CANARGO ENERGY CORP
Form 10-K
March 13, 2008

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

[X] **ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2007

OR

[ ] **TRANSITION REPORT UNDER SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from __________ to __________

Commission File Number **001-32145**

CANARGO ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**91-0881481**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

P.O. Box 291, St Peter Port, Guernsey, British Isles GY1 3RR
(Address of principal executive offices)
Registrant s telephone number, including area code: **+(44) 1481 729 980**
Securities Registered Pursuant to Section 12(b) of the Act:

Title of each class	**Name of each exchange on which registered**
Common Stock, par value $0.10 per share	American Stock Exchange
	Oslo Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
YES___NO Ö__

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act
YES ___NO Ö__

Indicate by check mark whether the registrant: (1) filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
YES Ö__ NO___

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.
[ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer __ Accelerated filer Ö__ Non-accelerated filer __ Smaller reporting company __
(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
YES__ NO ü

The aggregate market value of the voting and non voting common equity held by-non-affiliates as of the most recently completed second fiscal quarter (June 30, 2007), based on the price at which the common equity was last sold on such date was approximately $184 million, based upon the last reported sales price of such stock on The American Stock Exchange on that date.

Indicate the number of shares outstanding of each of the registrant s classes of common stock, as of the latest practicable date: Common Stock, $0.10 par value, 242,120,974 shares outstanding as of March 7, 2008.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant s definitive Proxy Statement issued in connection with its 2008 Annual Meeting of Shareholders are incorporated by reference in Part III of this Report. Other documents incorporated by reference in this Report are listed in the Exhibit Index.

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PART I

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (Securities Act) and Section 21E of the Securities Exchange Act of 1934, as amended (Exchange Act). When used in this Report, the words estimate, project, anticipate, expect, intend, hope, may and similar expressions, as well as will, shall and other indications of future tense, are intended to identi forward-looking statements. The forward-looking statements are based on our current expectations and speak only as of the date made. These forward-looking statements involve risks, uncertainties and other factors that in some cases have affected our historical results and could cause actual results in the future to differ significantly from the results anticipated in forward-looking statements made in this Report. Important factors that could cause such a difference are discussed in this Report, particularly in the sections entitled Risk Factors and Management s Discussion and Analysis of Financial Condition and Results of Operations . You are cautioned not to place undue reliance on the forward-looking statements.

Few of the forward-looking statements in this Report, including the documents that are incorporated by reference, deal with matters that are within our unilateral control. Joint venture, acquisition, financing and other agreements and arrangements must be negotiated with independent third parties and, in some cases, must be approved by governmental agencies. These third parties generally have interests that do not coincide with ours and may conflict with our interests. Unless the third parties and we are able to compromise their various objectives in a mutually acceptable manner, agreements and arrangements will not be consummated.

Although we believe our expectations reflected in forward-looking statements are based on reasonable assumptions, no assurance can be given that these expectations will prove to have been correct. Important factors that could cause actual results to differ materially from the expectations reflected in the forward-looking statements include, among others:

- the market prices of oil and gas;
- uncertainty of drilling results, reserve descriptions, characteristics, estimates and reserve replacement;
- operating uncertainties and hazards;
- economic and competitive conditions;
- natural disasters and other changes in business conditions;
- inflation rates;
- legislative and regulatory changes;
- financial market conditions;
- accuracy, completeness and veracity of information received from third parties;
- wars and acts of terrorism or sabotage;
- political and economic uncertainties of foreign governments; and
- future business decisions.

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In light of these risks, uncertainties and assumptions, the events anticipated by our forward-looking statements might not occur. We undertake no obligation to update or revise our forward-looking statements, whether as a result of new information, future events or otherwise.

In this Annual Report, CanArgo or the Company , we , us and our refer to CanArgo Energy Corporation and, u otherwise indicated by the context, our consolidated subsidiaries.

GLOSSARY OF CERTAIN TERMS

The definitions set forth below shall apply to the indicated terms as used in this Form 10-K. All volumes of natural gas referred to herein are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit and in most instances are rounded to the nearest major multiple.

AMEX The American Stock Exchange, Inc.

bbl One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

boe Barrel of oil equivalent, determined by using the ratio of one bbl of oil or natural gas liquids to six Mcf of gas.

bopd Barrels of oil produced per day.

Brent Pricing point for selling North Sea crude oil.

Development drilling The drilling of a well within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Exploration prospects or locations A location where a well is drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir or to extend a known reservoir.

Finding and development costs Costs associated with acquiring and developing proved natural gas and oil reserves which are capitalized pursuant to generally accepted accounting principles, including any capitalized general and administrative expenses.

Farm-in or farm-out An agreement under which the owner of a working interest in an oil and gas lease assigns the working interest or a portion thereof to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a farm-in while the interest transferred by the assignor is a farm-out.

Gross acreage or gross wells The total acres or wells, as the case may be, in which a working interest is owned.

Km Kilometer.

Mcf One thousand cubic feet of natural gas.

MMcf One million cubic feet of natural gas.

Bcf One billion cubic feet of natural gas.

MCM One thousand cubic metres of natural gas.

MMCM One million cubic metres of natural gas.
mD Millidarcies.
MMbbl One million barrels.
MMboe Million barrels of oil equivalent.
Net acres or net wells The sum of the fractional working interests owned in gross acres or gross wells.
Producing property A natural gas and oil property with existing production.
Proved developed reserves Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.
Proved reserves The estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.
Proved undeveloped reserves Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units that offset productive units and that are reasonably certain of production when drilled.
PSC or PSA Production Sharing Contract or Production Sharing Agreement.
Recomplete This term refers to the technique of drilling a separate well-bore from all existing casing in order to reach the same reservoir, or redrilling the same well-bore to reach a new reservoir after production from the original reservoir has been abandoned.
SEC United States Securities and Exchange Commission.
Undeveloped acreage Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains proved reserves.
Working interest An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and to receive a share of production.
Workovers Operations on a producing well to restore or increase production.

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ITEM 1. BUSINESS.

General Development of Business

We operate as an oil and gas exploration and production company and as a holding company carry out our activities through a number of operating subsidiaries and associated or affiliated companies. These operating companies are generally focused on one of our projects, and this structure assists in maintaining separate cost centers for these different projects.

The address of the principal and administrative offices of CanArgo is P.O. Box 291, St Peter Port, Guernsey, British Isles GY1 3RR (Tel. No. (44) 1481 729 980).

We file reports with the Securities and Exchange Commission (the Commission). The public may read and copy any materials that we file with the Commission at the Commission s Public Reference Room at 450 Fifth Street, NW, Washington, DC 20549. We make available free of charge our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act on our internet website at www.canargo.com as soon as reasonably practicable after we electronically file or furnish such material with or to the Commission.

Our principal activities are oil and gas exploration, development and production, principally in Georgia. We direct most of our efforts and resources to our exploration and appraisal program in Georgia and the development of the Ninotsminda Field in Georgia. Our management and technical staff have substantial experience in our areas of operation. Currently our principal product is crude oil, and the sale of crude oil is our principal source of revenue.

Exploration, Development and Production Activities

In Georgia our exploration, development and production activities are carried out under four production sharing contracts or agreements (PSC or PSA), these being:

1. The Ninotsminda, Manavi and West Rustavi Production Sharing Contract, covering Block XI^{E}, (Ninotsminda PSC), in which Ninotsminda Oil Company Limited owns a 100% interest. Ninotsminda Oil Company Limited is a wholly owned subsidiary of CanArgo. This PSC covers an area of approximately 27,923 acres (113 Km^{2}) This area, excluding any development area, is subject to a voluntary 25% relinquishment in May 2008;

2. The Nazvrevi and Block XIII Production Sharing Contract (Nazvrevi PSC), covering Blocks XI^{D} and XIII, in which CanArgo (Nazvrevi) Limited owns a 100% interest. CanArgo (Nazvrevi) Limited is a wholly owned subsidiary of CanArgo. This PSC covers an area of approximately acres 194,223 acres (787 Km^{2}), following a 50% relinquishment of the contract area in February 2008;

3. The Norio (Block XI^{C}) and North Kumisi Production Sharing Agreement (Norio PSA) in which CanArgo Norio Limited currently owns a 100% interest, although this interest may be reduced to 85% should the state oil company, Georgian Oil, exercise an option available to it under the PSA for a limited period following the submission of a field development plan. As a contractor party, Georgian Oil would be liable for all costs and expenses in relation to any interest it may acquire in the PSA. This PSA covers an area of approximately 265,122 acres (1,061 Km^{2}) following a 25% relinquishment in April 2006 and will be subject to a further 50% relinquishment of the remaining contract area less any development area in April 2011;

4. The Block XI^{G} and XI^{H} Production Sharing Contract (Tbilisi PSC), in which CanArgo Norio Limited owns a 100% interest. CanArgo Norio Limited is a wholly owned subsidiary of CanArgo. This PSC covers an area of approximately 119,845 acres (485 Km^{2}). A first relinquishment of 25% of the contract area, excluding any development, area is due in September 2008 but we are negotiating an extension to this date.

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Until February 16, 2006, we held an interest in the Samgori, Block XI B Production Sharing Contract (Samgori PSC), in which CanArgo Samgori Limited acquired a 50% interest in 2004 subject to completion of an agreed work program to be completed in part by September 16, 2006 and in full by June 2008. This work program did not commence in time and the Samgori PSC was returned to the previous owner without CanArgo retaining any interest. CanArgo Samgori Limited is a wholly owned subsidiary of CanArgo.

Georgia Location Map

Under production sharing contracts, the contractor party (generally a foreign investor) assumes the risk and provides investment into the project (in the above mentioned contracts, CanArgo through its appropriate subsidiary is a contractor party) and in return is entitled to a share of any petroleum produced which is split into a cost recovery and profit share element. The remaining profit petroleum produced from the project is delivered to the State from which the State will assume, pay and discharge, in the name and on behalf of each contractor party, the contractor party s profit tax liability and all other host State taxes, levies and duties. PSCs are a common form of oil and gas exploration and production contract in many parts of the world.

Oil and Gas Fields

Since 1997, our resources have, through our wholly owned subsidiary Ninotsminda Oil Company Limited, been mainly focused on the development of the Ninotsminda Field and related exploration activities in Georgia, including the Manavi prospect. The Ninotsminda Field covers approximately 3,276 acres (13.26 Km ^{2}) and is located approximately 25 miles (40 Kms) north east of the Georgian capital, Tbilisi. It is adjacent to and east of the Samgori Oil Field, which was Georgia s most productive oil field (we acquired an interest in this Field in early 2004 which we held until February 2006). The Ninotsminda Field was discovered later than the Samgori Field and has experienced substantially less development activity. The Georgian State oil company, Georgian Oil and others, including Ninotsminda Oil Company Limited, have drilled 36 wells in the Ninotsminda Field, of which 11 are currently producing.

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We believe that the Ninotsminda PSC area both outside of and beneath the currently producing reservoirs of the Field has significant additional exploration and appraisal potential. To date, we have invested and continue to invest substantial funds in exploring the Ninotsminda PSC area including the Manavi prospect where we made an oil discovery in a deeper stratigraphic interval in 2003.

Other Projects

We have additional exploratory and developmental oil and gas properties and prospects in Georgia which we are actively exploring. Previously we had oil and gas interests in Ukraine, but we exited this country in 2004 when we disposed of our single remaining Ukrainian asset, the Bugruvativske Field. We also had interests in Kazakhstan, but our Kazakhstan assets were discontinued with our disposition of our interest in Tethys Petroleum Limited, which held such assets, on August 3, 2007.

Business Structure

CanArgo is a holding company organized under the laws of the State of Delaware. Our principal product is crude oil, and the sale of crude oil is our principal source of revenue. CanArgo s principal active subsidiaries are held through our wholly owned subsidiary company CanArgo Limited as follows:

Background

Ninotsminda PSC

Our activities at the Ninotsminda Field and on the Manavi prospect are conducted through Ninotsminda Oil Company Limited, a Cypriot corporation (NOC) which became a wholly owned subsidiary of CanArgo in July 2000.

NOC (then named JKX Ninotsminda Limited) obtained its rights to the Ninotsminda Field, including all existing wells, one other field (West Rustavi) and exploration acreage in Block XI ^{E} under a 1996 production sharing contract with Georgian Oil and the State of Georgia (Ninotsminda PSC) which came into effect in February 1996. NOC s rights under the contract expire in December 2019, subject to the possible loss of undeveloped areas prior to that date and a possible extension with regard to developed areas. As such the initial term of the Ninotsminda PSC is until 2019, however, in respect of any development area, if commercial production remains possible beyond 2019 upon giving notice to the State we have an automatic right to extend the contract in respect of such development area for an additional term of 5 years (until 2024) or, if earlier, for the producing life of the development area. Under the Ninotsminda PSC, NOC is required to relinquish at least

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half of the area then covered by the production sharing contract, but not in portions being actively developed, at five year intervals commencing December 1999. In 1998, these terms were amended with the initial relinquishment being due in 2008 and a reduction in the area to be relinquished at each interval from 50% to 25%.

Under the Ninotsminda PSC, up to 50% of petroleum produced under the contract (Production) is allocated to NOC for the recovery of the cumulative allowable capital, operating and other project costs associated with the Ninotsminda Field and exploration in Block XI ^{E} (cost recovery petroleum). NOC pays 100% of the costs incurred in the project as the sole contractor party under the Ninotsminda PSC. The balance of Production (profit petroleum) is allocated on a 70/30 basis between Georgian Oil as the State representative in the PSC and NOC respectively. While NOC continues to have unrecovered costs, it will receive 65% of Production (cost recovery plus profit petroleum). After recovery of its cumulative capital, operating and other allowable project costs, NOC will receive 30% of Production. Thus, while NOC is responsible for all of the costs associated with the Ninotsminda PSC, it is only entitled to receive 30% of Production after cost recovery. The allocation of a share of Production to Georgian Oil, however, relieves NOC of all obligations it would otherwise have to pay the State of Georgia for taxes, duties and levies related to activities covered by the production sharing contract. Georgian Oil and NOC take their respective shares of oil production in kind, and they market their oil independently, however the intention is to market gas jointly.

Samgori PSC

In April 2004, we acquired a 50% interest in the Samgori PSC in Georgia. This interest was acquired from Georgian Oil Samgori Limited (GOSL), a company wholly owned by Georgian Oil, by one of our subsidiaries, CanArgo Samgori Limited (CSL). Under the terms of the agreement dated January 8, 2004, up to 10 horizontal wells were to be drilled on the Samgori Field as a result of GOSL s earlier acquisition of the contractor s interest in the PSC from the original contractor party to the Samgori PSC, National Petroleum Limited (NPL). Completion of well S302 in the autumn of 2004, which was funded 100% by us, satisfied our commitment to GOSL under the acquisition agreement. The intention was that the remainder of the drilling program would be funded jointly by CSL and GOSL, the contractor parties, pro rata their interest in the Samgori PSC. The total cost to us of participating in the whole program, which was due to be completed within 36 months of the commencement of the joint work program, was anticipated to be up to $13,500,000.

On February 17, 2006 we issued a press release announcing that our subsidiary, CSL, was not proceeding with further investment in the Samgori PSC and associated farm-in, and accordingly we terminated our interest in the Samgori PSC with effect from February 16, 2006. The decision by CSL not to proceed with further investment under the current farm-in arrangements was due to the inability of CSL s partner in the project, GOSL, to provide its share of funding to further the development of the Field. We consider that there would have been insufficient time to meet the commitments under the agreement with NPL and we were not prepared to fund the project, which is not without risk, on a 100% basis without different commercial terms and an extension to the commitment period. It was not possible to negotiate a satisfactory position on either matter. NPL subsequently exercised its right to take back 100% of the contractor share in the Samgori PSC from GOSL and, accordingly, effective February 16, 2006 we have withdrawn from the Samgori PSC.

