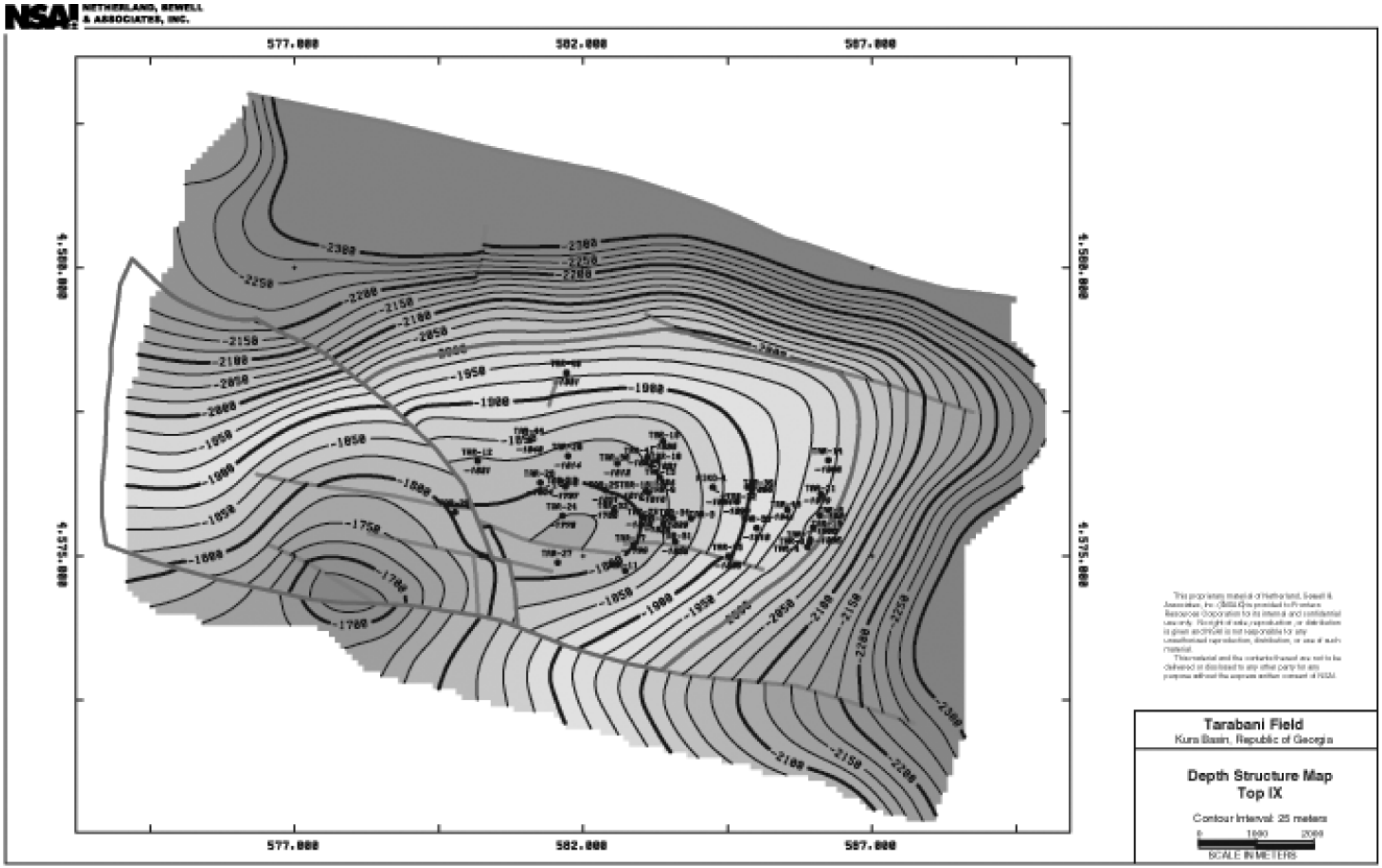
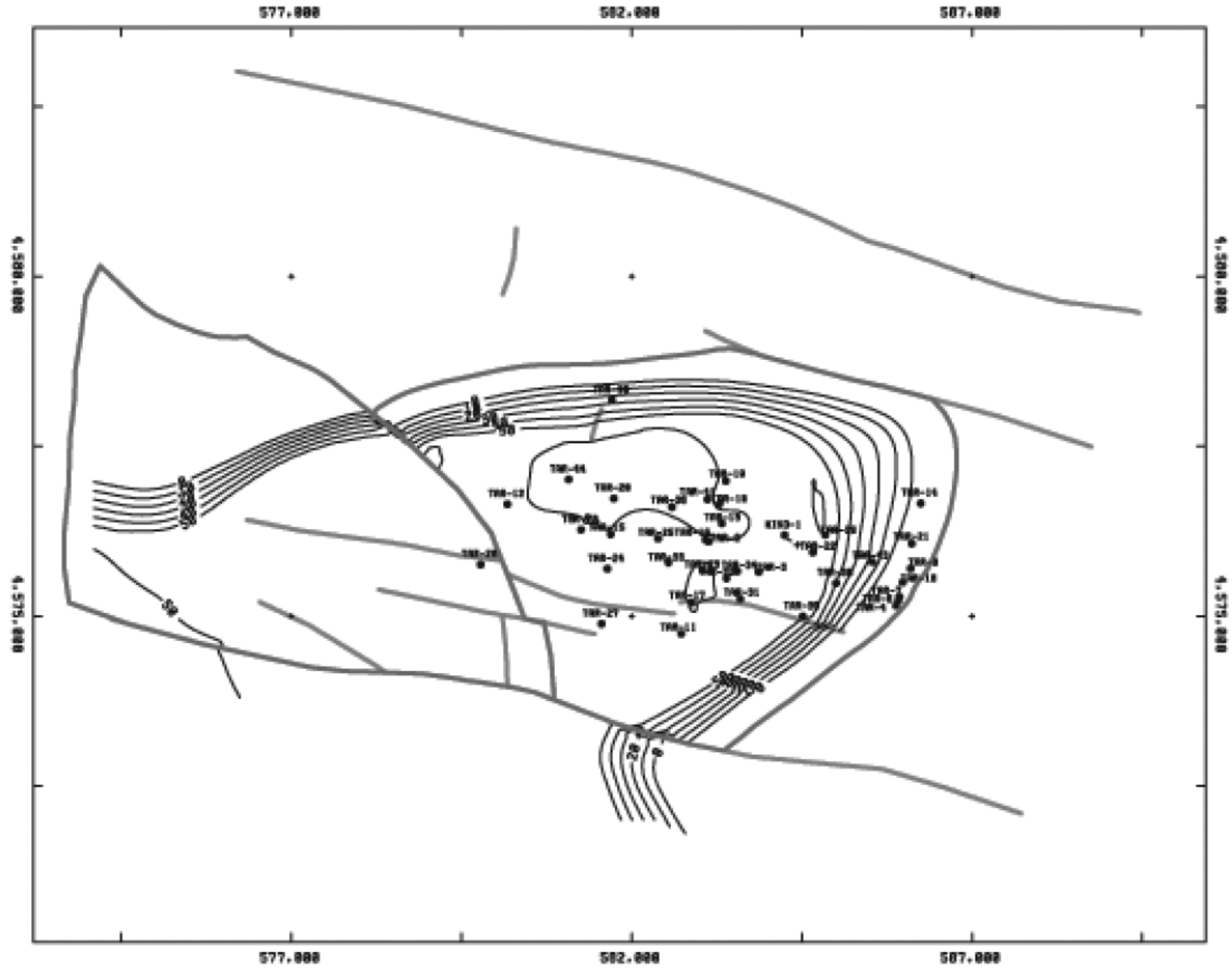

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.
577.000
582.000
587.000
4.580.000
4.575.000
Tarabani Field
Kura Basin, Republic of Georgia
Depth Structure Map
Top IX
Contour Interval: 25 meters
0 1000 2000
SCALE IN METERS

Figure 8

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.



Tarabani Field
Kura Basin, Republic of Georgia

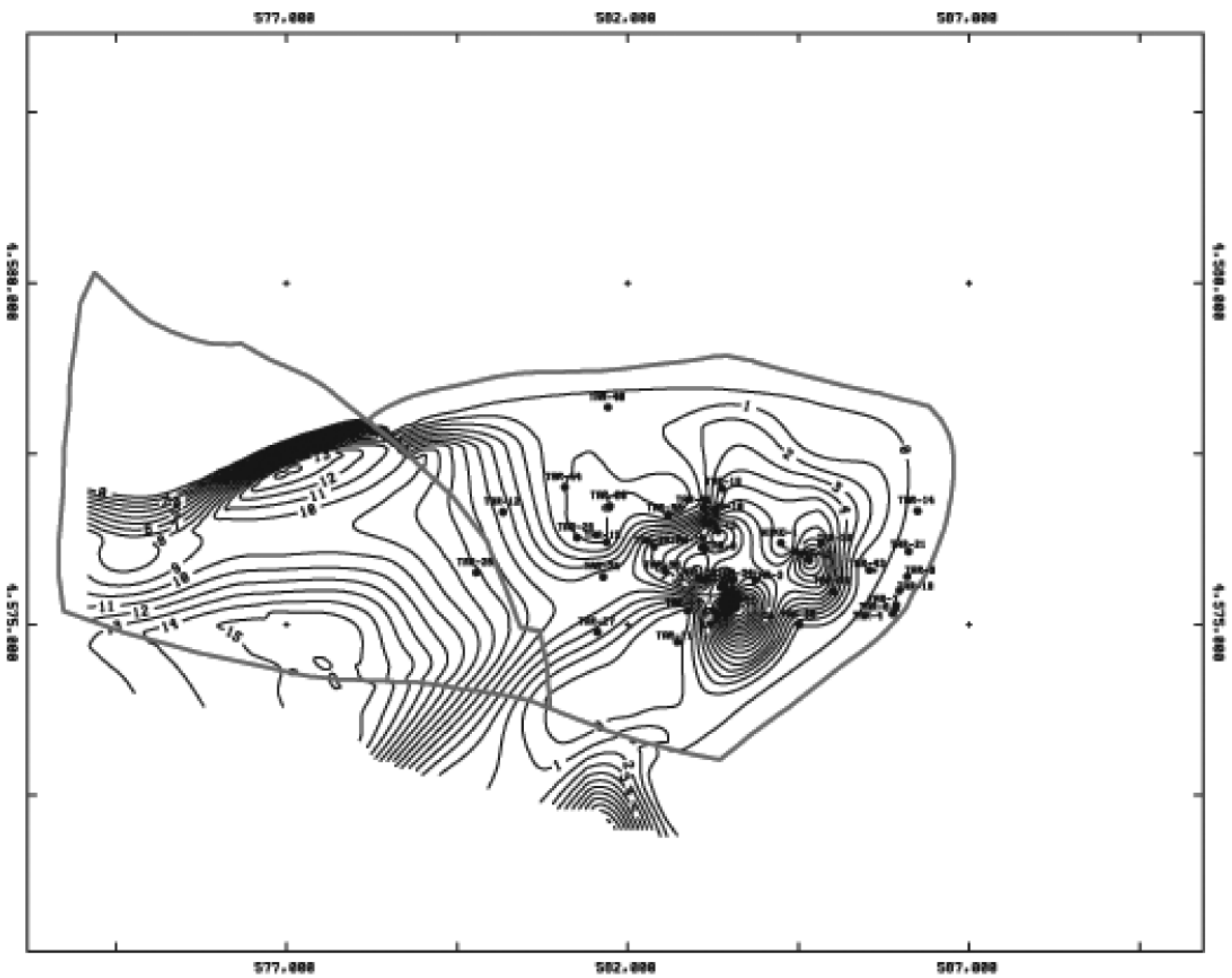
Gross Rock Volume Map
Zone IX

Contour Interval: 10 meters

0 1000 2000
SCALE IN METERS

Figure 9

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.



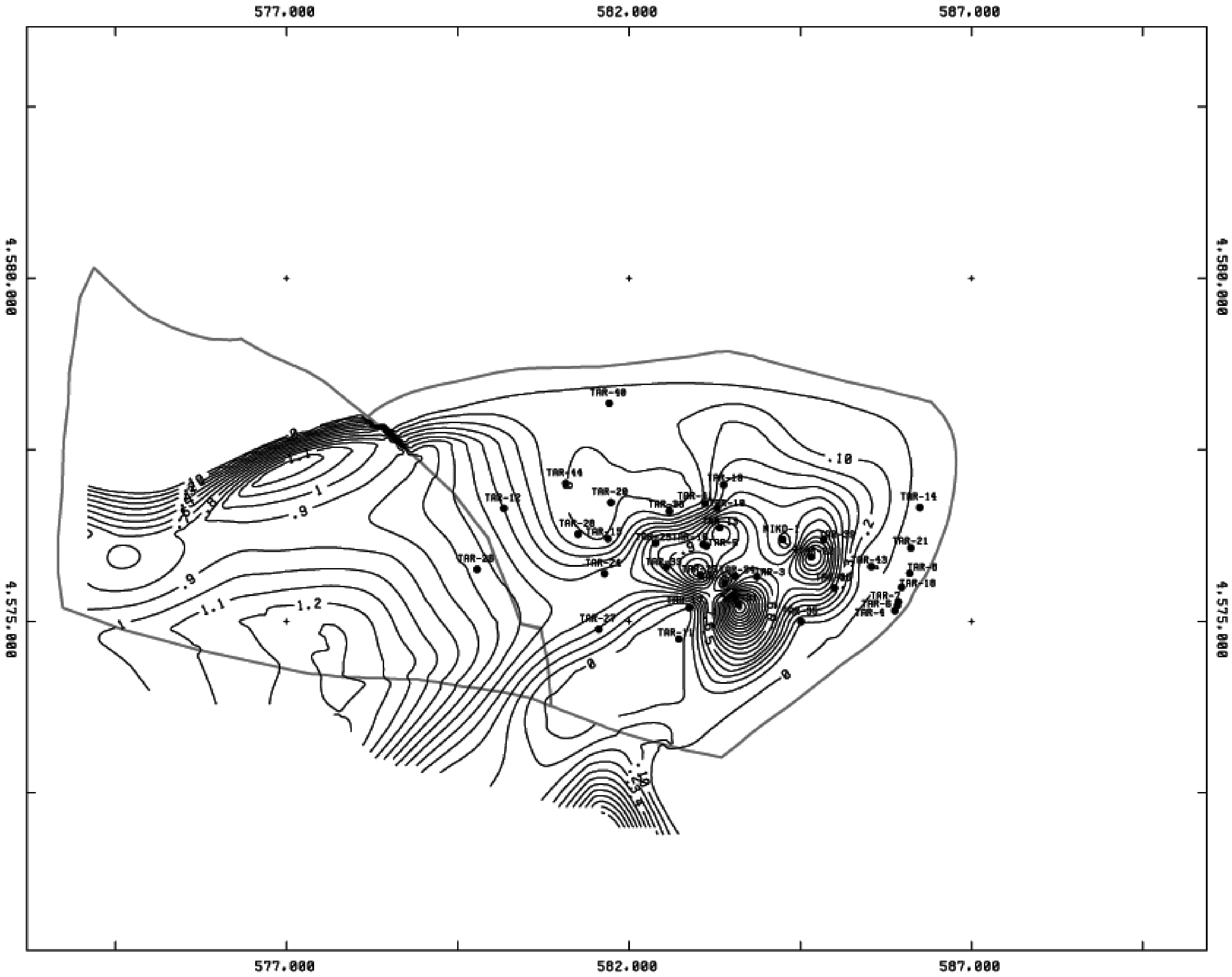
Tarabani Field
Kura Basin, Republic of Geogia

Net Rock Volume Map
Zone IX

Contour Interval: 1 meter
0 1000 2000
SCALE IN METERS

Figure 10

NETHERLAND, SEWELL & ASSOCIATES, INC.



Tarabani Field
Kura Basin, Republic of Georgia

Hydrocarbon Pore Volume Map
Zone IX

Contour Interval: 0.1 meters

0 1000 2000
SCALE IN METERS

Figure 11

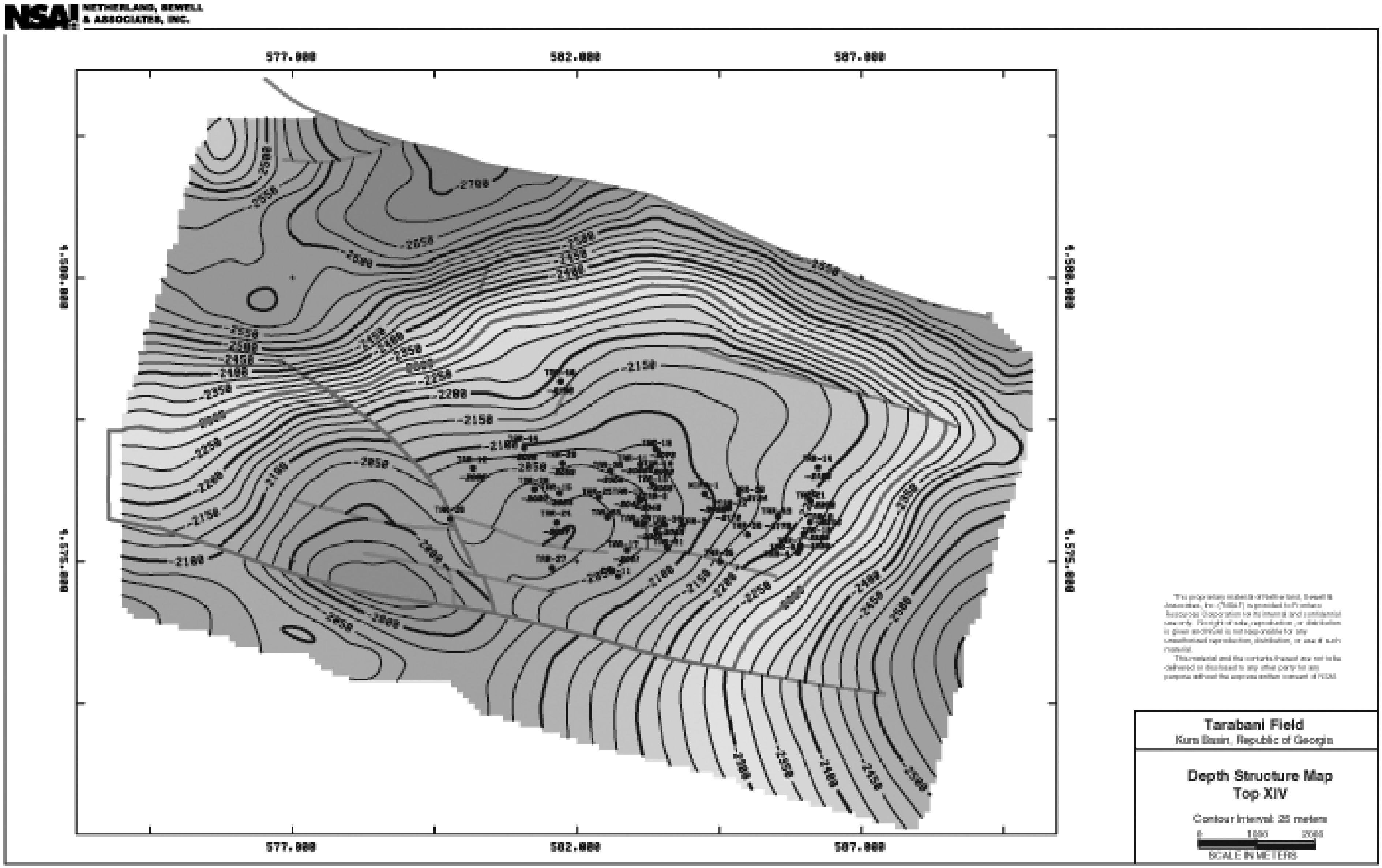
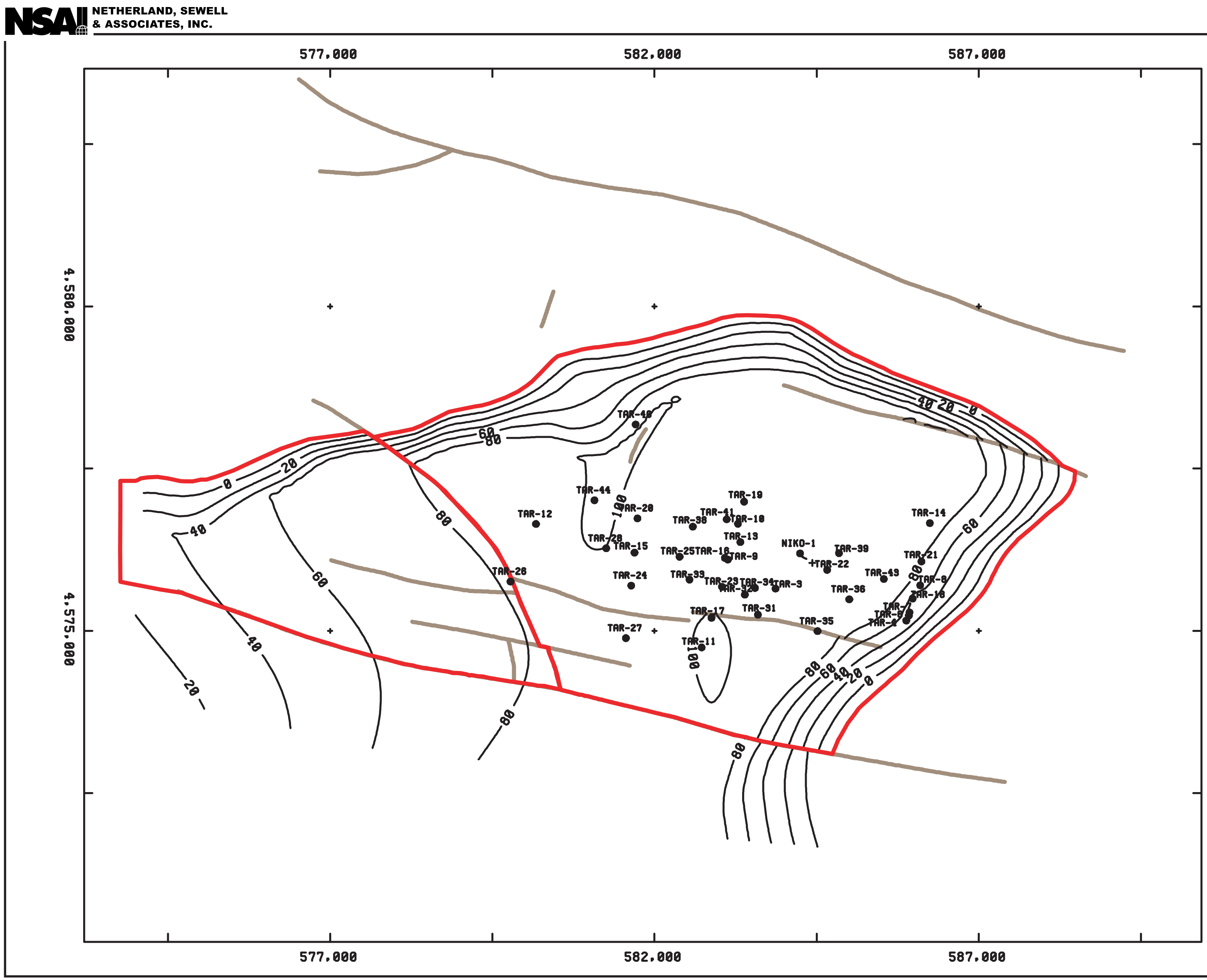

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.
577.000
582.000
587.000
4.580.000
4.575.000
-2150
-2100
-2050
-2200
-2250
-2300
-2350
-2400
-2450
-2500
-2550
-2600
-2650
-2700
Tarabani Field
Kura Basin, Republic of Georgia
Depth Structure Map
Top XIV
Contour Interval: 25 meters
0
1000
2000
SCALE IN METERS

Figure 12



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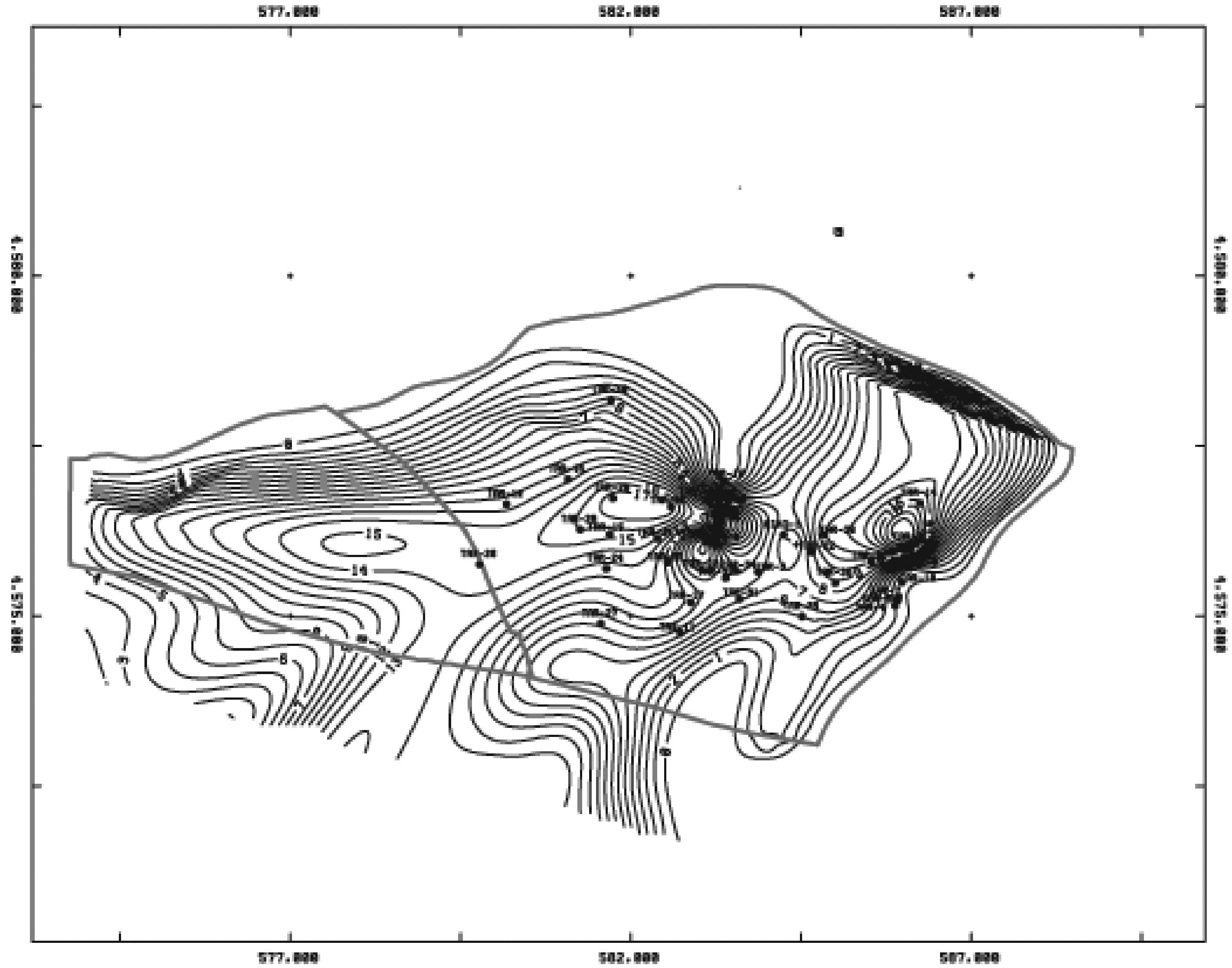
Tarabani Field
Kura Basin, Republic of Georgia

Gross Rock Volume Map
Zone XIV

Contour Interval: 20 meters

0 1000 2000
SCALE IN METERS

Figure 13



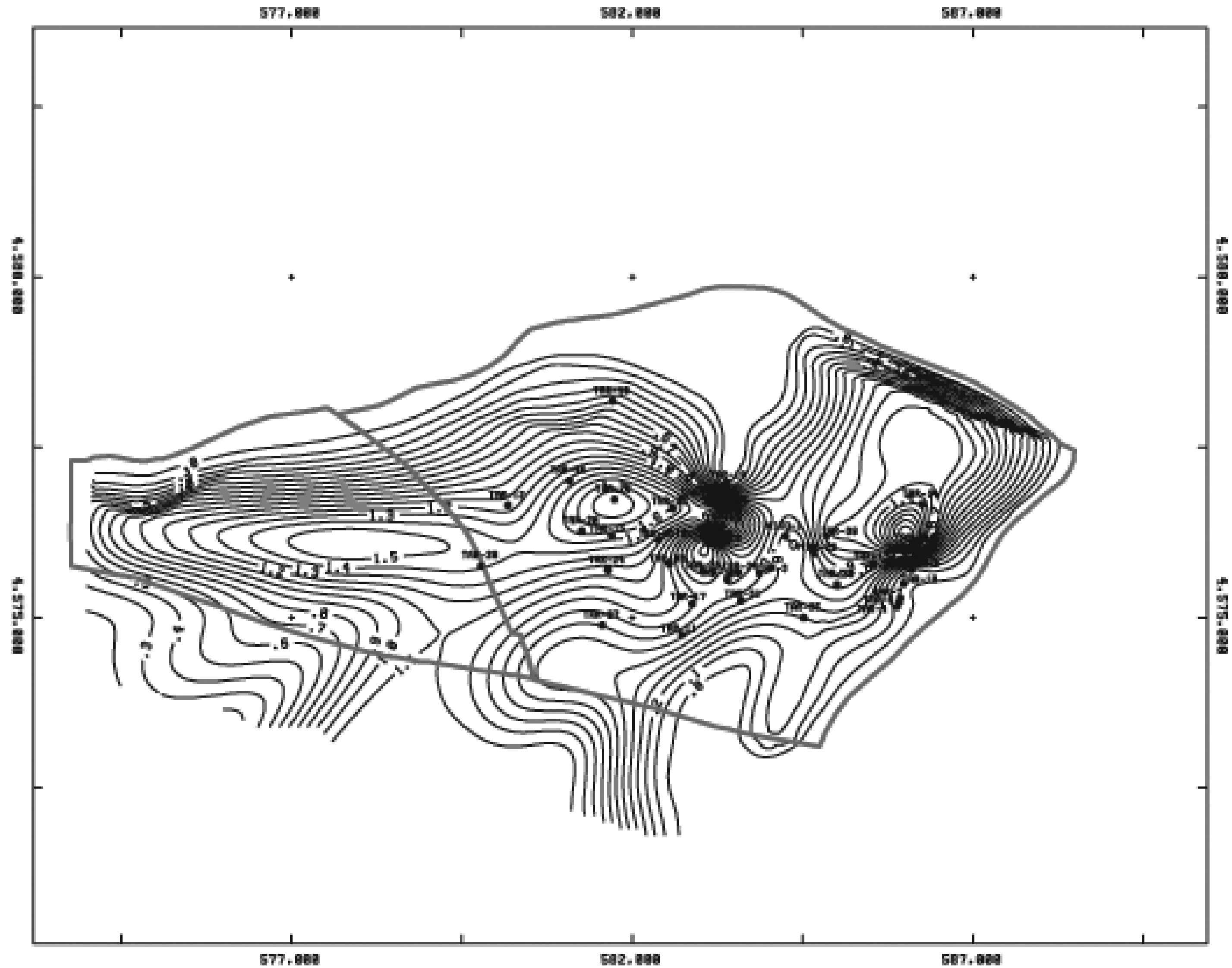
Tarabani Field
Kura Basin, Republic of Georgia

Net Rock Volume Map
Zone XIV

Contour Interval: 1 meter
0 1000 2000
SCALE IN METERS

Figure 14

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.



Tarabani Field

Kura Basin, Republic of Georgia

Hydrocarbon Pore Volume Map
Zone XIV

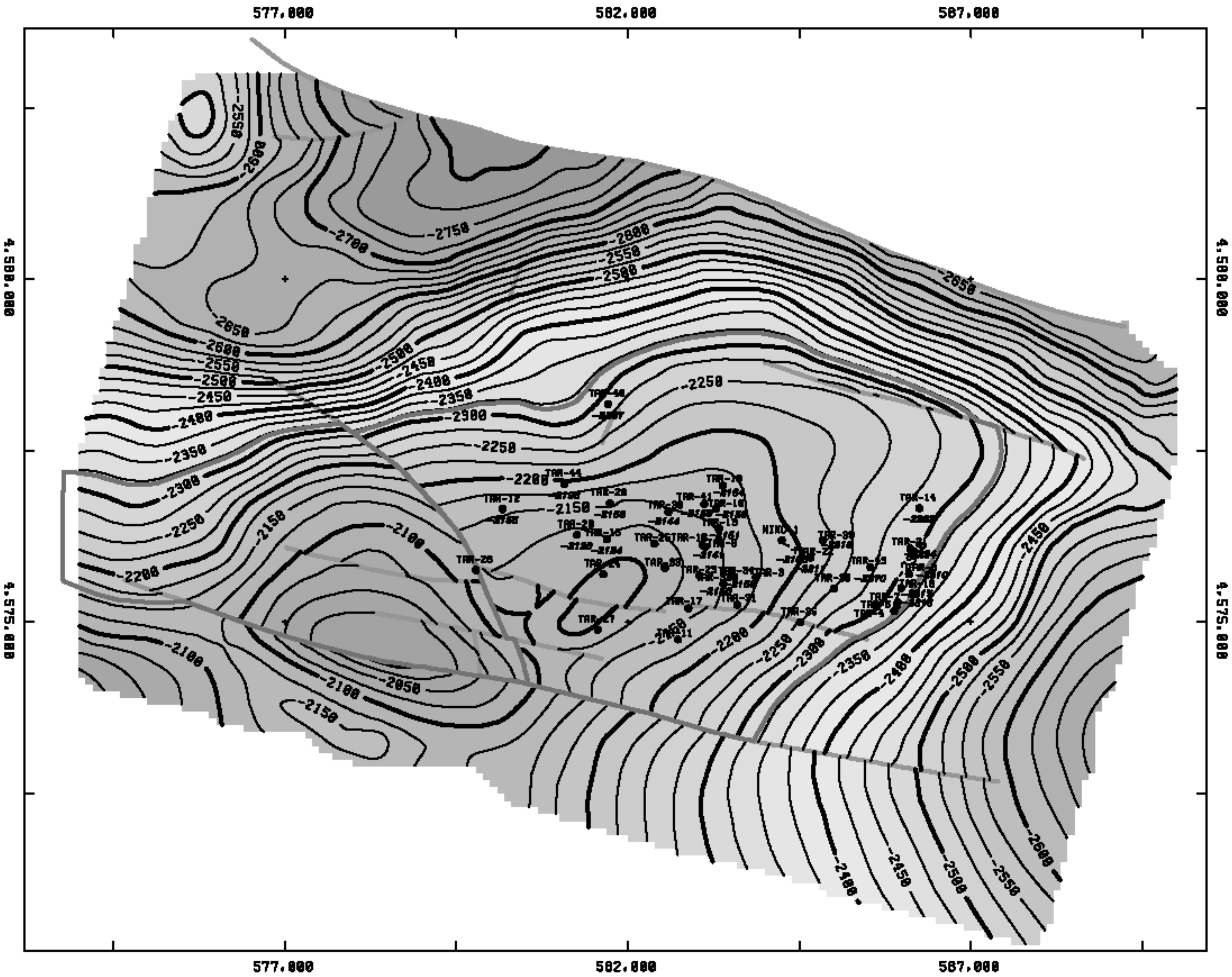
Contour Interval: 0.1 meters

0 1000 2000

SCALE IN METERS

Figure 15

NETHERLAND, SEWELL & ASSOCIATES, INC.