CanArgo Georgia Limited

Pursuant to the terms of CanArgo s PSCs in Georgia, a Georgian not-for-profit company must be appointed as field operator. Until February 2005, there were three such field operating companies, relating to CanArgo s PSCs: Georgian British Oil Company Ninotsminda, Georgian British Oil Company Nazvrevi and Georgian British Oil Company Norio (in respect of both the Norio PSA and the Tbilisi PSC), each of which is 50% owned by a company within the CanArgo group with the remainder owned by Georgian Oil, but with CanArgo having chairmanship of the board and a casting vote. However, on February 1, 2005 Georgian Oil, the State Agency for Regulation of Oil and Gas Resources in Georgia and CanArgo reached agreement on restructuring the field operator companies in our PSCs. A single operator company, CanArgo Georgia Limited, a wholly owned subsidiary company of CanArgo, was appointed the field operator for the Ninotsminda, Nazvrevi, Norio and Tbilisi PSCs. The field operator provides the operating personnel and is responsible for day-to-day operations.

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CanArgo or a company within the CanArgo group pays the operating company s expenses associated with the development of the fields, and the operating company performs its services on a non-profit basis.

Operations under each of the PSCs are determined by a co-ordinating body (Co-ordinating Committee) composed of members designated by the respective CanArgo company and Georgian Oil, representing the State, with the deciding vote allocated to us. If the State believes that any action proposed by us with which the State disagrees would result in permanent damage to a field or reservoir or in a material reduction in production over the life of a field or reservoir, it may refer the disagreement to a western independent expert for binding resolution. Since we acquired our interest in the PSCs, there has been no such disagreement. Georgian regulatory authorities must approve any drilling sites tentatively selected by us before drilling may commence.

Ninotsminda, Manavi and West Rustavi Production Sharing Contract

Ninotsminda

The Ninotsminda Field was discovered in 1979, with commercial production from the Middle Eocene reservoir established in the same year. When NOC assumed developmental responsibility for the Field in 1996, production was minimal. We believe that production was hampered by, among other factors, a lack of funding, civil strife and utilization of old technology and methods.

The Ninotsminda Field is the easternmost element of an elongate anticline which includes the Samgori and Patardzeuli Fields. The Ninotsminda Field is separated from the Patardzeuli Field to the west by a saddle and a NW-SE trending cross fault. The field structure comprises an elongate anticline which measures 6.2 miles (10 Km) (E-W) by 1.9 miles (3 Km) and has a maximum structural relief of around 2,493 feet (760 metres). The main reservoir horizon is the Middle Eocene which consists of well-bedded deep marine sedimentary rocks eroded from volcanoes. Such rocks typically have low matrix porosity with the gross field wide effective porosity of around 0.1% and permeability in the range of 0.5-10 mD, however, in the Ninotsminda Field there are well developed sub-vertical fractures which provide secondary porosity and permeability of up to 100-500 mD. The reservoir which in the field area is up to 1,640 feet (500 metres) thick is at a depth of 8,530 feet (2,600 metres) below surface to 9,843 feet (3,000 metres) below surface. Production from the Field is facilitated by a strong water drive. The oil accumulation has a gas cap which together form a maximum hydrocarbon column of 1,060 feet (323 metres) thickness, with the gas-oil contact at 4,839 feet (1,475 metres) True Vertical Depth Sub Sea (TVDSS) and the oil-water contact at 5,413 feet (1,650 metres) TVDSS. The oil itself is a high quality sweet crude: 41°API, with just 0.24% sulphur, 4.9% paraffin and 8.7% tar and asphaltene.

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NOC began an immediate rehabilitation of the Ninotsminda Field in 1996 which included repairing and adding perforations to existing wells, acquiring additional seismic data and a limited drilling program. The first new well (named N96) was completed in October 1997 and a second well (N98) was completed in October 1998 which was sidetracked as a horizontal producer in 2000. The N98 horizontal well is the most easterly producing well on the field and, although not oriented in an optimal direction so as to best encounter the sub vertical fractures which are important for production, the well has produced approximately 510,000 barrels of oil to date and continues to produce at a steady rate of approximately 200 barrels of oil per day (bopd) with less than 1% water cut.

As a result of this development work, subsequent drilling and the completion of a dynamic reservoir model, it was suggested that a higher level of production could be achieved from the Middle Eocene reservoir from horizontal wells drilled in a preferred orientation so as to intersect the main fracture sets. During 2003, we completed three horizontal sidetrack wells with a total of 3,720 feet (1,134 metres) of horizontal section having been drilled through the reservoir using our own equipment and conventional drilling techniques. Although individual wells tested at rates of over 2,000 barrels of oil per day (bopd) when completed, the wells were put on production at lower rates in accordance with the recommendations of independent petroleum engineering specialists in order to maintain production. However, it has not been possible to maintain production at these levels due to water incursion resulting from what we believe to be coning of water up the fractures, caused to an extent by reservoir damage caused by conventional drilling techniques. Nevertheless, the total production to date from these wells amounts to approximately 745,000 barrels of oil and 597 MMcf (16,908 MCM) of natural gas.

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Despite the fact that initial production results from the horizontal wells indicated significant improvement compared to production from offsetting vertical wells, production was not sustainable at the same high levels due to, what we believe, being drilled overbalanced with a water-based mud that resulted in highly overbalanced pressures and mud invasion into what is already a low permeability reservoir. In an attempt to address this issue, it was decided to employ under balanced drilling (UBD), as well as drilling with coiled tubing (CT) as these technologies have been combined successfully in the international oil industry to drill undamaged horizontal sections for improved production and exploitation of both oil and gas reservoirs.

In June 2004, we signed a contract with WEUS Holding Inc., a subsidiary of Weatherford International Ltd (Weatherford), for the supply of Under Balanced Coiled Tubing Drilling (UBCTD) services to our projects in Georgia. Under the terms of the contract, Weatherford were to supply and operate a UBCTD unit to be used on a program of up to 14 horizontal well-bores on the Ninotsminda and Samgori Fields (we were party to the Samgori PSC at this time). It was considered that these combined drilling technologies would provide the best way to develop and produce both the Ninotsminda and Samgori Fields.

We planned to drill at least five under balanced horizontal sidetracks on the Ninotsminda Field starting with the N22H well which is located in the east part of the Field where the reservoir is tighter but it is believed to be relatively un-drained. We prepared the well with our own crew which involved sidetracking from the existing well-bore at 8,661 feet (2,640 metres) down to 9,193 feet (2,802 metres) and setting a 4$^1/2$ inch liner. Weatherford commenced operations in December 2004. However, technical problems with the Weatherford equipment caused a number of delays which resulted in the UBD not being completed until late February, 2005 with a much shorter than planned section being drilled, and the well not achieving its objective, despite flowing gas at reported high rates through the gas cap section.

Subsequent operations by Weatherford on both N100H2 (an eastern sidetrack to the well where we earlier successfully drilled a conventional horizontal side track to the west) and N49H wells also proved unsuccessful, with Weatherford failing to drill any horizontal section in these wells. Progress was hampered by multiple failures of the downhole motors, other equipment malfunctions and the loss of bottom hole assemblies in the wells. As a result of the failure of Weatherford to successfully complete any horizontal sidetrack development wells on the Ninotsminda Field using UBCTD technology, Weatherford demobilized its equipment and left Georgia in July 2005.

Despite this lack of success, which we attribute mainly to multiple equipment failures, we still believe that under-balanced technology is an appropriate technology for the development of this type of reservoir. However, due to alternative UBCTD equipment not being available in the short to medium term due to a high demand for oil field equipment and services in general, we decided to continue with our horizontal development and production program and drill at least two additional sidetrack wells with our own equipment.

In October 2005 we successfully sidetracked the N100H2 well, having drilled a horizontal section of 1,667 feet (508 metres). A pre-perforated liner was run over a 1,421 foot (433 metres) interval in the horizontal section and was tested at a rate of up to 13.07 MMcf (370 MCM) of gas per day plus 301 barrels of condensate per day. The well is currently producing at a steady rate of approximately 1.4 MMcf (40 MCM) of gas per day and 60 barrels of oil per day (bopd).

The last horizontal sidetrack well to be drilled was the N97H well which we completed in March 2006. It targeted oil volumes un-drained from previous offset area wells and was put on production test following the installation of a slotted liner over a 1,509 feet (460 metres) interval furthest from the heel of the well. The well produced initially with a high water cut, approximately 70%, and an oil rate which peaked at 385 barrels of oil per day (bopd) before declining. Subsequent pressure surveys run with downhole gauges suggested that the N97H well was in communication with the offset N4H well. The most likely assumed scenario was that some of the fracture sets encountered at the end of the N97H well were drained by the N4H well and were hence water filled. Once a very high permeability connection is established with the aquifer, water will flow in preference to any oil filled fractures or matrix of lower permeability.

On the basis of the test data, and due to the fact that the N97H well is approximately 36 feet (11 metres) structurally higher than the N4H well which is still producing oil, we decided to attempt to conduct remedial water isolation. The slotted liner deployed in the horizontal section limited mechanical options for shutting off the toe end of the horizontal section. Previous experience in the field has shown that pulling a liner once set has a very low chance of success due to formation collapse around the liner. Also, a traditional cement isolation was considered to have a low chance of success in a horizontal section, so we opted for a coiled tubing deployed chemical shut-off. Water isolation operations have been performed but subsequent production testing showed that the treatment was not successful.

We plan to set a cement retainer in the solid liner section of the N97H well in order to isolate and abandon the slotted liner part and then perforate the liner in the build up and heel section of the well where there is potential to recomplete this well as a gas producer. This operation will be subject to having a suitable gas off take agreement in place.

Production and development to date at the Ninotsminda Field has focused on the western 2/3rds of the field. The eastern most wells drilled on the field are the N98 horizontal well and the N52 well which is an inclined well towards the southeast. Both of these wells have proven the oil-water contact to be at a deeper level than in the western part of the field. N52, which is a Soviet era well, has never produced from the reservoir due to a complex fish being left in the hole with the well subsequently abandoned. The eastern part of the field has not been exploited because most of the area falls within an environmental protection zone where drilling is prohibited. CanArgo has future plans, subject to financing being available, to develop this area by drilling a highly deviated well from the vicinity of the N98H surface location into the eastern part of the field and completing the well with at least two horizontal sections in the reservoir interval.

During the year, we continued to perform workover operations on the N52 well on the Ninotsminda Field using our own CanArgo Rig #1 and crew to extract the fish (approximately 9,300 feet (2,843 metres) comprising drill pipe, tubing and a milling assembly) from the well and perforate the liner over the reservoir interval. The operation is further complicated due to the inclined nature of the well which has a number of severe doglegs and the potential for the tubing to have deformed when dropped. Although the fishing operation was always considered to present a considerable technical challenge, we did succeed in recovering approximately 7,155 feet (2,181 metres) of 2 7/8 and 2 3/8 tubing. However, we have now reached the pulling capacity of Rig #1 and are unable to progress further with this unit. We are re-evaluating the operation and if we deem the chances of success to be reasonable, we will consider moving our larger rig to the site once it has completed operations on Manavi.

Apart from the Middle Eocene sequence on the Ninotsminda Field there are a number of other reservoirs which contain oil. We have not yet fully evaluated the reserves and economics of production from these zones which include shallower oil reservoirs, the gas cap on the Ninotsminda Field itself or from the hydrocarbon bearing zones below the Middle Eocene. To fully evaluate these zones, further seismic, technical interpretation and the employment of modern drilling techniques such as radial drilling may be required.

Manavi & Cretaceous Exploration

Historically, the main focus of oil and gas exploration in Georgia has been directed at the Middle Eocene sequence which provides the reservoir for the Samgori and Ninotsminda Fields. Although the potential of the underlying Cretaceous sequence has long been recognised from limited drilling, surface outcrop and by analogy to the Cretaceous in nearby Chechnya and Dagestan, this sequence remains very under explored. The Cretaceous is deeper; it was less well defined on Soviet era seismic data and technically more difficult to drill hence the general lack of exploration. As a result, the Cretaceous of the Kura Basin in Georgia has potential to contain very significant volumes of oil and gas reserves and we are fortunate to hold a significant acreage position in this very attractive play fairway.

The Upper Cretaceous stratigraphy typically comprises a chalk and chalky limestone sequence which is of the order of 1,000 feet (300 metres) thick. These rocks, because of their brittle nature, are generally fractured, as seen in outcrop, thus providing reservoirs with potentially significant permeability. Such age rocks are prolific producers in the North Caucasus, and indeed worldwide. The carbonates are deposited on top of a thick pile of

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Cretaceous volcanic rocks which at outcrop are seen to be mainly pillow (submarine) lavas. Although not as good a reservoir as the carbonates, pillow lavas provide a ready made fracture system in the shrinkage joints that separate the individual pillows of a massive lava flow. In the West Rustavi Field well #16 (within CanArgo s acreage) which reached a total depth in the Cretaceous penetrated a volcanic interval which flow tested water with gas at over 3,000 barrels per day thus demonstrating significant permeability.

Following the acquisition and interpretation of new multi-channel 2D seismic data in the Ninotsminda, Manavi and West Rustavi Production Sharing Contract (Ninotsminda PSC) area in 1998 and 2000, we identified several large structures at the Cretaceous level, the largest of which is the Manavi prospect. Manavi is located approximately 28 miles (45 Km) to the east of Tbilisi and just to the east of the Ninotsminda Field and is mapped as a very large, east west trending anticlinal feature at Top Cretaceous reservoir level, measuring approximately 12 miles by 4 miles (19 Km by 5 Km) with 2,950 feet (900 metres) of vertical relief. The prospect lies principally within the Ninotsminda PSC area, but part of the prospect extends into the adjacent Nazvrevi PSC area (also owned by CanArgo). All exploration costs in the Ninotsminda PSC area can be added to the cost recovery pool to be recovered from the sale of oil produced from the Ninotsminda Field subject to there being sufficient production available. CanArgo holds a 100% interest in both of these PSCs through wholly owned subsidiary companies.

The first exploration well drilled on the Manavi structure, Manavi 11 (M11), reached a total depth (TD) of 14,765 feet (4,500 metres) in the Cretaceous in September 2003. The well encountered the Cretaceous limestone target at 14,265 feet (4,348 metres) with over 490 feet (150 metres) of hydrocarbons indicated on wireline logs and with no evidence of an oil-water contact present. On test the M11 well flowed light sweet 34.4°API oil at a visibly significant rate and at a high pressure prior to the test being terminated due to the mechanical failure of the production tubing. Oil was also discovered in the shallower Middle Eocene sequence, but was not tested.

Attempts to recover the damaged tubing from the M11 well were unsuccessful. The well was prepared and subsequently sidetracked using a Saipem S.p.A. (Saipem) Ideco E-2100Az drilling rig equipped with a top-drive drilling system and an oil based mud system provided by Baker-Hughes International (Baker) to control the swelling clays which had proved difficult to drill in the original well.

The Manavi M11Z well reached a TD of 14,994 feet (4,570 metres) in the Cretaceous in October 2005. The well was completed in the Cretaceous using slim-hole drilling technology due to the small size of the casing from which the well was sidetracked. The primary Cretaceous limestone target was encountered at 14,032 feet (4,277 metres) some 230 feet (70 metres) higher than in the original M11 well while the secondary Middle Eocene target zone was penetrated at 13,009 feet (3,965 metres) again significantly higher than in the M11 well. The carbonate section itself was proven to be approximately 980 feet (~300 metres) thick. Drilling data and slim hole wireline logs indicated the presence of hydrocarbons in both the Cretaceous and Middle Eocene target zones. Again no oil water contact was identified.

As initial flow testing only produced small amounts of oil and gas, it quickly became apparent that the reservoir needed to be stimulated in order to properly complete the testing operation. Considering the small diameter of the hole which would limit our ability to optimally test this well, and the fact that the specialist equipment required for this job is both difficult to source and expensive to mobilise for a single operation, we decided to delay completion of this test until after the completion of the planned M12 appraisal well.

The M12 well is located approximately 1.25 miles (2 Km) to the west of the original discovery well. This well was drilled using the Saipem rig and an oil based mud capability with Baker providing mud engineering services. Oil based mud was used in an attempt to control the swelling clays above the target horizon which had proved difficult to drill in the original well. A TD of 16,762 feet (5,109 metres) was reached in mid December 2006 with a total thickness of 1,827 feet (557 metres) of Cretaceous carbonates and volcanics having been encountered. The significant hydrocarbon shows observed during the drilling process and the data obtained from wireline logs indicated a potentially significant hydrocarbon column in the well with no obvious presence of a hydrocarbon-water contact.

Prior to testing the well, an 886 feet (270 metre) 5 pre-perforated production liner was run over the potential reservoir interval and a production testing string set to test the Cretaceous carbonate and interbedded units.

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During setting of the test string, the well began flowing and it was necessary to increase the mud weight to control the well whilst the test string was set. Despite the flow and gas observed at surface during drilling operations, the initial testing operations resulted in a pressure increase at surface but with no discernable flow. Subsequent re-perforating of parts of the test interval has resulted in minor flow with gas being flared and black 40.5º API oil collected at surface. However it is considered likely that formation damage has occurred, probably whilst controlling the well during the setting of the test string, with mud penetrating and blocking the formation.

We concluded that stimulation techniques using acid to clean the well and create conductive pathways from the reservoir to the well-bore and hence bypass any reservoir damage would be required to fully production test the potential of the well. Acid stimulation is a fairly common procedure required to stimulate flow in carbonate reservoirs of the same age in the North Caucasus and indeed elsewhere. However, prior to going to the expense of mobilizing a full acid fracturing spread, it was decided first to conduct a simple acid wash to ensure the effectiveness of acid stimulation under the reservoir conditions encountered in M12. FracTech Ltd., a UK company providing independent well completion and stimulation laboratory testing, design and consultancy services, and Schlumberger well completions experts provided advice on the chemicals and the stimulation program. The stimulation itself was performed through coiled tubing over a 564 foot (172 metres) interval consisting primarily of Cretaceous limestone where the best hydrocarbon shows were observed during drilling. On stimulation, involving a low pressure acid squeeze, the well flowed back unaided and produced liquids at rates of up to 46 barrels per hour (1,104 barrels per day) and a sizeable gas flare. Over a 12 hour period, the well produced a total of 402 barrels of liquids consisting of pumped fluid and chemicals, polymer drilling mud released from the reservoir, oil and gas. The maximum oil cut observed was in excess of 50%.

The well, however, did not sustain flow, and it was concluded that the extent of the formation damage was beyond that which could be cleaned using a simple acid stimulation process, and as such a proper hydraulic fracturing of the formation with acid was required. The results of the initial treatment suggested that acid was the correct approach to opening this formation up to flow while at the same time proving the presence of oil in the reservoir.

On August 13, 2007 we announced that Schlumberger had been contracted to provide pumping equipment, chemicals and services to the Company in order to perform a hydraulic acid fracturing treatment of the Cretaceous reservoir interval in the Manavi 12 well. In order to prepare the well for the fracture stimulation, our operating company, CanArgo Georgia, replaced the 2 7/8 inch production string with a 5 inch fraccing string, and set a temporary plug to reduce the treatment interval, in order to give the operation the best chance of success.

On January 29, 2008 we announced that the acid fracturing operation at the Manavi 12 well had been successfully completed by Schlumberger. The acid fracturing stimulation was conducted using a multi-stage treatment comprising the pumping of a fracture initiating gel followed by hydrochloric acid stimulating fluids and diverter agents. This process was repeated a number of times for maximum efficiency. Approximately 2,700 barrels of treatment fluids were pumped at a maximum rate of up to 15 barrels per minute. An interval totalling 227 feet (69 metres) across the Cretaceous carbonate reservoir section in the well from 15,354 feet (4,680 metres) to 15,581 feet (4,749 metres) was isolated for the treatment. Pressure readings recorded during the operation indicate that fractures were successfully created.

Following the fracturing operation, the well commenced to flow unaided with spent acid and chemicals being flowed to a surface pit. During this time, the effectiveness of the fracture stimulation in opening the reservoir up to flow and the potential deliverability of the reservoir itself was demonstrated by the flow-back rate which reached a maximum flow-back of 223 barrels per hour (5,352 barrels per day). However, despite the initial encouraging oil and gas shows (30 to 35 foot (10 to 11 metre) gas flare) observed during the flow-back or clean up phase, the oil cut did not exceed 7% of the total flow from the well following the clean up process. It would appear that the well was producing excess water, but without further testing and data collection it has not to date been possible to ascertain where this water was coming from. As part of the planned testing program, it is intended to run a production long in the well to determine the origin of this water.

In order to proceed with the testing program, it was necessary to replace the 5 inch frac string required for the stimulation operation with 2 7/8 inch production grade tubing. Attempts to set a blanking plug in the lower completion

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in the well (to isolate the reservoir interval) using coil tubing were abandoned following a mechanical failure of the injector head on the coil tubing unit causing damage to the coil tubing, plug and upper completion string. A wireline unit was mobilised from Baku to reset the plug. This was successfully completed, but on extraction of the frac string by CanArgo Georgia it became apparent that damage had also been caused to the completion which resulted in a modification to the final well completion being required. The production tubing is now in place and pressure tested, however, operations to retrieve the mechanical plug have encountered further complications and additional equipment will need to be mobilised to Georgia to complete the operation. Once the plug is removed, well testing operations will continue. As part of the planned testing program, a wireline-conveyed production logging tool will be run in the well to help locate fluid entry points to the well and provide downhole flow rate and pressure data during the test. This data will assist in the evaluation of well conditions and reservoir performance and help assess the overall potential of the well.

In order to fully evaluate the potential of the Manavi prospect as a whole, significant additional drilling and analysis will be required. As part of this analysis, we are also evaluating the technical feasibility of acquiring a 3-D seismic data survey over the Manavi structure. All these exploratory activities are, however, dependent upon the Company securing additional Funding.

West Rustavi and Kumisi

The West Rustavi Field is located approximately 25 miles (40 Km) southwest of the Ninotsminda Field. Prior to NOC gaining the Ninotsminda PSC, Georgian Oil drilled ten wells in the West Rustavi Field area, two of which produced oil. The Middle Eocene zone is thinner and less productive in this area than at the Ninotsminda Field and only limited production has taken place from the West Rustavi Field. However, NOC has carried out only very limited workover activity on West Rustavi, and potential may yet exist for further oil production from the Middle Eocene dependant on technical and economic factors. Horizontal drilling may also be appropriate for this deposit.

One of the ten wells drilled in the West Rustavi Field by Georgian Oil was deepened to test the deeper Cretaceous and Paleocene horizons. This well, named WR16, was tested and produced at rate of over 1 MMcf (35 MCM) of gas and 3,500 barrels of water per day, thus demonstrating the ability of the Cretaceous to produce at good rates. The WR16 well is interpreted to have tested the down dip extent of a potential Cretaceous gas deposit named Kumisi. Following the signature of the Nazvrevi and Block XIII Production Sharing Contract (Nazvrevi PSC) which lies to the west and south of the West Rustavi Field, we acquired and interpreted additional seismic data over this structure and identified a potentially large prospect extending across the Nazvrevi PSC area with the crestal part of the structure located in the Block XI^{G} which was subsequently secured by CanArgo as part of the Tbilisi PSC area. The structure is potentially very large with the principal risk being closure on the structure to the north and west which is dependent on a downthrown fault seal.

Following an undertaking by the government to purchase any gas produced from the Kumisi prospect on agreed commercial terms, we drilled a well to appraise this prospect in 2007 up-dip of the WR16 well. The Kumisi #1 well is located within the Nazvrevi PSC area and is approximately 7.5 miles (12 Km) southeast of Tbilisi. It is close to the domestic gas transportation grid and the route of the new South Caucasus gas trunkline from Azerbaijan to Turkey. The well commenced drilling in February 2007 and reached a total depth of 11,841 feet (3,609 metres) in June in the Cretaceous.

An extensive testing program was conducted over the Cretaceous section where six separate intervals totalling 482 feet (147 metres) were perforated and tested. Despite elevated gas readings being recorded during drilling, these tests resulted in no discernable flow from the formation and without any hydrocarbons being detected. It is, therefore, reasonable to assume that the Cretaceous reservoir at this location is tight unlike the rocks encountered in other wells in the area. This conclusion was confirmed by a low pressure hydro squeeze which was performed over two separate zones with the data obtained suggesting that these rocks are tight and lack permeability.

Further tests were carried out of potential reservoir units in the overlying Middle and Lower Eocene sequences. Three separate tests were conducted with a total of 79 feet (24 metres) of sandstones being perforated and flow tested. These tests produced water with gas flow to surface in flareable quantities, but non commercial volumes. Each interval was flow tested for a number of days over which there was no increase in the amount of gas produced and the testing was subsequently terminated.

On October 18, 2007 we announced that the Kumisi #1 was being plugged and abandoned. The well results, particularly for the Cretaceous interval, will be reviewed and incorporated into our technical evaluation of the

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area in order to fully understand the remaining potential of the Kumisi area. As part of this analysis, consideration will be given to acid fracture stimulation techniques as a means by which to enhance permeability within the prospect. As no water has been recovered from the well, management believes that potential for a large gas prospect may still exist up-dip of the WR16 well given better reservoir quality.

ITEM 1A. RISK FACTORS

Reference is hereby made to the Section entitled CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS with respect to certain qualifications regarding the following information. The risks described below are not the only ones facing the Company. Additional risks not presently known to us or that we currently deem immaterial may also impair our business operations and adversely affect the price of our shares.

RISKS ASSOCIATED WITH OUR BUSINESS AND BUSINESS OPERATIONS.

We Have Experienced Recurring Losses.

For the fiscal years ended December 31, 2007, 2006, 2005, 2004, and 2003, we recorded net losses of $53,777,214, $60,540,851, $12,335,314, $4,611,031, and $7,473,346 respectively, and have an accumulated deficit of $231,519,571 as at December 31, 2007. Impairments of oil and gas properties, ventures and other assets in 2007 included writedowns of $42,000,000 in our carrying value of the Ninotsminda Field. The Company may never achieve or maintain profitability. The Company will need to generate significant revenues to achieve and maintain profitability. The Company cannot guarantee that it will be able to generate these revenues.

Our Ability To Pursue Our Activities Is Dependent On Our Ability To Generate Cash Flows.

Our ability to continue to pursue our principal activities of acquiring interests in and developing oil and gas fields is dependent upon generating funds from internal sources, external sources and, ultimately, maintaining sufficient positive cash flows from operating activities. Our financial statements have been prepared in accordance with U.S. GAAP, which contemplates continuation of the Company as a going concern. The Company incurred net losses from continuing operations to common stockholders of approximately $65,315,000 $54,432,000 and $12,522,000 for the years ended December 31, 2007, 2006 and 2005 respectively. These net losses included non-cash charges related to depreciation and depletion, impairments, loan interest, amortization of debt discount, extinguishment of debt and stock-based compensation of approximately $61,936,000, $48,213,000 and $7,175,000 for the years ended December 31, 2007, 2006 and 2005 respectively.

In the years ended December 31, 2007 and 2006, the Company s revenues from its Georgian operations did not cover the costs of its operations. At December 31, 2007 the Company had unrestricted cash and cash equivalents available for general corporate use or for use in the Georgian operations of approximately $6,869,000. In 2007 the Company experienced a net cash outflow from operations of approximately $1,800,000 in Georgia. In addition, the Company has a planned capital expenditure budget in 2008 of approximately $12,000,000 in Georgia. The exploration and development wells currently undergoing or waiting to undergo production testing in Georgia currently do not produce enough commercially available quantities of oil and or gas and the Company will not have sufficient working capital and may have to delay or suspend its capital expenditure plans and possibly make cutbacks in its operations. There are no assurances the Company could raise additional sources of equity financing and the covenants contained in the Note Purchase Agreements to which the Company is a party (see Note 9 of the consolidated financial statements) restrict the Company from incurring additional debt obligations unless it receives consent from Noteholders holding at least 51% in aggregate outstanding principal amount of the of the Notes covered by such Agreements.

Consequently, the aforementioned items raise substantial doubt about the Company s ability to continue as a going concern.

We currently have sufficient cash on hand to support our operations through to the third quarter 2008. In order to fund our planned capital expenditure program and to continue our operations after the third quarter 2008, we need to raise substantial funds. As noted elsewhere we are pursuing raising additional funds through -private placements of our equity or debt securities or a possible rights offering to shareholders. We are also actively pursuing the farming out a number of our exploration projects. We are required under the covenants of our existing Convertible Notes to obtain the approval of a majority of our debt holders in order to incur additional indebtedness in excess of $2.5 million, which approval we cannot guarantee. In the event we attempt to raise funds through an equity offering, we would more than likely be required to offer our equity securities at a substantial discount to the current public market price in order to attract investors. In the event that we were to do so, provisions in our outstanding Convertible Notes and Warrants would cause their exercise prices to reset to the lower price in any offering. If low enough, this could effect a significant dilution to current shareholders or possibly to a change of control event.

There can be no assurance of our success in raising these funds. In the event that we are unable to raise additional funds on terms acceptable to us, we will be required to significantly curtail our operations in Georgia and to abandon our currently planned capital expenditure program.

Our Current Operations Are Dependent On the Success of Our Georgian Exploration Activities and Our Activities on the Ninotsminda Field.

To date we have directed substantially all of our efforts and most of our available funds to the development of the Ninotsminda Field in the Kura Basin in the eastern part of Georgia, appraisal of the Manavi oil discovery, and exploration in that area and some ancillary activities in the Kura Basin area. This decision is based on management s assessment of the promise of the Kura Basin area. However, our focus on the Ninotsminda Field has over the past several years resulted in overall losses for us. We cannot assure investors that the exploration and development plans for the Ninotsminda Field will be successful. For example, the Ninotsminda Field may not produce sufficient quantities of oil and gas and at sufficient rates to justify the investment we have made and are planning to make in the Field, and we may not be able to produce the oil and gas at a sufficiently low cost or to market the oil and gas produced at a sufficiently high price to generate a positive cash flow and a profit. Our Georgian exploration program, particularly in the Manavi and Norio areas, is an important factor for future success, and this program may not be successful, as it carries substantial risk. See Our oil and gas activities involve risks, many of which are beyond our control below for a description of a number of these potential risks and losses. In accordance with customary industry practices, we maintain insurance against some, but not all, of such risks and some, but not all, of such losses. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial condition and results of operations.

Our Operation Of The Ninotsminda Field Is Governed By a Production Sharing Contract Which May Be Subject To Certain Legal Uncertainties.