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Tarabani Field
Kura Basin, Republic of Georgia

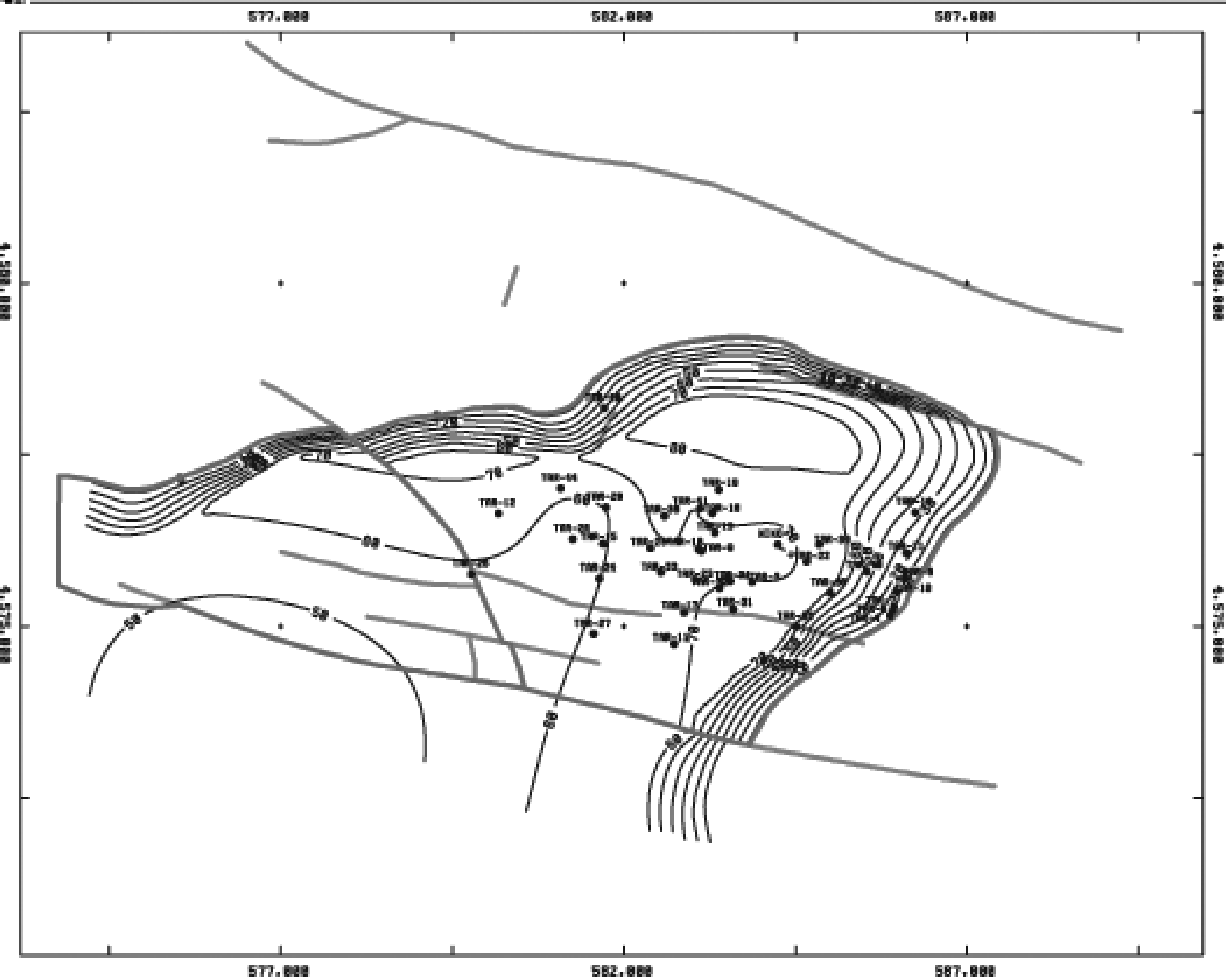
Depth Structure Map
Top XV

Contour Interval: 25 meters

0 1000 2000
SCALE IN METERS

Figure 16

NETHERLAND, SEWELL & ASSOCIATES, INC.



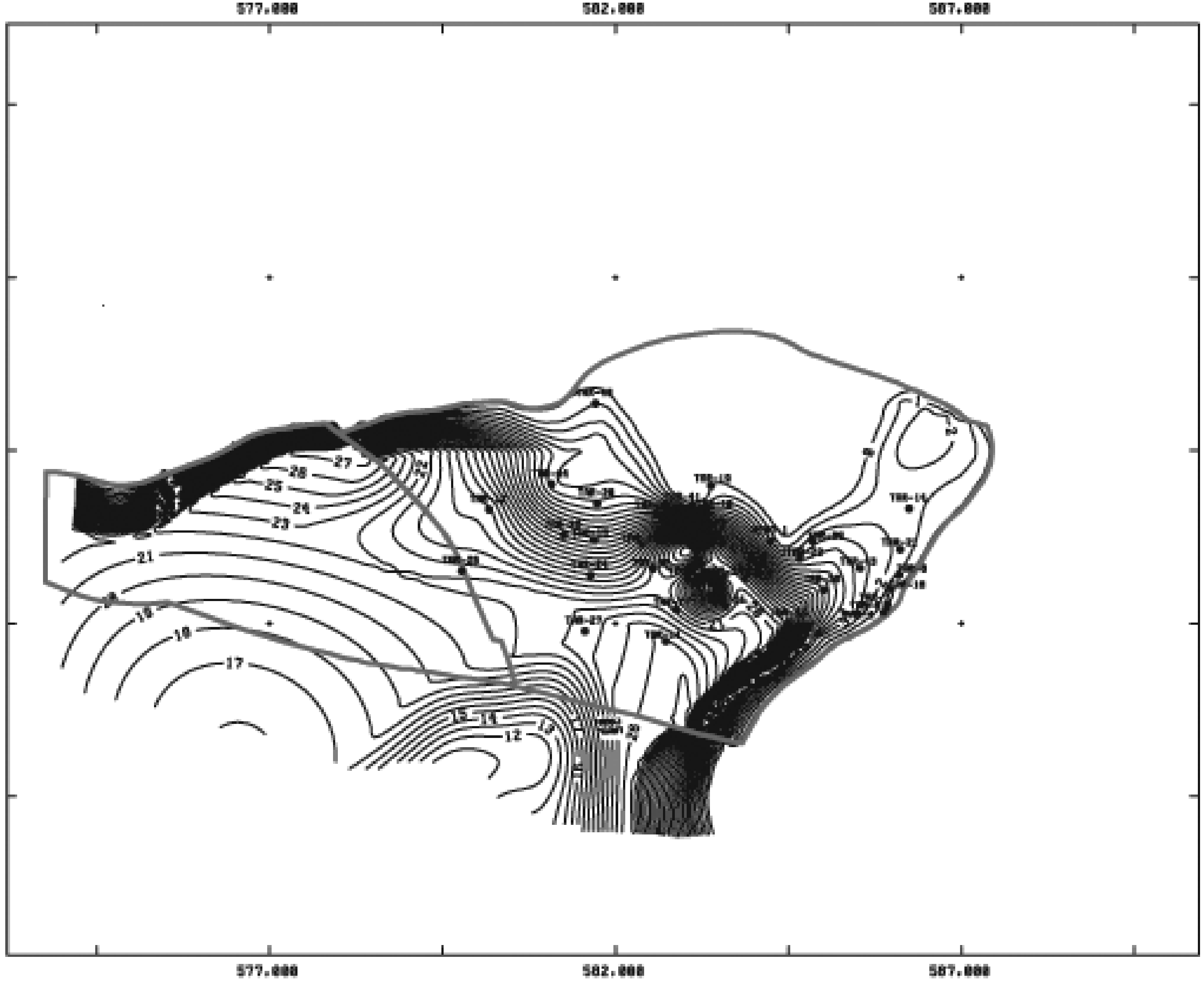
Tarabani Field
Kura Basin, Republic of Georgia

Gross Rock Volume Map
Zone XV

Contour Interval: 10 meters
0 1000 2000
SCALE IN METERS

Figure 17

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.



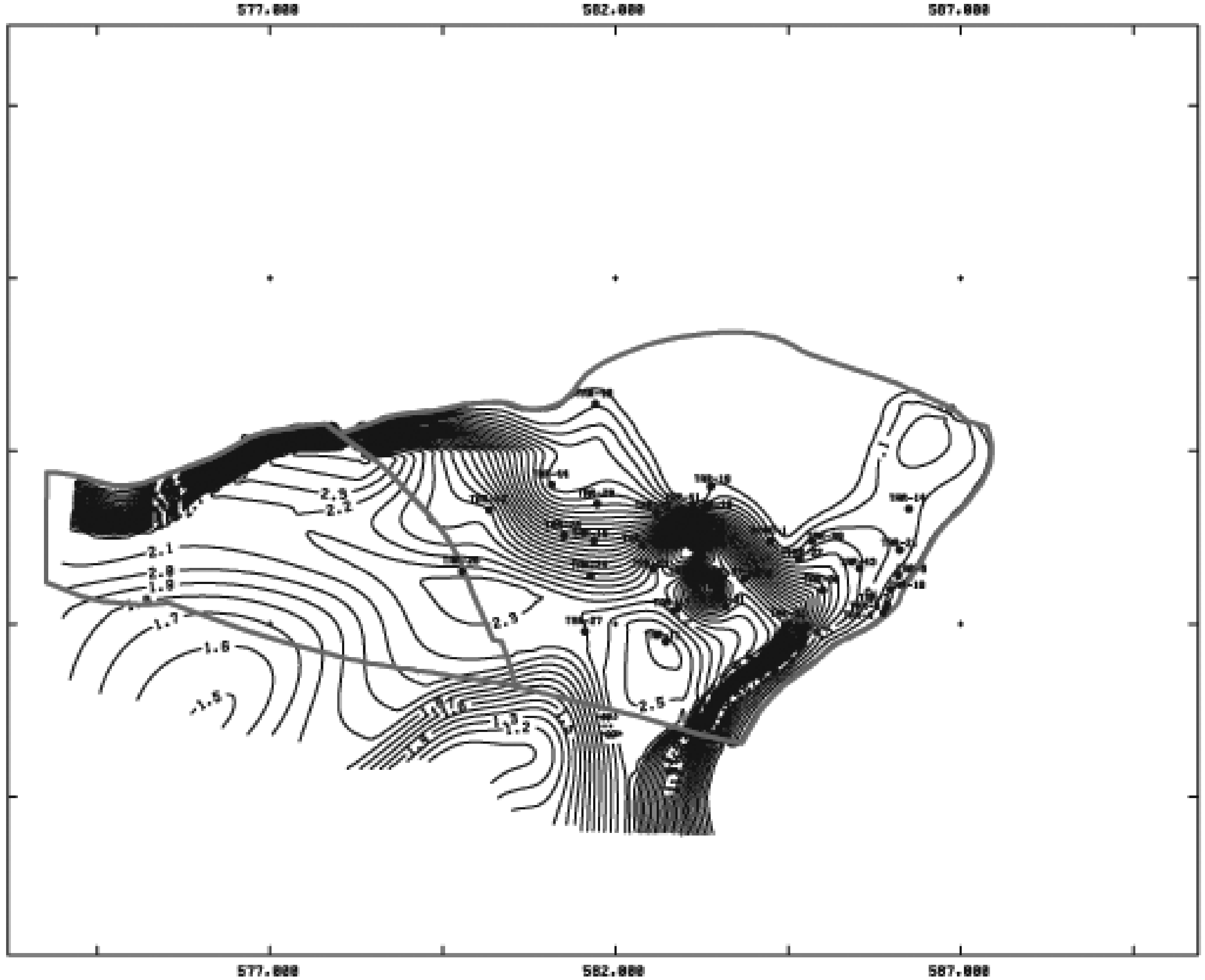
Tarabani Field
Kura Basin, Republic of Georgia

Net Rock Volume Map
Zone XV

Contour Interval: 1 meter

0 1000 2000
SCALE IN METERS

Figure 18



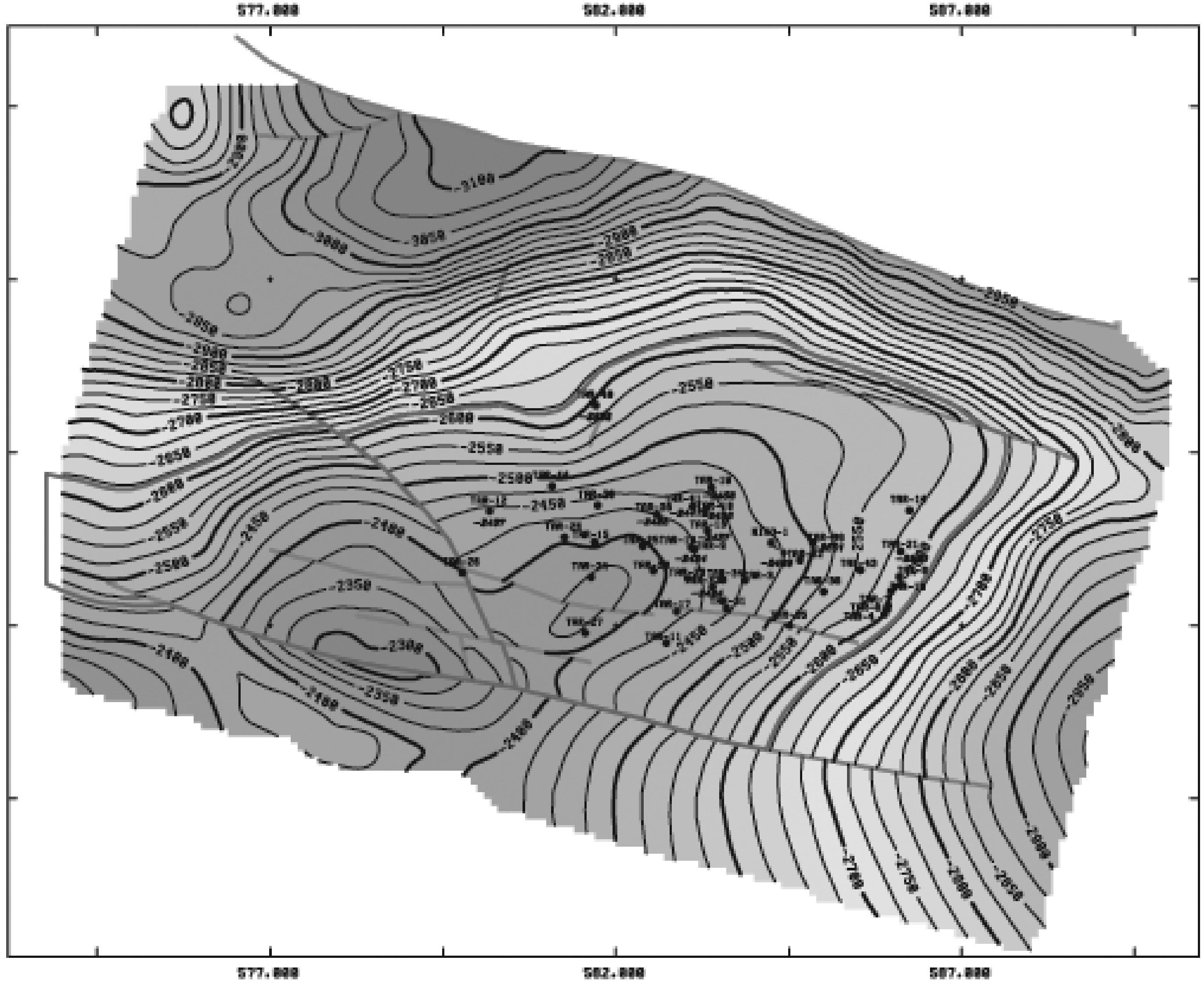
Tarabani Field
Kura Basin, Republic of Georgia

Hydrocarbon Pore Volume Map
Zone XV

Contour Interval: 0.1 meters
0 1000 2000
SCALE IN METERS

Figure 19

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.



Tarabani Field
Kura Basin, Republic of Georgia

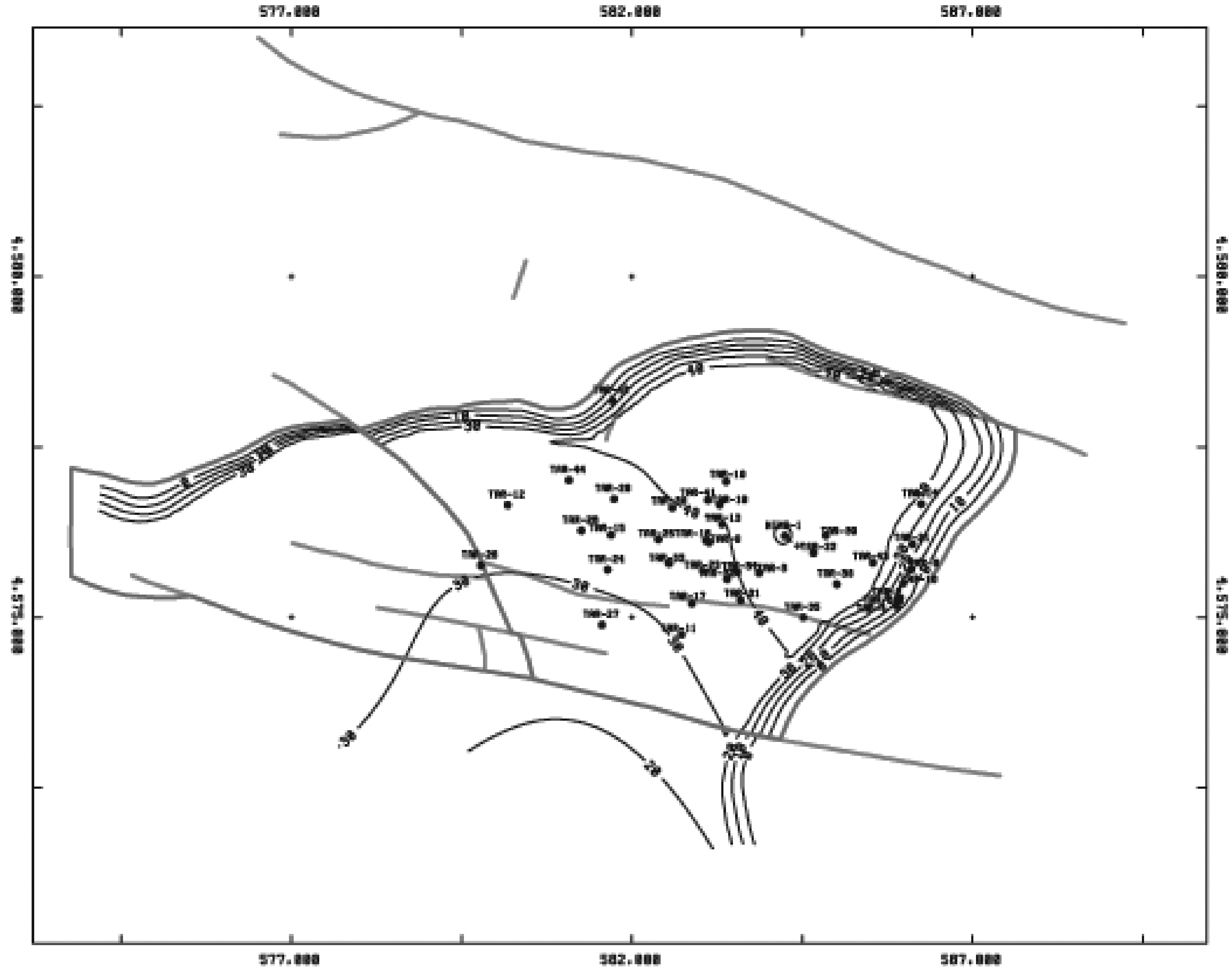
Depth Structure Map
Top XIX

Contour Interval: 25 meters

0 1000 2000
SCALE IN METERS

Figure 20

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.



Tarabani Field

Kura Basin, Republic of Georgia

Gross Rock Volume Map
Zone XIX

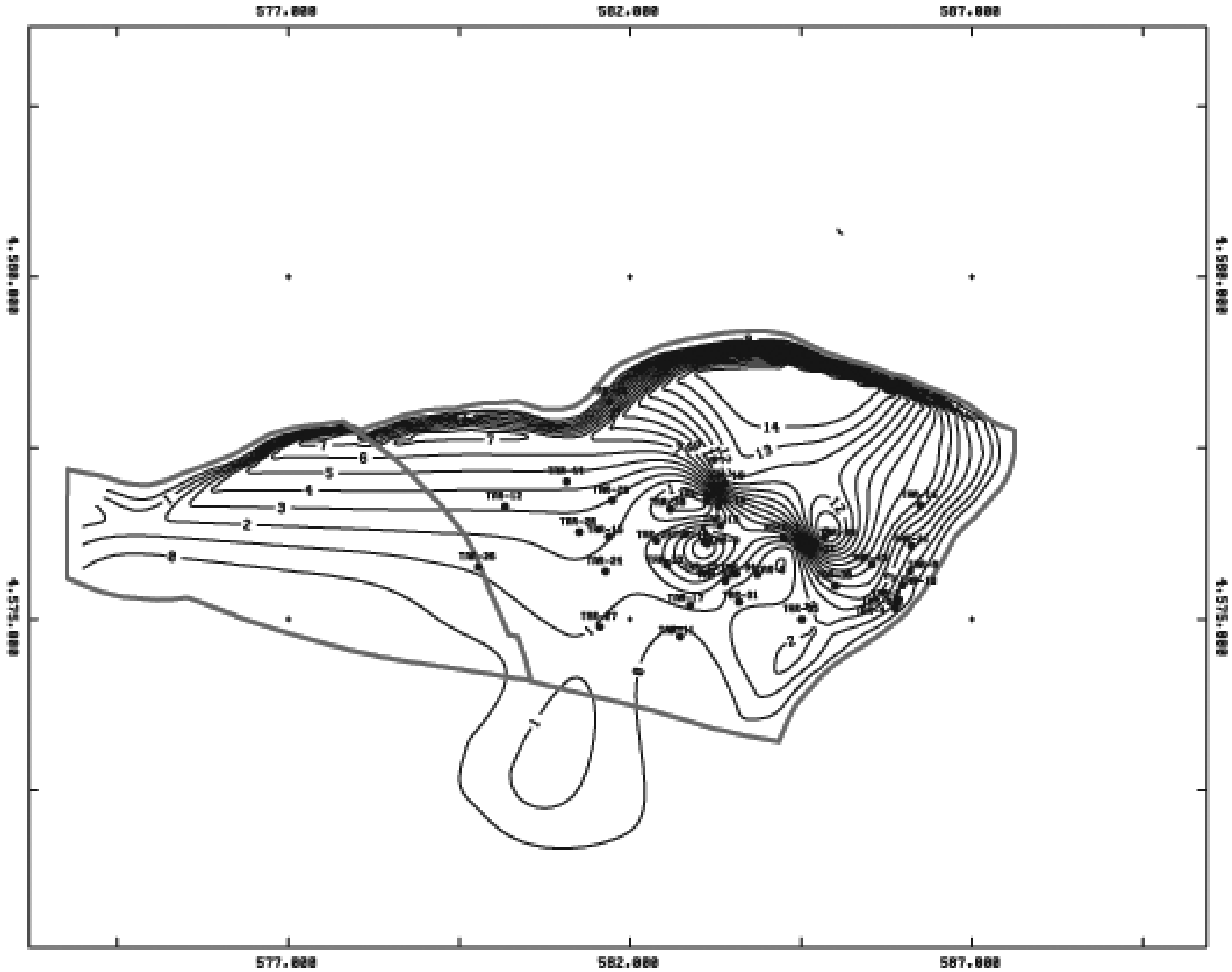
Contour Interval: 10 meters

0 1000 2000

SCALE IN METERS

Figure 21

NETHERLAND, SEWELL & ASSOCIATES, INC.



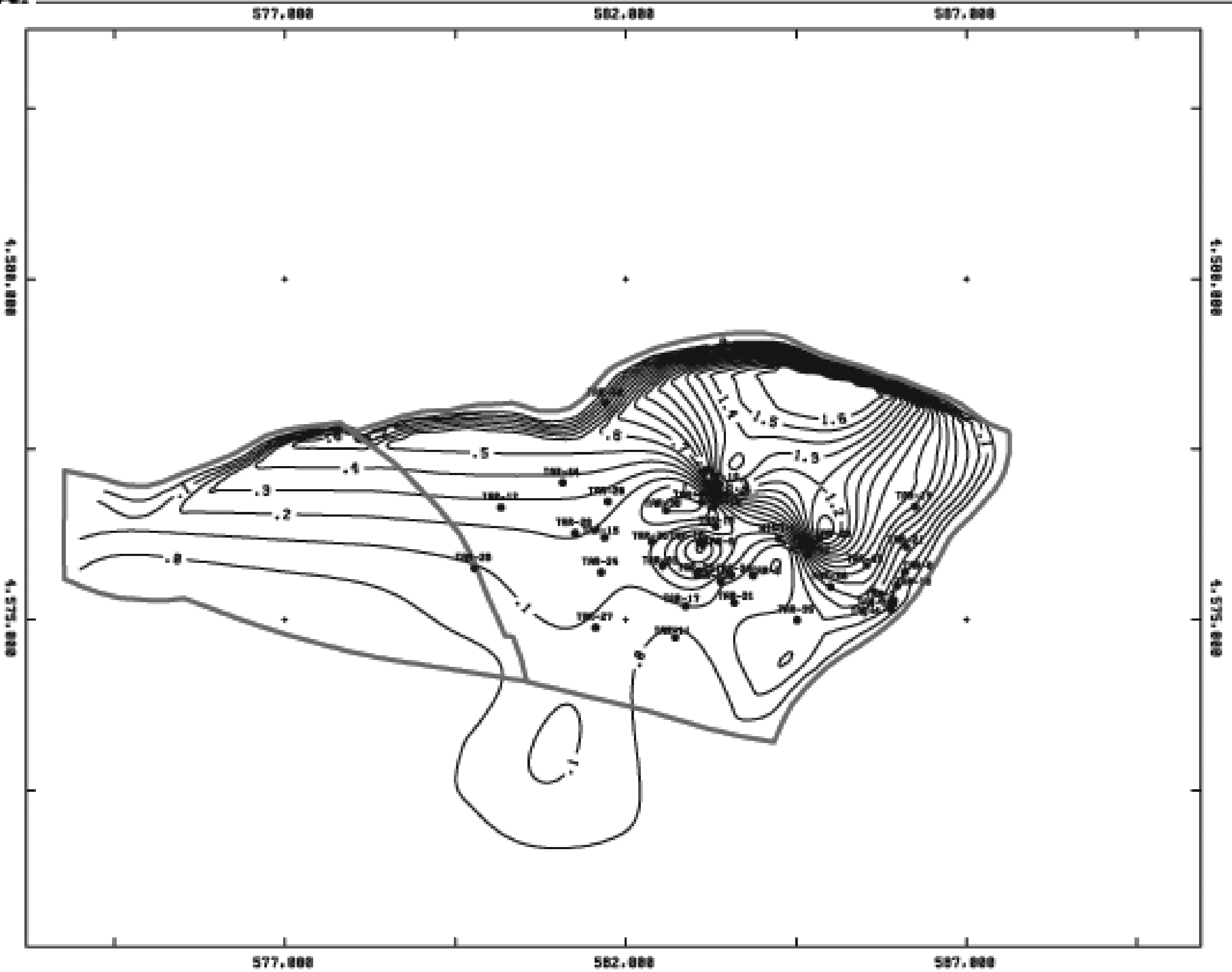
Tarabani Field
Kura Basin, Republic of Georgia

Net Rock Volume Map
Zone XIX

Contour Interval: 1 meter
0 1000 2000
SCALE IN METERS

Figure 22

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.



Tarabani Field
Kura Basin, Republic of Georgia

Hydrocarbon Pore Volume Map
Zone XIX

Contour Interval: 0.1 meters

0 1000 2000
SCALE IN METERS

Figure 23

POSSIBLE GROSS (100 PERCENT) RESERVE CASE[1]
BLOCK 12, TARABANI FIELD
KURA BASIN, REPUBLIC OF GEORGIA

Horizon	Gross Rock Volume (Ac-Ft)	Net Rock Volume (Ac-Ft)	Pore Volume (Ac-Ft)	Hydrocarbon Pore Volume (Ac-Ft)	Average NTG (%)	Average Porosity (decimal)	Average Oil Saturation (decimal)	OOIP (MMBO)	EUR (MMBO)
IX	1,805,153	211,570	42,372	19,001	0.117	0.200	0.448	134.007	20.101
XIV	3,358,919	333,759	70,793	31,469	0.099	0.212	0.445	221.939	33.291
XV	2,178,931	486,828	107,409	47,368	0.223	0.221	0.441	334.071	50.111
XIX	1,268,625	147,883	27,698	13,933	0.117	0.187	0.503	98.263	14.739
							Total	788.280	118.242

(1) No proved or probable reserves exist for Tarabani Field.

Figure 24

VOLUMETRIC PARAMETERS FOR PROSPECTS
BLOCK 12
KURA BASIN, REPUBLIC OF GEORGIA

Prospect Name	Gross Rock Volume (Ac-Ft) Lognormal		Net-to-Gross Ratio (Decimal) Triangular			Average Porosity (Decimal)			Hydrocarbon Saturation (decimal)			1/FVF (Decimal)	Recovery Factor (Decimal) Triangular		
	P90	P10	Min	ML	Max	Min	ML	Max	Min	ML	Max		Min	ML	Max
Basin Edge B Cretaceous	1,731,400	16,599,200	0.060	0.150	0.400	0.190	0.205	0.220	0.440	0.470	0.500	0.909	0.050	0.200	0.350
Basin Edge C Cretaceous	1,461,443	12,641,696	0.060	0.150	0.400	0.190	0.205	0.220	0.440	0.470	0.500	0.909	0.050	0.200	0.350
Basin Edge B S3	2,125,931	24,940,692	0.060	0.150	0.350	0.190	0.205	0.220	0.440	0.470	0.500	0.909	0.050	0.150	0.250
Basin Edge C S3	1,560,000	13,419,000	0.060	0.150	0.350	0.190	0.205	0.220	0.440	0.470	0.500	0.909	0.050	0.150	0.250
Kila Kupra	1,469,263	2,448,772	0.060	0.105	0.250	0.190	0.205	0.220	0.440	0.470	0.500	0.909	0.050	0.150	0.250
Iori	453,509	755,848	0.060	0.105	0.250	0.190	0.205	0.220	0.440	0.470	0.500	0.909	0.050	0.150	0.250
Mirzaani South	343,538	572,563	0.060	0.150	0.350	0.190	0.205	0.220	0.440	0.470	0.500	0.909	0.050	0.150	0.250
Mirzaani Deep	668,076	1,113,460	0.060	0.150	0.350	0.190	0.205	0.220	0.440	0.470	0.500	0.909	0.050	0.150	0.250
Pkhoveli	141,480	3,020,787	0.060	0.150	0.350	0.190	0.205	0.220	0.440	0.470	0.500	0.909	0.050	0.150	0.250

Figure 25

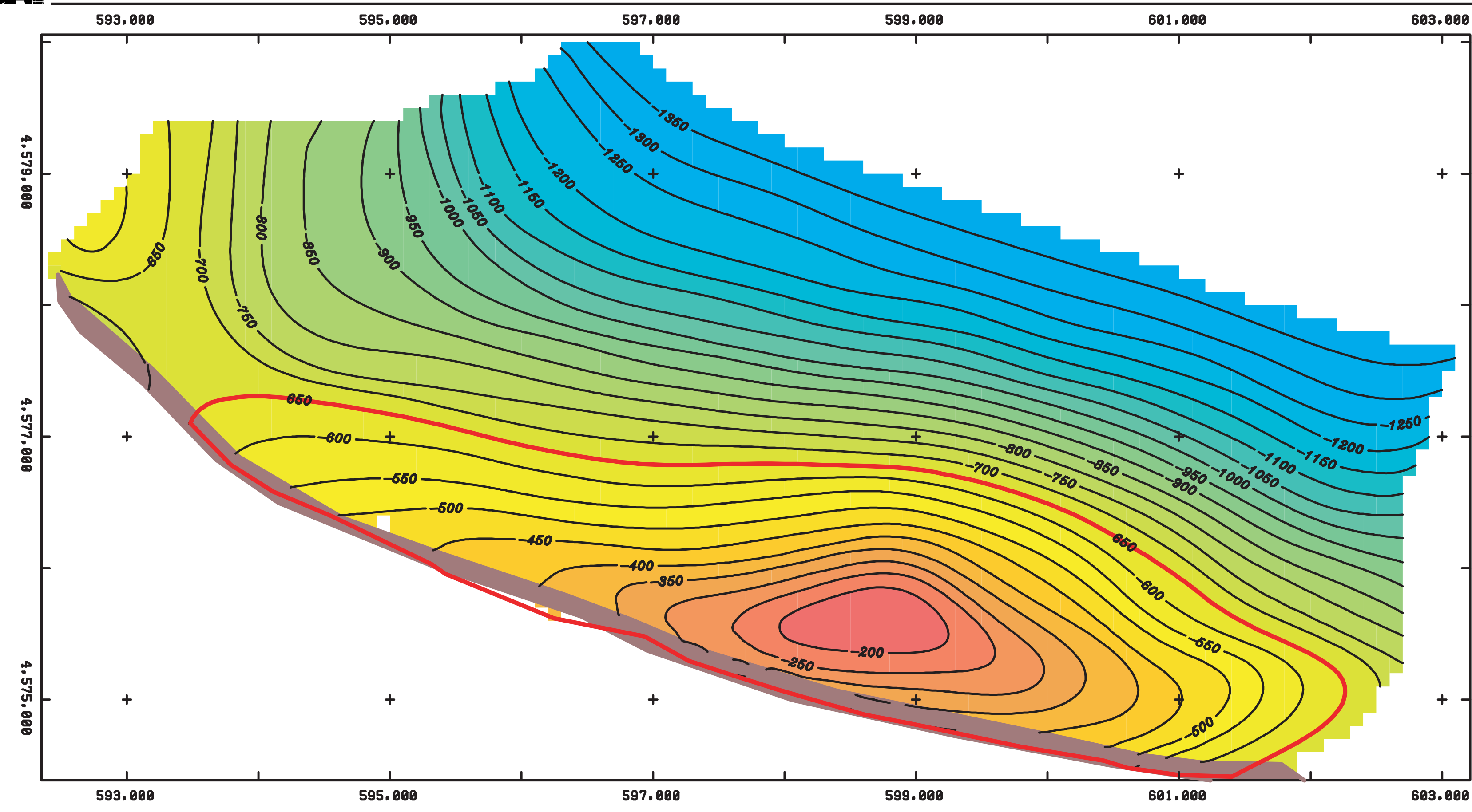
UNRISKED GROSS (100 PERCENT) PROSPECTIVE OIL RESOURCES
BLOCK 12
KURA BASIN, REPUBLIC OF GEORGIA

	Original Oil-in-Place (MMBO)				Estimated Ultimate Recovery (MMBO)			
Prospect Name	**Low Side**	**Most Likely**	**Mean**	**High Side**	**Low Side**	**Most Likely**	**Mean**	**High Side**
Basin Edge B Cretaceous	198	632	856	1,810	34	120	171	376
Basin Edge C Cretaceous	168	534	703	1,483	30	100	140	307
Basin Edge B S3	219	799	1,115	2,488	30	115	168	375
Basin Edge C S3	173	515	675	1,432	23	74	102	220
Kila Kupra	105	170	180	270	13	25	27	44
Iori	33	52	56	83	4	8	8	13
Mirzaani South	31	54	56	86	4	8	8	14
Mirzaani Deep	61	103	110	167	8	15	17	27
Pkhoveli	15	69	110	267	2	10	16	40
Total(1)	1,002	2,929	3,861	8,086	148	475	657	1,417

(1) Totals may not add due to rounding.

Figure 26

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.