Our principal business and assets are derived from production sharing contracts in Georgia. The legislative and procedural regimes governing production sharing agreements and mineral use licenses in Georgia have undergone a series of changes in recent years resulting in certain legal uncertainties. Our production sharing agreements and mineral use licenses, entered into prior to the introduction in 1999 of a new Petroleum Law governing such agreements have not as yet been amended to reflect or ensure compliance with current legislation. As a result, despite references in the current legislation grandfathering the terms and conditions of our production sharing contracts, conflicts between the interpretation of our production sharing contracts and mineral use licenses and current legislation could arise. Such conflicts, if they arose, could cause an adverse effect on our rights under the production sharing contracts.

We May Encounter Difficulties In Enforcing Our Title To Our Properties.

Since all of our oil and gas interests are currently held in countries where there is currently no private ownership of oil and gas in place, good title to our interests is dependent on the validity and enforceability of the governmental licenses and production sharing contracts and similar contractual arrangements that we enter into with government entities, either directly or indirectly. As is customary in such circumstances, we perform a minimal title investigation before acquiring our interests, which generally consists of conducting due diligence reviews and in certain circumstances securing written assurances from responsible government authorities or legal opinions. We believe that we have satisfactory title to such interests in accordance with standards generally accepted in the crude oil and natural gas industry in the areas in which we operate. Our interests in properties are subject to royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, none of which we believe materially interferes with the use of, or affects the value of, such interests. However, as is

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discussed elsewhere, there is no assurance that our title to our interests will be enforceable in all circumstances due to the uncertain nature and predictability of the legal systems in some of the countries in which we operate.

We Will Require Additional Funds To Implement Our Long-Term Oil And Gas Development Plans.

It will take many years and substantial cash expenditures to develop fully our oil and gas properties. We generally have the principal responsibility to provide financing for our oil and gas properties and ventures. Accordingly, we will need to raise additional funds from outside sources in order to pay for project development costs. We may not be able to obtain that additional financing. If adequate funds are not available, we will be required to scale back or even suspend our operations or such funds may only be available on commercially unattractive terms. The carrying value of the Ninotsminda Field may not be realized unless additional capital expenditures are incurred to develop the Field. Furthermore, additional funds will be required to pursue exploration activities on our existing undeveloped properties. While expected to be substantial, without further exploration work and evaluation the amount of funds needed to fully develop all of our oil and gas properties cannot at present be quantified.

We May Be Unable To Finance Our Oil And Gas Projects.

Our long term ability to finance most of our present oil and gas projects and other ventures according to present plans is dependent upon obtaining additional funding. An inability to obtain financing in the future will require us to scale back or abandon part or all of our future project development, capital expenditure, production and other plans. The availability of equity or debt financing to us or to the entities that are developing projects in which we have interests is affected by many factors, including:

- world and regional economic conditions;
- the state of international relations;
- the stability and the legal, regulatory, fiscal and tax policies of various governments in the areas in which we have or intend to have operations;
- fluctuations in the world and regional price of oil and gas and in interest rates;
- the outlook for the oil and gas industry in general and in areas in which we have or intend to have operations; and
- competition for funds from possible alternative investment projects.

Potential investors and lenders will be influenced by their evaluations of us and our projects, including their technical difficulty, and comparison with available alternative investment opportunities.

Our Operations May Be Subject To The Risk Of Political Instability, Civil Disturbance And Terrorism.

Our principal oil and gas properties and activities are in Georgia, which is located in the former Soviet Union. Operation and development of our assets are subject to a number of conditions endemic to former Soviet Union countries, including political instability. The present governmental arrangements in countries of the former Soviet Union in which we operate were established relatively recently, when they replaced communist regimes. If they fail to maintain the support of their citizens, other institutions, including a possible reversion to totalitarian forms of government, could replace these governments. As recent developments in Georgia have illustrated, the national governments in these countries often must deal with civil disturbances and unrest which may be based on religious, tribal and local and regional separatist considerations. Further, relations between Georgia and the Russian Federation have involved periods of political tension. Our operations typically involve joint ventures or other participatory arrangements with the national government or state-owned companies. The production sharing contract covering the Ninotsminda Field is an example of such arrangements. As a result of such dependency on government participants, our operations could be adversely affected by political instability, terrorism, changes in government institutions, personnel, policies or legislation, or shifts in political power. There is also the risk that governments could seek to nationalize, expropriate or otherwise take over our oil and gas properties either directly or through the enactment of laws and regulations which have an economically

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confiscatory result. We are not insured against political or terrorism risks because management deems the premium costs of such insurance to be currently prohibitively expensive.

We Face The Risk Of Social, Economic And Legal Instability In The Countries In Which We Operate.

The political institutions of the countries that were a part of the former Soviet Union have become more fragmented and the economic institutions of these countries have converted to a market economy from a planned economy. New laws have been introduced, and the legal and regulatory regimes in such regions may be vague, containing gaps and inconsistencies, and are subject to amendment. Application and enforceability of these laws may also vary widely from region to region within these countries. Due to this instability, former Soviet Union countries are subject to certain additional risks including the uncertainty as to the enforceability of contracts. Social, economic and legal instability have accompanied these changes due to many factors which include:

- low standards of living;
- high unemployment;
- under-developed and changing legal and social institutions; and
- conflicts within and with neighbouring countries.

This instability could make continued operations difficult or impossible. Georgia has democratically elected a President following a popular revolt against the previous administration in November 2003 and has successfully quelled a potential separatist uprising in one of its regions. Although the new administration has made public statements supporting foreign investment in Georgia, and has provided specific written support for our activities, there can be no guarantee that this will continue, or that these changes will not have an adverse affect on our operations. There are also some separatist areas within Georgia that receive support from the Russian Federation that may cause instability and potentially affect our activities.

We Face An Inadequate Or Deteriorating Infrastructure In The Countries In Which We Operate.

Countries in the former Soviet Union often either have underdeveloped infrastructures or, as a result of shortages of resources, have permitted infrastructure improvements to deteriorate. The lack of necessary infrastructure improvements can adversely affect operations. For example, we have, in the past, suspended drilling and testing procedures due to the lack of a reliable power supply.

We May Encounter Currency Risks In The Countries In Which We Operate.

Payment for oil and gas products sold in former Soviet Union countries may be in local currencies. Although we currently sell our oil principally for U.S. dollars, we may not be able to continue to demand payment in hard currencies in the future. Most former Soviet Union country currencies are presently convertible into U.S. dollars, but there is no assurance that such convertibility will continue. Even if currencies are convertible, the rate at which they convert into U.S. dollars is subject to fluctuation. In addition, the ability to transfer currencies into or out of former Soviet Union countries may be restricted or limited in the future. We may enter into contracts with suppliers in former Soviet Union countries to purchase goods and services in U.S. dollars. We may also obtain from lenders credit facilities or other debt denominated in U.S. dollars. If we cannot receive payment for oil and oil products in U.S. dollars and the value of the local currency relative to the U.S. dollar deteriorates, we could face significant negative changes in working capital.

We May Encounter Tax Risks In The Countries In Which We Operate.

Countries may add to or amend existing taxation policies in reaction to economic conditions including state budgetary and revenue shortfalls and political considerations. Since we are dependent on international operations, specifically those in Georgia, we may be subject to changing taxation policies including the possible imposition of confiscatory excess profits, production, remittance, export and other taxes. While we are not aware of any recent or proposed tax changes which could materially adversely affect our operations, such changes could occur although we have negotiated economic stabilization clauses in our production sharing contracts in Georgia and all current taxes are payable from the State s share of petroleum produced under the production sharing contracts.

We have identified material weaknesses in our internal controls over financial reporting which, if not remediated, may adversely affect our ability to timely and accurately meet our financial reporting responsibilities.

We identified a number of material weaknesses in our internal controls over financial reporting as of December 31, 2007. Our management, in consultation with our audit committee, is continually reviewing the most cost effective way to address material weaknesses and deficiencies identified. Our failure to complete this remediation process may adversely affect our ability to accurately report our financial results in a timely manner.

We currently are not in compliance with American Stock Exchange (AMEX), Continued Listing Rules

On October 2, 2007, the Company announced that on September 27, 2007, in correspondence with the AMEX, it acknowledged that it was not in compliance with the rules of the AMEX as they relate to the requirement that there be at least a majority of independent directors and at least three independent directors on the audit committee with the possible risk that the Company s common stock may be delisted from such Exchange. We have been advised by AMEX that our common stock will continue to be listed until April 4, 2008 within which period we must regain compliance with the AMEX corporate governance rules or face delisting.

Risks Associated with our Industry.

We May Be Required To Write-Off Unsuccessful Properties And Projects.

In order to realize the carrying value of our oil and gas properties and ventures, we must produce oil and gas in sufficient quantities and then sell such oil and gas at sufficient prices to produce a profit. We have a number of unevaluated oil and gas properties. The risks associated with successfully developing unevaluated oil and gas properties are even greater than those associated with successfully continuing development of producing oil and gas properties, since the existence and extent of commercial quantities of oil and gas in unevaluated properties have not been established. We could be required in the future to write-off our investments in additional projects, including the Ninotsminda Field project, if such projects prove to be unsuccessful.

Our Oil And Gas Activities Involve Risks, Many Of Which Are Beyond Our Control.

Our exploration, development and production activities are subject to a number of factors and risks, many of which may be beyond our control. We must first successfully identify commercial quantities of oil and gas, which is inherently subject to many uncertainties. Thereafter, the development of an oil and gas deposit can be affected by a number of factors which are beyond the operator s control, such as:

- unexpected or unusual geological conditions;
- the recoverability of the oil and gas on an economic basis;
- the availability of infrastructure and personnel to support operations;
- labor disputes;
- local and global oil prices; and
- government regulation and legal and political uncertainties.

Our activities can also be affected by a number of hazards, such as:

- natural phenomena, such as bad weather and earthquakes;
- operating hazards, such as fires, explosions, blow-outs, pipe failures and casing collapses; and
- environmental hazards, such as oil spills, gas leaks, ruptures and discharges of toxic gases.

Any of these factors or hazards could result in damage, losses or liability for us. There is also an increased risk of some of these hazards in connection with operations that involve the rehabilitation of fields where less than

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optimal practices and technology were employed in the past, as was often the case in the countries that were part of the former Soviet Union. We do not purchase insurance covering all of the risks and hazards or all of our potential liability that are involved in oil and gas exploration, development and production.

We May Have Conflicting Interests With Our Partners.

Joint venture, acquisition, financing and other agreements and arrangements must be negotiated with independent third parties and, in some cases, must be approved by governmental agencies. These third parties generally have objectives and interests that may not coincide with ours and may conflict with our interests. Unless we are able to compromise these conflicting objectives and interests in a mutually acceptable manner, agreements and arrangements with these third parties will not be consummated. We may not have a majority of the equity in the entity that is the licensed developer of some projects that we may pursue in the countries that were a part of the former Soviet Union, even though we may be the designated operator of the oil or gas field. In these circumstances, the concurrence of co-venturers may be required for various actions. Other parties influencing the timing of events may have priorities that differ from ours, even if they generally share our objectives. Demands by or expectations of governments, co-venturers, customers, and others may affect our strategy regarding the various projects. Failure to meet such demands or expectations could adversely affect our participation in such projects or our ability to obtain or maintain necessary licenses and other approvals.

Our Operating Direct And Indirect Subsidiaries And Joint Ventures Require Governmental Registration.

Operating entities in various foreign jurisdictions must be registered by governmental agencies and production licenses and contracts for the development of oil and gas fields in various foreign jurisdictions must be granted by governmental agencies. These governmental agencies generally have broad discretion in determining whether to take or approve various actions and matters. In addition, the policies and practices of governmental agencies may be affected or altered by political, economic and other events occurring either within their own countries or in a broader international context.

We Are Affected By Changes In The Market Price Of Oil And Gas.

Prices for oil and natural gas and their refined products are subject to wide fluctuations in response to a number of factors which are beyond our control, including:

- global and regional changes in the supply and demand for oil and natural gas;
- actions of the Organization of Petroleum Exporting Countries;
- weather conditions;
- domestic and foreign governmental regulations;
- the price and availability of alternative fuels;
- political conditions and terrorist activity in the Middle East, Central Asia and elsewhere; and
- overall global and regional economic conditions.

A reduction in oil prices can affect the economic viability of our operations. There can be no assurance that oil prices will be at a level that will enable us to operate at a profit. We may also not benefit from rapid increases in oil prices as the market for the levels of crude oil produced in Georgia by Ninotsminda Oil Company Limited can in such an environment be relatively inelastic. Contract prices are often set at a specified price determined with reference to world market prices (often based on the average of a number of quotations for a marker crude including Dated Brent Mediterranean or Urals Mediterranean at the time of sale) subject to appropriate discounts for transportation and other charges which can vary from contract to contract.

Our Actual Oil And Gas Production Could Vary Significantly From Reserve Estimates.

Estimates of oil and natural gas reserves and their values by petroleum engineers are inherently uncertain. These estimates are based on professional judgments about a number of elements:

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- the amount of recoverable crude oil and natural gas present in a reservoir;
- the costs that will be incurred to produce the crude oil and natural gas; and
- the rate at which production will occur.

Reserve estimates are also based on evaluations of geological, engineering, production and economic data. The data can change over time due to, among other things:

- additional development activity;
- evolving production history; and
- changes in production costs, market prices and economic conditions.

As a result, the actual amount, cost and rate of production of oil and gas reserves and the revenues derived from sale of the oil and gas produced in the future will vary from those anticipated in the reports on the oil and gas reserves prepared by independent petroleum consultants at any given point in time. The magnitude of those variations may be material. The rate of production from crude oil and natural gas properties declines as reserves are depleted. Except to the extent we acquire additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, identify additional productive zones in existing wells or secondary recovery reserves, our proved reserves will decline as reserves are produced. Future crude oil and natural gas production is therefore highly dependent upon our level of success in replacing depleted reserves.

Our Oil And Gas Operations Are Subject To Extensive Governmental Regulation.

Governments at all levels, national, regional and local, regulate oil and gas activities extensively. We must comply with laws and regulations which govern many aspects of our oil and gas business, including:

- exploration;
- development;
- production;
- refining;
- marketing;
- transportation;
- occupational health and safety;
- labor standards; and
- environmental matters.

We expect the trend towards more burdensome regulation of our business to result in increased costs and operational delays. This trend is particularly applicable in developing economies, such as those in the countries that were a part of the former Soviet Union where we have our principal operations. In these countries, the evolution towards a more developed economy is often accompanied by a move towards the more burdensome regulations that typically exist in more developed economies.

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We Face Significant Competition.

The oil and gas industry, including the refining and marketing of crude oil products, is highly competitive. Our competitors include integrated oil and gas companies, government owned oil companies, independent oil and gas companies, drilling and income programs, and wealthy individuals. Many of our competitors are large, well-established, well-financed companies. Because of our small size and lack of financial resources, we may not be able to compete effectively with these companies.

Our Profitability May Be Subject To Changes In Interest Rates.

Our profitability may also be adversely affected during any period of unexpected or rapid increase in interest rates. While we currently have only limited amounts of long term debt, increases in interest rates may adversely affect our ability to raise debt capital to the extent that our income from operations will be insufficient to cover debt service.

Risks Associated with our Stock.

Limited Trading Volume In Our Common Stock May Contribute To Price Volatility.

Our common stock is listed for trading on the Oslo Stock Exchange (OSE) in Norway, and on the American Stock Exchange (AMEX) in New York. During the year ended December 31, 2007, the average daily trading volume for our common stock on the OSE was 2,858,528 shares and 464,611 shares on the AMEX both as reported by Yahoo© and the closing price of our stock during such period ranged from a low of NOK 1.97 and $0.35 to a high of NOK 9.80 and $1.42 on the OSE and AMEX, respectively, as reported by Yahoo©. As a relatively small company with a limited market capitalization, even if our shares are more widelydistributed, we are uncertain as to whether a more active trading market in our common stock will develop. As a result, relatively small trades may have a significant impact on the price of our common stock.

The Price Of Our Common Stock May Be Subject To Wide Fluctuations.

The market price of our common stock could be subject to wide fluctuations in response to quarterly variations in our results of operations, changes in earnings estimates by analysts, changing conditions in the oil and gas industry or changes in general market, economic or political conditions.

We Do Not Anticipate Paying Cash Dividends In The Foreseeable Future.

We have not paid any cash dividends to date on the common stock and there are no plans for such dividend payments in the foreseeable future.

We Have A Significant Number Of Shares Eligible For Future Sale.

At March 7, 2008, we had 242,120,974 shares of common stock outstanding. In addition, at March 7, 2008, we had 45,270 shares issuable upon exchange of CanArgo Oil & Gas Inc. Exchangeable Shares without receipt of further consideration; 8,346,000 shares of common stock subject to outstanding options granted under certain stock option plans (of which 7,844,333 shares were vested at March 7, 2008); 34,911,111 shares issuable upon exercise of outstanding warrants; up to 8,378,667 shares of common stock reserved for issuance under our existing option plans; up to 15,437,500 shares reserved for issuance in connection with certain existing contractual arrangements, including 10,600,000 shares upon conversion of the 12% Subordinated Convertible Guaranteed Note due June 28, 2010 (12% Subordinated Notes) and 4,650,000 shares upon conversion of the Senior Subordinated Convertible Guaranteed Notes due September 1, 2009 (Subordinated Notes). The shares of common stock issuable upon exercise of the stock options have been registered under the Securities Act. In addition, the 29,393,881 shares issued and issuable pursuant to contractual arrangements, including under the Subordinated Notes, are subject to certain registration rights and, therefore, will be eligible for resale in the public market after registration statements covering such shares are declared effective. Sales of shares of common stock under Rule 144 or pursuant to an effective registration statement could have a material adverse effect on the price of the common stock and could impair our ability to raise additional capital through the sale of our equity securities.

Our Ability To Incur Additional Indebtedness Is Restricted Under the Terms of the 12% Subordinated Notes and the Subordinated Notes.

Pursuant to the terms of the Note Purchase Agreements entered into by and between CanArgo and the purchasers of the 12% Subordinated Notes and the Subordinated Notes, we may not incur future indebtedness or issue additional senior or *pari passu* indebtedness, except with the prior consent of the beneficial holders of at

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least 50% of the outstanding principal amount of each such Notes or in limited permitted circumstances. The definition of indebtedness in each of the Note Purchase Agreements encompasses all customary forms of indebtedness, including, without limitation, liabilities for deferred consideration, liabilities for borrowed money secured by any lien or other specified security interest (except permitted liens), liabilities in respect of letters of credit or similar instruments (excluding letters of credit which are 100% cash collateralized) and guarantees in relation to such forms of indebtedness (excluding parent company guarantees provided by CanArgo in respect of the indebtedness or obligations of any of our subsidiaries under any Basic Documents (as defined in each of the Note Purchase Agreements).

Our Ability To Make Future Stock Issuances, the Terms of the 12% Subordinated Notes and the Subordinated Notes And The Provisions Of Delaware Law Could Have Anti-Takeover Effects.

Our board of directors may at any time issue additional shares of preferred stock and common stock without any prior approval by the stockholders, which might impair or impede a third party from making an offer to acquire us. Holders of outstanding shares have no right to purchase a pro rata portion of additional shares of common or preferred stock issued by us. Further, under the terms of the 12% Subordinated Notes and the Subordinated Notes, in the event of a Change of Control or a Control Event we are required to offer to prepay the Notes which might also dissuade a third party from making an acquisition offer. See note 9 of the consolidated financial statements for the definition of Change of Control and Control Event . In addition, the provisions of Section 203 of the Delaware General Corporation Law, to which we are subject, places certain restrictions on third parties who seek to effect a business combination with a company opposed by our board of directors.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

Not applicable.

ITEM 2. PROPERTIES.

Production History

Ninotsminda

The Ninotsminda Field was discovered and initial development began in 1979. Current average gross field production for the month of January 2008 was approximately 425 bopd. Gross and net production from the Ninotsminda Field for the past three years was as follows:

	Oil (Barrels)		Gas (mcf)	
Year Ended December 31,	**Gross**	**Net (PSC Entitlement)(1)**	**Gross**	**Net (PSC Entitlement)(1)**
2007	162,800	105,820	17,776	11,554
2006	178,474	116,008	20,093	13,061
2005	184,952	120,219	71,241	46,307

(1) PSC Entitlement Volumes attributed to CanArgo are calculated using the economic interest method applied to the terms of the production sharing contract. PSC Entitlement Volumes are those produced volumes which, through the production sharing contract, accrue to the benefit of the contractor party after deduction of Georgian Oil s share which includes all Georgian taxes, levies and duties. Ninotsminda Oil Company Limited (NOC) owns 100% of the contractor s interest in the PSC. As a result of CanArgo s interest in NOC, these volumes accrue to the benefit of CanArgo for the recovery of capital, repayment of operating costs and share of profit.

Samgori

Between April 2004 and February 16, 2006 we had a 50% interest in the Samgori (Block XI ^{B}) Production Sharing Contract (Samgori PSC) in Georgia. We terminated our interest with effect from February 16, 2006.

The gross and net production for the period in which we had an interest in the Samgori PSC including the period January 1, 2006 to February 16, 2006 was as follows:

	Oil (Barrels)		
Year Ended December 31,	Gross	Net (PSC Entitlement)(2)	CSL Net Share
2007	-	-	-
2006 (two months)	10,226	7,669	3,835
2005	166,298	124,723	62,362

(2) PSC Entitlement Volumes attributed to CanArgo are calculated using the economic interest method applied to the terms of the production sharing contract. PSC Entitlement Volumes are those produced volumes which, through the production sharing contract, accrue to the benefit of the contractor parties after deduction of Georgian Oil s share which includes all Georgian taxes, levies and duties. CanArgo Samgori Limited (CSL) owned 50% of the contractor s interest in the PSC. As a result of CanArgo s interest in CSL, these volumes accrued to the benefit of CanArgo for the recovery of capital, repayment of operating costs and share of profit.

We ceased to have an interest in this project on February 16, 2006.

Productive Wells and Acreage

The following table summarizes as of December 31, 2007, 2006 and 2005 with respect to NOC the number of productive oil and gas wells and the total developed acreage for the Ninotsminda Field. Such information has been presented on a gross basis, representing our 100% interest in NOC.

	Gross Number of Wells	Acres
2007	11	492
2006	11	492
2005	11	492

On December 31, 2007, there were no other productive wells or developed acreage within the Ninotsminda PSC area except for one gross well on the West Rustavi Field which was shut-in at that date.

The only other productive wells or developed acreage on any of our other Georgian properties were within the Samgori PSC area on the Samgori Field. This information below as of December 31, 2007, 2006 and 2005 is presented on a net basis representing our 100% interest in CSL which in turn had a 50% interest in the Samgori PSC. Our interest in the Samgori PSC was terminated with effect from February 16, 2006.

	Net Number of Wells	Acres
2007	-	-
2006	-	-
2005	11.5	950

Reserves

<u>Ninotsminda Field, Georgia</u>

The following table summarizes net hydrocarbon reserves for the Ninotsminda Field in Georgia. This information is derived from a report dated as of January 1, 2008 prepared by Oilfield Production Consultants (OPC), independent petroleum consultants headquartered in London, England. This report is available for inspection at our principal executive offices during regular business hours. The reserve information in the table below has also been filed with the Oslo Stock Exchange.

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Oil Reserves	Oil Reserves Gross (Million Barrels)	PSC Entitlement Volumes (1) (Million Barrels)
Proved Developed	1.386	0.901
Proved Undeveloped	0.979	0.637
Total Proven	2.365	1.538

Gas Reserves	Gas Reserves - Gross (Billion Cubic Feet)	PSC Entitlement Volumes (1) (Billion Cubic Feet)
Proved Developed	1.921	1.249
Proved Undeveloped	0.587	0.381
Total Proven	2.508	1.630

(1) PSC Entitlement Volumes attributed to CanArgo are calculated using the economic interest method applied to the terms of the production sharing contract. PSC Entitlement Volumes are those produced volumes which, through the production sharing contract, accrue to the benefit of the respective contractor parties after deduction of Georgian Oil s share which includes all Georgian taxes, levies and duties. As a result of CanArgo s interest in NOC, these volumes accrue to the benefit of CanArgo for the recovery of capital, repayment of operating costs and share of profit.

No independent reserves have been assessed for the West Rustavi Field.

Exploration and Development Wells

The following table summarizes as of December 31, 2007 the number of exploration and development oil and gas wells in progress. Such information has been presented on a gross basis, representing our 100% interest in these wells.

	Exploration	Development
Ninotsminda Field	2	
Norio Field	1	
Nazvrevi Field	0	
	3	

The following table summarizes as of December 31, 2007, 2006 and 2005, the total number of dry exploration oil and gas wells drilled. The information has been represented on a gross basis, representing our 100% interest in this well.

	2007	2006	2005

Ninotsminda Field	1	1	1
	1	1	1

The following table summarizes as of December 31, 2007, 2006 and 2005, the total number of dry development oil and gas wells drilled. The information has been presented on a gross basis representing our 100% interest in this well. Our interest in the Samgori PSC was terminated with effect from February 16, 2006.

	2007	**2006**	**2005**
Nazvrevi Field	1	0	0
Samgori Field*	1	1	1
	2	1	1

* CSL 100% funded a development well drilled on the Samgori complex in 2004.

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The following table summarizes as of December 31, 2007, 2006 and 2005, the total number of completed wells that flowed commercial quantities of oil and gas. The information has been represented on a gross basis, representing our 100% interest in these wells.

	2007	**2006**	**2005**
Ninotsminda Field	8	8	8
	8	8	8

Proved reserves are those reserves estimated as recoverable under current technology and existing economic conditions from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economically and technically successful in the subject reservoir. Proved reserves include proved developed reserves (producing and non-producing reserves) and proved undeveloped reserves.

Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive wells that are reasonably certain of production when drilled.

Uncertainties exist in the interpretation and extrapolation of existing data for the purposes of projecting the ultimate production of oil from underground reservoirs and the corresponding future net cash flows associated with that production. The estimating process requires educated decisions relating to the evaluation of all available geological, engineering and economic data for each reservoir. The amount and timing of cost recovery is a function of oil and gas prices which can fluctuate significantly over time. The oil price used in the Ninotsminda Field report by OPC as of January 1, 2008 was $94.00 per barrel based on the Brent spot price per barrel at year end less $7.50 per barrel discount, in line with CanArgo s most recent contractual arrangement. The net gas price used in the Ninotsminda Field report was $0.71 per Mcf in line with CanArgo s contractual arrangements at the time of issuing the report. Having considered the geological and engineering data in the interpretation process, the Company believes with reasonable certainty that the stated proven reserves represent the estimated quantities of oil and gas to be recoverable in future years under existing operating and economic conditions.

Undeveloped Acreage

The following table summarizes the gross and net undeveloped acreage held under the Ninotsminda, Nazvrevi/Block XIII, Norio/North Kumisi, and Tbilisi production sharing contracts as of December 31, 2007.

The information regarding net acreage represents our interest based on our 100% interest in NOC and the subsidiaries holding the Nazvrevi/Block XIII contract, the Norio/North Kumisi and the Tbilisi Block XI^G and XI^H contracts.

PSC	**Gross**		**Net**	
	Acres	**Square Kilometres**	**Acres**	**Square Kilometres**
Ninotsminda, Manavi and West Rustavi covering Block XI^E	27,923	113	27,923	113
Nazvrevi and Block XIII	388,447	1,572	388,447	1,572
Norio (Block XI^C) and North Kumisi (1)	265,122	1,061	265,122	1,061
Block XI^G and XI^H	119,845	485	119,845	485
Total	801,337	3,231	801,337	3,231

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The following table summarizes the gross and net undeveloped acreage held under the Ninotsminda, Nazvrevi/Block XIII, Norio/North Kumisi and Tbilisi production sharing contracts as of March 7, 2008. The information regarding net acreage represents our interest based on our 100% interest in NOC and the subsidiaries holding the Nazvrevi/Block XIII contract, the Norio/North Kumisi, and the Tbilisi Block XI^G and XI^H contracts.

PSC	Gross Acres	Gross Square Kilometres	Net Acres	Net Square Kilometres
Ninotsminda, Manavi and West Rustavi covering Block XI^E	27,923	113	27,923	113
Nazvrevi and Block XIII	194,223	787	194,223	787
Norio (Block XI^C) and North Kumisi (1)	265,122	1,061	265,122	1,061
Block XI^G and XI^H	119,845	485	119,845	485
Total	607,113	2,446	607,113	2,446

Office Space

We lease office space in London, England; Guernsey, Channel Islands; and Tbilisi, Georgia. The leases have remaining terms varying from one to seven years and nine months and annual rental charges ranging from approximately $48,000 to $347,000.

Processing, Sales and Customers Georgia

Georgian Oil built a considerable amount of infrastructure in and adjacent to the Samgori and Ninotsminda Fields prior to entering into the production sharing contracts for these Fields. NOC now uses that infrastructure, including initial processing equipment and CSL used it during the term of the Samgori PSC.

The mixed oil, gas and water fluid produced from the Ninotsminda Field wells flows into a two-phase separator located at the Ninotsminda Field, where gas associated with the oil is separated. The oil and water mixture is then transported approximately seven miles (11 Km) either in a pipeline or by truck to Georgian Oil s central processing facility at Sartichala for further treatment.

At Sartichala, the water is separated from the oil. NOC then sells its share of oil in this state to buyers at Sartichala for local consumption or transfer it by pipeline approximately 12 miles (20 Km) to a railhead at Gatchiani or by road tanker to Vaziani rail loading terminal primarily for export sales. At the railheads, the oil is loaded into railcars for transport to the Black Sea port of Batumi, Georgia, where oil can be loaded onto tankers for international shipment. Buyers transport the oil at their own risk and cost from the delivery point at Sartichala.

In 2007 NOC sold all of its oil production to international buyers. In early 2006, NOC sold its oil production in accordance with the terms of a sales agreement concluded with Primrose Financial Group (PFG) in February 2005 which included the sale of oil to other customers nominated by PFG under this agreement. Later oil was sold to third party buyers under unrelated contracts. During the year, oil was purchased and paid for by a total of 2 customers each representing sales greater than 10% of oil revenue:

Customer	Percent of Oil Revenue
Caspian Trading	84.1%
Interchem Energy	15.9%

Management believes that the loss of any customer should not materially adversely affect our production

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revenues because of the existence of a ready market for our production and an established export route for crude oil from the Caspian area via Georgia and its Black Sea ports. However, there can be no assurance that such substitute purchasers of our production will offer to purchase our production on the same terms and conditions as previously obtained.