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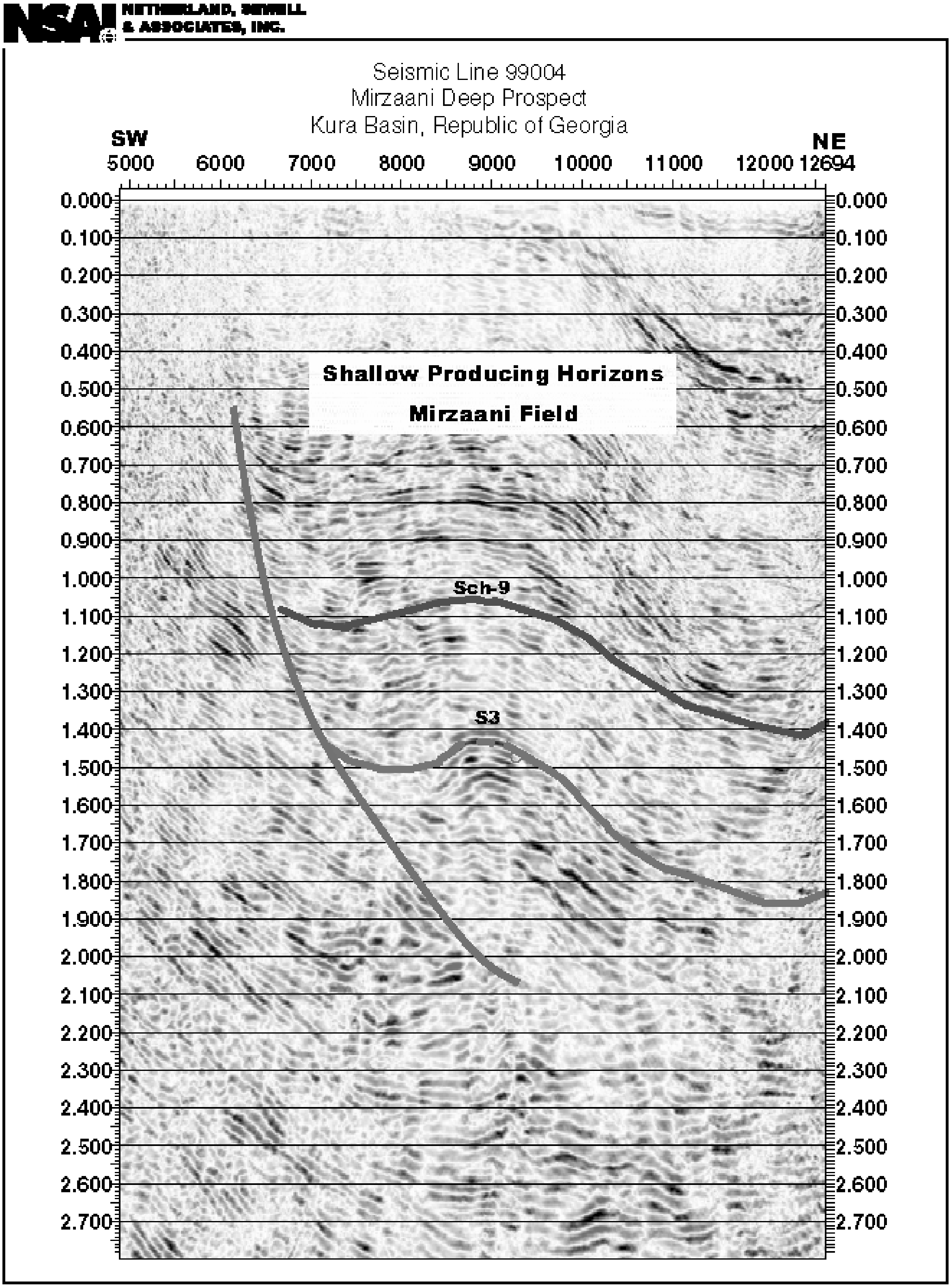
Mirzaani South Prospect
Kura Basin, Republic of Georgia

Depth Structure Map
Top Upper Sarmatian
Contour Interval: 50 meters

0 1000 2000
SCALE IN METERS

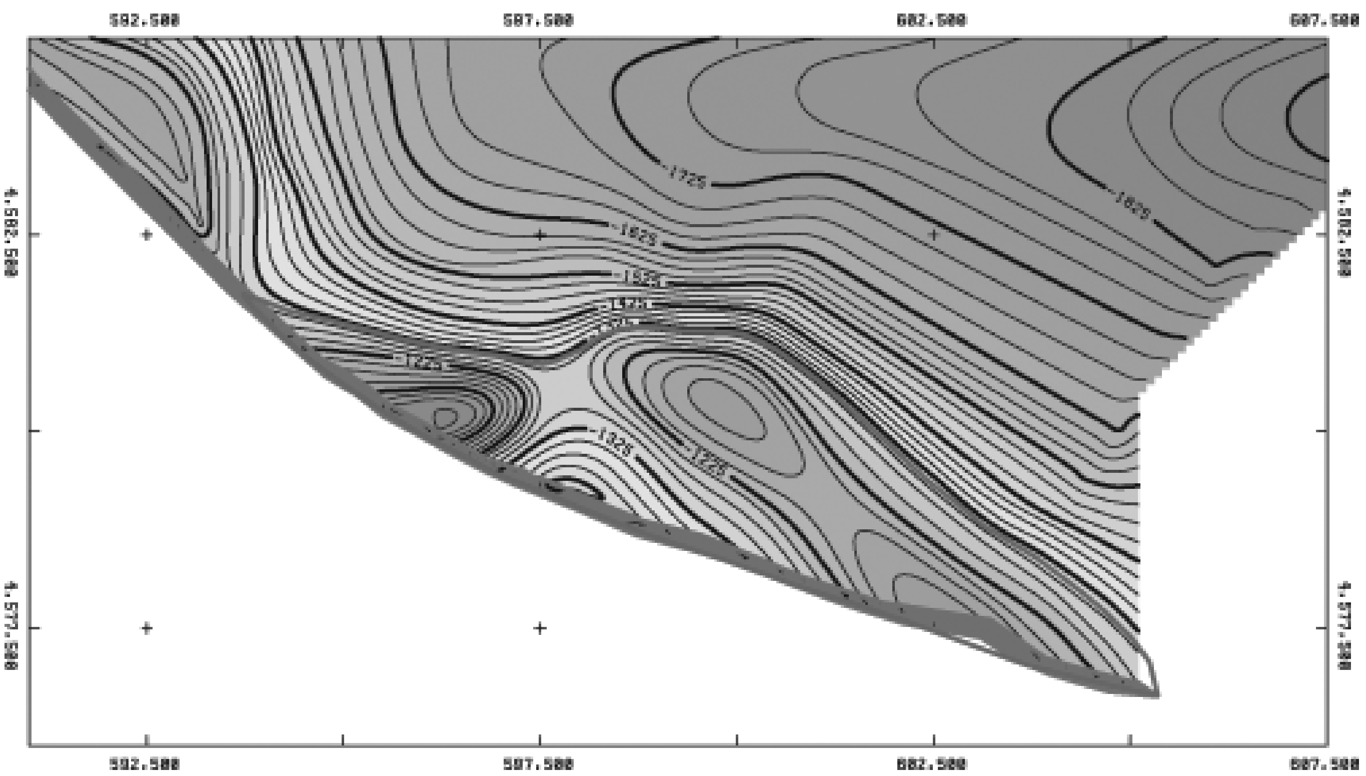
Figure 27



NETHERLAND, SEWELL
& ASSOCIATES, INC.
Seismic Line 99004
Mirzaani Deep Prospect
Kura Basin, Republic of Georgia
SW
NE
5000
6000
7000
8000
9000
10000
11000
12000 12694
Shallow Producing Horizons
Mirzaani Field
Sch-9
S3
0.000
0.100
0.200
0.300
0.400
0.500
0.600
0.700
0.800
0.900
1.000
1.100
1.200
1.300
1.400
1.500
1.600
1.700
1.800
1.900
2.000
2.100
2.200
2.300
2.400
2.500
2.600
2.700

Figure 28

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.



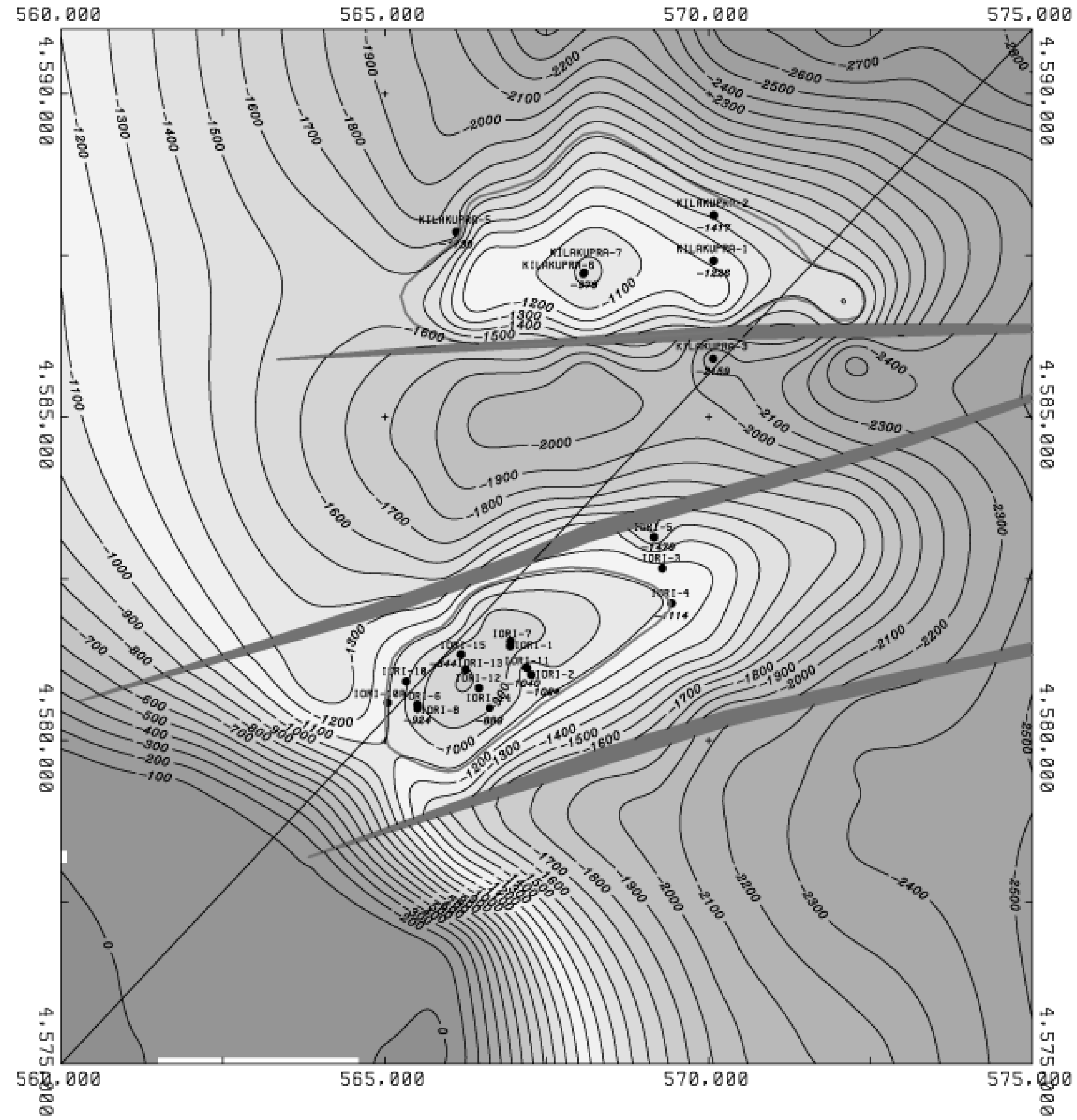
Mirzaani Deep Prospect
Kura Basin, Republic of Georgia

Depth Structure Map
Top S3
Contour Interval: 25 meters

0 1000 2000
SCALE IN METERS

Figure 29

NETHERLAND, SEWELL & ASSOCIATES, INC.



Iori and Kila Kupra Fields

Kura Basin, Republic of Georgia

Depth Structure Map
Top XIV (S3)

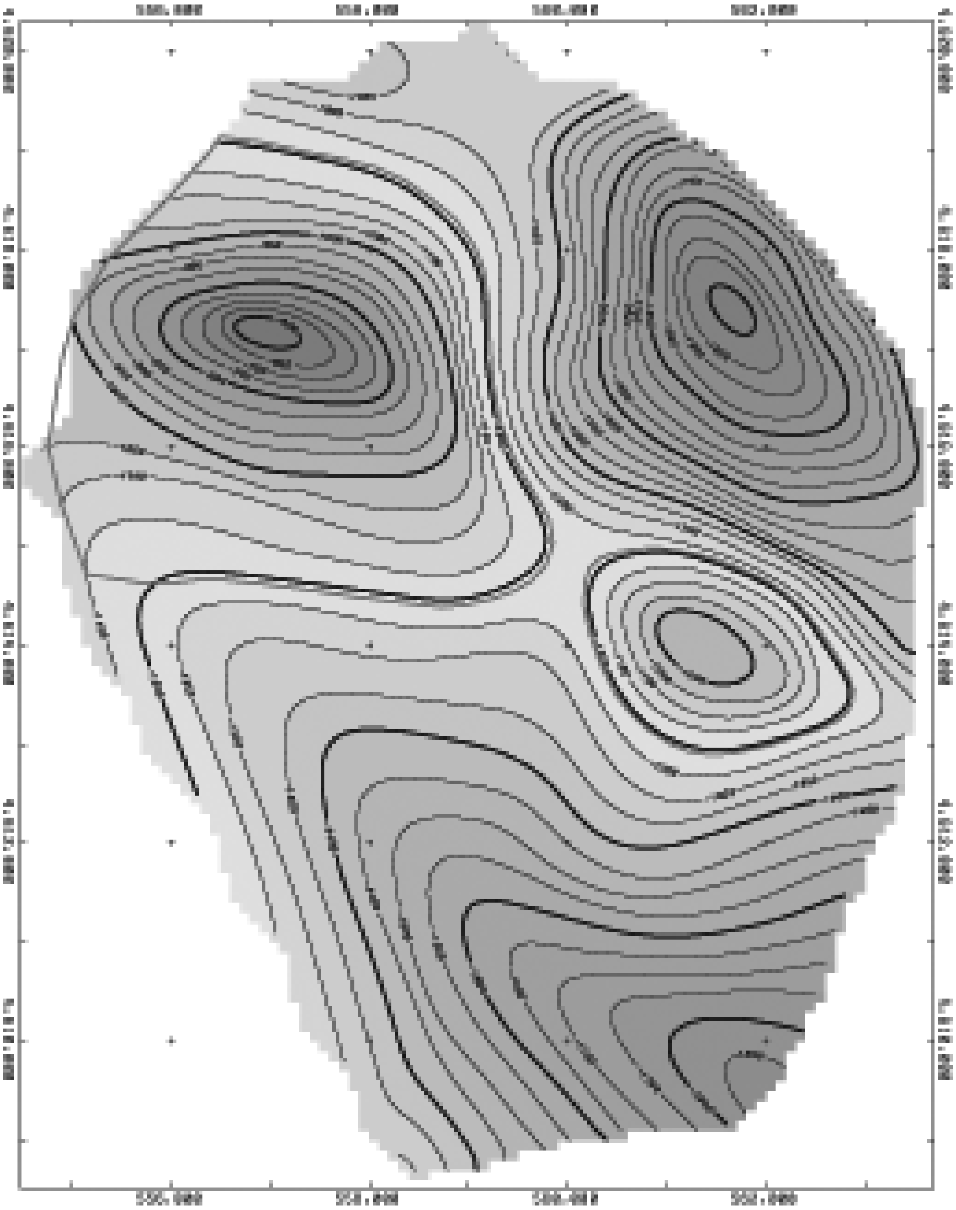
Contour Interval: 100 meters

0 1000 2000

SCALE IN METERS

Figure 30

NETHERLAND, SEWELL
& ASSOCIATES, INC.



Pkhoveli Prospect
Kura Basin, Republic of Georgia

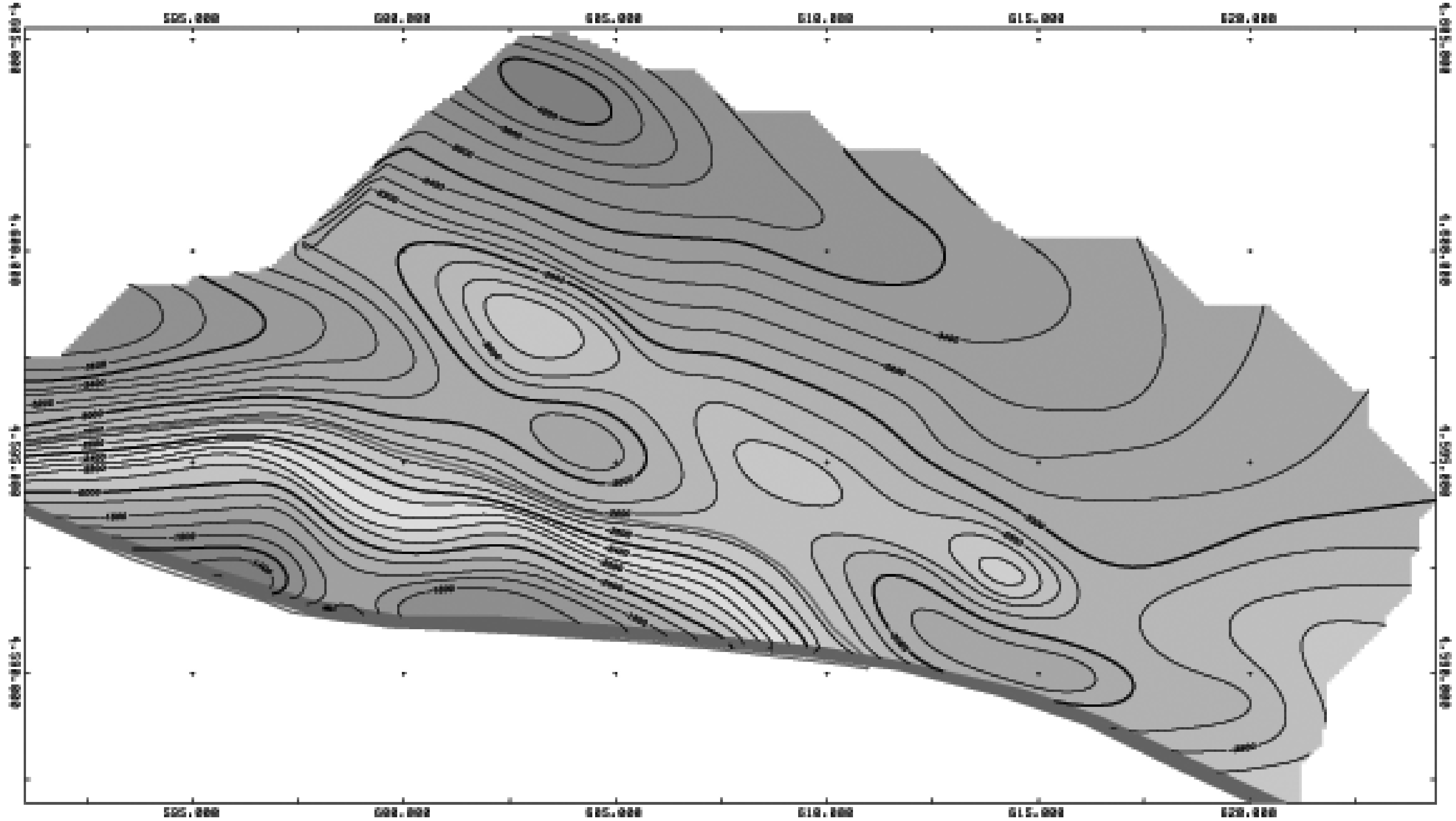
Depth Structure Map
Top XIV (S3)

Contour Interval: 50 meters

SCALE IN METERS

Figure 31

NETHERLAND, SEWELL & ASSOCIATES, INC.



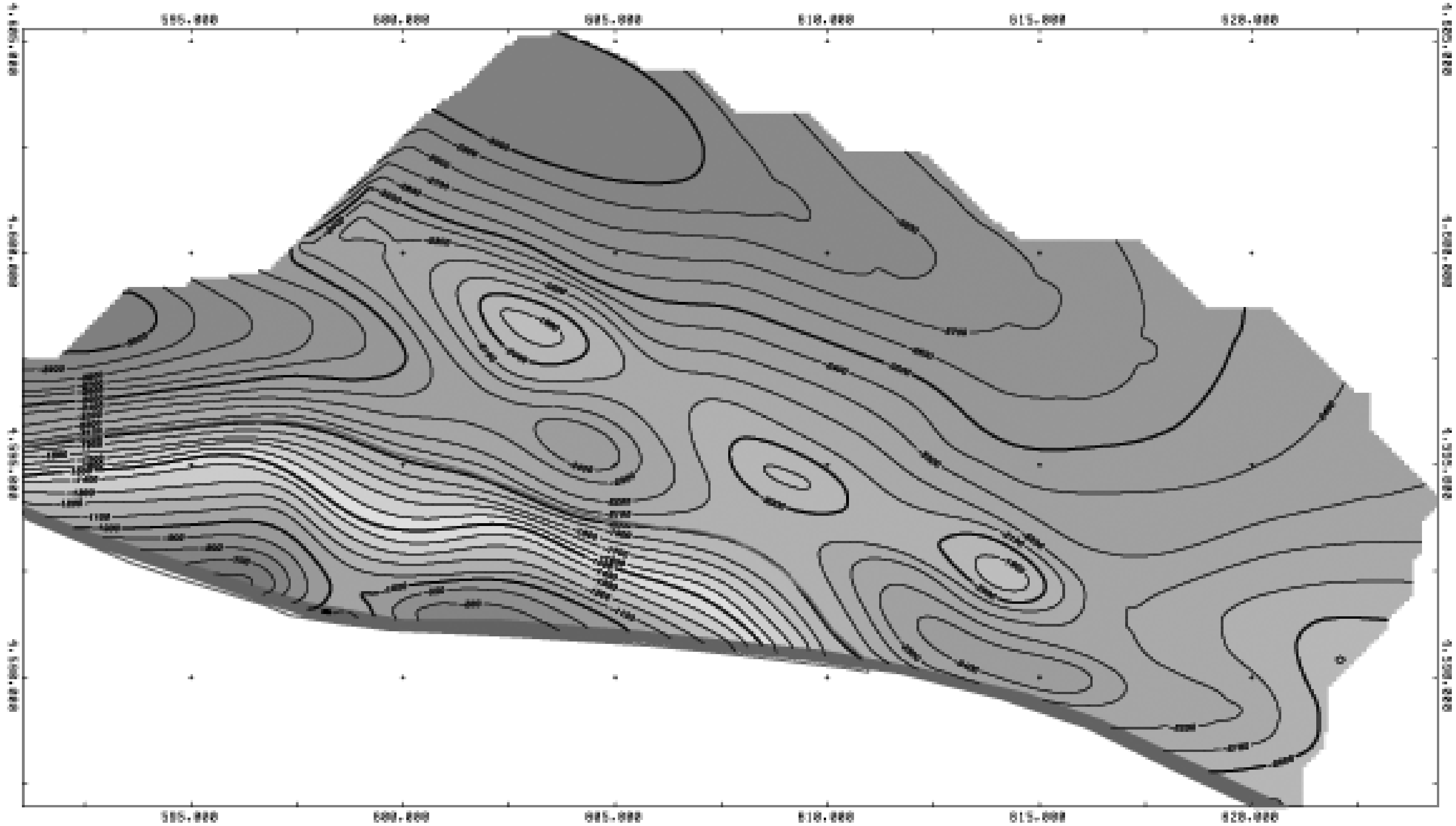
Basin Edge B Prospect
Kura Basin, Republic of Georgia

Depth Structure Map
Top Cretaceous
Contour Interval : 100 meters

0 1000 2000
SCALE IN METERS

Figure 32

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.



Basin Edge B Prospect
Kura Basin, Republic of Georgia

Depth Structure Map
Top S3

Contour Interval : 100 meters

0 1000 2000
SCALE IN METERS

Figure 33

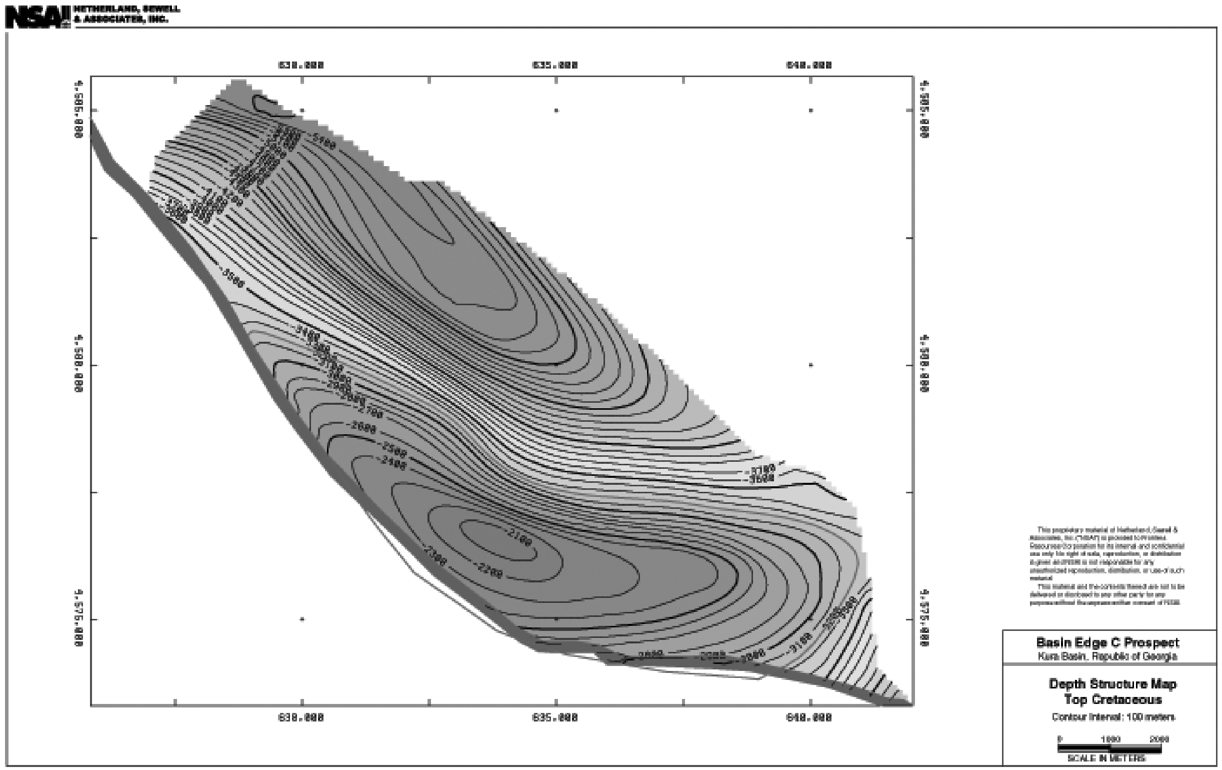
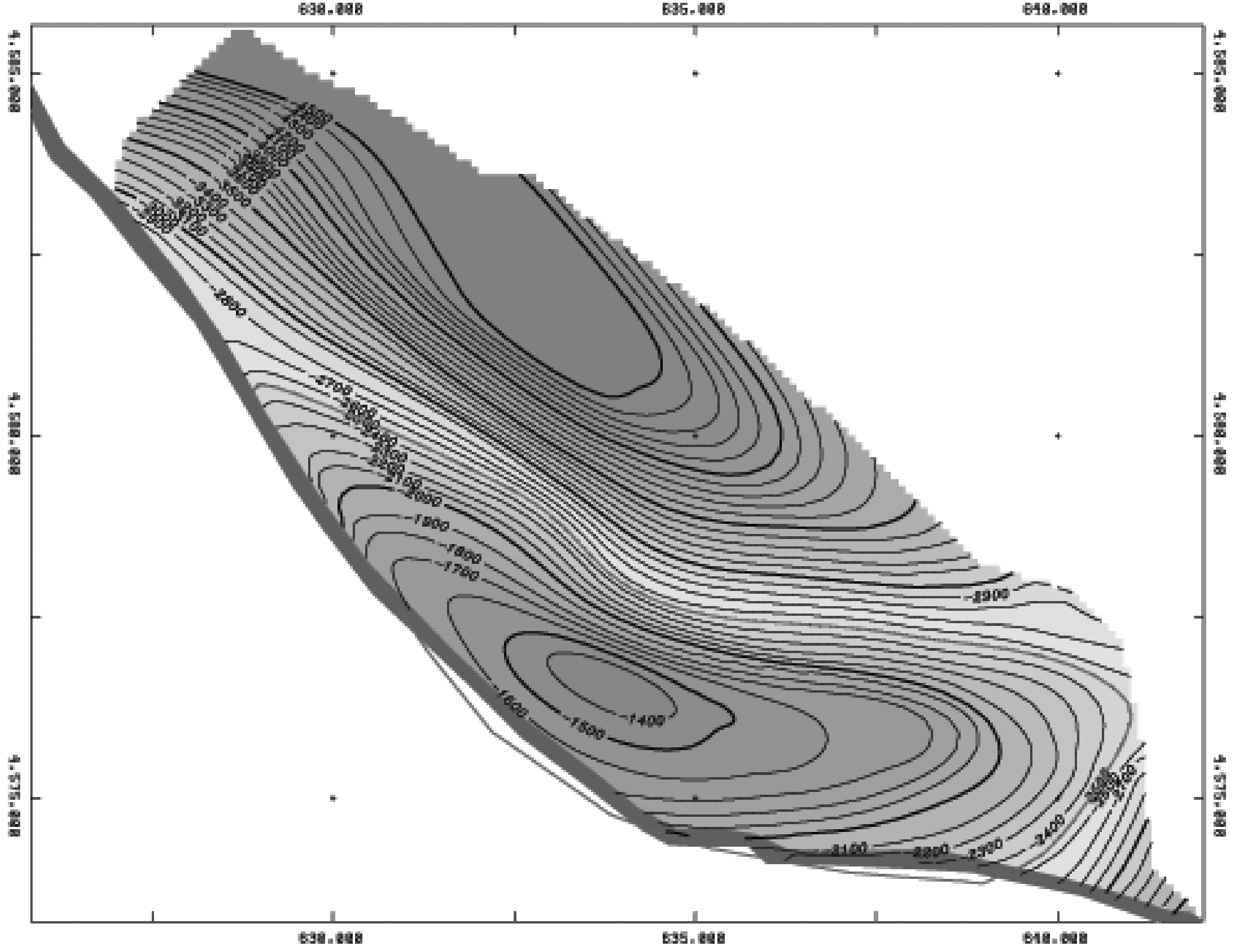

NETHERLAND, SEWELL & ASSOCIATES, INC.
Basin Edge C Prospect
Kura Basin, Republic of Georgia
Depth Structure Map
Top Cretaceous
Contour Interval: 100 meters
0 1000 2000
SCALE IN METERS
630,000
635,000
640,000
4,585,000
4,580,000
4,575,000

Figure 34

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.



Basin Edge C Prospect
Kura Basin, Republic of Georgia

Depth Structure Map
Top S3

Contour Interval : 100 meters

0 1000 2000
SCALE IN METERS

Figure 35

PART V

ACCOUNTANTS' REPORT

ERNST & YOUNG

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London SE1 2AF

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Frontera Resources Corporation
3040 Post Oak Boulevard
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Houston
Texas 77056
USA

Morgan Stanley & Co. International Limited
20 Cabot Square
Canary Wharf
London E14 4QA

9 March 2005

Dear Sirs

1. INTRODUCTION

We report on the financial information set out below. This financial information has been prepared for inclusion in the admission document dated 9 March 2005 of Frontera Resources Corporation ("the Admission Document").

Basis of preparation

The financial information set out in paragraphs 2 to 6 is based on the audited consolidated financial statements of Frontera Resources Corporation for the three years ended 31 December 2004 to which no adjustments were considered necessary. The financial information has been prepared on the basis set out in Note C, and in conformity with accounting principles generally accepted in the United States ("US GAAP"), modified by the exclusion of certain unaudited information about oil and gas producing activities.

UHY Mann Frankfort Stein & Lipp LLP, Certified Public Accountants of 12 Greenway Plaza, Suite 1202, Houston, Texas 77046-1289, USA audited the consolidated financial statements of Frontera Resources Corporation for the three years ended 31 December 2004. The audit report for these financial statements was unqualified, although it did contain an explanatory paragraph expressing a substantial doubt about Frontera Resources Corporation's ability to continue as a going concern. On 9 March 2005, the Company entered into an underwritten placing agreement with Morgan Stanley & Co. International Limited, pursuant to which it will raise £42 million (approximately $80 million), which resolves the doubt about Frontera Resources Corporation ability to continue as a going concern.

Responsibility

Such financial statements are the responsibility of the directors of Frontera Resources Corporation who approved their issue.

The directors of Frontera Resources Corporation are responsible for the contents of the Admission Document dated 9 March 2005 in which this report is included.

It is our responsibility to compile the financial information set out in our report from the financial statements, to form an opinion on the financial information and to report our opinion to you.

Basis of opinion

We conducted our work in accordance with the Statements of Investment Circular Reporting Standards issued by the Auditing Practices Board. Our work included an assessment of evidence relevant to the amounts and disclosures in the financial information. The evidence included that recorded by the auditors who audited the financial statements underlying the financial information. It also included an assessment of significant estimates and judgements made by those responsible for the preparation of the financial statements underlying the financial information and whether the accounting policies are appropriate to the entity's circumstances, consistently applied and adequately disclosed.

We planned and performed our work so as to obtain all the information and explanations which we considered necessary in order to provide us with sufficient evidence to give reasonable assurance that the financial information is free from material misstatement whether caused by fraud or other irregularity or error.

Opinion

In our opinion, the financial information presents fairly, in all material respects, for the purposes of the Admission Document dated 9 March 2005, the consolidated financial position of Frontera Resources Corporation as at the dates stated and the consolidated results of its operations and its consolidated cash flows for the years then ended, in conformity with US GAAP, modified as described above.

Consent

We consent to the inclusion in the Admission Document dated 9 March 2005 of this report and accept responsibility for this report for the purposes of paragraph 45(2)(b)(iii) of Schedule 1 to the Public Offers of Securities Regulations 1995.