In 2006, NOC sold its oil production to two customers of which the following customer represented sales greater than 10% of oil revenue:

Customer	Percent of Oil Revenue
Interchem Energy	91.6%

In 2005, NOC sold its oil production to four customers of which the following two customers represented sales greater than 10% of oil revenue:

Customer	Percent of Oil Revenue
Interchem Energy	74.5%
Gero	15.8%

For NOC, sales during 2007 were based on the average of a number of quotations for Dated Brent Mediterranean as quoted in *Platts Crude Oil Marketwire* © with an appropriate average discount for transportation and other charges amounting to $7.85 per barrel. Sales in 2006 were also sold against a Brent quotation at an average discount of $8.44 per barrel. Sales in 2005 were also sold against a Brent quotation at an average discount of $7.50 per barrel.

The average sales price and the average production cost per unit (excluding depreciation, depletion and amortization) of oil and gas produced by NOC for each of the last three years was as follows:

Year Ended December 31,	Average Sales Price		Unit Production Cost $/boe
	Oil $/boe	Gas $/Mcf	
2007	67.97	0.70*	12.20
2006	53.69	0.66*	10.94
2005	44.78	0.53	14.83

* In 2007 and 2006, due to the uncollectibility of gas revenues, the Company decided to record gas revenues on a cash basis. Average sales prices above reflect contractual prices for gas delivered and revenues from these deliveries may not have been collected during the year.

Prior to withdrawing from the Samgori PSC in February 2006, CSL sold its share of production to 1 customer for the period to December 31, 2006:

Customer	Percent of Oil Revenue
Interchem Energy	100.0%

In 2005, CSL sold its share of production to four customers of which the following one customer represented sales greater than 10% of oil revenue for the period to December 31, 2005:

Customer	Percent of Oil Revenue
Interchem Energy	80.0%

For the period in which CSL was selling production in 2006, sales to international markets were based on the average of a number of quotations for Dated Brent Mediterranean with an appropriate discount for transportation and other charges. The average discount to the price of Brent crude oil as quoted in *Platts Crude Oil Marketwire*

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© for Brent Dated Mediterranean for all sales in 2006 was $8.44 per barrel. Sales in 2005 were also sold against a Brent quotation at an average discount of $6.16 per barrel. The higher discounts in 2006 are due to smaller quantities of oil being available for sale.

The average sales price and the average production cost per unit of oil and gas produced by CSL for the past three years were as follows:

Year Ended December 31,	Average Sales Price		Unit Production Cost $/boe
	Oil $/boe	Gas $/mcf	
2007	-	-	-
2006*	59.57	0.00	64.62
2005	46.12	0.00	18.79

* Our interest in the Samgori PSC was terminated with effect from February 16, 2006.

Prices for oil and natural gas are subject to wide fluctuations in response to a number of factors including:

global and regional changes in the supply and demand for oil and natural gas;

actions of the Organization of Petroleum Exporting Countries;

weather conditions;

domestic and foreign governmental regulations;

the price and availability of alternative fuels;

political conditions in the Middle East and elsewhere; and

overall global and regional economic conditions.

Other Georgian Production Sharing Contracts

Nazvrevi and Block XIII Production Sharing Contract (Nazvrevi PSC)

In February 1998, our wholly owned subsidiary, CanArgo (Nazvrevi) Limited (CNZ) entered into a second production sharing contract with Georgian Oil and the State of Georgia. This contract covers the Nazvrevi (Block XI^{D}) and Block XIII areas of East Georgia, an approximately 496,186 acre (2,008 Km ^{2}) exploration area adjacent to the Ninotsminda and West Rustavi Fields and containing existing infrastructure. The agreement came into effect on February 20, 1998 and extends for twenty-five years with the final year of the contract being 2023. We are required to relinquish at least half of the area then covered by the Nazvrevi PSC, but not any portions being actively developed, at five-year intervals commencing in 2003. The first relinquishment was made in 2003, followed by a further relinquishment in February 2008 of the southern part of the area, reducing the area to approximately 194,233 acres (787 Km ^{2}).

Under the Nazvrevi PSC, CNZ pays all operating and capital costs. We first recover our cumulative operating costs from production. After deducting production attributable to operating costs, 50% of the remaining production (cost recovery petroleum), considered on an annual basis, is applied to reimburse us for our cumulative capital costs. While cumulative capital costs remain unrecovered, the other 50% of remaining production (profit petroleum) is allocated on a 50/50 basis between Georgian Oil and CNZ. After all cumulative capital costs have been recovered by us, remaining production after deduction of operating costs is allocated on a 70/30 basis between Georgian Oil and CNZ, respectively. Thus, while we are responsible for all of the costs associated with the Nazvrevi PSC we are only entitled to receive 30% of production after cost recovery. The allocation of a share of production to Georgian Oil, however, relieves us of all obligations we would otherwise have to pay the State of Georgia for taxes and similar levies related to activities covered by the production sharing contract. Both Georgian Oil and CNZ will take their respective shares of oil production under the Nazvrevi PSC in kind but the intent is to jointly market any available gas production.

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The first phase of the preliminary work program under the Nazvrevi PSC involved primarily a seismic survey of a portion of the exploration area and the processing and interpretation of the data collected. The seismic survey has been completed, and the results of those studies have been interpreted and possible oil and gas prospects and exploration drilling locations are being identified. The cost of the seismic program was approximately $1.5 million, and met the minimum obligatory work commitment under the contract. The Department for Protection of Mineral Resources and Mining has confirmed that CNZ have met the requirements of the work program defined in the production sharing contract. The Manavi oil discovery may extend into the Nazvrevi PSC area and the West Rustavi 16 (WR16) gas discovery located within the Ninotsminda PSC area may extend into Block XIII (the Kumisi prospect), and there are several identified prospects, however as the Nazvrevi and Block XIII area is an exploration area and no discoveries have been made to date, it is not possible to estimate the expenditures needed to discover and, if discovered, produce commercial quantities of oil and gas.

One of the ten wells drilled in the West Rustavi Field by Georgian Oil was deepened to test the deeper Cretaceous and Paleocene horizons. This well, named WR16, was tested and produced at rate of over 1 MMcf (35 MCM) of gas and 3,500 barrels of water per day, thus demonstrating the ability of the Cretaceous to produce at good rates. The WR16 well is interpreted to have tested the down dip extent of a potential Cretaceous gas deposit named Kumisi. We acquired and interpreted additional seismic data over this structure and identified a potentially large prospect extending across the Nazvrevi PSC area with the crestal part of the structure located in the Block XI^G which was subsequently secured by CanArgo as part of the Tbilisi PSC area. The structure is potentially very large with the principal risk being closure on the structure to the north and west which is dependent on a downthrown fault seal.

Following an undertaking by the government to purchase any gas produced from the Kumisi prospect on agreed commercial terms, we drilled a well to appraise this prospect in 2007 up-dip of the WR16 well. The Kumisi #1 well is located within the Nazvrevi PSC area and is approximately 7.5 miles (12 Km) southeast of Tbilisi. It is close to the domestic gas transportation grid and the route of the new South Caucasus gas trunkline from Azerbaijan to Turkey. The well commenced drilling in February 2007 and reached a total depth of 11,841 feet (3,609 metres) in June in the Cretaceous.

An extensive testing program was conducted over the Cretaceous section where six separate intervals totalling 482 feet (147 metres) were perforated and tested. Despite elevated gas readings being recorded during drilling, these tests resulted in no discernable flow from the formation and without any hydrocarbons being detected. It is, therefore, reasonable to assume that the Cretaceous reservoir at this location is tight unlike the rocks encountered in other wells in the area. This conclusion was confirmed by a low pressure hydro squeeze which was performed over two separate zones with the data obtained suggesting that these rocks are tight and lack permeability.

Further tests were carried out of potential reservoir units in the overlying Middle and Lower Eocene sequences. Three separate tests were conducted with a total of 79 feet (24 metres) of sandstones being perforated and flow tested. These tests produced water with gas flow to surface in flareable quantities, but non commercial volumes. Each interval was flow tested for a number of days over which there was no increase in the amount of gas produced and the testing was subsequently terminated.

On October 18, 2007 we announced that the Kumisi #1 was being plugged and abandoned. The well results, particularly for the Cretaceous interval, will be reviewed and incorporated into our technical evaluation of the area in order to fully understand the remaining potential of the Kumisi area. As part of this analysis consideration will be given to acid fracture stimulation techniques as a means by which to enhance permeability within the prospect. As no water has been recovered from the well, management believes that potential for a large gas prospect may still exist up-dip of the WR16 well given better reservoir quality.

Norio (Block XI^C) and North Kumisi Production Sharing Agreement (Norio PSA)

In December 2000, CanArgo, through its then 50% owned subsidiary CanArgo Norio Limited (CNL), entered into a third production sharing contract with the State of Georgia represented by Georgian Oil and the State Agency for Regulation of Oil and Gas Resources in Georgia. The Norio PSA covers the Norio and North

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Kumisi blocks of East Georgia, an exploration area of approximately 265,122 acres (1,061 Km ^{2}), following the first contractual relinquishment in April 2006, adjacent to the Ninotsminda and Samgori Fields. The Norio PSA came into effect on April 9, 2001 and extends for a period of twenty-five years with the final year of the contract being 2026. We are required to relinquish at least 50% of the remaining contract area, but not any portions being actively developed at five-year intervals commencing in 2011 up to 2026. There are two existing oil fields on the Norio PSA area, Norio and Satskhenisi which are old, small, relatively shallow fields and which produce small quantities of oil. CNL has determined production from these fields to be uneconomic, and the fields are currently being operated by Georgian Oil whereby Georgian Oil takes all production to compensate it for its costs under what is effectively a social program. If CNL wishes, it could take over field operations and production from these fields forthwith.

The commercial terms of the Norio PSA are similar to those of the Nazvrevi PSC with the exception that after all cumulative capital costs have been recovered by CNL, remaining production after deduction of operating costs is allocated on a 60/40 basis between Georgian Oil and CNL, respectively. Thus, while CNL is responsible for all of the costs associated with development of the Norio PSA, it is only entitled to receive 40% of production after cost recovery. On September 30, 2004 we announced that we had increased our interest in CNL, by buying out the remaining minority shareholders who held a 25% interest in that company. CNL is now a wholly owned subsidiary of CanArgo.

The first phase of the preliminary work program under the Norio PSA involved primarily a seismic survey of a portion of the exploration area and the processing and interpretation of the data collected. The seismic survey has been completed, and the results of those studies have and will continue to be interpreted. In addition to the main target, which is the Middle Eocene, the potential of the license area to produce from the Miocene, Sarmatian, Upper Eocene and Cretaceous is being assessed. The cost of the seismic program was approximately $1.5 million.

The second phase of the preliminary work program under the Norio PSA commenced in January 2002 when the first exploration well named MK72 was spudded on the Norio prospect using the CanArgo Ural Mash rig. Norio is a large prospect identified at Middle Eocene level and is analogous in size to the nearby Samgori and Ninotsminda Field complex immediately to the south and east of the block. It has been reported that the Samgori Oil Field alone has produced approximately 180 million barrels of oil to date.

Completion of the MK72 well was delayed as a result of technical problems encountered whilst drilling, and the need to farm out a portion of the equity in the block in order to partly fund the drilling. In September 2003, CNL signed a farm-in agreement relating to the Norio PSA with a wholly owned subsidiary of Georgian Oil, the Georgian State Oil Company. This farm-in agreement obligated Georgian Oil to pay up to $2.0 million to deepen, to a planned depth of 16,733 feet (5,100 metres), the MK-72 well in return for a 15% interest in the contractor share of the Norio PSA. Georgian Oil also had an option, exercisable for a limited period after completion of the well, to increase its interest to 50% of the contractor share of the Norio PSA on payment to CNL of $6.5 million. Due to Georgian Oil s inability to continue to fund the drilling of the well, operations were subsequently suspended and only resumed after May 2005 when we repaid to Georgian Oil the investment it had made in the MK72 well to terminate the farm-in agreement and option and secure a 100% working interest in the Norio PSA.

In August 2005 the Saipem drilling rig and Baker oil-based mud system was mobilized to the MK72 exploration well as our Ural Mash rig had difficulty drilling through a highly over-pressured section of swelling clays above the prognosed target zone. On December 29, 2005 we announced that the MK72 well reached a depth of 16,076 feet (4,900 metres) in the Middle Eocene reservoir having encountered very good oil and gas shows. Before the well could be drilled to the planned depth and tested, the bottom hole assembly (BHA) became stuck due to hole collapse. Subsequent attempts to retrieve the BHA were not successful and we decided to abandon the lower target due to a limited chance of sidetracking the well at this depth in a small diameter hole and to focus our attention on the shallower oil discovery in the overlying Oligocene sands which were the secondary target for the well. From the data obtained from the Middle Eocene (the primary target for the well) we believe that an oil discovery has been made at this level, and that the reservoir has exhibited both permeability (evidenced by drilling mud losses whilst drilling) and the presence of movable light oil. As such, even though the Middle Eocene has not been fully evaluated, the MK72 well has encountered the Middle Eocene

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reservoir on prognosis, and with hydrocarbons thus achieving many of the objectives of this wildcat exploration well.

A comprehensive testing program on the oil bearing Oligocene sandstones encountered in the Norio MK72 well commenced in mid-March 2006 when a total of 322 feet (98 metres) of net sands were perforated over the interval 12,096 feet (3,687 metres) to 13,622 feet (4,152 metres). These sands had good oil shows whilst drilling, with oil to surface and with hydrocarbons being interpreted on the electric logs which also indicated a substantial thickness of net pay sands. Following an extensive testing program, the well sustained flow on a small choke size with low average gross fluid rates of approximately 13 barrels per day consisting of light 48.6ºAPI oil, gas and water.

A number of surge clean up flows, a re-perforation of selected intervals, and a low pressure hydrofrac using our own pumping unit have been attempted but these have not improved reservoir deliverability. It is believed that the current flow is limited to a thinner, less permeable, interval whilst the better quality reservoir remains isolated due to potential reservoir damage caused by the invasive fluid damage of the drilling mud. The lower zones in the well, which would have been in communication with the Oligocene interval through the well-bore, were drilled with a 1.9 to 2.2 Specific Gravity (SG) mud due to anticipated reservoir pressures while the results from the testing program indicate that the mid interval reservoir pressure for the Oligocene whilst still over pressured, is lower at 1.7 SG equivalent. As a result of possible mud damage, the current perforations may have not penetrated deep enough beyond the damaged zone to allow proper communication between the more permeable formations and the well-bore.

We considered mobilising a more powerful fraccing unit and equipment to Georgia in order to pump a propant and fluid into the well at high pressure and volume, but the potential for this technology is limited due to a lack of a cement bond behind the casing and the large interval which has been perforated. The well has been left on test production for the past several months but there has been no discernable increase in gross fluid production rate. As we would appear to have exhausted all the low cost options available to us at this time to bypass any damage that may exist in the near-well-bore area and establish better communication between the well-bore and the reservoir, we believe that the only effective option remaining is to sidetrack the well or to drill a new well. The latter, of course, would enable us to attempt to test both the Oligocene and Middle Eocene intervals both of which are considered to have significantly reduced geological risk.

The Norio PSA covers a large exploration area with what management believe to be good oil and gas potential with the presence of reservoir rocks and moveable hydrocarbons having been confirmed by drilling. We have mapped several significant prospects at different stratigraphic levels within the area several of which are on trend with the MK72 well. Both the Oligocene and Middle Eocene prospects as mapped are potentially large and warrant appraising. It is planned, subject to financing being available from internal resources or through a farm out arrangement, that an appraisal well will be drilled to fully evaluate these attractive discoveries, with the well being designed to enter the Middle Eocene reservoir with a larger hole size. In 2007, several companies undertook a technical review of the Norio area and a number of these have expressed an interest in further evaluating a farm-in to this acreage.

As the area in which we are currently drilling is an exploration area with no commercial discoveries (excluding the small shallow fields currently operated by Georgian Oil), it is not possible to estimate the expenditures needed to discover and, if discovered, produce commercial quantities of oil and gas.

Block XI^G and XI^H Production Sharing Contract (Tbilisi PSC)

In November 2002, our subsidiary, CanArgo Norio Limited (CNL), won the tender for the oil and gas exploration and production rights to the Tbilisi PSC, an area of approximately 119,845 acres (485 Km^2) in eastern Georgia adjacent to the Norio, Block XIII and West Rustavi areas. In July 2003, it was announced that CNL, had signed a Production Sharing Contract covering these areas. The Tbilisi PSC came into effect on September 29, 2003 and will continue for an initial period of ten years at which time it will terminate unless we have made a commercial discovery in which case the PSC will continue in full force and effect until September 29, 2028. The commercial terms of the Tbilisi PSC are similar to those of the Norio PSA with the exception that Georgian Oil does not have an option to acquire an interest in the contractor party s share following a commercial discovery.

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Under the Tbilisi PSC we have a commitment to evaluate existing seismic and geological data which we have completed and to acquire additional seismic data within three years of the effective date of the contract which is September 29, 2003. This work was delayed until after the completion of the Kumisi #1 well which has an impact on the future prospectivity of this acreage. We are in negotiation with the State Agency for Oil & Gas Regulation in Georgia and Georgian Oil and Gas Corporation about an appropriate exploration program for this PSC in light of the Kumisi #1 results. The total commitment over the remaining period is $350,000.

Following our acquisition of the minority shareholding in CNL in September 2004, our interest in the Tbilisi PSC increased from 75% to 100%.

Geophysical evaluation of the Kumisi prospect up-dip of the WR16 well in the Nazvrevi PSC area showed the structure to extend across the Nazvrevi PSC area with the crestal part of the structure located in the Block XI^{G} in the Tbilisi PSC. The Kumisi structure has been partly evaluated by the Kumisi #1 well drilled in 2007 and abandoned in October 2007 following an extensive well testing program. The well results, particularly for the Cretaceous interval, will be reviewed and incorporated into our technical evaluation of the area in order to fully understand the remaining potential of the Kumisi structure both within the Nazvrevi PSC and Tbilisi PSC. As no water has been recovered from the well, the potential for a large gas prospect still exists up-dip of the WR16 well given better reservoir quality.

Refining and Other Activities

We also have engaged in other oil and gas activities in Georgia and elsewhere. A discussion of discontinued operations is incorporated herein by reference from note 17 to the consolidated financial statements included elsewhere herein.

Drilling Rigs and Associated Equipment

We own several items of drilling equipment, and other related machinery primarily for use in our Georgian operations. These include two drilling rigs, pumping equipment and ancillary machinery. This equipment is currently being used by our operator company to drill exploration wells and provide support to our development work on the Ninotsminda Field and on the Manavi and Norio discoveries.

EMPLOYEES

As of December 31, 2007, we had 150 full time employees. Of our full time employees, the entity acting as operator of the Ninotsminda Field for NOC has 124 full time employees, and substantially all of that company s activities relate to the production and development of the Ninotsminda Field. We have not experienced any strikes, work stoppages or other labour disputes and management believes the Company s relations with its employees are satisfactory.

ITEM 3. LEGAL PROCEEDINGS.

On September 12, 2005, WEUS Holding Inc (WEUS) a subsidiary of Weatherford International Ltd lodged a formal Request for Arbitration with the London Court of International Arbitration against CanArgo Energy Corporation in respect of unpaid invoices for work performed under the Master Service Contract dated June 1, 2004 between the Company and WEUS for the supply of under-balanced coil tubing drilling equipment and services during the first and second quarter of 2005. Pursuant to the Request for Arbitration, WEUS demand for relief is $4,931,332. The Company is contesting the claim and has filed a counterclaim.

On July 27, 2005, GBOC Ninotsminda, an indirect subsidiary of the Company, received a claim raised by certain of the Ninotsminda villagers (listed on pages 1 to 76 of the claim) in the Tbilisi Regional Court in respect of damage caused by the blowout of the N100 well on the Nintosminda Field in Georgia on September 11, 2004. An additional claim was received in December 2005 and amended in March 2006, thus bringing the relief sought pursuant to both claims to the sum of approximately 314,000,000 GEL (approximately $198,000,000 at the exchange rate of GEL to US dollars in effect on December 31, 2007).

We believe that we have meritorious defenses to both claims and are defending them vigorously.

The Company has been named in with a group of defendants by former interest holders of the Lelyaki oil field in Ukraine. The plaintiffs are seeking damages of approx 600,000 CDN (approx $611,000 at December 31, 2007 exchange rates). The former owners of UK-Ran Oil Company disposed of their investment in the field prior to selling the Company to CanArgo. CanArgo believes the claim against it to be meritless.

Other than the foregoing, as at December 31, 2007 there were no legal proceedings pending involving the Company, which, if adversely decided, would have a material adverse effect on our financial position or our business. From time to time we are subject to various legal proceedings in the ordinary course of our business.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

No matters were submitted to a vote of our security holders during the fourth quarter of the year ended December 31, 2007.

PART II

ITEM 5. MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

CanArgo is listed on the Oslo Stock Exchange in Norway (OSE) where our stock trades under the symbol CNR and also on the AMEX where our common stock trades under the symbol CNR . Until April 21, 2004 our common stock traded on the NASDAQ Over The Counter Bulletin Board (OTCBB) under the symbol GUSH .

The following table sets forth the high and low sales prices of the common stock on the OSE and the AMEX for the periods indicated. Average daily trading volume on these markets during these periods is also provided. OSE and AMEX data is derived from published financial sources. Sales prices on the OSE were converted from Norwegian kroner into United States dollars on the basis of the daily exchange rate for buying United States dollars with Norwegian kroner announced by the central bank of Norway. Prices in Norwegian kroner are denominated in NOK . For historical price verification in Norway please see http://uk.table.finance.yahoo.com/k?s=cnr.ol&g=d and for exchange rate conversion $/NOK for the corresponding dates please see www.oanda.com/convert/fxhistory.

	OSE			AMEX		
Fiscal Quarter Ended	High	Low	Average Daily Volume	High	Low	Average Daily Volume
March 31, 2006	1.44	1.07	1,109,034	1.46	1.03	804,198
June 30, 2006	1.18	0.65	1,260,919	1.20	0.65	691,559
September 30, 2006	1.58	0.63	7,025,224	1.55	0.62	1,278,022
December 31, 2006	1.63	1.04	2,556,167	1.66	1.05	752,662
March 31, 2007	1.57	0.91	3,672,925	1.42	0.87	683,251
June 30, 2007	1.10	0.69	2,935,388	1.12	0.67	432,919
September 30, 2007	1.03	0.70	2,494,248	1.02	0.73	353,638
December 31, 2007	0.95	0.36	2,321,990	0.95	0.35	396,655

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At March 7, 2008, the closing price of our common stock was $0.44 on the AMEX and $0.46 on the OSE. On March 7, 2008 one U.S. dollar equalled 5.13 Norwegian kroner.

On March 1, 2008 the number of holders of record of our common stock was approximately 15,000. We have not paid any cash dividends on our common stock.

Dividend Policy

We currently intend to retain future earnings, if any, for use in our business and, therefore, do not anticipate paying any cash dividends in the foreseeable future. The payment of future dividends, if any, will depend, among other things, on our results of operations and financial condition and on such other factors as our Board of Directors may, in their discretion, consider relevant. In addition, the terms of our outstanding notes prohibit us from paying dividends and making other distributions.

Equity Compensation Plan Information

The following table provides information as of December 31, 2007 with respect to shares of our common stock that may be issued under our equity compensation plans as of December 31, 2007:

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price per share of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders	8,346,000	$ 0.80	8,378,667
Equity compensation plans not approved by security holder			
	8,346,000	$ 0.80	8,378,667

PERFORMANCE GRAPH

The chart set forth below shows the value of an investment of $100 on December 31, 2002 in each of the Company s Common Stock, the American Stock Exchange Index and a peer group of certain oil and gas exploration and development companies. The peer group consists of the following independent oil and gas exploration companies: Aminex plc, Bow Valley Energy Ltd., EuroGas, JKX Oil & Gas plc, Lundin, Ramco Energy plc and Soco International plc. As the Company is listed on the American Stock Exchange, the AMEX Index of listed stocks has been included in the comparison table.

All values assume reinvestment of the pre-tax value of dividends paid by companies included in these indices and are calculated as of December 31 of each year. The share price performance is weighted based on market capitalisation using the number of outstanding shares at the beginning of each period. The historical stock price performance of the Common Stock shown in the performance graph below is not necessarily indicative of future stock price performance.

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Year End	2002	2003	2004	2005	2006	2007
CNR	100	1,058	2,480	5,389	7,275	4,789
Peer Index	100	219	270	604	798	930
AMEX	100	142	174	213	249	292

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ITEM 6. SELECTED FINANCIAL DATA.

Reference is hereby made to the Section entitled CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS with respect to certain qualifications regarding the following information.

The following selected financial data, derived from our historical audited consolidated financial statements, reflect the historical results of operations and selected balance sheet items of CanArgo and should be read in conjunction with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and the consolidated financial statements included in Item 8. Financial Statements and Supplementary Data herein.

	Year Ended December 31,				
Reported in $000 s Except for per Common Share Amounts	**2007**	**2006**	**2005**	**2004**	**2003**
Financial Performance					
Operating revenues from continuing operations	7,208	6,527	5,279	7,833	8,105
Impairments of oil and gas properties and other assets	42,000	39,000		175	
Operating loss from continuing operations	(46,581)	(48,519)	(11,015)	(4,036)	(159)
Other expense	(18,733)	(5,913)	(1,507)	(2,226)	(597)
Net loss from continuing operations	(63,315)	(54,432)	(12,522)	(6,262)	(756)
Net income (loss) from discontinued operations, net of taxes and minority interest(1)	11,537	(6,109)	187	1,504	(6,608)
Cumulative effect of change in accounting policy					41
Net loss	(53,777)	(60,541)	(12,335)	(4,757)	(7,323)
Net loss per common share basic and diluted before cumulative effect of change in accounting principle from continuing operations	(0.27)	(0.24)	(0.06)	(0.05)	(0.01)
Net income (loss) per common share basic and diluted before cumulative effect of change in accounting principle from discontinued operations	0.05	(0.03)	(0.00)	0.01	(0.07)
Net loss per common share basic and diluted	(0.22)	(0.27)	(0.06)	(0.04)	(0.08)
Cash generated by (used in) operations	(1,763)	(9,320)	(8,872)	(4,312)	4,431
Working capital	715	11,628	14,808	23,952	3,890
Total assets	59,552	136,485	147,448	105,160	73,360
Long term obligations	11,697	37,264	26,524	1,254	
Temporary Equity	2,120	2,120	2,120		
Stockholders equity	38,009	79,369	105,729	96,821	56,708
Cash dividends per common share					

(1) In September 2002, CanArgo approved a plan to sell CanArgo Standard Oil Products Limited (CSOP) to finance its Georgian and Ukrainian development projects and in October 2002, CanArgo agreed to sell its 50% holding to Westrade Alliance LLC, an unaffiliated company, for $4 million in an arms-length transaction, with legal ownership being transferred upon receipt of final payment due in August 2003. The agreed consideration to be exchanged does not result in an impairment of the carrying value of assets held for sale. The assets and liabilities of CSOP have been classified as Assets held for sale and Liabilities for sale for all periods presented. The results of operations of CSOP have been classified as discontinued for all periods presented. The minority interest related to CSOP has not been reclassified for any of the periods presented, however net income from discontinued operations is disclosed net of taxes and minority interest.

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

Qualifying Statement With Respect To Forward-Looking Information and Risks

THE FOLLOWING INFORMATION CONTAINS FORWARD-LOOKING INFORMATION. See Cautionary Statement Regarding Forward-Looking Statements above and Forward-Looking Statements below. Our activities and investments in our common stock involve a high degree of risk. Each of the risks in Item 1A Risk Factors may have a significant impact on our future financial condition and results of operations. The following should be read in conjunction with the audited financial statements and the notes thereto included herein.

General

We are an independent energy company engaged in operations located primarily in countries comprising the former Soviet Union involving the acquisition, exploration, development, production and marketing of crude oil and, to a lesser extent, natural gas. Our principal means of growth has been through the acquisition and subsequent development and exploitation of producing oil and gas properties by means of entering into production sharing arrangements and licence arrangements with governmental or local oil companies. As a result of our historical exploration and acquisition activities, we believe that we have a substantial inventory of exploitation and development opportunities, the successful completion of which is critical to the maintenance and growth of our current production levels. We have incurred net losses in the last five years, and there can be no assurance that operating income and net earnings will be achieved in future periods. Our financial results depend upon many factors, particularly the following factors which most significantly affect our results of operations:

the sales prices of crude oil and, to a lesser extent, natural gas;

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- the level of total sales volumes of crude oil and, to a lesser extent, natural gas;

- the availability of, and our ability to raise additional, capital resources and provide liquidity to meet cash flow needs; and

- the level and success of exploration and development activity.

Reserves and Production Volumes

Year end gross total proved oil reserves at the Ninotsminda Field were 2.365 MMbbl down 30% from 2006 s 3.379 MMbbl. Over the same period, gross total proved natural gas reserves from the Ninotsminda Field in Georgia were 2.508 Bcf down 11% from 2006 s 2.807 Bcf.

The reduction in our proved oil reserves was primarily the result of our unsuccessful completion of the work-over of the N52 well in the eastern part of the Ninotisminda Field and our failure to implement other planned operations during the year. This resulted in a reduction in total proved undeveloped reserves of 589,000 bbls. The remaining proved undeveloped reserves of 979,000 bbls could face further impairment if the N99 well we have budgeted in 2008 is unsuccessful or in the event we are unable to fund those expenditures.

Because our proved reserves will decline as crude oil and natural gas and natural gas liquids are produced, unless we acquire additional properties containing proved reserves or conduct successful exploration and development activities, our reserves and production will decrease. Our ability to acquire or find additional reserves in the near future will be dependent, in part, upon the amount of available funds for acquisition, exploitation and development projects.

Exploitation and Development Activity

<u>Ninotsminda</u>

Following the rehabilitation and development work undertaken on the Ninotsminda Field, we realised that the performance of wells was being negatively impacted by being drilled over-balanced with conventional drilling methods and we decided to employ under-balanced drilling technology in order to maximise productivity and recoverability from the field. It was planned that future horizontal wells on the field should be drilled using this technology. In June 2004, we signed a contract with WEUS Holding Inc., a subsidiary of Weatherford International Ltd (Weatherford), for the supply of Under-Balanced Coiled Tubing Drilling (UBCTD) services to our projects in Georgia. Under the terms of the contract, Weatherford were to supply and operate an UBCTD unit to be used on a program of up to 14 horizontal well-bores on our Ninotsminda and Samgori Fields (we were party to the Samgori PSC at this time). Elsewhere in the oil industry, the use of under-balanced drilling techniques has been shown to result in significantly less formation damage, resulting in higher sustained production rates and ultimate recovery. At the same time, utilisation of coiled tubing drilling gives greater flexibility in the drilling process and in the control of the horizontal section. It was considered that these combined drilling technologies would provide the best way to develop and produce both the Ninotsminda and Samgori Fields.