2. CONSOLIDATED BALANCE SHEETS

	At 31 December		
	2002	**2003**	**2004**
	$000	**$000**	**$000**
Assets			
Current assets			
Cash	1,071	160	1,504
Trade receivables net	—	—	508
Accounts receivable — other	566	2,658	638
Inventory	372	191	1,700
Prepaid expenses and other	31	40	138
Total current assets	2,040	3,049	4,488
Property and equipment, net	1,439	660	213
Oil and gas properties, full cost method			
Properties being depleted	22,362	21,651	24,214
Properties not subject to depletion	144	144	144
	22,506	21,795	24,358
Less: accumulated depletion	(20,195)	(20,219)	(20,328)
Net oil and gas properties	2,311	1,576	4,030
Total assets	5,790	5,285	8,731

2. CONSOLIDATED BALANCE SHEETS (CONTINUED)

	At 31 December		
	2002	2003	2004
	$000	$000	$000
Liabilities and stockholders' deficit			
Current liabilities			
Accounts payable	6,020	5,344	576
Accrued liabilities	210	674	2,086
Accrued interest	737	492	1,586
Deferred gain	—	1,458	—
Line of credit	—	—	851
Current portion of notes payable, related party	1,490	5,208	12,784
Current portion of vendor notes payable	1,343	—	—
Total current liabilities other than shares	9,800	13,176	17,883
Redeemable preferred shares			
Series A1, stated at redemption value	4,386	4,595	4,805
Series A2, stated at redemption value	1,836	1,924	2,012
Series B, stated at redemption value	3,476	3,641	3,806
Total redeemable preferred shares	9,698	10,160	10,623
Total current liabilities	19,498	23,336	28,506
Notes payable			
Related party, less current portion	8,463	7,424	6,404
Vendor, less current portion	—	—	3,451
Total notes payable	8,463	7,424	9,855
Other long-term liabilities	110	827	2,419
Total liabilities	28,071	31,587	40,780
Commitments and contingencies	—	—	—
Stockholders' deficit			
Convertible preferred stock — Series D	—	—	—
Convertible preferred stock — Series E	—	—	—
Common stock	—	—	—
Additional paid-in capital	43,157	43,184	48,383
Preferred stock warrants	5,269	5,269	—
Common stock warrants	39	37	37
Treasury stock, at cost	(345)	(496)	(568)
Accumulated deficit	(70,401)	(74,296)	(79,901)
Total stockholders' deficit	(22,281)	(26,302)	(32,050)
Total liabilities and stockholders' deficit	5,790	5,285	8,731

3. CONSOLIDATED STATEMENTS OF OPERATIONS

	Year ended 31 December		
	2002	2003	2004
	$000	$000	$000
Revenue			
Crude oil sales	868	728	1,041
Gain on sale of oil and gas properties and other assets	786	2	—
Total revenue	1,654	730	1,041
Expenses			
Field operating and project costs	1,704	21	189
General and administrative	5,355	2,845	4,036
Depreciation, depletion and amortisation	1,324	432	526
Total expenses	8,383	3,298	4,751
Loss from operations	(6,729)	(2,568)	(3,710)
Other income/(expense)			
Forgiveness of debt	62	415	115
Interest expense	(2,367)	(1,739)	(2,019)
Other, net	23	(4)	9
Total other income/(expense)	(2,282)	(1,328)	(1,895)
Loss from continuing operations	(9,011)	(3,895)	(5,605)
Discontinued operations			
Gain on sale of oil and gas properties and other assets	14,693	—	—
Net income/(loss)	5,682	(3,896)	(5,605)
Preferred Stock dividend accretion	(94)	—	—
Net income/(loss) attributable to common stockholders	5,588	(3,896)	(5,605)
Income/(loss) per common share:			
From continuing operations			
Basic	$ (1.74)	$ (0.69)	$ (0.94)
Diluted	$ (1.74)	$ (0.69)	$ (0.94)
From discontinued operations			
Basic	$ 2.81	—	—
Diluted	$ 1.51	—	—
Net income/(loss)			
Basic	$ 1.07	$ (0.69)	$ (0.94)
Diluted	$ 0.62	$ (0.69)	$ (0.94)
Weighted average common shares			
Outstanding:			
Basic	5,231,426	5,610,899	5,994,276
Diluted	9,757,368	5,610,899	5,994,276

4. CONSOLIDATED STATEMENTS OF STOCKHOLDERS' DEFICIT

	Convertible preferred stock Series D	Convertible preferred stock Series E	Common stock	Additional paid in capital	Preferred stock warrants	Common stock warrants	Treasury stock	Accumulated deficit	Total stockholders' deficit
	$000	$000	$000	$000	$000	$000	$000	$000	$000
Balance, 1 January 2002	—	—	—	43,157	5,269	38	(345)	(75,989)	(27,870)
Issuance of common stock warrants	—	—	—	—	—	1	—	—	1
Redeemable preferred stock dividend accretion	—	—	—	—	—	—	—	(94)	(94)
Net income	—	—	—	—	—	—	—	5,682	5,682
Balance, 31 December 2002	—	—	—	43,157	5,269	39	(345)	(70,401)	(22,281)
Exercise of common stock warrants	—	—	—	26	—	(2)	—	—	24
Purchase of treasury stock	—	—	—	—	—	—	(150)	—	(150)
Net loss	—	—	—	—	—	—	—	(3,895)	(3,895)
Balance, 31 December 2003	—	—	—	43,183	5,269	32	(495)	(74,296)	(26,302)
Exercise of common stock warrants	—	—	—	1	—	—	—	—	1
Repurchase of preferred stock Series E warrants	—	—	—	5,190	(5,269)	—	—	—	(79)
Issuance of common stock options for services	—	—	—	8	—	—	—	—	8
Purchase of treasury stock	—	—	—	—	—	—	(73)	—	(73)
Net loss	—	—	—	—	—	—	—	(5,605)	(5,605)
Balance, 31 December 2004	—	—	—	48,382	—	37	(568)	(79,901)	(32,050)

5. CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended 31 December		
	2002	2003	2004
	$000	$000	$000
Cash flows from operating activities			
Net income/(loss)	5,682	(3,896)	(5,605)
Adjustments to reconcile net income/(loss) to net cash used in operating activities:			
Depreciation, depletion and amortisation	1,324	432	526
Gain on disposal of assets	(15,479)	(2)	—
Interest on redeemable preferred shares	369	462	462
Net amortisation of debt discounts	(28)	(136)	(75)
Common stock options issued for compensation	—	—	7
Forgiveness of debt income	(62)	(415)	(115)
Changes in operating assets and liabilities:			
Receivables	(45)	158	(450)
Inventory	549	182	44
Prepaid expenses and other	59	(9)	123
Accounts payable	(138)	(493)	(1,014)
Accrued liabilities	2,453	464	(986)
Accrued interest	1,527	(107)	1,095
Net cash used in operating activities	(3,789)	(3,359)	(5,988)
Cash flows from investing activities			
Purchase of property and equipment	(13)	(7)	—
Proceeds from sale of oil and gas properties	4,627	299	—
Net cash provided by investing activities	4,614	292	—
Cash flows from financing activities			
Proceeds from line of credit	—	—	851
Proceeds from related party notes	210	3,227	6,631
Exercise of common stock warrants	—	—	1
Payment on related party notes	(233)	—	—
Proceeds from issuance of stock warrants	—	(389)	—
Payment on vendor notes	(41)	(532)	—
Purchase of treasury stock	—	(150)	(152)
Net cash (used in)/provided by financing activities	(64)	2,156	7,331
Net increase/(decrease) in cash	761	(911)	1,343
Cash — beginning of year	310	1,071	161
Cash — end of year	1,071	160	1,504
Supplemental cash flow information			
Cash paid for interest	569	1,779	555

6. NOTES TO THE FINANCIAL INFORMATION

A. NATURE OF OPERATIONS

Frontera Resources Corporation, a Delaware corporation, and its subsidiaries (collectively "Frontera" or the "Company") are engaged in the development of oil and gas projects in emerging marketplaces. Frontera was founded in 1996 and is headquartered in Houston, Texas. The Company emphasises development of reserves in known hydrocarbon-bearing basins, and is attracted to exploitation projects that have significant exploration upside. Beginning in 2002, the Company has focused substantially all of its efforts on the exploration and development of oilfields within the Republic of Georgia ("Georgia"), a member of the former Soviet Union. Prior to 2002, the Company's other significant operating focus was on the exploration and development of an oilfield within the Azerbaijan Republic ("Azerbaijan"), which was sold during 2002 and all operating activities in Azerbaijan ceased at that time (See Note G).

In June 1997, the Company entered into a 25 year production sharing agreement with the Ministry of Fuel and Energy of Georgia and National Oil Company Georgian Oil ("Georgian Oil"), which gives the Company the exclusive right to explore, develop and produce crude oil in a 5,060 square kilometre area in eastern Georgia known as Block 12, hereafter referred to as the "Block 12 PSA". The Block 12 PSA can be extended if commercial production remains viable upon its expiration in June 2022.

Under the terms of the Block 12 PSA, the Company is entitled to conduct exploration and production activities and is entitled to recover its cumulative costs and expenses from the crude oil produced from Block 12. Following recovery of cumulative costs and expenses from Block 12 production, the remaining crude oil sales, referred to as Profit Oil, are allocated between Georgian Oil and Frontera in the proportion of 51% and 49%, respectively.

Under the terms of the Block 12 PSA, Frontera is exempt from all taxes imposed by the government of Georgia, and any taxes imposed on the Company shall be paid by Georgian Oil on behalf of the Company from Georgian Oil's 51% share of Profit Oil. Taxes are defined by the Block 12 PSA to mean all levies, duties, payments, fees, taxes or contributions payable to or imposed by any government agency, subdivision, municipal or local authorities within the Government of Georgia.

B. GOING CONCERN

The financial information has been prepared on the basis that the Company is a going concern, which contemplates the realisation of assets and the satisfaction of liabilities in the normal course of business. The Company has made substantial investments in oil and gas properties which have not yet been fully developed. As a result, the Company has incurred recurring operating losses and has a working capital deficiency and a capital deficit of approximately $24 million and $32 million, respectively, as of 31 December 2004.

On 9 March 2005, the Company entered into an underwritten placing agreement with Morgan Stanley & Co. International Limited pursuant to which it will raise £42 million (approximately $80 million) by the issue of shares. The proceeds from the placing will be used to repay a portion of the outstanding debt and payables, and to facilitate oil and gas activities in Georgia. On the basis of this placing, the directors of the Company believe that the Company is a going concern.

C. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation: The consolidated financial statements include the accounts of Frontera Resources Corporation ("FRC") and its wholly and majority owned subsidiaries. The wholly owned subsidiaries are Frontera International Corporation ("FIC"); Frontera Resources Caucasus Corporation ("FRCC"); Frontera Resources Georgia Corporation ("FRGC"); Frontera Resources Azerbaijan Corporation ("FRAC"); Frontera Resources Overseas Corporation ("FROC"); Frontera Azerbaijan Ventures Corporation ("FAVC") and Frontera Resources Georgia, Limited ("FRGL"). Also included are the accounts of Frontera Eastern Georgia, Limited ("FEGL"), a 50%-owned subsidiary, as control is deemed to reside with the Company. All significant intercompany transactions and accounts have been eliminated in consolidation.

Use of Estimates: The preparation of financial statements in conformity with accounting principles generally accepted in the United States ("US GAAP") requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates.

Concentrations of Credit and Other Risks: Financial instruments which potentially subject the Company to concentrations of credit risk consist principally of cash and accounts receivables. The Company maintains its cash in bank deposits with various major financial institutions in the USA and Georgia. The accounts held with US institutions, at times, exceed federally insured limits. Deposits in the United States are guaranteed by the Federal Deposit Insurance Corporation up to $100,000. The Company monitors the financial condition of the financial institutions and has not experienced any losses on such accounts.

Receivables that potentially subject the Company to credit risk consist principally of amounts due from unrelated parties in Georgia. The Company establishes an allowance for doubtful accounts based on factors surrounding the credit risk of the specific debtor, historical trends and other related information. Collateral is generally not required to secure receivables.

Foreign Operations: Frontera's future revenues depend on operating results from its operations in Georgia. The success of Frontera's operations are subject to various contingencies beyond management control. These

C. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

contingencies include general and regional economic conditions, prices for crude oil, competition and changes in regulation. Frontera is subject to various additional political and economic uncertainties in Georgia which could include restrictions on transfer of funds, import and export duties, quotas and embargoes, domestic and international customs and tariffs, and changing taxation policies, foreign exchange restrictions, political conditions and regulations.

Inventory: Inventory consists primarily of materials to be used in the Company's foreign field operations and crude oil held in stock tanks. Inventory is valued using the first-in, first-out method and is stated at the lower of cost and market. Inventory consists of the following:

	At 31 December		
	2002	**2003**	**2004**
	$000	**$000**	**$000**
Materials and supplies	241	125	1,604
Crude oil	131	66	96
	372	191	1,700

Property and Equipment: Property and equipment are stated at cost. Expenditures for major renewals and betterments, which extend the original estimated economic useful lives of applicable assets, are capitalised. Expenditures for normal repairs and maintenance are charged to expense as incurred. The costs and related accumulated depreciation of assets sold or retired are removed from the financial statements, and any gain or loss thereon is reflected in operations. Depreciation of property and equipment is computed using the straight-line method over the estimated useful lives of the assets, ranging from three to seven years.

Oil and Gas Properties: The Company follows the full cost method of accounting for oil and gas properties. Accordingly, all costs associated with acquisition, exploration, and development of oil and gas reserves, including directly related overhead costs, are capitalised.

All capitalised costs of oil and gas properties, including the estimated future costs to develop proved reserves, are depleted on the unit-of-production method using estimates of proved reserves. Investments in unproved properties and major development projects are not depleted until proved reserves associated with the projects can be determined or until impairment occurs. In addition, the capitalised costs are subject to a "ceiling test," which limits such costs to the aggregate of the future net revenues from proved reserves, based on current economic and operating conditions, discounted at a 10% interest rate, plus the lower of cost and fair market value of unproved properties. No impairment writedown was necessary for the years ended 31 December 2002, 2003 and 2004.

Sales of proved and unproved properties are accounted for as adjustments of capitalised costs with no gain or loss recognised, unless such adjustments would significantly alter the relationship between capitalised costs and proved reserves of oil and gas, in which case the gain or loss is recognised in income. Abandonments of properties are accounted for as adjustments of capitalised costs with no loss recognised.

Fair Value of Financial Instruments: Frontera's financial instruments consist of cash, accounts receivable, accounts payable, and a variety of debt instruments, including a line of credit, and senior and subordinated notes payables (collectively, the "Debt Instruments"). The fair value of cash, accounts receivable and accounts payable are estimated to approximate the carrying value due to the liquid nature of these instruments. The fair value of the Debt Instruments was determined based upon discount rates which approximate variable interest rates for borrowings of a similar nature. The fair values of the Debt Instruments on 31 December 2002, 2003 and 2004 were approximately $10.2 million, $12.1 million and $22.5 million, respectively.

Revenue Recognition: Revenues and their related costs are recognised upon delivery of commercial quantities of crude oil produced from proven reserves, in accordance with the accrual method of accounting.

Foreign Currency Transactions: The financial statements of the foreign subsidiaries are prepared in United States dollars, and the majority of transactions are denominated in United States dollars. Gains and losses on foreign currency transactions are the result of changes in the exchange rate between the time a foreign currency-denominated invoice is recorded and when it is ultimately paid and are included in operations. Foreign currency transaction gains and losses were not material for the years ended 31 December 2002, 2003 and 2004.

Stock-Based Compensation: In accordance with the provisions of Statement of Financial Accounting Standards ("SFAS") No. 123, "*Accounting for Stock-Based Compensation*", the Company has elected to follow

C. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

the Accounting Principles Board's Opinion No. 25, "*Accounting for Stock Issued to Employees*", ("APB 25") and related interpretations in accounting for its employee stock-based compensation plans. Under APB 25, if the exercise price of the Company's employee stock options equals or exceeds the fair value of the underlying stock on the date of grant as determined by the Company's Board of Directors, no compensation expense is recognised.

If the Company applied the fair value provisions of SFAS No. 123, net income (loss) would have been as follows:

	Year ended 31 December		
	2002	2003	2004
	$000	$000	$000
Net income/(loss) attributable to common stockholders, as reported	5,588	(3,895)	(5,605)
Deduct: total stock based compensation expense determined under fair value based method for all amounts, net of related income tax	—	—	(5)
Net income/(loss) attributable to common stockholders, pro forma	5,588	(3,895)	(5,610)
Basic income/(loss) per share:			
As reported	$ 1.07	$ (0.69)	$ (0.94)
Pro forma	$ 1.07	$ (0.69)	$ (0.94)
Diluted income/(loss) per share:			
As reported	$ 0.62	$ (0.69)	$ (0.94)
Pro forma	$ 0.62	$ (0.69)	$ (0.94)

The fair value for these options was estimated at the date of grant using a minimum value option pricing model with the following weighted-average assumptions:

	At 31 December		
	2002	2003	2004
Risk-free interest rate	2.64%	1.65%	2.38%
Dividend yield	—	—	—
Weighted-average expected life of options (years)	10	10	10

Income Taxes: The Company follows the provisions of SFAS No. 109, "*Accounting for Income Taxes*", which requires the recognition of deferred tax liabilities and assets for the expected future tax consequences of events that have been included in the financial statements or tax returns. Under this method, deferred tax liabilities and assets are determined based on the difference between the financial statements and the tax basis of assets and liabilities using enacted rates in effect for the years in which the differences are expected to reverse. Valuation allowances are established, when appropriate, to reduce deferred tax assets to the amount expected to be realised.

Major Customers: For the years ended 31 December 2003 and 2004, 100% of the Company's crude oil sales were to one unrelated customer. For the year ended 31 December 2002, approximately 83% of the Company's crude oil sales were to one unrelated customer.

Earnings per share: Basic earnings per share amounts are calculated based on the weighted average number of shares of Common Stock outstanding during each period. Diluted earnings per share is based on the weighted average number of shares of Common Stock outstanding for the periods, including the dilutive effect of stock options, warrants granted, convertible notes, and convertible Preferred Stock. Dilutive options and warrants that are issued during a period or that expire or are cancelled during a period are reflected in the computations for the time they were outstanding during the periods being reported. Options and warrants where the exercise price exceeds the average stock price for the period are considered antidilutive, and therefore are not included in the calculation of dilutive shares.

Recently Issued Accounting Pronouncements: Effective 1 January 2003, the Company adopted Statement of Financial Accounting Standards No. 143, "*Accounting for Asset Retirement Obligations*", ("SFAS No. 143"), which requires liability recognition for retirement obligations associated with tangible long-lived assets, such as producing well sites and associated equipment. The obligations included within the scope of SFAS No. 143 are those for which a company faces a legal obligation. The initial measurement of the asset retirement obligation is to record a separate liability at its fair value with an offsetting asset retirement cost recorded as an increase to the related property and equipment on the consolidated balance sheet. The asset retirement cost is depreciated using a

C. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

systematic and rational method similar to that used for the associated property and equipment. As of 31 December 2002, 2003 and 2004, the Company has not recorded an asset retirement obligation because there is no present legal obligation in Georgia to plug and abandon the producing wells and any future abandonment costs that the Company intends to incur are not significant.

D. MANDATORY REDEEMABLE PREFERRED STOCK

Series A1 and Series A2 Redeemable Preferred Stock: As of 1 January 2002 and 31 December 2002, 2003 and 2004 the Company had 322,400 designated, issued and outstanding shares of Series A1 Redeemable Preferred Stock ("Series A1 Stock") and 135,000 designated, issued and outstanding shares of Series A2 Redeemable Preferred Stock ("Series A2 Stock"). Shares of Series A1 Stock and Series A2 Stock have a par value of $0.00001 per share, have no voting or conversion rights and are not entitled to dividends. The Company was obligated to redeem both the Series A1 Stock and Series A2 Stock on 15 March 2002, at a redemption price of $10 per share, increasing at a simple rate of 6.5% per annum from the date of original issuance until redemption. However, this stock has not been redeemed by the Company due to the Company's lack of liquidity. The holders of Series A1 Stock and Series A2 Stock are afforded preference in liquidation and in redemption over the Company's common stock, Series B Redeemable Preferred Stock, Series D Convertible Preferred Stock and Series E Convertible Preferred Stock.

During each year ended 31 December 2002, 2003 and 2004, the Company accreted interest by $297,310 on the Series A1 Stock and Series A2 Stock.

The Company adopted the provisions of SFAS No. 150, "*Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity*, effective in 2004. SFAS No. 150 requires that financial instruments that are mandatorily redeemable on a certain date or upon an event certain to occur be classified as liabilities. Accordingly, the Series A1 Stock and Series A2 Stock, have been classified as liabilities and, as they were redeemable on 15 March 2002, these instruments have been classified as current liabilities on the accompanying consolidated balance sheets for all periods presented.

Although the Series A1 Stock and Series A2 Stock holders were not, by initial agreement, able to convert their stock into the Company's Common Stock, it has subsequently been agreed that, immediately prior to admission of the Company's Common Stock to trading on AIM ("Admission"), holders of Series A1 Stock and Series A2 Stock will convert all their Series A1 Stock and Series A2 Stock into the Company's Common Stock at a conversion rate of 6.0047 common shares per share of Series A1 Stock and Series A2 Stock.

Series B Redeemable Preferred Stock: As of 1 January 2002 and 31 December 2002, 2003 and 2004, the Company had 254,000 designated, issued and outstanding shares of Series B Redeemable Preferred Stock ("Series B Stock"). Shares of Series B Stock have a par value of $0.00001 per share and are identical to shares of Series A1 Stock and Series A2 Stock except no shares of Series B Stock may be redeemed until all shares of Series A1 Stock and Series A2 Stock have been redeemed and Series B Stock is subordinated in liquidation to Series A1 Stock, Series A2 Stock, Series D Convertible Preferred Stock and Series E Convertible Preferred Stock. The Company was obligated to redeem the Series B Stock on 15 March 2002 for a redemption price of $10 per share, increasing at a simple rate of 6.5% per annum from date of original issuance until redemption. However, this stock has not been redeemed by the Company due to the Company's lack of liquidity. In accordance with SFAS No. 150, these shares have been classified as a current liability on the accompanying consolidated balance sheets for all periods presented.

During each year ended 31 December 2002, 2003 and 2004, the Company accreted interest of $165,100 on the Series B Stock.

Although the Series B Stock holders were not, by initial agreement, able to convert their stock into the Company's Common Stock, it has subsequently been agreed that, immediately prior to Admission, holders of Series B Stock will convert all their Stock into the Company's Common Stock at a conversion rate of 6.0367 common shares per share of Series B Stock.

E. STOCKHOLDERS' DEFICIT

The Company has the authority to issue up to 10,000,000 shares, par value $.00001, of serial preferred stock. The Board of Directors may designate and authorise the issuance of such shares with such voting power and in such classes and series, and with such designation, preferences and relative participation, optional, or other special rights, qualifications, limitations, or restrictions as deemed appropriate by the Company's Board of Directors.

Series D Convertible Preferred Stock: As of 1 January 2002 and 31 December 2002, 2003 and 2004, the Company had 23,600 designated, issued and outstanding shares of Series D Convertible Preferred Stock ("Series D Stock"). Shares of Series D Stock have a par value of $0.00001 per share and are voting convertible equity securities that are not redeemable. Each share of Series D Stock is convertible, at the option of the holder thereof, at any time after the date of issuance of such share into the number of shares of Common Stock at the conversion price then in effect upon the earlier to occur of (i) the closing of an underwritten public offering pursuant to an effective registration statement under the Securities Act of 1933, as amended (the "Securities Act"), covering the offer and sale of Common Stock with an offering price per share of at least twice the conversion price (as adjusted to reflect certain recapitalisations) and with gross offering proceeds (prior to underwriting discounts and commissions and offering expenses) to the Company of at least $25 million, or (ii) the date specified by vote or written consent of the holders of at least a majority of the then outstanding Series D Preferred Stock, voting as a class, for such conversion.

The price at which shares of Common Stock are deliverable upon conversion of the Series D Stock is initially $237.295 per share of Common Stock, which conversion price is subject to adjustment in a prescribed manner. As of 31 December 2004, the conversion price for the Series D Stock was $7.55891.

Except as otherwise required by law, the holder of each share of Series D Stock has the right to one vote for each full share of Common Stock into which such Series D Stock could then be converted. With respect to such vote, such holder has full voting rights and powers equal to the voting rights and powers of the holders of Common Stock and is entitled to vote, together with holders of Common Stock and the holders of any other class or series of stock that also has the right to vote with the holders of the Common Stock, with respect to any question upon which holders of the Common Stock have the right to vote. The holders of Series D Stock also have certain special voting rights that require their consent prior to certain major corporate actions, as defined.

In December 2004, the Company signed an agreement with the holders of Series D Stock that, immediately prior to Admission, all shares of Series D Stock will be converted into shares of Common Stock of the Company at a rate of 94.9153 shares of Common Stock for each share of Series D Stock.

Series E Convertible Preferred Stock: As of 1 January 2002 and 31 December 2002, 2003 and 2004, the Company had 4,000,000 designated shares of Series E Convertible Preferred Stock ("Series E Stock") and 2,883,322, 2,883,322, 2,021,253 and 1,660,099 issued and outstanding shares of Series E Stock respectively. Shares of Series E Stock have a par value of $0.00001 per share and are voting convertible equity securities with a preference in liquidation over Series B Stock and Common Stock but Series E Stock is subordinate in liquidation to Series A1 Stock and Series A2 Stock. Each share of Series E Stock is convertible, at the option of the holder thereof, at any time after the date of issuance of such share into the number of shares of Common Stock equal to $11.60 divided by the conversion price then in effect. Each share of Series E Stock automatically converts into shares of Common Stock at the conversion price then in effect upon the earlier to occur of (i) the closing of an underwritten public offering pursuant to an effective registration statement under the Securities Act covering the offer and sale of the Company's Common Stock with an offering price per share of at least $18.99 (as adjusted to reflect certain recapitalisations) and with gross offering proceeds (prior to underwriting discounts and commissions and offering expenses) to the Company of at least $25 million, or (ii) the date specified by vote or written consent of the holders of at least a majority of the then outstanding Series E Preferred Stock, voting as a class, for such conversion.

The price at which shares of Common Stock are deliverable upon conversion of the Series E Preferred Stock initially is $8.878214 per share of Common Stock of the Company, which conversion price is subject to adjustment in a prescribed manner. As of 31 December 2004, the conversion price for the Series E Stock was $8.836545.

The holders of the Series E Stock have a right to have the Company redeem their shares of Series E under certain limited circumstances after 31 December 2003, none of which have occurred. The redemption price is $11.60 per share, less the per-share amount of any dividends previously declared and paid to holders of Series E Stock, plus the per-share amount of any declared but unpaid dividends, plus interest on $11.60 per share at a simple rate of 6.5% per annum, calculated from the later of the date of issuance and 30 September 1999, to and including the applicable redemption date.

E. STOCKHOLDERS' DEFICIT (CONTINUED)

Other than rights of redemption and the number of shares convertible into the Company's Common Stock, the conversion, voting, and dividend rights of the Series E Stock are substantially identical to those of the Series D Stock. Similar to Series D Stock, the holders of Series E Stock have certain special voting rights that require their consent prior to certain major corporate actions, as defined.

In December 2004, the Company signed an agreement with the holders of Series E Stock that, immediately prior to Admission, all shares of Series E Stock will be converted into Common Stock of the Company at a rate of 4.64 shares of Common Stock for each share of Series E Stock.

Preferred Series E Stock Warrant: In 1999, the Company sold a warrant to purchase 96,035 shares of Series E Stock or an equivalent number of shares of Common Stock as determined by the conversion price at the earliest of the exercise date or the last conversion date of the warrant holder's share of Series E Stock. The Company sold the warrant for $1,017,965. In 2000, the Company sold another warrant to purchase 401,035 shares of Series E Stock of the Company or an equivalent number of shares of Common Stock for total proceeds of $4,250,971. Both warrants have no expiration date. During 2004, both warrants were repurchased by the Company in a transaction that also included the repurchase of certain shares of Series E Stock, for a total purchase price of $150,000. The portion of the purchase price allocated to the warrants was $79,034. The balance of the original proceeds after the $79,034 repurchase was recorded to additional paid-in capital.

As of 31 December 2004, the status of the preferred shares designated and issued and outstanding is summarised as follows:

	Shares designated	Shares issued and outstanding
Series A1 redeemable preferred stock	322,400	322,400
Series A2 redeemable preferred stock	135,000	135,000
Series B redeemable preferred stock	254,000	254,000
Series D convertible preferred stock	23,600	23,600
Series E convertible preferred stock	4,000,000	1,660,099
	4,735,000	2,395,099
Undesignated	5,265,000	
Total shares authorised	10,000,000	

Common Stock: As of 31 December 2004, the Company is authorised to issue 65,000,000 shares of Common Stock, par value $.00004 per share. As of 31 December 2002, 2003 and 2004, the Company had 5,231,426, 5,990,372 and 6,027,872 shares of Common Stock issued and outstanding, respectively. At 31 December 2004, there were an additional 25.8 million shares of Common Stock reserved for the exercise of existing options and warrants. The Company obtained Board approval in December 2004 to increase the authorised number of common shares to 200,000,000, contingent on the closing of the public offering.

Treasury Stock: The Company has repurchased both Common Stock and Series E Stock as treasury stock. As of 31 December 2002, 2003 and 2004, the Company had 38,364, 900,433 and 1,265,433 shares of Series E Stock, respectively, and 36,209 shares of Common Stock held as treasury stock.

1998 Employee Stock Incentive Plan: In 1998, the Company's stockholders approved the 1998 Employee Stock Incentive Plan (the ''Plan''), pursuant to which options may be granted to purchase up to 15% of the Company's shares of Common Stock authorised to be issued by the Company, reduced by the total number of shares of stock subject to stock options and stock awards that have been granted under the Plan and the Frontera Resources Corporation 2000 Nonqualified Stock Option and Stock Award Plan at any given time. The Board of Directors has appointed Frontera's chief executive officer as administrator of the Plan. In this capacity, the administrator determines which employees will receive options, the number of shares covered by any option agreement, and the exercise price and other terms of each such option. The Board of Directors is responsible for administering the Plan as it relates to options granted to the chief executive officer.

Under the terms of the Plan, any issued options expire ten years after the date of grant, with the exception of options granted to 10% stockholders that expire five years after the date of grant, or upon earlier termination of employment. Options granted vest over periods ranging from immediate vesting to vesting in equal increments over three years from the date of grant.

E. STOCKHOLDERS' DEFICIT (CONTINUED)

2000 Nonqualified Stock Option and Stock Award Plan: In 2000, the Company's Board of Directors approved the 2000 Nonqualified Stock Option and Stock Award Plan (the "Stock Award Plan"), pursuant to which options may be granted to employees, directors, consultants, and advisors of the Company or any of its affiliates, to purchase up to 15% of the Company's common shares authorised to be issued by the Company, reduced by the total number of shares of stock subject to stock options and stock awards that have been granted under the Plan and the Stock Award Plan. The Board of Directors has appointed Frontera's chief executive officer as administrator of the Stock Award Plan. In this capacity, the administrator determines which employees will receive options, the number of shares covered by any option agreement, and the exercise price and other terms of each such option. The Board of Directors is responsible for administering the Plan as it relates to options granted to the chief executive officer.

Under the terms of the Stock Award Plan, any issued options expire ten years after the date of grant or upon earlier of termination of employment or affiliation relationship between the grantee and the Company. Options granted vest over periods ranging from immediate vesting to vesting in equal increments over three years from the date of grant.

A summary of the Company's stock option activity and related information follows:

	Options	Weighted-average exercise price $
Options outstanding at 1 January 2002	1,336,889	6.81
Granted	2,844,000	1.06
Exercised	—	—
Surrendered	(27,376)	8.84
Options outstanding at 31 December 2002	4,153,513	2.85
Granted	1,844,000	1.00
Exercised	—	—
Surrendered	—	—
Options outstanding at 31 December 2003	5,997,513	1.28
Granted	60,000	1.00
Exercised	—	—
Surrendered	(62,000)	1.84
Options outstanding at 31 December 2004	5,995,513	1.26

	Options outstanding			Options exercisable	
Range of exercise prices $	Number outstanding at 31 December 2004	Weighted-Average remaining contractual life (years)	Weighted-average exercise price $	Number exercisable at 31 December 2004	Weighted-average exercise price $
.92 – 1.00	4,888,000	8.12	0.99	4,888,000	0.99
2.00	1,002,513	5.78	2.00	1,002,513	2.00
5.28 – 8.85	105,000	3.36	6.30	105,000	6.30
	5,995,513		1.26	5,995,513	1.26

During 2003, the Company repriced certain outstanding options downward to be more in line with the value of the Company. According to FIN 44, *Accounting for Certain Transactions Involving Stock Compensation — An Interpretation of APB Opinion No. 25*, if a fixed stock option or award is cancelled or modified such that a new measurement of compensation cost or variable accounting is required, compensation cost shall be adjusted for increases or decreases in the intrinsic value of the modified award in subsequent periods until that award is exercised, is forfeited, or expires unexercised. However, compensation cost shall not be adjusted below the intrinsic value (if any) of the modified stock option or award at the original measurement date unless the award is forfeited because the employee fails to fulfil an obligation. As of 31 December 2004, there are 644,084 remaining options subject to variable accounting.

F. PROPERTY AND EQUIPMENT

Property and equipment consists of the following:

	Estimated useful lives	At 31 December 2002	2003	2004
		$000	$000	$000
Field equipment	7 years	2,083	1,709	1,709
Automobiles	5 years	193	193	193
Telecommunication equipment	7 years	375	367	367
Office furniture, fixtures and computer-related equipment	7 years	1,392	1,399	1,423
Leasehold improvements	3 years	25	25	25
		4,068	3,693	3,717
Less: accumulated depreciation		2,629	3,033	3,504
		1,439	660	213

G. DISCONTINUED OPERATIONS

In May 2000, the Company, through its FRCC subsidiary, entered into a $10 million convertible loan agreement with the European Bank for Reconstruction and Development (''EBRD'') to fund operating activities in Azerbaijan and Georgia. In November 2000, FRCC entered into a borrowing base loan to allow for up to $50 million in additional credit. By April 2001, the Company had borrowed $10 million against the convertible loan and $16 million against the borrowing base loan. At that time, the EBRD informed the Company that it was in non-compliance with the current ratio covenants contained in the borrowing base loan agreement, and that it would not waive these defaults.

In July 2001, in accordance with the aforementioned loan agreements, the EBRD took possession of FRCC's interests in the Azerbaijan oilfield properties. In March 2002, the EBRD sold the Azerbaijan oilfield properties for approximately $53.3 million. In addition to the sales proceeds, the EBRD also collected net revenues from oil sales during the period when the properties were held by the EBRD of approximately $3.2 million which were applied to the final proceeds. The Company's basis in the Azerbaijan assets was approximately $41.8, resulting in a gain of approximately $14.7 million. The Company has classified this gain as discontinued operations in accordance with SFAS No, 144, ''*Accounting for the Impairment or Disposal of Long-Lived Assets*'', as the Azerbaijan operations met the definition of a component of the Company's oil and gas operations.

At the time of the sale, the value of the EBRD note payable, including accrued interest, fees and penalties was approximately $53.8 million. In September 2002, the Company received a payment from the EBRD of $2.7 million related to the disposition of the Azerbaijan properties and the crude oil sales during the period in which the EBRD held the properties until they were sold.

H. GAC ENERGY FARMOUT AGREEMENT

In August 2002, Frontera entered into a Farmout Agreement with GAC Energy (''GAC''), a Houston-based exploration and production company. Under the terms of the Farmout Agreement, Frontera agreed to farmout an interest in the Block 12 PSA to GAC in consideration of a cash payment and work commitments. In 2002, GAC paid Frontera $1,750,000. Although the Company follows the full cost method of accounting for its oil and gas properties, a gain of approximately $786,000 was recognised on this sale because the reduction to the full cost pool for the total proceeds received would have resulted in a significantly altered relationship between capitalised costs and proved reserves.

In August 2003, GAC exercised an option under the Farmout Agreement that created an additional obligation to Frontera that resulted in a gain of approximately $1,458,000, which was deferred because the obligation was entirely financed with an account receivable from GAC. As discussed below, GAC began experiencing financial difficulty and never paid the receivable. Accordingly, the deferred gain was reversed in 2004 and never recorded to the Company's statement of operations.

Shortly after August 2003, GAC began experiencing financial difficulty. As a result, Frontera began making cash calls on behalf of GAC, and recording this as an account receivable from GAC. In February 2004, the Company notified GAC that it was in default of the terms of the Farmout Agreement. At that time, GAC informed the Company that it was putting a financing arrangement in place; however it was unsuccessful in these efforts.

H. GAC ENERGY FARMOUT AGREEMENT (CONTINUED)

As a result, in July 2004, the Company once again notified GAC of the default and set out to remedy GAC's default in accordance with the provisions of the Farmout Agreement. In accordance with prescribed remedies under the Farmout Agreement, GAC's interest in the Block 12 PSA was officially reassigned to Frontera on 29 September 2004. Upon GAC's default, in addition to the interest in the Block 12 PSA, the Company acquired all operating assets, primarily consisting of materials and supplies and also assumed all liabilities, primarily consisting of unpaid operating invoices. Combined with the reassignment of assets and the assumption of liabilities, the Company also applied a receivable from GAC which resulted in a total reassignment cost of approximately $2.4 million.

I. NOTES PAYABLE AND LINE OF CREDIT

Notes payable and line of credit consist of the following:

		At 31 December		
		2002	2003	2004
		$000	$000	$000
Line of Credit:				
16% due 24 May 2005	(1)	—	—	851
Notes Payable — Related Party:				
15% Senior, due 1 April 2005	(2)	4,272	4,107	4,000
12% Senior, due 14 May 2006	(3)	—	3,228	6,000
12% Convertible, due 15 March 2005	(4)	—	—	2,500
2001 Stockholders notes	(5)	360	360	360
6% Notes	(6)	366	371	404
2004 Stockholder notes	(7)	—	—	1,358
Dynamic Trading, Inc.	(8)	250	250	250
SEM Consulting LLC (#1)	(9)	81	81	81
SEM Consulting LLC (#2)	(10)	210	210	210
CSTN, Ltd.	(11)	100	100	100
Glenmont Enterprises S.A.	(12)	100	100	100
DDJ assigned note	(13)	3,825	3,825	3,825
Employee notes	(14)	389	—	—
Total Notes Payable — Related Party		9,953	12,632	19,188
Less: Current portion		1,490	5,208	12,784
Long-term Notes Payable — Related Party		8,463	7,424	6,404
Notes Payable — Vendor:				
Saipem S.p.A.	(15)	—	—	3,451
M-I Drilling Fluids Co.	(16)	692	—	—
MacGregor Energy Services Ltd.	(17)	412	—	—
Weatherford International	(18)	232	—	—
West Oak/Nissei Associates	(19)	7	—	—
Total Notes Payable — Vendor		1,343	—	3,451
Less: Current portion		1,343	—	—
Long-term Notes Payable — Vendor		—	—	3,451

Maturities of notes payable and line of credit as of 31 December 2004 are as follows:

Year ending 31 December	$000
2005	13,635
2006	6,404
2007	3,451
Total	23,562

I. NOTES PAYABLE AND LINE OF CREDIT (CONTINUED)

(1) Line of credit

In November 2004, the Company raised $850,670 under an unsecured line of credit for up to $1,000,000 from Bank Republic, a financial institution in Georgia. The line of credit bears interest at a rate of 16% per annum and amounts drawn are due on 24 May 2005.

(2) 15% Senior Notes Payable — Related Party

During August 2001, the Company raised $400,002, less commitment fees totalling $20,001, from the issuance of three promissory notes to a syndicate made up of three funds managed by DDJ Capital Management, LLC ("DDJ"), a shareholder with a position on the Board of Directors at Frontera. Each promissory note contained the same provisions and terms. Each note was for $133,334, was due in March 2002 and carried an initial interest rate of 15% which increased by 1% per annum at the beginning of each month starting on 1 October 2001. At the same time these three $133,334 notes payable were issued, the Company raised $3,500,000, less commitment fees totalling $113,000, from the issuance of a promissory note to DDJ. This note payable was due in March 2002 and carried an initial interest rate of 15%, which increased by 1% per annum at the beginning of each month starting on 1 October 2001.

On 1 September 2002, the three $133,334 notes payable and the $3,500,000 note payable were renegotiated to increase the aggregate principal amount due to $4,000,000, an increase of $99,998, to remove the upward adjusting interest rate, to amend certain covenants and to issue new promissory notes and warrants to purchase 1,950,000 shares of Common Stock of the Company at a price of $2.00 per share and expiring on 1 September 2007. Under the terms of the renegotiated note payable agreement, each note holder received a note payable of $1,333,333 bearing interest at 15% per annum, due on 1 September 2004, and 650,000 warrants to purchase shares of Common Stock. The notes payable agreements are subject to various operational and non-financial covenants, the violation of which results in an event of default. Should there be an event of default, the outstanding note balances are subject to an additional 3% interest per annum and the notes payable can be accelerated to be due immediately. Effective 31 December 2004, the terms of the notes were amended to waive any and all events of default, including cross-defaults, and to extend the maturity date to 1 April 2005.

At the time the $4,000,000 debt was issued, $929,626 in accrued interest was due on the 15% Senior Notes. In accordance with the restructuring agreement, of this amount, $99,998 was converted into debt and applied to the new principal balance, $500,000 was paid to the holders of the 15% Senior Notes, $75,000 was applied to the purchase of the 1,950,000 warrants to purchase shares of Common Stock and $254,628 was forgiven. The Company accounted for the restructuring of these notes as a troubled debt restructuring in accordance with SFAS No. 15 "*Accounting for Debtors and Creditors for Troubled Debt Restructurings*", and accordingly no gain was recognised on the restructuring. Rather, the face value of $4,000,000 was increased by the amount of accrued interest, offset by the cash paid and warrants transferred, which had a fair value of $1,268 based on the Black-Scholes model. The difference between the carrying value of the notes and the aggregate future cash payments required by the new debt terms is being amortised over the life of the new loan as interest expense using the effective interest method.

(3) 12% Senior Notes Payable — Related Party

In May 2003, the Company entered into a senior note purchase agreement with a syndicate that included two funds managed by DDJ; two directors of the Company; CSTN Ltd., a trust whose primary beneficiary is a director of the Company; Glenmont Enterprises, S.A., an entity controlled by a director of the Company; and Baker Hughes Finance, Incorporated, a shareholder with a position on the Company's board of directors. Under the terms of the agreement, the syndicate committed to loan the Company up to $6,000,000 at a 12% annual interest rate through two different lending tranches. The 12% senior notes are due on 14 May 2006. Under the terms of the note payable agreement, the Company pays interest on the unpaid principal amount outstanding in cash quarterly in arrears from their date of issuance until the senior notes are paid in full. The note purchase agreement included warrants to purchase up to 3,000,000 shares of Common Stock of the Company, at a price of $1.00 per share, allocated among the syndicate members in the same pro rata percentage as their loan commitment. The warrants expire on 14 May 2006. No portion of the proceeds raised through the note payable agreement was allocated to the warrants as the fair value of the warrants on the date of issuance was immaterial.

The note payable agreement is subject to various operational and non-financial covenants, the violation of which results in an event of default. Should there be an event of default, the outstanding note balance is subject to an additional 3% interest per annum and the notes payable can be accelerated to be due immediately. The notes

I. NOTES PAYABLE AND LINE OF CREDIT (CONTINUED)

were in default, due to breaches of certain of the covenants. However, effective 31 December 2004, the Company obtained a waiver that cured any and all events of default, including cross-defaults through 31 December 2004.

(4) 12% Convertible Note Payable — Related Party

In December 2004, the Company raised $2.5 million through the issuance of four convertible notes payable to a syndicate made up of three funds which are controlled by DDJ and a company controlled by a Frontera director. Each convertible note payable has the same terms and conversion features including an interest rate of 12% per annum and a due date of March 15, 2005. Under the terms of the convertible note payable agreement, the Company pays interest on the unpaid principal amount outstanding monthly from the date of issuance until the note is converted or matures. At any time prior to one business day prior to the maturity date, upon the successful closing of the public offering, the holders of the convertible notes may convert all or a portion of the notes into common shares of the Company at a conversion price which is equal to 80% of the price established by the underwriter in connection with the potential public offering. This discount from the public offering price constitutes a beneficial conversion, which will be valued and recorded if and when the public offering closes and the number of shares that may be converted is known.

(5) 2001 Stockholder Notes

During March 2001, the Company raised $360,000 from the issuance of debt in the form of three notes payable of $120,000 each to certain stockholders at a rate of 6% per annum. Under the original terms, the notes were due on or before 14 April 2001. Due to the financial condition of the Company, no portion of the stockholder notes payable has been paid since the date of issuance. Effective 31 December 2004, the terms of the notes were amended to waive any and all events of default, including cross-defaults, and to extend the maturity date to April 15, 2005.

(6) 6% Notes Payable — Related Party

Effective 31 December 2001, the Company raised $500,394 through a Rights Offering consisting of 6% Notes payable plus Warrants (together, a ‘‘Right’’) which entitle the holders to purchase an aggregate of 15,637,329 shares of Common Stock of the Company at an exercise price of $0.032 per share. The notes are due on 31 December 2006, and the warrants expire on 31 December 2006. Holders of Common Stock were entitled to purchase one Right for every 20.8333 shares of Common Stock held on 19 December 2001. Holders of Series D Stock and Series E Stock were entitled to purchase one Right for every 20.8333 shares of Common Stock into which their preferred stock could be converted on 19 December 2001. Each Right entitled the holder to purchase for a $1 subscription price $1 in principal amount of Notes and Warrants to purchase 31.25 shares of Common Stock. In accordance with APB No. 14 ‘‘*Accounting for Convertible Debt and Debt Issued with Stock Purchase Warrants*’’, the Company allocated the proceeds to the Notes and the Warrants based on relative fair values. Accordingly, $338,347 was allocated to the Notes, $37,478 was allocated to the Warrants, and the remaining proceeds of $124,566 were recorded in paid-in capital.

During 2003, a warrant holder exercised warrants to purchase 758,946 shares of Common Stock for $24,286, resulting in a $24,286 decrease in notes payable and a corresponding aggregate increase in Common Stock and additional paid in capital. During 2004, a warrant holder exercised warrants to purchase 37,500 shares of Common Stock for $1,200, resulting in a $1,200 decrease in notes payable and a corresponding aggregate increase in common stock and additional paid-in capital.

(7) 2004 Stockholder Notes — Related Party

During 2004, the Company raised an aggregate amount of $1,358,211 from directors, officers and stockholders of the Company in amounts ranging from $10,000 up to $600,003 through the issuance of negotiable promissory notes. The terms and conditions of the notes payable were identical, each issued at a rate of 1% per month due on various dates throughout 2004. Effective 31 December 2004 the terms of the notes were amended to waive any and all events of default, including cross-defaults, and to extend the maturity date to 15 April 2005.

(8) Negotiable Promissory Note Payable to Dynamic Trading, Inc. — Related Party

During March 2001, the Company raised $250,000 from the issuance of debt in the form of a negotiable promissory note payable to Dynamic Trading, Inc. (‘‘Dynamic Trading’’), a company controlled by a director of

Frontera, at a rate of 6% per annum. At the time it was issued, the note was due on 27 April 2001. Due to the financial condition of the Company, no portion of the note payable to Dynamic Trading has been paid. Effective 31 December 2004, the terms of the note were amended to waive any and all events of default, including cross-defaults, and to extend the maturity date to 15 April 2005.

(9) Negotiable Promissory Note Payable to SEM Consulting, LLC #1 — Related Party

During April 2001, in exchange for consulting services provided, the Company issued to SEM Consulting, LLC ("SEM"), a company controlled by a director of Frontera, a $175,000 negotiable promissory note payable at a rate of 6% per annum. At the time it was issued, the note was due on 9 May 2001. Due to the financial condition of the Company, Frontera was unable to make the required payment as of the due date. During 2002, the Company made a payment to SEM of $108,200, of which $94,200 was applied to outstanding debt and $14,000 was applied to accrued interest. Effective 31 December 2004, the terms of the note were amended to waive any and all events of default, including cross-defaults, and the maturity date was extended to April 15, 2005.

(10) Negotiable Promissory Note Payable to SEM Consulting, LLC #2 — Related Party

During December 2002, in exchange for consulting services provided, the Company issued SEM a $210,000 negotiable promissory note payable at a rate of 6% per annum. At the time it was issued, the note was due on 31 December 2003. Due to the financial condition of the Company, Frontera was unable to make the required payment as of the due date. As of 31 December 2002, 2003 and 2004, accrued interest payable associated with the SEM negotiable note payable was $0, $12,600 and $25,200, respectively. Effective 31 December 2004, the terms of the note were amended to waive any events of default, including counter-defaults, and to extend the due date to April 15, 2005.

(11) Negotiable Promissory Note Payable to CSTN, Ltd. — Related Party

During August 2001, the Company raised $100,000, less a $5,000 commitment fee, from the issuance of a $100,000 negotiable promissory note payable to CSTN, Ltd. ("CSTN") at a rate of 15% per annum. At the time it was issued, the note was due on 8 March 2002. Due to the financial condition of the Company, no portion of the CSTN note payable has been paid. Effective 31 December 2004, the terms of the note were amended to waive any and all events of default, including cross-defaults, and to extend the maturity date to April 15, 2005.

(12) Negotiable Promissory Note Payable to Glenmont Enterprises S.A. — Related Party

During August 2001, the Company raised $100,000, less a $5,000 commitment fee, from the issuance of a $100,000 negotiable promissory note payable to Glenmont Enterprises S.A. at a rate of 15% per annum. At the time it was issued, the note was due on 8 March 2002. Due to the financial condition of the Company, no portion of the Glenmont note payable has been paid. Effective 31 December 2004, the terms of the note were amended to waive any and all events of default, including cross-defaults, and to extend the maturity date to April 15, 2005.

(13) DDJ Assigned Note Payable — Related Party

In August 2002, the Company settled a disputed account payable which was incurred in 2001 to Schlumberger Overseas S.A. ("Schlumberger") by issuing a note payable for $4,000,000. Under the terms of the Schlumberger note payable and settlement agreement, the Company agreed to pay Schlumberger $175,000 at the time of the settlement and the remaining $3,825,000 on or before August 22, 2005. The note bears interest at 5% per annum.

The Schlumberger note was purchased by two funds controlled by DDJ (collectively, the "Assignees") on 29 October 2003. The Assignees assumed all legal rights to the note to which Schlumberger was entitled. On 31 December 2004, the Assignees and the Company agreed to an option whereby the Company would be allowed to purchase the Schlumberger note payable from the Assignees for $1.3 million, plus interest accrued at a rate of 12% per annum beginning on 31 December 2004. Further, the Company agreed to a mandatory repurchase of the Schlumberger note payable within ten business days of a successful public stock offering. This option expires on 1 June, 2005, and the terms of the original Schlumberger note payable agreement will revert at that time if the option has not been exercised.

I. NOTES PAYABLE AND LINE OF CREDIT (CONTINUED)

(14) Employee Notes Payable

On 31 December 2001, in exchange for services related to employment, the Company issued seven individual notes payable totalling $527,544 in amounts ranging from $40,000 to $115,186 to permanent employees who were also either directors, officers or stockholders of the Company. The terms and conditions of the notes were identical, each issued at a rate of 6% per annum and due on 31 December 2002. Due to the financial condition of the Company, a balance of $389,237 remained unpaid as of 31 December 2002. The full amount outstanding was repaid in full during 2003.

(15) Saipem SpA Note Payable

Effective October 1, 2004, the Company converted a $3,450,941 account payable to Saipem SpA (''Saipem'') into a note payable for the same amount. Under the terms of the Saipem note payable agreement, the Company agreed to pay Saipem quarterly interest-only payments until 30 September, 2007, the maturity date, at which date the note is due in full. The note bears interest at 5% per annum.

(16) M-I Drilling Fluids Co. Note Payable

During April 2001, the Company converted a $691,623 account payable to M-I Drilling Fluids Co. (''M-I'') into a note payable for the same amount. Under the terms of the M-I note payable agreement, the Company agreed to pay M-I $691,623 on or before 1 April 2002. The note bore interest at 9% per annum, payable monthly beginning on 1 May 2001. Due to the financial condition of the Company during that period, the Company was unable to make all required principal and interest payments, and the note was renegotiated in August 2003. At that time, the Company agreed to pay M-I $175,000 to settle the outstanding note payable and accrued interest. This settlement resulted in forgiveness of $516,623 in debt and $124,492 in accrued interest. In exchange for agreeing to settle the note payable, the Company agreed to pay M-I up to 20% of its share of Profit Oil, as defined in the Production Sharing Contract and Refinery Study between the Company and Georgian Oil, in excess of operating costs through the earlier of August 2007 or until M-I has recovered $641,115 from the Company in additional cash payments. Because Profit Oil is determined based on cumulative operating expenses, the Company does not expect to pay M-I any additional amounts under this settlement; however, the $641,115 will continue to be reflected in other long-term liabilities until August 2007 when the contingent aspect of the settlement expires.

(17) MacGregor Energy Services Limited Note Payable

During April 2001, the Company converted a $441,551 account payable to MacGregor Energy Services Limited (''MacGregor'') into a note payable for the same amount. Under the terms of the MacGregor note payable agreement, the Company agreed to pay MacGregor $441,551 on or before 1 April 2002. The note bore interest at LIBOR plus 3% per annum, payable monthly beginning on 1 May 2001. Due to the financial condition of the Company during that period, the Company was unable to make all required principal payments, and the note was renegotiated in September 2002. Under the terms of the September 2002 settlement, the Company paid MacGregor $50,000 (representing $29,251 in principal and $20,749 in accrued interest), and the Company agreed to a 5% per annum note payable to MacGregor of $412,300 including principal and interest payments on a quarterly basis until the note was to mature in August 2005. The Company repaid $40,000 in loan principal and $5,196 in accrued interest in August 2003, under the terms of the repayment schedule. The MacGregor note payable was renegotiated again in September 2003. Under the terms of the September 2003 renegotiation, the Company agreed to pay MacGregor $110,000 to settle the remaining note payable. This settlement resulted in forgiveness of debt of $262,300.

(18) Weatherford International Note Payable

During April 2001, the Company converted a $232,304 account payable to Weatherford International (''Weatherford'') into a note payable for the same amount. Under the terms of the Weatherford note payable agreement, the Company agreed to pay Weatherford $232,304 on or before 1 April 2002. The note bore interest at LIBOR plus 1% per annum, payable monthly beginning on 1 May 2001. Due to the financial condition of the Company during that period, the Company was unable to make any required principal and interest payments. In February 2002, Weatherford filed a claim against the Company for failure to meet the payment conditions of the note payable agreement. This claim was ultimately settled in September 2003. The Company also had a $107,236 account payable to Offshore Rentals, Inc., a vendor that was later acquired by Weatherford, and the settlement

I. NOTES PAYABLE AND LINE OF CREDIT (CONTINUED)

also included that account payable. At that time, the Company agreed to pay Weatherford $200,000 to settle the outstanding note payable, account payable and accrued interest. This settlement resulted in forgiveness of $32,304 in debt, $107,236 in accounts payable and $13,004 in accrued interest.

(19) West Oak/Nissei Associates Note Payable

During May 2002, the Company converted rent payable to West Oak/Nissei Associates of $28,691 into a note payable of the same amount, bearing interest at a rate of 8% per annum and due in monthly instalments of $2,582 through April 2003, at which date the note was paid in full.

J. INCOME TAXES

The Company and its domestic subsidiaries file a consolidated US federal income tax return. No benefit for US income taxes has been recorded in these consolidated financial statements because of Frontera's inability to recognise deferred tax assets under provisions of SFAS 109. A reconciliation of the differences between income taxes computed at the US federal statutory rate of 34% and Frontera's reported provision for income taxes is as follows:

	Year ended 31 December		
	2002	2003	2004
	$000	$000	$000
Income tax benefit (expense) at statutory rate	(1,932)	1,324	1,887
Utilisation (benefit) of losses not recognised	1,932	(1,324)	(1,887)
Income tax expense (benefit) at effective tax rate	—	—	—

At 31 December 2004, the Company has a net operating loss carry forward of approximately $69.7 million for regular U.S. tax purposes that will expire at various dates through 2024.

Significant components of the Company's deferred tax liabilities and assets as of 31 December 2002, 2003 and 2004 are as follows:

	At 31 December		
	2002	2003	2004
	$000	$000	$000
Deferred tax liabilities:			
Depreciation and amortisation	59	32	—
Accrued salaries	1	149	—
Other	—	11	—
Deferred tax assets:			
Net operating losses — US	5,418	6,098	7,941
Net operating losses — Foreign	15,025	15,695	15,773
Depreciation and amortisation	—	—	61
Other	6	7	9
	20,389	21,608	23,784
Valuation allowance	(20,389)	(21,608)	(23,784)
Net deferred tax assets	—	—	—

The valuation allowance is primarily attributed to US federal and foreign deferred tax assets. Management believes enough uncertainty exists regarding the realisation of these items and has recorded a full valuation allowance.

Profits derived from oil and gas operating activities are subject to a profits tax on taxable income as defined by Georgian law. However, under the terms of the Block 12 PSA, Georgian Oil is responsible for paying the Company's profit tax liabilities with respect to income derived from these activities. Although the Company has incurred operating losses in Georgia, no adjustment with respect to deferred tax assets or a potentially related valuation allowance has been made, as any future benefit related to these operating losses would serve to reduce Georgian Oil's liability.

K. DEFINED CONTRIBUTION SAVINGS PLAN

The Company sponsors a defined contribution 401(k) savings plan which covers all eligible employees. Company matching contributions to the defined contribution plan are discretionary. During each of the years ended 31 December 2002, 2003 and 2004, the Company made contributions of $6,500 to the defined contribution plan.

L. COMMITMENTS AND CONTINGENCIES

Operating Leases: The Company has non-cancellable operating leases for office facilities and lodging. Future minimum annual rental commitments under these operating leases are as follows:

Year ending 31 December	$000
2005	194
2006	51
2007	56
2008	2
	303

Rental expense for the years ended 31 December 2002, 2003 and 2004 was $168,000, $135,000 and $161,000, respectively.

BJ Services Company Middle East Limited Litigation: In September 2004, BJ Services Company Middle East Limited (''BJ Services'') filed a claim in Tbilisi District Court in Tbilisi, Georgia against FEGL due to non-payment for services rendered. BJ Services performed certain oil field services for FEGL between May and June 2003; however, the Company has argued that the services were defective and that certain other charges were not properly levied. The BJ Services claim with interest and penalties is $299,375, net of a $160,000 prepayment made by the Company in advance of the services being undertaken. In the opinion of management and outside counsel, any potential outcome or settlement of this litigation will not have a material adverse effect on the Company's financial position or future operating results.

SOCAR Arbitration: In June 1998, the Company, through its wholly owned subsidiary FRAC, entered into a production sharing agreement with SOCAR, hereafter referred to as the ''Azerbaijan PSA''. The Azerbaijan PSA covered onshore oilfields in an area of Azerbaijan known as the K&K Block. The Company and an operating partner undertook a successful exploration and development program on the K&K Block. The Company's relationship with SOCAR deteriorated as a result of several disputes under the Azerbaijan PSA and the Company was unsuccessful at reaching a settlement with SOCAR (See Note G for additional detail).

In October 2003, FRAC initiated arbitration proceedings against SOCAR to recoup funds to FRAC for oil deliveries made between 1999 and 2002. The Azerbaijan PSA provided that arbitration shall be governed by the United National Commission on International Trade Law rules on arbitration and a hearing has been scheduled for March 2005 in Stockholm, Sweden. FRAC is seeking damages from SOCAR for three separate breaches for non-payment totalling approximately $15.7 million, plus interest and certain costs. At this point, the outcome of the claim against SOCAR cannot be reasonably determined and no gain has been recognised by the Company with respect to any potential outcome of the arbitration hearing or subsequent rulings.

Should the arbitration result in the Company's favour, SOCAR has alleged an offsetting cross-claim against FRAC for up to $11.2 million, arguing that FRAC underpaid SOCAR the difference between local market obligation value and the world market value of the oil which SOCAR alleges should have been delivered in 1999 and 2000. Frontera management believes the counter-claim is without merit and no provision has been made in the financial information.

Vendor Invoices: In August 2003 and July 2004, the Company settled vendor invoices of $79,036 and $1,607,214, respectively. The terms of both settlement agreements provided that Frontera would not be responsible to repay the liability unless the Company generated Profit Oil revenues, as defined in the Block 12 PSA by August 2007 and July 2008, respectively. Because Profit Oil is determined based on the recovery of cumulative costs incurred for the development of Block 12, the Company does not expect to pay these vendors any additional amounts under the settlements; however, the costs will continue to be reflected in liabilities until the Profit Oil contingency expires.

M. NON-CASH INVESTING AND FINANCING ACTIVITIES

The following non-cash transactions took place during the year ended 31 December 2002:

Series A1 Stock, Series A2 Stock and Series B Stock were accreted by a total of $93,749 which was charged directly to retained earnings. On 15 March 2002, these preferred shares became subject to a mandatory redemption and were classified as a current liability.

The following non-cash transactions took place during the year ended 31 December 2003:

A warrant holder exercised warrants to purchase 758,946 common shares for $24,286, resulting in a decrease in notes payable of $24,286, and a corresponding aggregate increase in Common Stock and additional paid-in capital.

The Company transferred a note payable to a vendor of $516,623 plus associated accrued interest of $124,492 to other long-term liabilities upon the negotiation of a settlement agreement which will not be recognised as income from forgiveness of debt until the contingent component of the agreement expires in 2007.

The Company transferred an account payable of $75,760 to other long-term liabilities upon the negotiation of a settlement agreement which will not be recognised as income from forgiveness of debt until the contingent component of the agreement expires in 2007.

The Company sold an interest in its oil and gas properties which was financed with an account receivable of $2,250,000.

The following non-cash transactions took place during the year ended 31 December 2004:

The Company converted a vendor account payable of $3,450,941 into a note payable which matures in 2007.

During 2004, the Company transferred a vendor account payable of $1,607,214 to long-term liabilities upon the negotiation of a settlement agreement which will not be recognised as income from forgiveness of debt until 2008.

During 2004, the Company reacquired oil and gas properties with a carrying value of $2,532,598 by agreeing to forgive a $1,962,268 payable with the operator and by assuming the payables and accrued liabilities of the operator. Included in this transaction was the assumption of $3,802,712 in current liabilities and the acquisition of current assets of $1,270,114. At the time this transaction closed, the Company reversed the existing $1,458,168 deferred gain associated with the 2003 sale of an interest in the property which was never recognised.

The Company renegotiated a note payable under a troubled debt restructuring, resulting in $428,358 of accrued interest being transferred to related party debt and $1,268 of accrued interest being transferred to Common Stock warrants.

The Company converted an account payable of $3,825,000 into a note payable which is due in 2005.

The Company transferred an account payable of $109,686 to other long-term liabilities upon the negotiation of a payment and interest schedule which extends payments on the liability through 2005.

As described more fully in Note G, the Company's Azerbaijan oilfield properties were sold by the EBRD for approximately $53.3 million. These proceeds along with approximately $3.2 million in revenues generated while the properties were operated by the EBRD were applied to the ending loan balance, accrued interest and other liabilities of approximately $53.8 million, resulting in final proceeds to the Company of approximately $2.7 million.

N. EARNINGS PER SHARE

The following table sets forth the computation of basic and diluted earnings/(loss) per share:

	Year ended 31 December		
	2002	2003	2004
	$000	$000	$000
Numerator:			
Net earnings/(loss) applicable to common stockholders	5,588	(3,895)	(5,605)
Plus income impact of assumed conversions:			
Preferred stock dividends/interest	462	462	462
Interest on convertible notes	—	—	9
Net earnings/(loss) applicable to common stockholders plus assumed conversions	6,050	(3,433)	(5,134)

	Year ended 31 December		
	2002 Number	2003 Number	2004 Number
Denominator:			
Denominator for basic earnings per share — weighted average shares outstanding	5,231,426	5,610,899	5,994,276
Effect of potentially dilutive common shares:			
Convertible preferred stock	4,525,942	—	—
Convertible notes	—	—	—
Employee and director stock options	—	—	—
Warrants	—	—	—
Denominator for diluted earnings per share — weighted average shares outstanding and assumed conversions	9,757,368	5,610,899	5,994,276
Basic earnings (loss) per share	$ 1.07	$ (0.69)	$ (0.94)
Diluted earnings (loss) per share	$ 0.62	$ (0.69)	$ (0.94)

Basic and diluted earnings per share for the years ended 31 December 2004 and 2003 are the same since the effect of all common stock equivalents is antidilutive to the Company's net loss per share under SFAS No. 128. For the year ended 31 December 2002, all shares of convertible preferred stock have been included in diluted earnings per share; however all common stock options and warrants have been excluded from diluted earnings per share because their effect would be antidilutive.

Yours faithfully

Ernst & Young LLP

PART VI

SUMMARY OF THE BLOCK 12 PSA AND MINERAL LICENCE

1. Block 12 PSA

1.1 Scope

Frontera derives its rights to explore for, develop and produce oil, including all existing wells, in Block 12 pursuant to a production sharing agreement entered into on 25 June 1997 between the Ministry of Fuel and Energy, Saknavtobi and Frontera Georgia (the "Block 12 PSA") and a 25 year mineral extraction licence relating to Block 12 that was granted to the Operating Company with effect from 22 August 1997 (the "Mineral Licence"). Frontera's activities in Block 12 are conducted through Frontera Georgia, a wholly owned subsidiary of the Company, and the Operating Company, a pass-through entity formed for execution and operational purposes only under the terms of the Block 12 PSA which is jointly and equally owned by Frontera Georgia and Saknavtobi.

The Block 12 PSA defines the rights and obligations of Frontera Georgia, the State Agency (being the successors of the Ministry of Fuel and Energy) and Saknavtobi, governs their mutual relations and the governance, responsibilities and powers of the Operating Company. The Block 12 PSA also establishes the rules and methods for the operations to be conducted in connection with the exploration for undiscovered crude oil and natural gas ("Petroleum") and the evaluation, development and production of discovered reserves (the "Petroleum Operations"), as well as the provisions relating to production sharing.

Under the Block 12 PSA, the Operating Company has the exclusive right to explore for, develop and produce oil in Block 12 during the term of the Block 12 PSA. Frontera Georgia has the right to perform any Petroleum Operations or any other activities necessary under the Block 12 PSA or the Mineral Licence to the extent that the Operating Company fails or refuses to perform such activities, and any such costs incurred in doing so shall be recoverable (see Recovery of Costs and Expenses at paragraph 1.5 of this Part VI). The Operating Company executes its responsibilities in accordance with instructions from Frontera Georgia and a coordination committee established under the Block 12 PSA (see paragraph 1.4 of this Part VI).

The Operating Company must provide technical resources and carry out all Petroleum Operations in accordance with approved work programmes and budgets and generally accepted standards in the international oil industry. Frontera Georgia must provide all financial resources for the Petroleum Operations undertaken by the Operating Company and such technical resources for the benefit of the Operating Company as required by the Block 12 PSA or as necessary or desirable. The Petroleum Operations carried out to date by the Operating Company have been sufficient to fulfil the minimum expenditure obligations under the Block 12 PSA. Frontera Georgia is able to recover these costs and expenses (see Recovery of Costs at paragraph 1.5 of this Part VI).

1.2 Term

The Block 12 PSA has a twenty-five year term which will expire on 13 November 2022. The term includes an exploration phase which will expire on 13 November 2012 (the "Exploration Phase"). If commercial production remains possible in relation to any part of Block 12 which is specified in a development area or areas under the Block 12 PSA ("Development Areas"), Frontera Georgia shall be entitled, after the expiration of the Block 12 PSA, to receive an extension of the term of the Block 12 PSA and the Mineral Licence regarding such Development Areas for a further period of five years (or the production life of the Development Area if this is shorter).

1.3 Relinquishments

Save as otherwise agreed between Frontera Georgia, the State Agency, and Saknavtobi, Frontera Georgia shall relinquish its rights to Block 12 in respect of any area outside of any Development Area at the end of the Exploration Phase.

1.4 Coordination Committee

The Block 12 PSA provides for a coordination committee to be established comprising six members (three appointed by Frontera Georgia and three appointed by Saknavtobi) which is given certain powers under the Block 12 PSA and provides the overall supervision and direction of, and ensures the performance of, the Petroleum Operations (the "Coordination Committee").

All actions are to be taken by a unanimous decision of the Coordination Committee. However, if the parties fail to reach agreement on any matter, then Frontera Georgia's proposal shall prevail, provided Frontera Georgia gives full reasons for such proposal and Saknavtobi does not reasonably believe that the proposal would result in serious depletion of a field or reservoir resulting in either permanent damage to that field or reservoir or materially reduced recovery of Petroleum over the life of the field or reservoir. If Saknavtobi decides to object to any decision taken by Frontera Georgia on these limited grounds, such matter will be referred to and finally determined by an independent expert appointed by Frontera Georgia and Saknavtobi.

1.5 Recovery of Costs and Expenses

Frontera Georgia shall provide or procure the provision of all funds required to conduct Petroleum Operations and shall be entitled to recover its costs and expenses incurred in respect of the Petroleum Operations from the Petroleum produced from Block 12. Those operational costs incurred in the day to day Petroleum Operations, including costs relating to production, processing, transportation, export, administration, finance, tax and insurance costs, are recoverable in full from oil produced. Thereafter, the nature of the costs and expenses incurred will determine the percentage of Petroleum produced that is available to reimburse Frontera Georgia for its non-operating costs and expenses:

(i) in respect of expenditure incurred in connection with the exploration for previously undiscovered Petroleum, or the evaluation of undiscovered reserves (''Exploration Operations''), Frontera Georgia is entitled to recovery of such expenses from 100 per cent of the Petroleum produced from Block 12;

(ii) in respect of expenditure incurred which benefits any Development Areas, Frontera Georgia is entitled to recovery of such expenses from 80 per cent of the Petroleum produced from Block 12; and

(iii) in respect of expenditure incurred benefiting those parts of Block 12 relating to discoveries made prior to the Block 12 PSA (the ''Exploitation Areas''), Frontera Georgia is entitled to recovery of such expenses from 60 per cent of the Petroleum produced from Block 12.

Frontera Georgia must follow a detailed accounting procedure set out in the Block 12 PSA for recovery of its costs and expenses which is open to audit and approval by Saknavtobi. Where outstanding recoverable costs and expenses for one year exceed the value of the Cost Recovery Crude Oil produced from Block 12, the excess can be carried forward for recovery in the next succeeding years until fully recovered but in no case after termination of the Block 12 PSA. The Company has incurred a total of approximately $87,128,000 of costs (including financing costs) in respect of its operations on Block 12, of which approximately $79,665,000 has been approved by Saknavtobi and approximately $5,309,000 is anticipated by the Company to be approved by Saknavtobi for recovery. Saknavtobi has requested further documentary evidence in respect of approximately $2,154,000 incurred by the Group prior to the grant of the Block 12 PSA. The Company has to date recovered a total of approximately $3,239,000 of its approved costs from oil sales.

1.6 Allocation of Production

Following recovery of costs and expenses from the Cost Recovery Crude Oil in accordance with the provisions set out in paragraph 1.5 of this Part VI, the remaining Petroleum (referred to as ''Profit Oil'') shall be allocated between Saknavtobi and Frontera Georgia in the proportion of 51 per cent to Saknavtobi and 49 per cent to Frontera Georgia. Frontera Georgia and the Operating Company are entitled to use Petroleum produced from Block 12 free of charge to the extent required for Petroleum Operations.

If in any calendar year Frontera Georgia's share of Cost Recovery Crude Oil and Profit Oil exceeds 90 per cent of the total Cost Recovery Crude Oil and Profit Oil, a quantity of crude oil equivalent to that excess (the ''Excess Crude'') shall be offered for sale to the government of Georgia (the ''State'') from Frontera Georgia's next available share of Petroleum. The State then has 20 days to elect to purchase and take delivery of such Petroleum at a price equal to the world market price for similar crude oil.

1.7 Taxation

The Operating Company shall have no tax liability whatsoever in respect of profit tax payable pursuant to Georgian tax laws (''Profit Tax'') or mineral use tax payable pursuant to Georgian tax laws (''Mineral Use Tax''). Save in respect of Profit Tax and Mineral Use Tax, both the Operating Company and Frontera Georgia shall be entitled to full exemption from all taxes payable under Georgian tax laws.

Both Saknavtobi and Frontera Georgia shall be subject to Profit Tax at the rate of 10 per cent. However, Saknavtobi agrees to pay Frontera's share of Profit Tax and Mineral Use Tax from its Profit Oil and, with the support and guarantee from the State, indemnifies Frontera Georgia from all taxes payable under Georgian tax laws. If the amount of Profit Tax which would have been owed by Frontera Georgia but for the provisions of the Block 12 PSA exceeds Saknavtobi's share of Profit Oil (the "Excess Crude"), Frontera Georgia shall advance to Saknavtobi a sum equivalent to the Excess Crude. Such sum shall be recoverable by Frontera Georgia in accordance with the Cost Recovery provisions (see paragraph 1.5 of this Part VI).

1.8 Assistance from the State

The State agrees to provide on request such assistance to enable Frontera Georgia and the Operating Company to properly carry out the Petroleum Operations. Such assistance includes, inter alia, providing approvals and permits, arranging office, transportation and communication facilities, assisting with customs formalities, liaising with appropriate departments and ministries of the State, providing land rights requested for the construction of facilities and installations, providing data and samples relating to Block 12 other than those produced pursuant to the Block 12 PSA, and procuring access to all existing facilities and infrastructure in Block 12 owned by or otherwise under the control of the State or Saknavtobi for the purpose of carrying out Petroleum Operations under the Block 12 PSA or any new or modernised pipelines or other infrastructure passing through Georgia.

The State agrees to observe, enforce and maintain the stability of the legal, tax, financial, mining and economic conditions of the Block 12 PSA for the duration of its term and to procure that all decrees, permits, resolutions, licences and access rights are made available to Frontera Georgia and the Operating Company. If there is a change to the laws and regulations of Georgia which have a material adverse impact on the economic position of Frontera Georgia, then (i) the terms of the Block 12 PSA shall be amended to restore Frontera Georgia to its position prior to such change and (ii) if such changes do not restore Frontera Georgia's economic position, then the State shall indemnify Frontera Georgia for such losses.

In addition, appended to the Block 12 PSA is a decree of the President of Georgia stating that no future Georgian law on petroleum production sharing shall act retrospectively to change the principles of production sharing under the Block 12 PSA or to amend the Block 12 PSA adversely to Frontera Georgia.

1.9 Export of Crude Oil

Frontera Georgia and any purchaser from Frontera Georgia shall have the unrestricted right to export from any export point chosen by Frontera Georgia the share of Petroleum to which Frontera Georgia is entitled under the Block 12 PSA, provided that access to such export point is not restricted generally on the grounds of safety or national security. Such exports shall be free of all taxes (including customs duties). Petroleum to which Frontera Georgia is entitled under the Block 12 PSA shall not be subject to any current or future export quotas or licence requirements (save as provided in the Block 12 PSA in respect of Excess Crude set out at paragraph 1.7 of this Part VI).

Ownership of any asset acquired by or on behalf of the Operating Company or Frontera Georgia in connection with Petroleum Operations shall vest in Saknavtobi without consideration when both (i) the costs of such asset have been recovered by Frontera Georgia under the terms of the Block 12 PSA and (ii) either the Block 12 PSA has come to an end or, if earlier, the asset is no longer required. The Operating Company has the right to enjoy the free, exclusive and unrestricted use of such assets at no cost until the Block 12 PSA is terminated or the assets are no longer needed.

1.10 Assignment

Frontera Georgia may transfer all or part of its rights and obligations under the Block 12 PSA to a third party provided, firstly, that such third party has the requisite technical and financial ability and accepts the terms of the Block 12 PSA and, secondly, that Saknavtobi has given its prior written consent to such assignment (such consent not to be unreasonably withheld or delayed).

Saknavtobi may transfer all or part of its rights and obligations under the Block 12 PSA to a third party provided that, inter alia, Frontera Georgia consents to such transfer (such consent not to be unreasonably withheld or delayed). The consent of Frontera Georgia (which cannot be unreasonably withheld or delayed) is also required to be given before the State and/or Saknavtobi can allow any third party to acquire an interest in Saknavtobi (or a company in its corporate group).

Any transfer of rights, obligations and interests arising under the Block 12 PSA must be accompanied by a transfer of an equivalent share of ownership in the Operating Company.

1.11 Termination

Frontera Georgia may by written notice to Saknavtobi relinquish its rights and be relieved of its obligations under the Block 12 PSA at any time if, in Frontera Georgia's opinion, circumstances do not warrant continuing Petroleum Operations. The State may only terminate the Block 12 PSA on ninety days' notice if Frontera Georgia has committed a material breach of the Block 12 PSA (being a fundamental breach tantamount to a frustration of the Block 12 PSA which may include failure to complete any work programmes approved pursuant to the Block 12 PSA) which is proved at arbitration.

1.12 Governing Law and Dispute Resolution

All disputes arising between Saknavtobi and Frontera Georgia shall be settled under UNCITRAL before a panel of three arbitrators. Any arbitration shall be held in Stockholm, Sweden and shall be conducted in the English language and text. Any party may by 30 days' written notice initiate the arbitration proceedings and any decision shall be final and binding on the parties. Any arbitration panel shall apply the terms of the Block 12 PSA as supplemented and interpreted by general principles of the laws of Georgia, the United States and the State of Texas as are in force on the date of the Block 12 PSA.

1.13 Refinery

The State granted to Frontera Georgia for the benefit of the Operating Company the sole right and licence for 25 years to study, design, erect and operate a crude oil refinery within the Kakheti and Kartli provinces of Georgia. Frontera Georgia has the option to extend the term of the refinery licence for an additional period of 25 years or for the life of the refinery, whichever is shorter, upon giving notice to the Ministry of Natural Resources. The Block 12 PSA transfers the licence to the Operating Company.

The PSA obliges the Contractor to commence a programme of study in respect of the design and operation of a refinery. Pursuant to the Block 12 PSA, the Contractor engaged Muse, Stancil and Co. to produce a preliminary refinery feasibility study in October 1997. Frontera has complied with all its obligations in respect of the refinery under the Block 12 PSA.

2. Mineral Licence

In accordance with the Law on Entrails and the Oil and Gas Law, exploration and production of oil is subject to a licencing regime. The Operating Company holds a mineral licence issued by the Ministry of Environment and Natural Resources Protection. The Mineral Licence is issued for 25 years and is valid until 27 August 2022. The Licence was issued to the Operating Company, in accordance with the Block 12 PSA, which provides that the Operating Company has the exclusive right to conduct Petroleum Operations in the Contract Area.

The Mineral Licence sets out the rights of the holder to the exploration and production of existing oil and gas deposits located within the territory of Block 12 of Georgia, the conduct of geological and ecological studies of the territory, and exploration and exploitation of oil and gas deposits in the territory of Dedopliskaro, Signagi, Sagarejo, Gurjaani, Marneuli and Gardabani. The area of geological allotment is approximately 5,060 km^2.

The Mineral Licence also contains provisions relating to the rate of mineral use tax payable by the Operating Company to the State and obligations imposed on the Operating Company, including compliance with applicable technical rules, keeping records of oil reserves, ensuring the security of employees and the notifications of disasters and accidents.

PART VII

US RESTRICTIONS ON TRANSFER OF COMMON SHARES

Investors are referred to the definition of a "US Person" on the following page of this Part VII.

This document has been prepared by the Company in making offers of the Placing Shares only to, or for the account or benefit of, non-US persons outside the United States in transactions exempt from the registration requirements of the US Securities Act in reliance on Regulation S thereunder. Terms used in the following description that are defined in Regulation S are used as therein defined.

The Placing Shares have not been registered under the US Securities Act and are "restricted securities" as defined in Rule 144 promulgated under the US Securities Act. A purchaser of Placing Shares may not offer, sell, pledge or otherwise transfer Placing Shares in the United States or to, or for the account or benefit of, any US Person, except pursuant to an effective registration statement under the US Securities Act, an exemption from the registration requirements of the US Securities Act, or in certain transactions specified in Regulation S. Hedging transactions in the Common Shares may not be conducted, directly or indirectly, unless in compliance with the US Securities Act. The certificates evidencing the Placing Shares will bear a legend to the following effect, unless the Company determines otherwise in compliance with applicable law.

"THE COMMON SHARES REPRESENTED BY THIS CERTIFICATE HAVE NOT BEEN REGISTERED UNDER THE US SECURITIES ACT OF 1933, AS AMENDED (THE "SECURITIES ACT") AND MAY NOT BE OFFERED, SOLD, PLEDGED OR OTHERWISE TRANSFERRED EXCEPT IF SUCH TRANSFER IS EFFECTED (1) IN A TRANSACTION MEETING THE REQUIREMENTS OF REGULATION S UNDER THE SECURITIES ACT (2) PURSUANT TO AN EFFECTIVE REGISTRATION STATEMENT UNDER THE SECURITIES ACT, OR (3) PURSUANT TO AN AVAILABLE EXEMPTION FROM THE REGISTRATION REQUIREMENTS OF THE SECURITIES ACT, IN EACH CASE IN ACCORDANCE WITH ALL APPLICABLE SECURITIES LAWS. HEDGING TRANSACTIONS INVOLVING THE COMMON SHARES OF THE COMPANY MAY NOT BE CONDUCTED, DIRECTLY OR INDIRECTLY, UNLESS IN COMPLIANCE WITH THE SECURITIES ACT."

Prior to one year after the later of (1) the time when the Placing Shares are first offered to persons other than distributors in reliance upon Regulation S or (2) the date of closing of the Placing:

(a) every purchaser of Placing Shares other than a distributor will be required to certify that it is not a US Person and is not acquiring the securities for the account or benefit of any US Person or is a US Person who purchased securities in a transaction that did not require registration under the US Securities Act;

(b) every purchaser of the Placing Shares will be required to agree to resell such Placing Shares only in accordance with the provisions of Regulation S, pursuant to registration under the US Securities Act, or pursuant to an available exemption from registration, and will be required to agree not to engage in hedging transactions, directly or indirectly, with regard to the Common Shares unless in compliance with the US Securities Act; and

(c) each distributor selling securities to a distributor, a dealer (as defined in Section 2(a)(12) of the US Securities Exchange Act of 1934, as amended), or a person receiving a selling concession, fee or other remuneration will be required to send a confirmation or other notice to the purchaser stating that the purchaser is subject to the same restrictions on offers and sales that apply to a distributor.

Pursuant to the Company's Bylaws, the Company will be required to refuse to register any transfer of its securities not made in accordance with the provisions of Regulation S, pursuant to registration under the US Securities Act, or pursuant to an available exemption from registration. Each purchaser of Placing Shares sold in reliance on Regulation S will be deemed to have represented and agreed as follows:

(1) the purchaser is not a US Person and is not acting for the account or benefit of a US Person (other than a distributor);

(2) the purchaser understands that the Placing Shares have not been registered under the US Securities Act and may not be offered, resold, pledged or otherwise transferred by such purchaser except (a) (i) in an offshore transaction meeting the requirements of Rule 903 or Rule 904 of Regulation S, (ii) pursuant to an effective registration statement under the US Securities Act, or (iii) pursuant to an available exemption from the registration requirements of the US Securities Act and (b) in accordance with all applicable securities laws of the states of the United States and other jurisdictions;

(3) the purchaser understands and agrees that, if in the future it decides to resell, pledge or otherwise transfer any Placing Shares or any beneficial interests in any Placing Shares prior to the date which is one year after the later of (1) the date when the Placing Shares are first offered to persons (other than distributors) pursuant to Regulation S and (2) the date of closing of the Placing, it will do so only outside the United States in an offshore transaction in compliance with Rule 903 or Rule 904 under the US Securities Act, pursuant to an effective registration statement under the US Securities Act or pursuant to an available exemption from the registration requirements of the US Securities Act and in each of such cases in accordance with any applicable securities law of any state of the United States;

(4) the purchaser agrees to and each subsequent holder is required to, notify any purchaser of the Placing Shares from it of the resale restrictions referred to in paragraphs (2) and (3) above, if then applicable;

(5) the purchaser acknowledges that, prior to any proposed transfer of Placing Shares other than pursuant to an effective registration statement, the transferee of Placing Shares may be required to provide certifications and other documentation relating to the non-US Person status of such transferee;

(6) the purchaser acknowledges that the Company, MSIL and MSSL and others will rely upon the truth and accuracy of the foregoing acknowledgements, representations and warranties and agrees that if any such acknowledgement, representation or warranty deemed to have been made by virtue of its purchase of Placing Shares is no longer accurate, it shall promptly notify the Company, MSIL and MSSL; and

(7) the purchaser acknowledges that the Placing Shares will bear a restrictive legend to the following effect, unless the Company determines otherwise in compliance with applicable law:

"PRIOR TO INVESTING IN THE PLACING SHARES OR CONDUCTING ANY TRANSACTIONS IN THE PLACING SHARES, INVESTORS ARE ADVISED TO CONSULT PROFESSIONAL ADVISERS REGARDING THE ABOVE RESTRICTIONS ON TRANSFER AND OTHER RESTRICTIONS REFERRED TO IN THIS DOCUMENT."

In this document, a "US Person" means:

(i) any natural person resident in or a citizen of the United States;

(ii) any partnership or corporation organised or incorporated under the laws of the United States;

(iii) any estate of which any executor or administrator is a US Person;

(iv) any trust of which any trustee is a US Person;

(v) any agency or branch of a foreign entity located in the United States;

(vi) any non-discretionary account or similar account (other than an estate or trust) held by a dealer or other fiduciary for the benefit or account of a US Person;

(vii) any discretionary account or similar account (other than an estate or trust) held by a dealer or other fiduciary organised, incorporated, or (if an individual) resident in the United States; and

(viii) any partnership or corporation if:

 (a) organised or incorporated under the laws of any foreign jurisdiction; and

 (b) formed by a US Person principally for the purpose of investing in securities not registered under the US Securities Act, unless it is organised or incorporated and owned, by accredited investors (as defined in Rule 501 (a) under the US Securities Act) who are not natural persons, estates or trusts.

This document does not constitute an offer of, or a solicitation of an offer to buy, any shares by or on behalf of the Company, MSIL or MSSL, in any jurisdiction or in any circumstances where it is not authorised or lawful to make such an offer or solicitation.

PART VIII

ADDITIONAL INFORMATION

1. Directors' Responsibility

The Directors of the Company, whose names appear on page 7, accept responsibility, including individual and collective responsibility, for the information contained in this document and compliance with the AIM Rules. To the best of the knowledge and belief of the Directors, who have taken all reasonable care to ensure that such is the case, the information contained in this document is in accordance with the facts and there is no omission likely to affect the import of such information.

2. The Company

2.1 The Company was incorporated under the name of Frontera Resources Corporation on 4 February 1997 as a corporation under the DGCL by the filing of its original Certificate of Incorporation with the Secretary of State of the State of Delaware.

2.2 The Company's registered office in Delaware is c/o Delaware — Corporation Service Company, 1013 Centre Rd., Wilmington, Delaware 19805. Its principal place of business is at 3040 Post Oak Boulevard, Suite 730 Houston, Texas 77056.

2.3 The liability of the Shareholders of the Company is limited. Under DGCL a stockholder of a corporation is not personally liable for the acts of the corporation, save that a stockholder may become personally liable by reason of his or her own acts.

3. Share Capital of the Company

3.1 General

At the date of this document, the authorised and issued share capital of the Company is as follows:

Authorised Number	Authorised Amount		Issued and fully paid Number	Issued and fully paid Amount
65,000,000	$ 2,600	Common Shares of $0.00004 each	7,218,017[1]	$288.72
10,000,000	$ 100	Preferred Shares of $0.00001 each	3,624,333[2]	$ 36.24

Notes:

(1) This number includes 36,209 Common Shares which are held by the Company in treasury at the date of this document.

(2) This number includes 1,229,234 Preferred Shares which are held by the Company in treasury at the date of this document.

Each holder of the issued Preferred Shares has agreed to convert his Preferred Shares into Common Shares immediately prior to the Placing. The conversion of the Preferred Shares will be effected on the following basis:

Series Preferred Stock	Number of Preferred Shares in issue	Number of Common Shares upon conversion
Series A1	322,400	1,935,913
Series A2	135,000	810,633
Series B	254,000	1,533,313
Series D	23,600	2,240,000
Series E	2,889,333[1]	13,406,505
Total	3,624,333	19,926,364

Note:

(1) This number includes 1,229,234 Preferred Shares which are held by the Company in treasury at the date of this document.

As a result of these conversions and immediately following the Placing, the authorised and issued share capital of the Company will be as follows:

Authorised			Issued and fully paid[1]	
Number	Amount		Number	Amount
200,000,000	$8,000	Common Shares of $0.00004 each	55,144,368[2]	$2,205.77
10,000,000	$ 100	Preferred Shares of $0.00001 each	—	—

Notes:

(1) Assuming that no warrants, options or convertible loan notes over or in respect of Common Shares are exercised or converted (as applicable) after the date of this document and on or before the Placing.

(2) 5,739,855 Common Shares will be held by the Company in treasury following (i) conversion of the Preferred Shares into Common Shares and (ii) completion of the Stock Lending Agreement referred to in paragraph 8.2.2 of this Part VIII.

Other than the holdings of the Directors, which are set out in paragraph 5.1 of this Part VIII, the Company is aware of the following persons who, as at the date of this document, directly or indirectly, jointly or severally hold, three per cent or more of the Company's share capital:

	No. of Preferred Shares	No. of Common Shares	No. of Common Shares following conversion of Preferred Shares[1]	Percentage of Common Share Capital[1]
Bill White	101,829	922,254	1,536,783	7.18
DDJ Capital Inc.	258,621	—	1,200,000	5.61
Baker Hughes Finance, Inc.	8,429	92,110	892,151	4.17
James R Crane	99,200	274,920	870,586	4.06
John Eddie Williams	172,414	0	800,000	3.73
Don Sanders — 1998 Childrens Trust	79,600	175,146	653,120	3.05

Note:

(1) Assuming that conversion of the Preferred Shares into Common Shares had occurred as at the date of this document.

The Company is not aware of any person who either alone or, together with any person with whom he is connected, will or could exercise control over the Company immediately following Admission.

The holdings of the Directors and the major shareholders set out in the table above is, at the date of this document, or will, following the Placing, be as follows:

	Common Share Capital as at the date of this document[1]		Common Share Capital on a fully diluted basis as at the date of this document[1][2]		Percentage of Fully Diluted Common Share Capital following the Placing
	No. of Common Shares	Percentage of Common Share Capital	No. of Common Shares	Percentage of Common Share Capital	
Existing Shares					
Directors					
Steve C. Nicandros[3]	1,449,659	6.8	4,626,747	10.00	6.2
Lan Bentsen[3]	1,684,530	7.9	2,465,909	5.3	3.3
Spyros N. Karnessis[3]	3,167,215	14.8	5,022,015	10.9	6.8
Stephen E. McGregor	199,520	0.9	801,690	1.7	1.1
Andrew J. Szescila	—	—	25,000	0.1	0.0
Major Shareholders					
DDJ Capital Inc.	1,200,000	5.9	12,194,246	26.4	16.4
Baker Hughes Finance, Inc.	892,151	4.4	1,552,256	3.4	2.1
Bill White	1,536,783	7.5	1,536,783	3.3	2.1
James R. Crane	870,586	4.3	870,586	1.9	1.2
John Eddie Williams	800,000	3.9	1,139,500	2.5	1.5
Don Sanders — 1998 Childrens Trust	653,120	3.1	915,840	2.0	1.2

Notes:

(1) Assuming that the conversion of the Preferred Shares into Common Shares had been effected as at the date of this document.

(2) Assuming that all outstanding options and warrants over or in respect of the Common Shares are exercised but no convertible loan notes are converted.

(3) Includes interests held by connected persons.

3.2 Common Shares

The holders of Common Shares are entitled to one vote for each share held of record on all matters submitted to a vote of the Shareholders. The Shareholders do not have cumulative voting rights in the election of Directors. Accordingly, holders of a majority of the Common Shares voting are able to elect all of the Directors. Subject to preferences that may be granted to any then outstanding Preferred Shares, holders of Common Shares are entitled to receive rateably only those dividends as may be declared by the Board out of funds legally available, as well as any distributions to the Shareholders. Details of the Company's dividend policy are set out in paragraph 15 of Part II.

In the event of the Company's liquidation, dissolution or winding up, holders of Common Shares are entitled to share rateably in all of the Company's assets remaining after the Company pays its liabilities and distributes the liquidation preference of any then outstanding Preferred Shares. Holders of Common Shares have no pre-emptive or other subscription or conversion rights.

The rights attaching to the Common Shares provided for in the Company's Certificate of Incorporation and Bylaws are set out in paragraph 4 of this Part VIII.

3.3 Preferred Shares

Upon completion of the Placing, the Board will have the authority, without further action by the Shareholders, to issue up to 10 million Preferred Shares in one or more series and to fix the rights, preferences, privileges and restrictions thereof. These rights, preferences and privileges include dividend rights, conversion rights, voting rights, terms of redemption, liquidation preferences, sinking fund terms and the number of shares constituting any series or the designation of such series, any or all of which may be greater than the rights of Common Shares. The Company has no present plan to issue Preferred Shares.

3.4 Warrants

The Company has issued warrants to subscribe for Common Shares which remain outstanding as at the date of this document as follows:

Series of Warrants	**Number of Warrants outstanding**	**Maximum number of Common Shares to be subscribed**	**Exercise Price ($ per share)**
2001 Warrants	469,710	13,686,929	0.032
2002 Warrants	1,950,000	1,950,000	2.00
2003 Warrants	3,000,000	3,000,000	1.00
Total	5,419,710	18,636,929	—

3.4.1 *2001 Warrants*

In December 2001, the Company issued non-transferable warrants to purchase an aggregate of 15,637,329 Common Shares at an exercise price of $0.032 per share (the "2001 Warrants") pursuant to a rights offering made to the holders of Common Shares, Series D Preferred Shares and Series E Preferred Shares. The 2001 Warrants are exercisable at any time up to December 2006. A holder of the 2001 Warrants may not exercise such warrants in part only. Holders of the 2001 Warrants are entitled to "piggy-back" registration of the Company's securities under the US Securities Act, subject to the Company's right to limit the number of shares to be registered. This right, if exercised, would effectively entitle the 2001 Warrant holders, upon exercise of their warrants, to publicly trade the underlying Common Shares in the US. These rights are exercisable 180 days from, and terminate within five years of, an initial public offering of the Company's shares.

At the date of this document, the rights to subscribe for 958,907 Common Shares pursuant to the 2001 Warrants have been exercised.

3.4.2 *2002 Warrants*

In April 2001, the Company issued warrants to purchase an aggregate of 1,950,000 Common Shares at an exercise price of $2 per share (the "2002 Warrants") in connection with the 2002 Amended Note Purchase Agreement. The 2002 Warrants are exercisable at any time up to 1 September 2007. Holders of the 2002 Warrants are entitled to "piggy-back" registration of the Company's securities under the US Securities Act, subject to the Company's right to limit the number of shares to be registered. This right, if exercised, would effectively entitle the holders of the 2002 Warrants, upon exercise of their warrants, to publicly trade the underlying Common Shares in the US. These rights are exercisable 180 days from, and terminate within five years of, an initial public offering of the Company's shares. The 2002 Warrants further provide that the holder will, if requested, sign a lock-up agreement (not to exceed 180 days), provided all Shareholders with an equivalent or greater shareholding, and all officers and directors of the Company, enter into similar agreements. No rights to subscribe for Common Shares have been exercised pursuant to the 2002 Warrants as at the date of this document.

3.4.3 *2003 Warrants*

In May 2003, the Company issued warrants to purchase an aggregate of 3,000,000 Common Shares at an exercise price of $1 per share (the "2003 Warrants") in connection with the 2003 Note Purchase Agreement. The 2003 Warrants are exercisable at any time up to May 2006. Holders of the 2003 Warrants are entitled to "piggy-back" registration of the Company's securities under the US Securities Act, subject to the Company's right to limit the number of shares to be registered. This right, if exercised, would effectively entitle the holders of the 2003 Warrants, upon exercise of their warrants, to publicly trade the underlying Common Shares in the US. These rights are exercisable 180 days from, and terminate within five years of, an initial public offering of the Company's shares. The 2003 Warrants further provide that the holder will, if requested, sign a lock-up agreement (not to exceed 180 days), provided all Shareholders with an equivalent or greater shareholding, and all officers and directors of the Company, enter into similar agreements. No rights to subscribe for Common Shares have been exercised pursuant to the 2003 Warrants as at the date of this document.

3.5 Options

3.5.1 General

At the date of this document there are 6,125,513 share options outstanding which grant rights to subscribe, in aggregate, for up to 6,125,513 Common Shares. These options have been issued by the Company pursuant to the 1998 Plan and the 2000 Plan. Further details of the terms of those plans are set out in paragraph 3.5.2 and 3.5.3 below.

Details of the options issued by the Company outstanding as at the date of this document are set out below:

Options outstanding and exercisable		
Range of Exercise Prices ($)	**Number outstanding at the date of this document**	**Expiry date range**
0.92	150,000	31/3/2008
1.00	4,868,000	31/12/2010-31/12/2014
2.00	1,002,513	31/3/2008-6/4/2013
5.28	75,000	31/3/2008
8.84	5,000	29/6/2010
8.85	25,000	31/3/2008
—	6,125,513	—

3.5.2 Frontera Resources Corporation 1998 Employee Stock Incentive Plan

The Frontera Resources Corporation 1998 Employee Stock Incentive Plan (the "1998 Plan") permits grants of options to purchase Common Shares. The 1998 Plan, which is a successor to previous plans, was amended in June 2000 to limit its application to company employees who are required to report and pay taxes on earnings pursuant to the Internal Revenue Code. All of the other company employees, as well as Directors, advisers and consultants, are eligible to participate in the Frontera Resources Corporation 2000 Non-Qualified Stock Option and Stock Award Plan (the "2000 Plan") adopted by the Board in June 2000. The maximum number of stock options that can be issued by the Company under the 1998 Plan is limited to 9,750,000 Common Shares, reduced by the total number of shares of stock subject to stock options and stock awards that have been granted under the 1998 Plan and the 2000 Plan.

Options granted under the 1998 Plan may be qualified as "Incentive Stock Options" under Section 422 of the Internal Revenue Code ("ISO's"), or may be non-qualified options under that section. The Plan also permits restricted stock awards within its terms.

The Board has appointed Frontera's chief executive officer as administrator of the 1998 Plan. The administrator is responsible for determining which employees will receive options, the number of shares covered by any option agreement, and the exercise price and other terms of each such option. The Board is responsible for administering the Plan as it relates to options granted to the chief executive officer.

Under the terms of the 1998 Plan, any issued options expire ten years after the date of grant, with the exception of options granted to Shareholders holding at least ten per cent of the Company's shares, which expire five years after the date of grant, or upon earlier termination of employment of the grantee. Options granted vest over periods ranging from immediate vesting to vesting in equal increments over three years from the date of grant.

3.5.3 Frontera Resources Corporation 2000 Non-Qualified Stock Option and Stock Award Plan

In December 2000 the Board approved the 2000 Plan, pursuant to which options may be granted to employees, directors, consultants, and advisors of the Company or any of its affiliates, to purchase up to 2,250,000 Common Shares, reduced by the total number of shares of stock subject to stock options and stock awards that have been granted under the 1998 Plan and the 2000 Plan. The Board has appointed Frontera's chief executive officer as administrator of the 2000 Plan who determines which employees will receive options, the number of shares covered by any option agreement, and the exercise price and other terms of each such option. The Board is responsible for administering the Plan as it relates to options granted to the chief executive officer.

Under the terms of the 2000 Plan, any issued options expire ten years after the date of grant or upon earlier of termination of employment or affiliation relationship between the grantee and the Company. Options granted vest over periods ranging from immediate vesting to vesting in equal increments over three years from the date of grant.

The 2000 Plan is limited to the grant of non-qualified stock options to purchase Common Shares. The 2000 Plan also permits restricted stock awards within its terms.

3.6 Convertible Loan Note

Pursuant to the terms of the 2004 Convertible Note Purchase Agreement, the Company issued the 2004 Convertible Notes convertible, at the option of the loan note holders, into Common Shares at a conversion price of 80 per cent of the price of the Common Shares offered pursuant to the Placing. The 2004 Convertible Notes mature and are due and payable by the Company on 15 March 2005. Interest accrues on the loan notes at the rate of 12 per cent per annum. The 2004 Convertible Notes are convertible into Common Shares at any time up to the date of maturity of the loan notes. Further details of the 2004 Convertible Note Purchase Agreement and the 2004 Convertible Notes are set out in paragraph 8.8 of this Part VIII.

4. Certificate of Incorporation and Bylaws

4.1 Certificate of Incorporation

The following is a brief summary of certain material provisions of the Company's Restated Certificate of Incorporation, as will be in effect immediately prior to the Placing:

(a) The purpose of the Company is to engage in any lawful act or activity for which a corporation may be organized under the DGCL.

(b) The Company is authorised to issue 210,000,000 shares, consisting of 200,000,000 Common Shares and 10,000,000 Preferred Shares at the date of this document.

(c) The management of the business and the conduct of the affairs of the Company are vested in the Board. The number of Directors shall be such number, not less than one or more than fifteen (exclusive of any directors elected by holders of Preferred Shares), as shall be provided from time to time by resolution adopted by the Board.

(d) Each Director shall serve until his successor is duly elected and qualified or until his death, resignation or removal. No decrease in the number of Directors constituting the Board shall shorten the term of any incumbent Director. Exclusive of Directors, if any, elected by holders of Preferred Shares, vacancies on the Board, however caused, and newly created directorships shall be filled by a vote of two-thirds of the Directors then in office, whether or not a quorum.

(e) The Board is divided into three classes, Class I, Class II and Class III. Directors elected to each respective class serve for three years.

(f) Nominations for the election of Directors and proposals for any new business to be taken up at any annual or special meeting of Shareholders may be made by the Board or by any Shareholder entitled to vote generally in the election of Directors. In order for a Shareholder to make any such nominations or proposals, he or she is required to give notice thereof in writing, delivered or mailed by first class United States mail, postage prepaid, to the Company Secretary not less than thirty days nor more than sixty days prior to any such meeting; provided, however, that if less than forty days notice of the meeting is given to Shareholders, such written notice shall be delivered or mailed, as prescribed, to the Company Secretary not later than the close of the tenth day following the day on which notice of the meeting was mailed to Shareholders.

Each notice given by a Shareholder with respect to nominations for the election of Directors shall set out: (i) the name, age, business address and, if known, residence address of each nominee proposed in such notice; (ii) the principal occupation or employment of each such nominee; and (iii) the number of shares in the Company which are beneficially owned by each such nominee. In addition, the Shareholder making such nomination shall promptly provide any other information reasonably requested by the Company.

(g) Any Director or all the Directors of a single class (but not the entire Board) may be removed, at any time, but only for cause and only by the affirmative vote of the holders of at least 75 per cent of the voting power of the outstanding share capital entitled to vote generally in the election of the Directors (considered for this purpose as one class). Notwithstanding the foregoing, whenever the holders of any one or more series of Preferred Shares have the right, voting separately as a class, to elect one or more Directors, the preceding shall not apply with respect to the Director or Directors elected by such holders of Preferred Shares.

(h) No Director shall be personally liable to the Company or its shareholders for damages for breach of any fiduciary duty owed to the Company or its shareholders, except for liability: (i) for any breach of such person's duty of loyalty to the Company or its shareholders; (ii) for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law; (iii) under Section 174 of the DGCL, which involves unlawful declarations of dividends or other distributions of assets to shareholders or the unlawful purchase of shares of the Company; or (iv) for any transaction from which the Director derived an improper personal benefit. If the DGCL is subsequently amended to permit further limitations on the personal liability of the Directors, then the liability of a Director shall be eliminated or limited to the fullest extent permitted by the DGCL, as so amended. Any repeal or modification of the provision regarding limitation of liability shall be prospective and shall not affect the rights in effect under that provision at the time of the alleged occurrence of any act or omission to act giving rise to liability or indemnification.

(i) The Board may adopt, alter, amend, repeal or rescind the Bylaws by a vote of two thirds of the Board. The Bylaws may also be adopted, altered, repeated, amended or rescinded by an affirmative vote of the holders of not less than 75 per cent of the voting power of the Company's outstanding share capital entitled to vote generally in the election of Directors.

(j) Special meetings of shareholders may be called at any time by the Board or a committee thereof.

(k) No action shall be taken by the shareholders by written consent unless the action to be effected by written consent and the taking of such action by written consent have been expressly approved in advance by the Board.

(l) Except as provided below, the Restated Certificate of Incorporation prohibits Frontera from engaging in certain ''business combinations'' with any ''related person'', unless:

(i) such business combination has been approved by at least 75 per cent of the voting power of the outstanding share capital entitled to vote thereon (and if any class or series of shares is entitled to vote thereon separately, the affirmative vote of at least 75 per cent of the outstanding share capital of each such class or series); and

(ii) such business combination has been approved by a majority of the voting power of the outstanding share capital entitled to vote thereon, other than those shares beneficially owned by such related person.

''Business combination'' includes any merger or consolidation involving a related person; any sale, transfer, pledge or other disposition of 25 per cent or more of the assets of the Company involving a related person; any merger or consolidation of a related person with or into the Company or a subsidiary thereof; any sale, transfer, pledge or other disposition of 25 per cent or more of the assets of the related person to the Company; any issuance of the Company's securities (or any securities of a subsidiary thereof) to a related person other than on a pro rata basis; any transaction involving the Company that has the effect of increasing by more than 1 per cent the proportionate share of the stock or any class or series beneficially owned by a related person; or the acquisition by the Company or any subsidiary thereof of any securities of a related person.

''Related person'' is generally defined as an entity or person beneficially owning 10 per cent or more of the outstanding Common Shares or any entity or person affiliated with or controlling or controlled by such entity or person.

However, the approval requirements set out above are not applicable to any particular business combination, and such business combinations shall require only such affirmative vote as is required by any other provision of the Restated Certificate of Incorporation, any provision of law, or any agreement with any regulatory agency or national securities exchange, if the business combination has been approved in advance by a two-thirds vote of the ''continuing directors''; provided, however, that such approval shall only be effective if obtained at a meeting at which a continuing director quorum is present. The term ''continuing director'' means any member of the Board who is unaffiliated with and who is not the related person and was a member of the Board prior to the time that the related person became a related person, and any successor of a continuing director who is unaffiliated with and who is not the related person and is recommended to succeed a continuing director by a majority of continuing directors.

(m) Frontera may from time to time, pursuant to authorisation by the Board and without action by the Shareholders, purchase or otherwise acquire shares of any class, bonds, debentures, notes, scrips, warrants, obligations, evidences of indebtedness, or other securities of Frontera in such manner, upon such terms, and in such amounts as the Board shall determine; subject, however, to such limitations or restrictions, if any, as are contained in the express terms of any class of shares of Frontera outstanding at the time of the purchase or acquisition in question or as are imposed by law.

4.2 Bylaws

The following is a brief summary of certain material provisions of the Bylaws:

(a) The number of Directors may be changed by resolution of the Board, subject to the approval and concurrence of two-thirds of the Directors then in office.

(b) Any Director or all the Directors of a single class (but not the entire Board) may be removed, at any time, but only for cause and only by the affirmative vote of the holders of at least 75 per cent of the voting power of the outstanding share capital entitled to vote generally in the election of the Directors (considered for this purpose as one class). Notwithstanding the foregoing, whenever the holders of any one or more series of Preferred Shares has the right, voting separately as a class, to elect one or more Directors, the preceding shall not apply with respect to the Director or Directors elected by such holders of Preferred Shares.

(c) Any vacancy occurring in the Board (by death, resignation, removal, increase in the number of directors or otherwise) may be filled by an affirmative vote of two-thirds of the remaining (or then-serving) Directors, even if the remaining (or then-serving) Directors are less than a quorum of the Board. A Director elected to fill a vacancy or a new seat on the Board shall be elected for a term expiring at the next annual meeting of Shareholders at which the term of the class to which the Director has been chosen expires and when the Director's successor is elected and qualified. If the entire Board is vacant, the vacancies shall be filled at any special or annual meeting of Shareholders, by the affirmative vote of a majority in number of shares of the Shareholders present, in person or by proxy, at the meeting and entitled to vote for the election of Directors.

(d) Shareholders must receive written notice of every meeting of Shareholders not less than ten or more than fifty days before the date of such meeting.

(e) No action shall be taken by the Shareholders by written consent unless the action to be effected by written consent and the taking of such action by written consent have been expressly approved in advance by the Board.

(f) The holders of a majority of the shares entitled to vote at the meeting, present in person or represented by proxy, shall constitute a quorum at all meetings of the Shareholders, except as otherwise provided by law, by the Certificate of Incorporation or by the Bylaws.

(g) At any meeting of the Shareholders, every Shareholder having the right to vote may vote either in person, or by proxy executed in writing by the Shareholder or by his duly authorised attorney-in-fact. No proxy shall be valid after eleven months from the date of its execution, unless otherwise provided in the proxy. Each proxy shall be revocable unless expressly provided therein to be irrevocable or unless otherwise made irrevocable by law. Each proxy shall be filed with the Company's secretary prior to or at the time of the meeting. Any vote may be taken by voice or by show of hands unless someone entitled to vote objects, in which case written ballots should be used.

(h) The Bylaws may be altered, amended, or repealed at any meeting of the Board at which a quorum is present, by the affirmative vote of two-thirds of the Board, provided notice of the proposed alteration, amendment, or repeal is contained in the notice of the meeting and such action does not specifically require the action of the Shareholders by virtue of the Certificate of Incorporation or the Bylaws. The Bylaws may be altered, amended or repealed at any meeting of the Shareholders at which a quorum is present or represented, by the affirmative vote of the holders of not less than 75 per cent of the voting power of the Company's outstanding share capital entitled to vote generally in the election of Directors (considered for this purpose as one class), provided that notice of the proposed alteration, amendment or repeal is contained in the notice of the meeting.

(i) At meetings of the Board, a quorum for the transaction of business will be constituted by a majority of the Directors. Save as otherwise provided by statute, the Certificate of Incorporation or the Bylaws, the act of a majority of the Directors present at any meeting at which there is a quorum will be an act of the Board. If a quorum is not present at any meeting of the Board, the Directors present may adjourn the meeting from time to time to another place, time or date, without notice other than an announcement at the meeting, until a quorum is present.

(j) The Company shall have a president, one or more vice presidents, a secretary, a treasurer, and such other officers (including a chairman of the Board, chief executive officer, or chief financial officer) and assistant officers and agents as the Board determines.

(k) The president shall have general and active management of the business and affairs of the Company, and shall see that all orders and resolutions of the Board are carried into effect. He shall supervise all other officers and employees of the Company. He is authorised to: exercise the authority delegated to him in Frontera's management handbook approved by the Board; manage the properties and business of the Company; hire employees; discharge employees, including officers elected by the Board; sign all notes, trust deeds, assignments, pledges, chattel mortgages and documents required by a lender in connection with debt authorised by resolution of the Board, including debt authorised by the consent of the Board in lieu of a first meeting; purchase or authorise the purchase of all goods, wares, merchandise, equipment, supplies and machinery required in the transaction of the business of the Company; sue on behalf of the Company; employ attorneys on behalf of the Company; and determine the purchase and sales price of all goods, wares, merchandise and commodities purchased or sold from the resources of the Company. He shall perform such other duties and have such other authority and powers as the Board may from time to time prescribe.

(l) The Company shall register the transfer of a certificate for shares presented to it for transfer if the certificate is properly endorsed by the registered owner or by its duly authorised attorney and the Company has no notice of an adverse claim or has discharged any duty to inquire in to such a claim.

(m) No Shareholder or other person shall have any preemptive right whatsoever unless (i) agreed to in writing on behalf of the Company and approved by not less than 75 per cent of the Directors then in office or (ii) provided for in the Restated Certificate of Incorporation.

(n) Shares (both treasury and authorised but unissued) may be issued for such consideration (not less than par value) and to such persons as the Board may determine from time to time. Shares may not be issued until the full amount of the consideration, fixed as provided by law, has been paid.

(o) The Company will not register any transfer of the Common Shares not made in accordance with the provisions of Regulation S under the US Securities Act, pursuant to registration under the US Securities Act, or pursuant to an available exemption from registration under the US Securities Act.

4.3 Restrictions on transferability of Common Shares

Details on the US restrictions on transferability of the Common Shares are set out in Part VII.

5. Directors' and others' interests in Common Shares

5.1 The interests of the Directors (all of which are beneficial unless otherwise stated) and (so far as is known to the Directors or could with reasonable diligence be ascertained by them) persons connected with the Directors within the meaning of section 346 of the Act (a "connected person") in the issued share capital of the Company as at the date of this document and which, if the Company were subject to the Act, would be required to be notified to the Company pursuant to sections 324 and 328 of the Act or shown in the register maintained under section 325 of the Act (but excluding any options over Common Shares), are or will be as follows:

	As at the date of this document			Following the Placing		Fully Diluted Common Share Capital	
	No. of Preferred Shares	No. of Common Shares	Percentage of Common Shares(2)	No. of Common Shares	Percentage of Enlarged Issued Common Share Capital(3)	No. of Common Shares	Percentage of Fully Diluted Common Share Capital
Lan Bentsen(1)	57,266	1,363,104	7.87	1,684,530	3.40	2,465,909	3.32
Spyros N. Karnessis(1)	357,497	138,863	14.80	3,167,215	6.41	5,022,016	6.77
Stephen E. McGregor	43,000	0	0.93	199,520	0.40	801,690	1.08
Steve C. Nicandros(1)	84,517	978,425	6.77	1,449,659	2.93	4,626,747	6.23
Andrew J. Szescila	—	—	—	—	—	25,000	0.03

Notes:

(1) Includes shares held by connected persons.

(2) Assuming that the conversion of the Preferred Shares into Common Shares had occurred as at the date of this document.

(3) Assuming that no outstanding options, warrants or convertible loan notes over or in respect of the Common Shares are exercised or converted (as applicable) after the date of this document and on or before the Placing.

5.2 As at the date of this document the following options had been granted to Directors (or their connected persons) under the 1998 Plan and the 2000 Plan:

Director	No. of Common Shares under option	Exercise price range	Expiry date ranges
Lan Bentsen	775,000	\$1.00 - \$2.00	29/6/2010 - 30/12/2013
Spyros N. Karnessis	33,000	\$1.00 - \$2.00	29/6/2010 - 30/12/2013
Stephen E. McGregor	467,500	\$1.00	29/6/2010 - 30/12/2013
Steve C. Nicandros	1,267,500	\$1.00 - \$2.00	29/6/2010 - 30/12/2013
Andrew J. Szescila	25,000	\$1.00	31/8/2014

5.3 As at the date of this document the following Directors (or their connected persons) have rights to exercise warrants in respect of the Common Shares:

Director	Number of warrants	Number of Common Shares upon exercise	Exercise Price (per share)	Expiry date
Lan Bentsen(1)	50,000	50,000	\$ 1.00	14/05/2006
	12,562	392,575	\$0.032	21/12/2006
Spyros N. Karnessis(1)	225,000	225,000	\$ 1.00	14/05/2006
	51,097	1,596,800	\$0.032	21/12/2006
Stephen E. McGregor	50,000	50,000	\$ 1.00	14/05/2006
	2,709	84,670	\$0.032	21/12/2006
Steve C. Nicandros(1)	50,000	50,000	\$ 1.00	14/05/2006
	59,506	1,859,585	\$0.032	21/12/2006
Andrew J. Szescila	—	—	—	—

Note:

(1) Includes warrants held by connected persons.

5.4 As at the date of this document, the following Directors (or their connected persons) hold loan notes convertible into Common Shares:

Director	Amount outstanding (including interest)	No. of Common Shares convertible into[1]
Spyros N. Karnessis[2]	1,232,000	533,139

Notes:

(1) Calculated on the basis of 80 per cent of the Placing Price.

(2) Held by a connected person.

6. Additional information on the Directors

6.1 Other than their directorships of the Company, the current directorships and partnerships of the Directors and partnerships held by them in the five years preceding the date of this document are as follows:

Director	Current Directorships/Partnerships	Past Directorships/Partnerships
Lan Bentsen	Car Wash Headquarters (directorship) 125/518, Ltd (partnership) Rincon Ventures, Ltd. (partnership)	Little Bay Web Works (directorship) Lab Holdings (directorship) Seafield Capital Corporation (directorship) Saginaw Partners, Ltd (partnership)
Spyros N. Karnessis	European Navigation Inc.	—
Stephen E. McGregor	—	Key Energy Services Marcum Natural Gas Metretek, Inc Harbor Capital Bank Contour Energy Services SEM Consulting, Inc.
Steve C. Nicandros	—	—
Andrew J. Szescila	—	—

6.2 Loans by the Directors

The Directors have made the following loans to the Company:

Director	Details of loan notes		
	Description	Due Date	Amount outstanding (including accrued interest) ($) (2)
Lan Bentsen	12 per cent Senior Note	14/5/2006	108,734
	Management Promissory Note	15/4/2005	34,275
	Management Promissory Note	15/4/2005	83,739
	Management Promissory Note	15/4/2005	10,718
	Management Promissory Note	15/4/2005	69,019
Spyros N. Karnessis	2004 Convertible Notes(1)	5/3/2005	1,232,000
	12 per cent Senior Notes(1)	14/5/2006	485,535
	Management Promissory Note(1)	15/4/2005	159,966
	Management Promissory Note(1)	15/4/2005	309,208
Stephen E. McGregor	12 per cent Senior Note(1)	14/5/2006	108,711
	Management Promissory Note(1)	15/4/2005	93,068
	Management Promissory Note(1)	15/4/2005	237,685
Steve C. Nicandros	12 per cent Senior Note(1)	14/5/2006	108,648
	Management Promissory Note(1)	15/4/2005	159,211
	Management Promissory Note	15/4/2005	148,420
	Management Promissory Note(1)	15/4/2005	52,691
	Management Promissory Note(1)	15/4/2005	73,469
	Management Promissory Note(1)	15/4/2005	33,609
	Management Promissory Note(1)	15/4/2005	127,635
	Management Promissory Note(1)	15/4/2005	76,321
	Management Promissory Note(1)	15/4/2005	262,576
Andrew J. Szescila	—	—	—

Notes:

(1) Owing and payable to a connected person.

(2) Figures shown are as at 11 March 2005 (the estimated date of repayment of the loan notes).

Each of the loans set out above will be repaid in the period immediately following Admission out of the proceeds of the Placing.

6.3 None of the Directors have any unspent convictions for indictable offences nor have any of the Directors been the subject of any public criticisms by statutory or regulatory authorities (including recognised professional bodies) and none of them have ever been disqualified by a court from acting as a director of, or from acting in the management or conduct of the affairs of any company.

6.4 None of the Directors has been a director of a company at the time of, or within the twelve months preceding, the commencement of a receivership, liquidation, administration, company voluntary arrangement or a composition or arrangement with creditors of that company or a partner of a partnership at the time of or within the twelve months preceding any compulsory liquidation, administration, receivership or partnership voluntary arrangement of that partnership. None of the Directors is or has been bankrupt or has made an individual voluntary arrangement with his creditors, or suffered the appointment of a receiver over any of his assets.

7. Directors' contracts, employment agreements and emoluments

7.1 *Messrs. Steve Nicandros and Lan Bentsen*

Messrs. Nicandros and Bentsen are employed pursuant to executive employment agreements with the Company both dated 1 April 1998. Mr. Nicandros' role is President and Chief Executive Officer of Frontera. Mr. Bentsen's role is Executive Vice President of Frontera. Mr. Nicandros' current annual salary is $252,000 and Mr. Bentsen's current annual salary is $201,600. The contracts do not provide for a bonus but specify the Directors' right to stock options in the Company. Both Messrs. Nicandros and Bentsen are entitled to three weeks annual holiday.

Both contracts prohibit conflicts of interest, contain confidentiality obligations, protect Frontera's rights to intellectual property created by the Director in the course of his employment and contain a limited non-competition clause. Each contract is for an initial term of six months continuing thereafter until terminated by either party. Disputes arising under the contracts are subject to mandatory binding arbitration. If the Director is discharged without cause, he is entitled to severance compensation, at the same rate in effect at the time of discharge, until 12 months after termination.

If a change of control of the Company occurs and if either (i) the Director's employment is terminated or (ii) the Director resigns after his terms and conditions of employment relating to, *inter alia*, his responsibility, position, salary and benefits have been altered in a manner detrimental to the Director without his consent, then the Director is entitled to payment of salary and bonus (if any bonus has previously been paid) and specified insurance benefits, until three years after termination of employment. Change of control is defined as the date that the Board declares that: (i) a person has acquired 30 per cent of the voting shares of the Company; (ii) there is a complete change to the Board or a significant change to the officers of the Company; (iii) certain insolvency events occur; and (iv) a "business combination" within an "interested stockholder" has occurred under the DGCL. The same provisions may apply to termination of a Director's employment or resignation by the Director up to six months before a change of control if the event was in connection with an anticipated change of control.

Mr. Nicandros and Mr. Bentsen receive a benefits package consisting of personal health insurance and the right to participate in the Group's dependent health insurance policy, dental, vision, disability, accident or death and life insurance programmes.

7.2 *Mr. Stephen E McGregor*

Mr. McGregor is engaged by Frontera pursuant to the terms of an engagement agreement with SEM Consulting. Details of this arrangement are set out in paragraph 8.5 of this Part VIII.

7.3 *Mr. Spyros N Karnessis and Mr. Andrew J Szescila*

Mr. Spyros N Karnessis and Mr. Andrew J Szescila serve as Directors but do not have in place any employment or service agreement. The Company remunerates these Directors by way of grant of stock options on a discretionary basis. The Company intends to continue this arrangement following Admission.

7.4 *Directors' emoluments*

The aggregate emoluments of the Directors (including benefits in kind) for the year ended 31 December 2004 amounted to $659,979.

The aggregate emoluments of the Directors for the financial period ending 31 December 2005 under arrangements in force at the date of this document will be approximately $700,000.

8. Material Contracts

Save as set out in this document, the following are the only contracts (being contracts otherwise than in the ordinary course of business) which have been entered into by members of the Group within the two years immediately preceding the date of this document and are or may be material to the Group or have been entered into by any member of the Group at any time and contain any provision under which any member of the Group has any obligation or entitlement which is material to the Group at the date of this document.

8.1 Block 12 PSA & Mineral Licence

A summary of the Block 12 PSA and the Mineral Licence is set out in Part VI.

8.2 Placing arrangements

8.2.1 *Placing Agreement*

MSIL, the Company and the Directors have entered into a placing agreement dated 9 March 2005, whereby the Company will issue and MSIL will conditionally procure subscribers for 28,000,000 Common Shares as agent and, failing which, will itself conditionally subscribe for such Common Shares.

In addition, the Company has granted an option (the "Over-allotment Option") to MSIL pursuant to which, subject to certain conditions, at MSIL's request the Company will issue and MSIL will procure subscribers (or itself subscribe) for up to 5,000,000 Common Shares for the purposes of allowing MSIL to meet over-allotments, if any, in connection with the Placing and to cover any short positions resulting from stabilisation transactions (the "Over-allotment Arrangements"). The number of Common Shares to be issued pursuant to the Over-allotment Option, if any, will be determined no later than 30 days from Admission (the "Option Closing Date"). Settlement of the Over-allotment Option will take place shortly after the exercise of the Over-allotment Option.

In consideration for its services under the Placing Agreement, MSIL will receive a commission of 5½ per cent of the amount equal to the issue price of the Common Shares issued to placees procured by MSIL or to MSIL itself under the Placing Agreement multiplied by the number of such Common Shares. The Company may also, in its absolute discretion, pay to MSIL a further commission of one per cent of the aggregate proceeds received by the Company in connection with the Placing. These commissions are payable in cash.

The obligations of MSIL under the Placing Agreement are conditional upon, amongst other things: (i) the Company and each of the Directors having complied with all their obligations and having satisfied all conditions to be satisfied by any of them under the Placing Agreement and certain other documents which fall to be performed or satisfied on or prior to Admission; (ii) Admission having occurred; (iii) there having occurred no material adverse change in the business of the Company or the Group; and (iv) the conversion of all of the Preferred Shares into Common Shares.

The Placing Agreement contains warranties given by the Company and the Directors as to the accuracy of the information contained in this document and other matters relating to the Group and its business. The Company has also agreed to indemnify MSIL and its affiliates and their respective directors, officers and employees against certain liabilities that they may incur under the Placing Agreement.

The Placing Agreement contains certain undertakings given by the Company to MSIL. These include an undertaking to take all such actions as MSIL may require in order to enable the Common Shares to be settled through CREST (or another similar system for paperless settlement of trades) if it becomes possible for the settlement of the Common Shares to be effected in that manner without the Company, the transferors or the transferees of such shares breaching any of the requirements of Regulation S of the US Securities Act.

In addition, the Company has undertaken that it shall not, without MSIL's prior written consent, between the date of the Placing Agreement and the date falling 360 days after the date of Admission: (i) declare, make or pay any dividend or other distribution on any of its share capital; (ii) subject to certain limited exceptions, enter into any agreement or arrangement or do or permit to be done any act or thing which may involve any increase in, or obligation (whether contingent or otherwise) to issue, allot, or grant options over, shares in the capital of the Company (other than on the exercise after the date of the Placing Agreement of options, warrants or rights under other securities convertible into shares granted prior to the date of the Placing Agreement); (iv) offer, pledge, sell, contract to sell, lend, or otherwise transfer or dispose of, directly or indirectly, any shares or any securities convertible into or exercisable or exchangeable for shares in the capital of the Company (including in each case shares held in the form of treasury shares); or (v) enter into any swap or other arrangement that transfers to another, in whole or in part, any of the economic consequences of ownership of any shares in the capital of the Company. The foregoing does not, however, apply to the transfer of Common Shares by the Company to or at the direction of MSIL under the Stock Lending Agreement.

MSIL has the right to terminate the Placing Agreement at any time on or before the Option Closing Date including where, amongst others things (i) it becomes impracticable or inadvisable to proceed with the Placing; (ii) there is a material adverse change in the business; (iii) the Company or any Director is in breach of its obligations under the Placing Agreement; or (iv) there is a breach of the warranties. If the Placing Agreement is terminated in such circumstances, the Company shall pay to MSIL any fees, commission and expenses incurred before such termination. No commission will be payable if no Common Shares are issued or sold pursuant to the Placing Agreement.

8.2.2 *Stock Lending Agreement*

In connection with the Over-allotment Arrangements, the Company has entered into a stock lending agreement (the "Stock Lending Agreement") with MSIL under which MSIL is able (but is not obliged) to borrow from the Company up to 5,000,000 Common Shares held by the Company in the form of treasury shares. The purpose of the loan is, amongst other things, to allow MSIL to settle, at Admission, any over-allotments made in connection with the Placing. If MSIL borrows any Common Shares under the Stock Lending Agreement it will be required to return equivalent securities to the Company by no later than 3 May 2005 (unless the Company and MSIL agree an earlier date).

8.3 Nominated Adviser and Broker Agreement

The Company, MSIL and MSSL have entered into a nominated adviser and broker agreement dated 9 March 2005 under which MSIL has accepted its appointment as the Company's nominated adviser and MSSL has accepted its appointment as the Company's broker in each case for the purpose of the AIM Rules. The Company will pay MSIL and MSSL an aggregate yearly fee of £40,000 in addition to the costs and expenses incurred by MSIL and MSSL in carrying out their obligations under the agreement. The agreement contains certain undertakings, confirmations and indemnities given by the Company to each of MSIL and MSSL. The agreement will terminate automatically if Admission does not take place by 21 March 2005. The appointment of MSIL and

MSSL may be terminated by the Company (on the one hand) and MSIL or MSSL (on the other) on immediate notice.

8.4 Lock-up and Orderly Trading Arrangements

Lock-up arrangements have been entered into by (i) the Directors and certain senior managers (such Directors and senior managers being referred to as the ''Lock-up Managers'') holding approximately 32 per cent of the Pre-Admission Share Capital, and (ii) certain Shareholders (excluding the Lock-up Managers) holding in aggregate approximately 58 per cent of the Pre-Admission Share Capital (the ''Lock-up Shareholders''), in each case in respect of all of the Common Shares held by all such persons, including any shares which may be acquired in the future through the exercise of any existing options, warrants or other securities convertible into Common Shares. In aggregate, these lock-up arrangements are binding on approximately 90 per cent of all of the Pre-Admission Share Capital.

The Lock-up Managers and Lock-up Shareholders have agreed (subject to certain limited exceptions), for the period up to and including the date 360 days after Admission (the ''Lock-up Period''), without the prior written consent of MSIL not to (i) offer, lend, sell, deposit, contract to sell, mortgage, pledge, create liens over, charge, assign, create any other security interest or equity over, issue options, warrants or other derivative instruments in respect of, or grant any option to purchase, or otherwise dispose of, directly or indirectly, any Common Shares held by them at any time during the Lock-up Period (or any other securities convertible into or exchangeable for Common Shares or which carry rights to subscribe for or purchase Common Shares or any interest therein or in respect thereof, including any warrants in issue from time to time); (ii) enter into any swap or other arrangement which transfers to another, in whole or in part, the economic consequences of ownership of any Common Share or any interest therein; or (iii) announce any intention to do, or agree to do, any of the foregoing.

During the period of 180 days immediately following the Lock-up Period, each Director and Lock-up Shareholder has agreed that, if immediately prior to Admission such Director or Lock-up Shareholder holds together with his/its Associates (as such term is defined in section 435 of the Insolvency Act 1986) more than 3 per cent of the Pre-Admission Share Capital, he/it will consult in good faith with MSIL at least 5 business days prior to selling any Common Shares held by that Director and Lock-up Shareholder and his/its Associates, including allowing for representations to be made to that Director and Lock-up Shareholder concerning the timing of any such sale of Common Shares and the possibility of shareholder sales of Common Shares being aggregated. The Directors and Lock-up Shareholders have agreed to take all reasonable steps to ensure that all of their Associates implement these orderly trading arrangements.

After the first 180 days of the Lock-up Period, MSIL may, in its sole discretion, waive in respect of any specifically identified securities, the lock-up and orderly trading arrangements agreed by the Lock-up Shareholders if MSIL concludes that to do so would be appropriate and would not disrupt the orderly trading of the Common Shares. The lock-up and orderly trading arrangements will continue to apply to all other securities which are not the subject of such waiver.

The Lock-up Managers, the Lock-up Shareholders and the Company have given certain representations and warranties to MSIL in connection with the lock-up and orderly trading arrangements described above.

8.5 Engagement agreement with SEM Consulting

The Company entered into an engagement agreement dated 5 March 2001 with SEM Consulting (the ''Engagement Agreement'') to assist Frontera in raising capital through either a strategic investment by Frontera, an initial public offering (''an IPO'') or through a merger or takeover (each a ''Transaction''). Mr. McGregor's role in the engagement is to provide Frontera's management with strategic financial advice and assistance. Mr. McGregor's current engagement agreement dated 5 June 2003, which is an extension of the Engagement Agreement, expires on 30 April 2005 with either party entitled to terminate the contract upon 15 days' written notice.

SEM Consulting shall be entitled to a success fee if its performance results in Frontera successfully completing a Transaction. If an IPO occurs, SEM Consulting shall be entitled to a success fee of 1 per cent of the proceeds of the IPO. If a merger or takeover occurs, SEM Consulting shall be entitled to a success fee as an investment adviser of 0.5 per cent of the total value of Frontera immediately before the merger or takeover. If a private placement of the Company's securities (excluding an initial public offering or takeover) or a loan or extension of credit is provided to Frontera, SEM Consulting shall be entitled to a success fee of 5 per cent of the gross proceeds of the placing, loan or credit extension.

SEM Consulting is entitled to a monthly engagement fee of $15,125 which remains payable for 6 months after the completion of a Transaction. Under the Engagement Agreement, the Company agreed to grant SEM Consulting options to purchase Common Shares. Further details of the options granted to Mr. McGregor are set out in paragraph 5.2 of this Part VIII.

If the Company terminates the Engagement Agreement other than for cause before completion of a Transaction, SEM Consulting shall be entitled to the aggregate monthly engagement fee for the remaining term of the agreement, provided that the payment does not exceed $120,000. For a period of six months after termination SEM Consulting shall be entitled to the success fee if Frontera enters into a Transaction within that period which was initiated and developed during the period of the Engagement Agreement prior to termination.

Frontera agrees to indemnify SEM Consulting and Mr. McGregor from and against any losses, claims, demands, damages or liability of any kind relating to or arising out of the activities and services performed pursuant to the Engagement Agreement.

8.6 Amended and Restated Note Purchase Agreement dated 1 September 2002 and related agreements

In August 2001 the Company raised approximately $3,900,000 net of fees from the issue of four promissory notes (the "15 per cent Senior Notes"). On 1 September 2002 the 15 per cent Senior Notes were amended to increase the aggregate principal amount due to $4,000,000, remove an upward adjusting interest rate, amend certain covenants and issue new promissory notes and the 2002 Warrants. The Company issued the amended and restated 15 per cent Senior Notes (the "Amended 15 per cent Senior Notes") pursuant to the terms of an Amended and Restated Note Purchase Agreement dated 1 September 2002 (the "2002 Amended Note Purchase Agreement"). The purchasers of the Amended 15 per cent Senior Notes were three funds managed by DDJ Capital Management, LLC ("DDJ"), a stockholder with a position on the Board.

Interest on the Amended 15 per cent Senior Notes accrues from the date of original issuance or, if interest has already been paid, from the date it was most recently paid, at a rate of 15 per cent per annum and is payable quarterly in arrear. The Company may only redeem the Amended 15 per cent Senior Notes after having given the required notice under the 2002 Amended Note Purchase Agreement. No premium or penalty is payable upon such redemption, which need not be in full provided each partial redemption is in the aggregate principal amount of not less than $500,000.

The Amended 15 per cent Senior Notes are subject to mandatory prepayment provisions under certain circumstances, including if Frontera International receives a dividend or other such "restricted payment" or if gross income received by the Group from operations exceeds $1.8 million in any calendar month. The 2002 Amended Note Purchase Agreement provides significant restrictions on the ability of the Group to incur debt, issue guarantees, declare or pay dividends, make investments, create or incur liens, consolidate, merge or sell its assets, enter into transactions with affiliates, transport certain hazardous substances, violate any environmental law or regulation, amend its charter documents (including its bylaws) and engage in certain transactions under ERISA.

As at 31 December 2004, the Company was in default under the 2002 Amended Note Purchase Agreement due to its failure to pay interest and principal on the Amended 15 per cent Senior Notes and certain other loan notes, a cross default resulting from the Company's default under the 2003 Amended Note Purchase Agreement (see paragraph 8.7 of this Part VIII) and breaches of covenant under the Amended 2002 Note Purchase Agreement.

As a result of these defaults, the 2002 Amended Note Purchase Agreement and the Amended 15 per cent Senior Notes were amended on 31 December 2004 to allow the Company, at its option, to accrue quarterly interest payments or make such payments in cash and to provide that the Amended 15 per cent Senior Notes accelerate in full and become immediately due and payable ten business days following closing of an initial public offering of the Company's securities. In addition, pursuant to the terms of a letter agreement of the same date, the holders of the Amended 15 per cent Senior Notes waived any prior default by the Company under the 2002 Amended Note Purchase Agreement and consented to certain amendments to the Company's Restated Certificate of Incorporation to increase the authorised Common Share capital of the Company and amend the certificates of designations for each series of Preferred Shares outstanding.

8.7 Amended Note Purchase Agreement dated 24 March 2004 and related agreements

In May 2003 the Company issued loan notes in the aggregate principal amount of $6,000,000 (the "12 per cent Senior Notes") pursuant to the terms of a note purchase agreement dated 14 May 2003 ("2003 Note Purchase Agreement"). The purchasers of the 12 per cent Senior Notes were a syndicate that included two funds managed by DDJ, two Directors, parties connected to two of the Directors and Baker Hughes Finance, Incorporated, a shareholder with a position on the Board. The 12 per cent Senior Notes were issued at the same time as the 2003 Warrants and mature on 14 May 2006 when they become immediately due and payable in full.

Interest on the 12 per cent Senior Notes accrues from the date of original issuance or, if interest has already been paid, from the date it was most recently paid, at a rate of 12 per cent per annum and is payable quarterly in arrear. The Company may only redeem the 12 per cent Senior Notes after having given the required notice under the 2003 Note Purchase Agreement. No premium or penalty is payable upon such redemption, which need not be in full provided each partial redemption is in the aggregate principal amount of not less than $500,000.

The 12 per cent Senior Notes are subject to mandatory prepayment provisions under certain circumstances, including if Frontera International receives a dividend or other "restricted payment" or if gross income received by the Group from operations exceeds $1.8 million in any calendar month. The 2003 Note Purchase Agreement provides significant restrictions on the ability of the Group to incur debt, issue guarantees, declare or pay dividends, make investments, create or incur liens, consolidate, merge or sell its assets, enter into transactions with affiliates, transport certain hazardous substances, violate any environmental law or regulation, amend its charter documents (including its bylaws) and engage in certain transactions under ERISA.

As at 31 December 2004, the Company was in default under the 2003 Note Purchase Agreement due to its failure to pay interest on the 12 per cent Senior Notes, a cross default resulting from the Company's default under the 2002 Amended Note Purchase Agreement and certain other loan notes and breaches of the covenant limiting the Company's ability to incur debt provided in the 2003 Note Purchase Agreement. In addition, the Company was prohibited from entering into the 2003 Note Purchase Agreement due to certain financial covenants set out in the 2002 Amended Note Purchase Agreement.

As a result of these defaults, the 2003 Note Purchase Agreement and the 12 per cent Senior Notes were amended on 31 December 2004 to allow the Company, at its option, to accrue quarterly interest payments or make such payments in cash and provide that the 12 per cent Senior Notes accelerate in full and become immediately due and payable ten business days following the closing of an initial public offering of the Company's securities. In addition, the holders of the 12 per cent Senior Notes waived any prior default under the 2003 Note Purchase Agreement as set out above and consented to certain amendments to the Company's Restated Certificate of Incorporation to increase the authorised Common Share capital and the certificates of designations for each series of Preferred Shares outstanding.

8.8 2004 Convertible Note Purchase Agreement and related agreements

In December 2004 the Company issued 12 per cent Convertible Notes (the "2004 Convertible Notes") in the aggregate principal amount of $2,500,000 pursuant to the terms of a note purchase agreement dated 20 December 2004 (the "2004 Convertible Note Purchase Agreement"). The 2004 Convertible Notes mature on 15 March 2005 when they become repayable in full. A syndicate made up of three funds controlled by DDJ purchased the 2004 Convertible Notes.

Interest on the 2004 Convertible Notes accrues from the date of original issuance or, if interest has already been paid, from the date it was most recently paid, at a rate of 12 per cent per annum and is payable quarterly in arrear. The Company may only redeem the 2004 Convertible Notes after having given the required notice under the 2004 Convertible Note Purchase Agreement. No premium or penalty is payable upon such redemption, which need not be in full provided each partial redemption is in the aggregate principal amount of not less than $500,000.

The 2004 Convertible Notes are subject to mandatory prepayment provisions under certain circumstances, including if Frontera International receives a dividend or other "restricted payment" or if gross income received by the Group from operations exceeds $1.8 million in any calendar month. The 2004 Convertible Note Purchase Agreement provides significant restrictions on the ability of the Group to incur debt, issue guarantees, declare or pay dividends, make investments, create or incur liens, consolidate, merge or sell its assets, enter into transactions with affiliates, transport certain hazardous substances, violate any environmental law or regulation, amend its charter documents (including its bylaws) and engage in certain transactions under ERISA.

The 2004 Convertible Notes convert, at the option of the holder, into fully paid Common Shares. The conversion price, which may be subject to adjustment, is calculated as 80 per cent of the price of the Common Shares offered pursuant to the Placing.

The Company was in default under the 2004 Convertible Note Purchase Agreement at the time it was entered into due to its default under the 15 per cent Senior Notes, the 12 per cent Senior Notes and certain additional loan notes. In addition, the Company was prohibited from entering into the 2004 Convertible Note Purchase Agreement due to certain financial covenants set out in the 2002 Amended Note Purchase Agreement and the 2003 Note Purchase Agreement.

Pursuant to the terms of a letter agreement dated 31 December 2004, the holders of the 2004 Convertible Notes waived any prior default of the Company under the 2004 Convertible Note Purchase Agreement and consented to certain amendments to the Company's Certificate of Incorporation to increase the authorised Common Share capital and amend the certificates of designations for each series of Preferred Shares outstanding.

8.9 Management Promissory Notes

The Company has outstanding various promissory notes with an aggregate principal amount of $2.55 million (''Management Promissory Notes'') issued between March 2001 and August 2004. The Management Promissory Notes bear interest at rates ranging from 6 per cent to 15 per cent and have varying maturity dates. The Management Promissory Notes were issued principally to the Directors and senior management of the Company. Details of the Management Promissory Notes issued to the Directors are set out in paragraph 6.2 of this Part VIII.

The Company has failed to pay any of the Management Promissory Notes at their stated maturity date, causing each of the Management Promissory Notes to be in default. This default resulted in a cross default under the 2002 Amended Note Purchase Agreement, the 2003 Note Purchase Agreement and the 2004 Convertible Note Purchase Agreement. In addition, the Company was prohibited from entering into the Management Promissory Notes by certain financial covenants set out in the 2002 Amended Note Purchase Agreement and the 2003 Note Purchase Agreement.

Pursuant to the terms of various agreements entered into in December 2004, the Company amended each of the Management Promissory Notes to extend their maturity date and to waive any defaults as a result of the failure to pay principal and interest on them.

8.10 Saipem S.p.A. (''Saipem'') satisfaction agreement and promissory note

Frontera Georgia and the Operating Company entered into a satisfaction agreement (the ''Satisfaction Agreement'') with Saipem S.p.A. (''Saipem'') dated 1 October 2004 pursuant to which Frontera Georgia assumed all duties and obligations in respect of $3,500,941 owed by the Operating Company to Saipem (the ''Debts''). A sum of $50,000 was paid by Frontera Georgia on entering into the satisfaction agreement with the balance of $3,450,941 being payable in accordance with a promissory note issued by Frontera Georgia to Saipem on 1 October 2004 (the ''Promissory Note''). Under the Promissory Note, interest only payments of 5 per cent per annum are payable quarterly in arrear by Frontera Georgia until 30 September 2007, when the full amount becomes due and payable.

8.11 Schlumberger Settlement Agreement and related agreements

Frontera Georgia and Frontera International entered into a settlement agreement with Schlumberger Overseas SA (''Schlumberger'') dated 22 August 2002 (the ''Settlement Agreement''). Pursuant to the Settlement Agreement, Frontera Georgia agreed to pay Schlumberger $4 million plus interest at 5 per cent per annum (the ''Schlumberger Note'') by 22 August 2005 in settlement of amounts owed by Frontera to Schlumberger under a service agreement entered into in relation to operations on Block 12.

The Company entered into a parent company guarantee in conjunction with the Settlement Agreement pursuant to which the Company guaranteed the performance of its subsidiaries' obligations under the Settlement Agreement.

The Schlumberger Note was purchased from Schlumberger by two funds controlled by DDJ on 29 October 2003 and DDJ assumed all rights in respect of the Schlumberger Note. On 31 December 2004, DDJ and the Company entered into an option agreement pursuant to which the Company was permitted to purchase the Schlumberger Note from DDJ for $1.3 million plus interest accruing from 31 December 2004 at a rate of 12 per cent per annum. Further, the Company agreed to a mandatory repurchase of the Schlumberger Note within ten business days of a successful public offering of the Company's shares. This option expires on 1 June 2005, at which point the terms of the original Schlumberger Note will be reinstated if the option remains unexercised.

9. Litigation

Save for the following, no member of the Group is engaged in, nor has pending or threatened against it, any legal or arbitration proceedings which may have or have had during the twelve months prior to the publication of this document a significant effect on the financial position of the Group.

Frontera Azerbaijan entered into an agreement dated 15 December 1998 relating to the Rehabilitation, Exploration, Development and Production Sharing for the block including the Kursangi & Karabagli oil fields in the Azerbaijan Republic between the State Oil Company of Azerbaijan ("SOCAR"), Frontera Azerbaijan, Delta/Hess and SOCAR Oil Affiliate (the "Azerbaijan PSA"). Frontera Azerbaijan, holding the largest foreign interest in the K&K Block, led the successful exploitation programmes in association with Amerada Hess, who held a minority interest in the project, increasing production in the block from approximately 3000 bpd to approximately 6000 bpd in two years.

In November 2001, SOCAR halted exports of crude oil from the K&K Block in contravention of the Azerbaijan PSA. The ongoing dispute with SOCAR contributed to a violation of a loan covenant causing Frontera to default under the terms of certain financing agreements in place with the EBRD at that time. The EBRD loan agreements, entered into in May and November 2000, permitted the Company to draw down up to $60 million depending on levels of production from the Company's interests in Georgia and Azerbaijan. The loans were secured over the assets of the Group in Georgia and Azerbaijan. Following the event of default, the EBRD foreclosed on the financing arrangements in 2001 and there was a forced sale of Frontera Azerbaijan's interest in the K&K Block in March 2002 for $53 million. The proceeds of the sale were used to repay in full all amounts outstanding under the loan from EBRD and the EBRD released its security over the Group's assets in Georgia.

Following the sale of the K&K Block, Frontera Azerbaijan initiated arbitration proceedings against SOCAR under the Azerbaijan PSA on 12 October 2003 to recoup funds due to Frontera Azerbaijan for oil deliveries made between 1999 and 2002. In accordance with the Azerbaijan PSA, the arbitration is governed by UNCITRAL. The hearing has been scheduled for five days commencing 7 March 2005 in Stockholm, Sweden.

Frontera Azerbaijan is seeking damages from SOCAR for three separate breaches for non-payment under the Azerbaijan PSA: (i) $2,274,499 due in respect of payment for oil delivered to SOCAR in the last quarter of 1999 and the first quarter of 2000; (ii) $1,968,709 due in respect of Frontera Azerbaijan oil shipments being wrongfully seized by SOCAR at the end of 2000; and (iii) $11,494,238 due in respect of Frontera Azerbaijan oil shipments being taken by SOCAR at the Government determined LMO price instead of the world market price between January 2001 and March 2002. The total amount sought by Frontera Azerbaijan is $15,737,447 plus interest and costs.

SOCAR has filed a Statement of Defence pursuant to which it asserts that, in respect of claims (i) and (ii) above, such claims were settled by the Protocol entered into on 4 July 2002 between, inter alia, SOCAR, the EBRD, SOCAR Oil Affiliate and Delta Hess. In respect of claim (iii) referred to above, SOCAR argues that the Protocol entered into between Frontera Azerbaijan and SOCAR in December 2000 which reinstated Frontera Azerbaijan's LMO obligation is valid and binding.

If the Arbitration Tribunal accepts Frontera Azerbaijan's claim that the Protocol purporting to release some of its rights to payment from SOCAR is invalid, SOCAR has asked the tribunal to consider a counter-claim against Frontera Azerbaijan for approximately $11 million. This counterclaim represents monies alleged to be due to SOCAR in respect of the difference in value between the LMO value and the world market value of the oil which, SOCAR alleges, should have been delivered in 1999 and 2000. To date, SOCAR has largely provided no evidential support for its counter-claim. Following receipt of legal advice and an assessment by the Directors of the counter-claim, Frontera and its legal advisers, Haynes and Boone, consider this counter-claim to be without merit and no reserve has been made in the accounts of Frontera Azerbaijan or of the Company in respect of the SOCAR counter-claim.

10. Working Capital

The Directors are of the opinion that, having made due and careful enquiry, the working capital available to the Company following the Placing will be sufficient for its present requirements, that is for at least twelve months from the date of Admission.

11. Taxation

11.1 United States Federal Tax Considerations

11.1.1 General

The following is a general discussion of certain US federal income and estate tax consequences of the ownership and disposition of Common Shares by Non-US Holders, as defined below. This discussion is based on existing legal authorities, including the Internal Revenue Code, existing and proposed Treasury Regulations, judicial decisions and administrative interpretations, as of the date of this document, all of which are subject to change, possibly with retroactive effect. This discussion does not purport to address all tax considerations that may be important to a particular Non-US Holder in light of the Non-US Holder's circumstances or to certain categories of investors that may be subject to special rules, such as a Non-US Holder who owns Common Shares through a partnership, a Non-US Holder that owns directly or indirectly 10 per cent of our voting stock or a US expatriate. In addition, this discussion does not address any aspect of US state, local or foreign taxation. POTENTIAL INVESTORS SHOULD CONSULT THEIR OWN TAX ADVISERS CONCERNING THE SPECIFIC US FEDERAL INCOME AND ESTATE TAX CONSEQUENCES TO THEM OF OWNING AND DISPOSING OF COMMON SHARES, AS WELL AS THE APPLICATION OF US STATE, LOCAL AND FOREIGN INCOME AND OTHER TAX LAWS.

A ''Non-US Holder'' is an individual or entity that beneficially owns Common Shares and, for US federal income tax purposes, is a (i) non-resident alien individual, other than certain former citizens and residents of the United States subject to tax as expatriates, (ii) foreign corporation, (iii) foreign partnerships or (iv) foreign estate or trust. Other rules apply to ''Qualified Intermediaries,'' as defined in the Treasury Regulations. A Non-US Holder does not include an individual who is present in the United States for 183 days or more in the taxable year of sale or other disposition of Common Shares and is not otherwise a resident of the United States for US federal income tax purposes. Such an individual is urged to consult his or her own tax adviser regarding the US federal income tax consequences of the sale or other disposition of Common Shares.

11.1.2 Dividends

As discussed under ''Dividend Policy'' above, the Company does not currently expect to pay dividends. In the event the Company does pay dividends, dividends paid to a Non-US Holder generally will be subject to withholding tax at a 30 per cent rate. A lower treaty rate may apply if the Non-US Holder is eligible for the benefits of an income tax treaty that provides for a lower rate. A 15 per cent withholding rate generally will apply if the Non-US Holder qualifies for such reduced withholding rate under the US/UK Double Tax Agreement. Even if a Non-US Holder is eligible for a lower treaty rate, the Company will generally be required to withhold at a 30 per cent rate (rather than the lower treaty rate) on dividend payments unless the Non-US Holder has furnished to the Company, or other withholding agent, a properly completed Internal Revenue Service Form W-8BEN or other required documentation claiming entitlement to the lower treaty rate.

Different tax rules apply to dividends that are effectively connected with a Non-US Holder's conduct of a trade or business within the United States. Dividends paid to a Non-US Holder that are effectively connected with such Non-US Holder's conduct of a trade or business within the United States are generally not subject to withholding tax, provided that the Non-US Holder has furnished to the Company a properly completed Internal Revenue Service Form W-8ECI claiming the withholding exemption. Although not subject to withholding taxes, effectively connected dividends are generally taxed at rates applicable to US persons, subject to an applicable tax treaty providing otherwise. A corporate Non-US Holder may also, under certain circumstances, be subject to an additional branch profits tax on effectively connected dividends.

11.1.3 Gain on Disposition

A Non-US Holder generally will not be subject to US federal income tax on gain from a sale or other disposition of Common Shares unless the gain is effectively connected with the Non-US Holder's conduct of a trade or business in the United States and, if required by an applicable tax treaty, attributable to the Non-US Holder's US permanent establishment. Gains that are effectively connected with the conduct of a trade or business within the United States by a corporate Non-US Holder may also, under certain circumstances, be subject to an additional branch profits tax.

11.1.4 Information Reporting and Backup Withholding

The Company may have to report annually to the Internal Revenue Service and to each Non-US Holder the amount of dividends paid to the Non-US Holder and any tax withheld on those dividends. Under an applicable tax treaty, that information may also be made available to tax authorities in the Non-US Holder's country of residence. Generally, backup withholding will not apply to dividend payments made to a Non-US Holder provided that the Non-US Holder certifies under penalties of perjury that it is not a US person or otherwise establishes an exemption and certain other requirements are satisfied.

Payments of the proceeds from a Non-US Holder's sale or other disposition of Common Shares made by or through a foreign office of a broker not having certain connections with the United States generally will not be subject to information reporting and backup withholding. Payment of the proceeds of a sale or other disposition made by or through the US office of a broker is generally subject to information reporting and backup withholding unless the Non-US Holder certifies under penalties of perjury that it is not a US person and certain other requirements are satisfied or otherwise establishes an exemption. Backup withholding is not an additional tax. Rather, any amounts withheld as backup withholding will be refunded or credited against the Non-US Holder's US federal income tax liability provided the required information is furnished to the Internal Revenue Service.

11.1.5 US Federal Estate Taxes

Individual Non-US Holders and entities the property of which is potentially includible in such an individual's gross estate for US federal estate tax purposes (for example, a trust funded by such an individual and with respect to which the individual has retained certain interests or powers), should note that, absent an applicable treaty benefit, the Common Shares will be treated as US situs property subject to US federal estate tax.

11.2 United Kingdom taxation

The comments below are of a general nature and are based on current UK law and Inland Revenue practice published as of the date of this document, both of which are subject to change, possibly with retroactive effect. This summary: (i) only addresses certain UK tax consequences for Shareholders who hold the Common Shares as capital assets and does not address the tax consequences which may be relevant to certain other categories of Shareholder, for example, dealers in securities or employees; (ii) assumes that the Shareholder is not a company which either directly or indirectly controls 10 per cent or more of the share capital or the voting power or the profits of the Company; and (iii) assumes that the Shareholder does not hold the Common Shares in trust. Special rules, not covered here, apply to individual Shareholders who are resident or ordinarily resident in the UK but are not domiciled in the UK.

The following is intended only as a general guide and is not intended to be, nor should it be considered to be, legal or tax advice to any particular Shareholder. Accordingly, potential investors should satisfy themselves as to the overall tax consequences, including the consequences under UK law and practice, of acquisition, ownership and disposition of Common Shares in their own particular circumstances, by consulting their own professional advisers.

11.2.1 Taxation of Chargeable Gains

A disposal of Common Shares by a Shareholder who is resident or, in the case of an individual, ordinarily resident in the UK may give rise to a chargeable gain or allowable loss for the purposes of UK taxation of chargeable gains (subject to any available exemptions or reliefs). A Shareholder who is not resident in the UK for tax purposes but who carries on a trade, profession or vocation in the UK through a branch, agency or, in the case of a corporate Shareholder, permanent establishment and has used, held or acquired the Common Shares for the purpose of such trade, profession or vocation may also be subject to UK taxation on chargeable gains on a disposal of those shares (subject to any available exemptions or reliefs). Special rules may apply to tax gains on disposals made by individuals at a time when they are temporarily not resident or ordinarily resident in the UK.

Any chargeable gain (or allowable loss) will be calculated by reference to the consideration received for the disposal of the Common Shares less the allowable cost to the Shareholder of acquiring such Common Shares.

For a Shareholder within the charge to UK corporation tax, an indexation allowance on the acquisition cost of the Common Shares may be available to reduce the amount of chargeable gain realised on a subsequent disposal. For an individual Shareholder, taper relief may be available to reduce the proportion of any chargeable gain subject to tax.

11.2.2 Dividends

Any Shareholder who is resident in the UK will generally be subject to UK income tax or corporation tax in respect of any dividends received on the Common Shares. As such dividends will be foreign income for the purposes of UK taxation, they will be subject to a different tax regime from that applying to dividends received from UK resident companies. In particular, the dividends will not carry the same tax credit as dividends received from a UK resident company.

Any Shareholder who is resident in the UK will generally be subject to United States dividend withholding tax ("WHT") at a lower rate of 15 per cent on any dividends received on Common Shares, under the terms of the US/UK Double Tax Agreement, provided the Shareholder furnishes the Company, or other withholding agent, with a properly completed US Internal Revenue Service Form W-8BEN or other required documentation before the payment of dividends.

If any dividend has been subject to WHT, the amount received plus the WHT will be included in the assessable income of the UK resident Shareholder. In these circumstances, the Shareholder may be entitled to a credit for the US tax paid. The credit would generally be limited to the lesser of the WHT due after relief under the US/UK Double Tax Agreement or the UK tax payable on the combined amount of the amount received plus the WHT.

11.2.3 UK Stamp Duty and Stamp Duty Reserve Tax

There is generally no liability to UK stamp duty or stamp duty reserve tax on the issue of Common Shares by the Company.

If a sale of Common Shares is completed by an instrument of transfer and it later became necessary to have that instrument stamped in the UK, UK stamp duty would be payable at the rate of 0.5 per cent of the value of the consideration for the sale; interest and, potentially, penalties may also be payable. Any instrument effecting or evidencing the transfer of Common Shares which is executed in the UK, or which relates to any matter or thing done or to be done in the UK, may not (except in criminal proceedings) be given in evidence or be available for any purpose whatsoever in the UK unless duly stamped. Whether or not an instrument of transfer is stamped, however, will not affect the registration of the transfer of Common Shares in the Company's share register or the fact that that registration will constitute the primary evidence of the transferee's title to the Common Shares. It is therefore unlikely that it will ever become necessary to stamp any such instrument and pay duty at the rate mentioned above (or any related interest or penalties).

No charge to UK stamp duty reserve tax will arise in respect of an agreement to transfer Common Shares, provided that the Common Shares are not registered in any register kept in the UK by or on behalf of the Company (there are no current proposals for such a register to be kept).

12. General

12.1 Save as disclosed in this document, the Directors are not aware of any exceptional factors which have influenced the Group's recent activities.

12.2 Save as described herein, there are no patents or other intellectual property rights, licences or particular contractors which are or may be of fundamental importance to the business of the Group.

12.3 Other than as disclosed in this document, there have been no known material changes in the financial or trading position of the Company since the date to which the latest published audited accounts of the Company were made up.

12.4 There are no significant recent trends concerning the development of the Group's business since 31 December 2004.

12.5 Save as disclosed the Company has no significant investments in progress.

12.6 Stephen McGregor, a director of the Company, will receive a success fee on completion of the Admission amounting to $808,794, being one per cent of the proceeds of the Placing, pursuant to the terms of his engagement agreement with the Company, further details of which are set out in paragraph 8.5 of this Part VIII. Mr Rod Peacock will receive $50,000 and 10,000 options as compensation for consultancy services provided to the Company in respect of the Placing and the Admission. Save as disclosed in this paragraph 12.6 no person (other than the Company's professional advisers otherwise disclosed in this document and trade suppliers) has received, directly or indirectly, from the Company within the twelve months preceding the date of this document, or entered into contractual arrangements (not otherwise disclosed in this document) to receive, directly or indirectly, from the Company on or after Admission fees totalling £10,000 or more, securities in the Company with a value of £10,000 or more at the Placing Price or any other benefit with a value of £10,000 or more at the date of this document.

12.7 The minimum amount which, in the opinion of the Directors, must be raised under the Placing to provide sums required in respect of the matters specified in paragraph 21(a) to Schedule I of the POS Regulations is £4,922,257 as set out below:

(i) Purchase of property: nil

(ii) Expenses of the Placing (including commissions): £4,700,000

(iii) Repayment of borrowings in respect of (i) and (ii) above: nil

(iv) Working capital: £222,257

13. Consents

13.1 Ernst & Young LLP has given and not withdrawn its written consent to the inclusion in Part V of this document of their audit report in respect of the consolidated financial statements of the Company for the three year period ended 31 December 2004 and references thereto in the form and context in which it is included for the purposes of paragraph 13(1)(g) of the POS Regulations and paragraph 45(2)(b)(iii) of Schedule 1 to the POS Regulations.

13.2 Netherland & Sewell has given and not withdrawn its written consent to the issue of this document with their name included in it and with inclusion therein of its report and references thereto in the form and context in which it is included for the purposes of paragraph 13(1)(g) of the POS Regulations.

14. Availability of documents for inspection

Copies of the following documents will be available for inspection during normal business hours on any weekday (excluding public holidays) at the offices of CMS Cameron McKenna, Mitre House, 160 Aldersgate Street, London EC1A 4DD from the date of this document until the fourteenth day after Admission:

14.1 the Restated Certificate of Incorporation and the Certificate of Incorporation of the Company;

14.2 the Bylaws of the Company;

14.3 the Petroleum Consultants' Report, a copy of which appears in Part IV;

14.4 the Accountants' Report, a copy of which appears in Part V;

14.5 the audited consolidated financial statements of the Company for the three years ended 31 December 2004;

14.6 the service contracts for the executive Directors referred to in paragraph 7.1 of this Part VIII;

14.7 the rules of the 1998 Plan and 2000 Plan referred to in paragraph 3.5.2 and 3.5.3 of this Part VIII;

14.8 copies of the material contracts referred to in paragraph 8 of this Part VIII; and

14.9 the letters of consent referred to in paragraphs 13.1 and 13.2 of this Part VIII.

15. Availability of this document

Copies of this document will be available for collection only, free of charge, from the offices of CMS Cameron McKenna, Mitre House, 160 Aldersgate Street, London EC1A 4DD during normal office hours on any weekday (Saturdays and public holidays excepted) for a period of not less than one month from the date of Admission.

9 March 2005

DEFINITIONS

The following definitions apply throughout this document unless the context requires otherwise:

"12 per cent Senior Notes"	the loan notes issued by the Company, further details of which are set out in paragraph 8.7 of Part VIII
"15 per cent Senior Notes"	the loan notes issued by the Company, further details of which are set out in paragraph 8.6 of Part VIII
"1998 Plan"	the Frontera Resources Corporation 1998 Employee Stock Incentive Plan
"2000 Plan"	the Frontera Resources Corporation 2000 Non-Qualified Stock Option and Stock Award Plan
"2001 Loan Notes"	the loan notes issued by the Company, further details of which are set out in paragraph 13 of Part II
"2001 Warrants"	warrants to subscribe for an aggregate of 15,637,329 Common Shares issued by the Company in connection with a rights offering to shareholders made in December 2001, further details of which are set out in paragraph 13 of Part II
"2002 Amended Note Purchase Agreement"	the note purchase agreement amending and restating the 15 per cent Senior Notes, further details of which are set out in paragraph 8.6 of Part VIII
"2002 Warrants"	warrants to subscribe for an aggregate of 1,950,000 Common Shares issued by the Company in connection with the 2002 Amended Note Purchase Agreement
"2003 Note Purchase Agreement"	the note purchase agreement entered into by the Company, further details of which are set out in paragraph 8.7 of Part VIII
"2003 Warrants"	warrants to subscribe for an aggregate of 3,000,000 Common Shares issued by the Company in connection with the 2003 Note Purchase Agreement
"2004 Convertible Notes"	the convertible loan notes issued by the Company, further details of which are set out in paragraph 8.8 of Part VIII
"2004 Convertible Note Purchase Agreement"	the $2.5 million convertible loan entered into by the Company, further details of which are set out in paragraph 8.8 of Part VIII
"2004 Convertible Notes"	loan notes issued in connection with the 2004 Convertible Note Purchase Agreement
"Act"	the Companies Act 1985, as amended
"Admission"	admission of the whole of the common share capital of the Company in issue and to be issued pursuant to the Placing to trading on AIM becoming effective in accordance with the AIM Rules
"AIM"	the AIM market operated by the London Stock Exchange
"AIM Rules"	the rules applicable to AIM companies and their nominated advisers as published by the London Stock Exchange from time to time
"Amended 15 per cent Senior Notes"	the loan notes issued by the Company pursuant to the 2002 Amended Note Purchase Agreement
"Azerbaijan PSA"	the agreement relating to the Rehabilitation, Exploration, Development and Production Sharing for the block including the Kursangi & Karabagli oil fields in the Azerbaijan Republic dated 15 December 1998 and entered into by SOCAR, Frontera Azerbaijan, Delta Hess and SOCAR Oil Affiliate

Basin Edge B Prospect	a prospect identified and high graded by the Company located in the Cretaceous Carbonate Play and further described in paragraph 6.3.2 of Part II
Basin Edge C Prospect	a prospect identified and high graded by the Company located in the Cretaceous Carbonate Play and further described in paragraph 6.3.2 of Part II
"Block 12"	the 5,060 km^2 area of land situated in the western end of the Kura Basin in Georgia, which has been designated as Block 12
"Block 12 PSA"	the production sharing agreement and refinery study dated 25 June 1997 between the MoFE, Saknavtobi and Frontera Georgia, details of which are set out in paragraph 7 of Part II and in Part VI
"Board" or **"Directors"**	the directors of the Company whose names are set out on page 7
"Code"	City Code on Takeovers and Mergers
"Combined Code"	the code of best practice, including the principles of good governance, set out in the Combined Code of Good Governance and Best Practice published in July 2003 by the Financial Reporting Council
"Common Shares"	the common stock of $0.00004 each in the share capital of the Company
"Company" or **"Frontera"**	Frontera Resources Corporation, a company incorporated and existing under the laws of the State of Delaware, United States of America
"Contract Area"	the 5,060 km^2 area specified in the Block 12 PSA as constituting Block 12
"Coordination Committee"	the committee established pursuant to the Block 12 PSA to provide overall supervision and direction of the operations in Block 12
"Cost Recovery Crude Oil"	Petroleum produced from Block 12 which Frontera Georgia is permitted to sell pursuant to the Block 12 PSA to recoup its permitted costs and expenses
"CREST"	the computer based system and procedures administered by CRESTCo Limited which enable title to securities to be evidenced and transferred without a written instrument
"Cretaceous Carbonate Play"	the area situated on the northern border of Block 12 identified by Frontera as containing potential oil reserves and further described in paragraph 6.3.2 of Part II
"DDJ"	DDJ Capital Management LLC
"Delta Hess"	Delta/Hess (K&K) Limited, a joint venture company owned by Amerada Hess and Delta Oil
"Development Areas"	all or any part of Block 12 specified in an approved development plan containing Petroleum, which area Frontera Georgia commits itself to develop and produce, but excluding any of those parts of Block 12 containing discoveries of Petroleum made prior to the grant of the Block 12 PSA
"DGCL"	Delaware General Corporation Law
"EBRD"	the European Bank for Reconstruction and Development
"Enlarged Issued Common Share Capital"	the Common Shares in issue immediately following the Placing, but excluding any Common Shares held by the Company in treasury and Common Shares subject to the Stock Lending Agreement

"Excess Crude"	Petroleum offered for sale to the State from Frontera Georgia's Profit Oil pursuant to the terms of the Block 12 PSA
"Exploitation Areas"	the volumes of rock within Block 12 which contain discoveries of Petroleum made prior to the grant of the Block 12 PSA
"F.O.B"	free on board
"Frontera Azerbaijan"	Frontera Resources Azerbaijan Corporation, a company incorporated and existing under the laws of the Cayman Islands
"Frontera Georgia" or **"Contractor"**	Frontera Resources Georgia Corporation, a company incorporated and existing under the laws of the Cayman Islands
"Frontera International"	Frontera International Corporation, a subsidiary of the Company incorporated and existing under the laws of the Cayman Islands
"FSMA"	the Financial Services and Markets Act 2000
"Fully Diluted Common Share Capital"	the Common Shares in issue following Admission assuming that (i) the 2001 Warrants, the 2002 Warrants and the 2003 Warrants are exercised in full, (ii) all outstanding options are exercised in full, and (iii) the 2004 Convertible Notes are converted in full
"GAC Energy"	GAC Energy Corporation, a corporation organised and existing under the laws of the State of Texas
"Group" or **"Frontera Group"**	the Company, its subsidiaries and the Operating Company at the date of this document
"Internal Revenue Code"	the US Internal Revenue Code of 1986, as amended
"K&K Block"	the block including the onshore Kursangi & Karabagli oil fields located in the Republic of Azerbaijan
"Kila Kupra Field, Iori Field and Bayda Field Complex"	the area situated within Block 12 containing the Kila Kupra Field, the Iori Field and the Bayda Field and further described in paragraph 6.4.2 of Part II
"Law on Entrails"	the 1994 Georgian Law on Entrails which regulated oil and gas operations in Georgia prior to the coming into force of the Oil and Gas Law
"London Stock Exchange"	London Stock Exchange plc
"Management Promissory Notes"	promissory notes issued by the Company to members of the Company's management team since March 2001 and further described in paragraph 8.9 of Part VIII
"Mineral Licence"	the 25 year mineral extraction licence granted to the Operating Company by the Ministry of Environmental Protection of Natural Resources of Georgia with effect from 25 August 1997
"Mineral Use Tax"	tax payable in respect of mineral use pursuant to the law of Georgia
"Mirzaani Deep Prospect"	the anticlinal structure which the Company believes to exist beneath the previously identified Mirzaani Field and further described in paragraph 6.4.1 of Part II
"Mirzaani Field"	the field situated within Block 12 known as the Mirzaani Field and further described in paragraph 6.4.1 of Part II
"Mirzaani Field Area"	the Mirzaani Field, the Patara Shiraki Field and the Nazerlebi Field
"MoFE"	the Ministry of Fuel and Energy of Georgia, the predecessor of the State Agency prior to the introduction of the Oil and Gas Law
"MSIL"	Morgan Stanley & Co. International Limited
"MSSL"	Morgan Stanley Securities Limited

"Nazerlebi Field"	the field situated within Block 12 known as the Nazerlebi Field
"Netherland & Sewell"	Netherland, Sewell & Associates Inc
"Netherland & Sewell Report"	the report by Netherland & Sewell which appears in Part IV
"Official List"	the official list of the UK Listing Authority
"Oil and Gas Law"	the Law of Georgia on Oil and Gas dated 16 April 1999, as amended
"Operating Company"	Frontera Eastern Georgia Limited, a society of limited responsibility organised pursuant to its charter and existing under the laws of Georgia
"Over-allotment Arrangements"	the arrangements pursuant to which the Company has granted an option to MSIL, the details of which are set out in paragraph 18 of Part II
"Over-allotment Shares"	the Common Shares to be issued by the Company pursuant to the Over-allotment Arrangements
"Patara Shiraki Field"	the field situated within Block 12 known as the Patara Shiraki Field
"Petroleum"	crude oil and natural gas
"Petroleum Operations"	the exploration for undiscovered Petroleum and the evaluation, development and production of discovered reserves
"Pkhoveli Prospect"	the prospect situated within the Tertiary Clastics Play known as the Pkhoveli Prospect
"Placees"	those persons who agree to subscribe for or acquire Placing Shares pursuant to the Placing
"Placing"	the proposed placing of the Placing Shares on behalf of the Company at the Placing Price pursuant to the terms and conditions of the Placing Agreement referred to in this document
"Placing Agreement"	the agreement dated 9 March 2005 between the Company, the Directors and MSIL relating to the Placing, details of which are set out in paragraph 8.2 of Part VIII
"Placing Price"	150 pence per Common Share
"Placing Shares"	the 28,000,000 new Common Shares which are the subject of the Placing
"POS Regulations"	the Public Offers of Securities Regulations 1995, as amended
"Pre-Admission Share Capital"	the Common Shares in issue immediately prior to Admission but subsequent to the conversion of all of the Preferred Shares into Common Shares, excluding any and all (i) Common Shares which would arise or be issued on the exercise of any warrants or options, or the conversion of any convertible loan notes, and (ii) shares held by the Company in the form of treasury shares
"Preferred Shares" or **"Preferred Stock"**	the preferred shares in the capital of the Company
"Profit Oil"	Petroleum produced from Block 12 to be shared among Frontera Georgia and Saknavtobi pursuant to the Block 12 PSA following allocation of the Cost Recovery Crude Oil
"Profit Tax"	profit tax payable in respect of the Petroleum Operations pursuant to the law of Georgia
"Registrars"	Capita IRC (Offshore) Limited, whose details are set out on page 7

"Saknavtobi" or **"Georgian Oil"**	the Joint Stock Company National Oil Company Georgian Oil in its capacity as the state-owned oil company organized and existing as a legal entity pursuant to its authority under the Oil and Gas Law
"SEM Consulting"	SEM Consulting L.L.C.
"SOCAR"	State Oil Company of the Republic of Azerbaijan
"Shareholder"	a holder of Common Shares
"State"	the government of Georgia
"State Agency"	the State Agency for Regulation of Oil and Gas Resources of Georgia in its capacity as the sovereign representative of the State pursuant to its authority under the Oil and Gas Law
"Stock Lending Agreement"	the stock lending agreement entered into by the Company and MSIL in connection with the Over-allotment Arrangements, further details of which are set out in paragraph 8.2.2 of Part VIII
"Taribani Field"	the field situated within Block 12 known as the Taribani Field and further described in paragraph 6.3.1 of Part II
"Tertiary Clastics Play"	the area situated in Block 12 containing seven known oil fields and certain other prospects identified by Frontera as containing potential oil reserves and further described in paragraphs 6.3.1 and 6.4 of Part II
"Trafigura"	Trafigura Beheer BV (Amsterdam)
"UHY"	UHY Mann Frankfort Stein & Lipp of 12 Greenway Plaza, Suite 1202 Houston, Texas 77046-1289
"UK Listing Authority" or **"UKLA"**	the Financial Services Authority, acting in its capacity as the competent authority for the purposes of FSMA
"United Kingdom" or **"UK"**	United Kingdom of Great Britain and Northern Ireland
"UNCITRAL"	the Arbitration Rules of the United Nations Commission on International Trade Law
"United States" or **"US"**	United States of America, its territories and possessions, any state in the US and the District of Columbia
"US$"** or **"$"	United States Dollars
"US/UK Double Tax Agreement"	the convention of 24 July 2001 between the Government of the United States and the Government of the United Kingdom for the Avoidance of Double Taxation and the Prevention of Fiscal Evasion with respect to Taxes on Income and on Capital Gains
"US Person"	has the meaning given to it in Part VII
"US Securities Act"	the United States Securities Act of 1933, as amended, and the rules and regulations promulgated thereunder

GLOSSARY OF TERMS

2D seismic (two-dimensional seismic data)	geophysical data that depicts the subsurface strata in two dimensions
3D seismic (three-dimensional seismic data)	geophysical data that depicts the subsurface strata in three dimensions. 3D seismic typically provides a more detailed and accurate interpretation of the subsurface structure and strata than can be achieved using 2D seismic data
anticline	a convex fold in rock, the central part of which contains the oldest section of rock
API	American Petroleum Institute
back-arc basin	isolated marine basin behind a subduction zone, formed by back arc spreading or addition of lithosphere to the overriding plate
block	an area designated by a government or any authority, entity or representative of a government for allocation to oil and gas exploration companies with a view to the granting of hydrocarbon exploration and production rights
bpd	barrels of oil per day
breached anticline	an anticline becomes breached when, due to the stress on the rocks, cracks form at the top of the anticline allowing erosion to occur causing a circular indent (sometimes with an end valley) to form
Cenozoic era	the last major division of geologic time lasting from around 65 million years ago to the present
conventional core	a sample of rock obtained by using a conventional core barrel in place of a drill bit
Cretaceous	a period of geologic time falling within the Mesozoic Era, around 146 to 65 million years ago, coming after the Jurassic period
drive mechanism	the characteristic of a reservoir being a key determinant of how pressure is defined in a field
depletion drive mechanism	a type of natural drive mechanism
down-dip	located down the slope of a dipping plane or surface. In a dipping (not flat-lying) hydrocarbon reservoir that contains gas, oil and water, the gas is up-dip, the gas-oil contact is down-dip from the gas, and the oil-water contact is further still down-dip
Eocene	part of the Tertiary period in the Cenozoic era lasting from approximately 55 to 34 million years ago
"EUR"	estimated ultimate recovery, as defined in the Netherland & Sewell Report
farm-out	a common form of agreement between oil operators pursuant to which an owner of an unproven resource property may transfer a part interest in the property to another person in exchange for exploration and development work on the transferred property
field	area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structure feature and/or stratigraphic condition
fluvio-deltaic	pertains to the deposition of sediment from a river delta
fold	a bend in a planar structure (e.g. rock strata or beds) such that the lower surface connects to an upper surface via a single simple slope

horizon	sedimentary deposits of a certain period, usually marked by characteristic fossils on time
Jurassic	the second period of the Mesozoic Era, lasting from around 208 to 146 million years ago
km	kilometres
km^2	square kilometres
LMO	local market oil
Maykop shales	fine-grained, detrital sedimentary rock made up of silt- and clay-sized particles being the principal source of oil in the South Caspian and Kura Basin
m	metres
Mesozoic Era	a major division of geologic time, immediately following the Cenozoic era and lasting from around 65 to 225 million years ago, which is divided into three time periods: the Triassic (around 245-208 million years ago), the Jurassic (around 208-146 million years ago), and the Cretaceous (around 146-65 million years ago)
Miocene	the fourth epoch of the Tertiary period in the Cenozoic era of geologic time, lasting from around 24.6 to 5.1 million years ago
monocline	a local steepening in an otherwise uniform gentle dip
Oligocene	the third epoch of the Tertiary period in the Cenozoic era of geologic time, lasting from 38 to 24 million years ago, coming after the Eocene epoch and before the Miocene epoch
nearshore marine	of or belonging to or caused by sea currents or ocean currents at the tidal break
NPV	net present value
outcrop	any place where bedrock is visible on the surface of the Earth
paleo deep water	refers to the pre-existing depth of a body of water from a specific period of geologic time as in Cretaceous, Eocene or Miocene
pay zone	reservoir rock where oil and gas are found
play	term used to describe a kind of exploration project not yet fully defined by seismic, well logs or producing fields; the term typically is associated with non-producing projects
Pliocene	the fifth epoch in the Cenozoic Era of geologic time, lasting from around 5.1 to 2 million years ago
prospect	an area that is a potential site of mineral deposits, based on preliminary exploration
prospective resources	has the meaning given to it on pages 47 and 48
proven plus probable plus possible reserves (P3)	has the meaning given to it on page 45
proven plus probable reserves (P2)	has the meaning given to it on pages 42 and 44
proven reserves (P1)	has the meaning given to it on pages 42 and 43
PSA	production sharing agreement
reservoir	subsurface body of rock having sufficient porosity and permeability to store and transmit fluids
Sarmatian	major division of Miocene rocks and time, around 23.7 to 5.3 million years ago

Shiraki	a local name for a rock formation indigenous to Georgia from the Lower Pliocene geologic time period
skin damage	usually in reference to the penetration by drilling fluids to the area of the bore-hole. Typically this is caused by excessive weighted drilling fluids or excessive exposure to drilling fluids
strike-slip fault	a fault in which two sections of rock have moved horizontally in opposite directions, parallel to the line of the fracture that divided them
sub-thrust anticlinal features	a structural feature that lies below an existing geologic thrust fault that often traps oil and gas
Tertiary	one of the two main sub-divisions of the Cenozoic Era
total organic carbon	a measure of the relative content of organic material usually in reference to source rock
up-dip	located up the slope of a dipping plane or surface
velocity profiles	a seismic reflection spread designed to record data that may be used to compute average velocities in the earth to reflecting horizons by observation of time variations compared with the geometrical ray path traveled
workover	process of performing major maintenance or remedial treatments on an oil and gas well, which may require the removal and replacement of the production tubing string after the well has been drilled and a workover rig has been placed on location