We planned to drill at least five under-balanced horizontal sidetracks on the Ninotsminda Field and UBCTD operations started on the first well in the program, the N22H well, in December 2004, but due to technical problems with the equipment the under-balanced drilling was not completed until late February 2005 and then only with a much shorter than planned section being drilled, and the well not achieving its objective, despite flowing gas at reported high rates through the gas cap section. Subsequent operations by Weatherford on both N100H2 and N49H wells also proved unsuccessful, with Weatherford failing to drill any horizontal section in these wells. Progress was hampered by multiple failures of the downhole motors, other equipment malfunctions and the loss of bottom hole assemblies in the wells.

Following the failure of Weatherford to successfully complete any horizontal sidetrack development wells on the Ninotsminda Field using UBCTD technology, Weatherford demobilized its equipment and left Georgia in July 2005. Despite this lack of success, which we attribute mainly to multiple equipment failures, we still believe that under-balanced technology is an appropriate technology for the development of this type of reservoir. However, as we withdrew from the Samgori PSC in February 2006, it would be prohibitively expensive to mobilise an UBCTD unit to Georgia solely for a drilling campaign on the Ninotsminda Field and we are considering other ways in which to most efficiently produce the remaining reserves of the field.

In the meantime, we have continued with our jointed pipe drilling operations using our own rigs and equipment and the directional drilling services of Baker Hughes International to drill horizontal sidetrack wells on the Ninotsminda Field. In October 2005 we completed the N100H2 sidetrack which tested at a rate of up to 13.07 MMcf (370 MCM) of gas per day plus 301 barrels of condensate per day (a total of 2,480 barrels oil

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equivalent[1]) on a 63/64 inch (25 mm) choke with a flowing tubing head pressure (FTHP) of 70 atmospheres (1,000 psig). The well is currently producing at a steady rate of approximately 1.4 MMcf (40 MCM) of gas per day and 60 barrels of oil per day (bopd).

The latest horizontal sidetrack well to be drilled on the field was the N97H well which we completed in March 2006. It targeted oil volumes un-drained from previous offset area wells and was put on production test following the installation of a slotted liner over a 1,509 feet (460 metres) interval furthest from the heel of the well. The well produced initially with a high water cut, approximately 70%, and an oil rate which peaked at 385 barrels of oil per day (bopd) before declining. Subsequent pressure surveys run with downhole gauges suggested that the N97H well was in communication with the offset N4H well. The most likely assumed scenario was then some of the fracture sets encountered at the end of the N97H well were drained by the N4H well and were hence water filled. Once a very high permeability connection is established with the aquifer, water will flow in preference to any oil filled fractures or matrix of lower permeability.

On the basis of the test data and due to the fact that the N97H well is approximately 36 feet (11 metres) structurally higher than the N4H well which is still producing oil, we decided to attempt to conduct remedial water isolation. The slotted liner deployed in the horizontal section limited mechanical options for shutting off the toe end of the horizontal section. Previous experience in the field has shown that pulling a liner once set has a very low chance of success due to formation collapse around the liner. Also, a traditional cement isolation was considered to have a low chance of success in a horizontal section, so we opted for a coiled tubing deployed chemical shut-off. Water isolation operations have been performed but subsequent production testing showed that the treatment was not successful.

We plan to set a cement retainer in the solid liner section of the N97H well in order to isolate and abandon the slotted liner part and then perforate the liner in the build up and heel section of the well where there is potential to re-complete this well as a gas producer. This operation will be subject to having a suitable gas off take agreement in place.

Our only reliable gas sales to date from the Ninotsminda Field were during the winter seasons of 1999 and 2001 when we supplied gas to AES Gardabani (a subsidiary of AES Corporation) who operated a number of units at the Gardabani thermal power plant in eastern Georgia at that time. Gas sales since then have been erratic and payment has been unreliable. In June 2006, our subsidiary company, Ninotsminda Oil Company Limited (NOC) concluded a gas sales agreement with the State of Georgia for the sale of gas to the State run power units at Gardabani once the State had completed repairs to the 25 mile (41 kilometres) pipeline between Ninotsminda and Gardabani. The initial planned quantity of gas to be supplied under the agreement was up to 7.06 MMscf (200 MCM) per day with initial delivery expected in the fall of 2006. However, due to the pipeline being much more extensively damaged than originally anticipated and issues over the commingling of gas, the State decided not to proceed with these repairs. As an alternative, the State proposed to connect the region of Georgia within which the Ninotsminda Field is located to the Georgian domestic gas grid. This work was completed in February 2008 and may eventually provide NOC with an alternative market for its gas production with potential for higher prices and regular sales.

For the past couple of years, NOC has supplied the gas produced from the Ninotsminda Field (mainly associated gas) at a low price to local villages as part of a social program rather than flare this gas. Despite the price being approximately $0.71 per Mcf ($25 per MCM) there is a significant outstanding debt to NOC for gas supplied. It was not possible for the Company to terminate supply in order to force payment as these villages did not have access to an alternative supply of gas. With the connection of these areas to the domestic gas grid, both NOC and Georgian Oil and Gas Corporation (GOGC), who is also the State representative in the Production Sharing Contract and sells its share of the gas together with NOC, believe that we are now in a better position to enforce payment and commercialise gas sales. Following the completion of the gas connection, the existing gas sales agreement between NOC, GOGC and the local gas supply company has been amended to increase the price for gas to an average of approximately $2.72 per Mcf ($97 per MCM). The new price is based on a quantity of gas being set aside for domestic household consumption at $0.71 per Mcf ($25 per MCM) with the balance supplied to the gas distribution company at $4.73 per Mcf ($167 per MCM). The amendment is effective from February 1,

1

using 6,000
cubic feet of gas
equals 1 barrel
of
oil/condensate

2008 and the gross quantity of gas to be supplied under the agreement is approximately 2.12 MMcf (60 MCM) per day. At present, the local gas distribution companies are State entities, but plans are in place to privatize all gas distribution companies in the near future. This is also expected to help with the payment for gas.

In an attempt to increase production at the field in 2007, we continued to perform workover operations on the N52 well using our own Rig #1 and crew to extract a complex fish (approximately 9,300 feet (2,843 metres) comprising drill pipe, tubing and a milling assembly) from the well. N52, which is a Soviet era well, has never produced from the reservoir due to the fish with the well subsequently being abandoned. The fishing operation was further complicated due to the inclined nature of the well which has a number of severe dog legs and the potential for the tubing to have deformed when dropped. Although the operation was always considered to present a considerable technical challenge, we did succeed in recovering approximately 7,155 feet (2,181 metres) of 2 7/8 and 2 3/8 tubing. However, we have now reached the pulling capacity of Rig #1 and are unable to progress further with this unit. We are re-evaluating the operation and if we deem the chances of success to be reasonable, we will consider moving our larger rig to the site once it has completed operations on Manavi.

Further to an ongoing technical re-evaluation of the field, we believe that there are significant potential reserves remaining both within and surrounding the main field area and we are working on a production enhancement strategy to increase the level of production subject to financing being available. Such production enhancement strategy might include:

1. Drilling a new well into the undeveloped eastern part of the field. This would be a highly deviated well from the vicinity of the N98H surface location with up to two horizontal sections being completed in the Middle Eocene reservoir interval. The eastern part of the Ninotsminda Field has not been exploited because most of the area falls within an environmental protection zone where drilling is prohibited. The N98 horizontal well is the most easterly producing well on the field and, although not oriented in an optimal direction so as to best encounter the sub vertical fractures which are important for production, the well has produced approximately 510,000 barrels of oil to date and continues to produce at a steady rate of approximately 200 barrels of oil per day (bopd) with less than 1% water cut. More optimally oriented horizontal wells such as N4H and N100H1 initially tested at rates of approximately 2,000 bopd.

2. The use of new technology such as radial drilling to produce trapped oil from shallower reservoirs overlying the main Middle Eocene reservoir. Previous attempts to produce these zones using perforations were largely unsuccessful due to near well bore reservoir damage caused by unsuitable drilling fluids used in Soviet times. We believe that radial drilling could have the ability to reach beyond this damage and we are currently in discussion with a service provider both on the suitability and availability of this technology.

3. General workover activity such as the application of perforations to unproduced reservoir intervals and the use of water isolation techniques to suppress water flow and increase oil production.

4. Following the completion of testing operations at M12, consideration may be given to mobilising CanArgo rig #2 to the N52 well to complete the fishing operation, add perforations to the reservoir interval and, if successful, put the well into production.

5. On the northern flank of the Ninotsminda Field is a potentially large accumulation of oil in the Oligocene interval which has been established by the N78 well. This well, drilled several years ago, initially tested oil at a rate of 1,074 bopd, but never produced at this high rate due to the incursion of water due to what is believed to be a poor cement bond behind the casing. A new vertical well to the west of N78 is being considered in order to better exploit this accumulation.

If crude oil and, to a lesser extent, natural gas prices return to depressed levels or if our production from our development program does not deliver a significant production increase, our revenues, cash flow from operations and financial condition will be materially adversely affected. For more information, see Liquidity and Capital Resources .

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Exploration and Appraisal

Manavi

The first exploration well drilled on the Manavi structure, Manavi 11 (M11), reached a total depth (TD) of 14,765 feet (4,500 metres) in the Cretaceous in September 2003. The well encountered the Cretaceous limestone target at 14,265 feet (4,348 metres) with over 490 feet (150 metres) of hydrocarbons indicated on wireline logs and with no evidence of an oil-water contact present. On test the M11 well flowed light sweet 34.4ºAPI oil at a visibly significant rate and at a high pressure prior to the test being terminated due to the mechanical failure of the production tubing. Oil was also discovered in the shallower Middle Eocene sequence, but was not tested.

Attempts to recover the damaged tubing from the M11 well were unsuccessful. The well was prepared and subsequently sidetracked using a Saipem S.p.A. (Saipem) Ideco E-2100Az drilling rig equipped with a top-drive drilling system and an oil based mud system provided by Baker-Hughes International (Baker) to control the swelling clays which had proved difficult to drill in the original well.

The Manavi M11Z well reached a TD of 14,994 feet (4,570 metres) in the Cretaceous in October 2005. The well was completed in the Cretaceous using slim-hole drilling technology due to the small size of the casing from which the well was sidetracked. The primary Cretaceous limestone target was encountered at 14,032 feet (4,277 metres) some 230 feet (70 metres) higher than in the original M11 well while the secondary Middle Eocene target zone was penetrated at 13,009 feet (3,965 metres) again significantly higher than in the M11 well. The carbonate section itself was proven to be approximately 980 feet (~300 metres) thick. Drilling data and slim hole wireline logs indicated the presence of hydrocarbons in both the Cretaceous and Middle Eocene target zones. Again no oil water contact was identified.

As initial flow testing only produced small amounts of oil and gas, it quickly became apparent that the reservoir needed to be stimulated in order to properly complete the testing operation. Considering the small diameter of the hole which would limit our ability to optimally test this well, and the fact that the specialist equipment required for this job is both difficult to source and expensive to mobilise for a single operation, we decided to delay completion of this test until after the completion of the planned M12 appraisal well.

The M12 well is located approximately 1.25 miles (2 Km) to the west of the original discovery well. This well was drilled using the Saipem rig and an oil based mud capability with Baker providing mud engineering services. Oil based mud was used in an attempt to control the swelling clays above the target horizon which had proved difficult to drill in the original well. A TD of 16,762 feet (5,109 metres) was reached in mid December 2006 with a total thickness of 1,827 feet (557 metres) of Cretaceous carbonates and volcanics having been encountered. The significant hydrocarbon shows observed during the drilling process and the data obtained from wireline logs indicated a potentially significant hydrocarbon column in the well with no obvious presence of a hydrocarbon-water contact.

Prior to testing the well, an 886 feet (270 metre) 5 pre-perforated production liner was run over the potential reservoir interval and a production testing string set to test the Cretaceous carbonate and interbedded units. During setting of the test string, the well began flowing and it was necessary to increase the mud weight to control the well whilst the test string was set. Despite the flow and gas observed at surface during drilling operations, the initial testing operations resulted in a pressure increase at surface but with no discernable flow. Subsequent re-perforating of parts of the test interval has resulted in minor flow with gas being flared and black 40.5º API oil collected at surface. However it is considered likely that formation damage has occurred, probably whilst controlling the well during the setting of the test string, with mud penetrating and blocking the formation.

We concluded that stimulation techniques using acid to clean the well and create conductive pathways from the reservoir to the well-bore and hence bypass any reservoir damage would be required to fully production test the potential of the well. Acid stimulation is a fairly common procedure required to stimulate flow in carbonate reservoirs of the same age in the North Caucasus and indeed elsewhere. However, prior to going to the expense of mobilizing a full acid fracturing spread, it was decided first to conduct a simple acid wash to ensure the effectiveness of acid stimulation under the reservoir conditions encountered in M12. FracTech Ltd., a UK company providing independent well completion and stimulation laboratory testing, design and consultancy services, and Schlumberger well completions experts provided advice on the chemicals and the stimulation program. The stimulation itself was performed through coiled tubing over a 564 foot (172 metres) interval consisting primarily of Cretaceous limestone where the best hydrocarbon shows were observed during drilling. On stimulation, involving a low pressure acid squeeze, the well flowed back unaided and produced liquids at rates of up to 46 barrels per hour (1,104 barrels per day) and a sizeable gas flare. Over a 12 hour period, the well produced a total of 402 barrels of liquids consisting of pumped fluid and chemicals, polymer drilling mud released from the reservoir, oil and gas. The maximum oil cut observed was in excess of 50%.

The well, however, did not sustain flow, and it was concluded that the extent of the formation damage was beyond that which could be cleaned using a simple acid stimulation process, and as such a proper hydraulic fracturing of the formation with acid was required. The results of the initial treatment suggested that acid was the correct approach to opening this formation up to flow while at the same time proving the presence of oil in the reservoir.

On August 13, 2007 we announced that Schlumberger had been contracted to provide pumping equipment, chemicals and services to the Company in order to perform a hydraulic acid fracturing treatment of the Cretaceous reservoir interval in the Manavi 12 well. In order to prepare the well for the fracture stimulation, our operating company, CanArgo Georgia, replaced the 2 7/8 inch production string with a 5 inch fraccing string, and set a temporary plug to reduce the treatment interval, in order to give the operation the best chance of success.

On January 29, 2008 we announced that the acid fracturing operation at the Manavi 12 well had been successfully completed by Schlumberger. The acid fracturing stimulation was conducted using a multi-stage treatment comprising the pumping of a fracture initiating gel followed by hydrochloric acid stimulating fluids and diverter agents. This process was repeated a number of times for maximum efficiency. Approximately 2,700 barrels of treatment fluids were pumped at a maximum rate of up to 15 barrels per minute. An interval totalling 227 feet (69 metres) across the Cretaceous carbonate reservoir section in the well from 15,354 feet (4,680 metres) to 15,581 feet (4,749 metres) was isolated for the treatment. Pressure readings recorded during the operation indicate that fractures were successfully created.

Following the fracturing operation, the well commenced to flow unaided with spent acid and chemicals being flowed to a surface pit. During this time, the effectiveness of the fracture stimulation in opening the reservoir up to flow and the potential deliverability of the reservoir itself was demonstrated by the flow-back rate which reached a maximum flow-back of 223 barrels per hour (5,352 barrels per day). However, despite the initial encouraging oil and gas shows (30 to 35 foot (10 to 11 metre) gas flare) observed during the flow-back or clean up phase, the oil cut did not exceed 7% of the total flow from the well following the clean up process. It would appear that the well was producing excess water, but without further testing and data collection it has not to date been possible to ascertain where this water was coming from. As part of the planned testing program, it is intended to run a production long in the well to determine the origin of this water.

In order to proceed with the testing program, it was necessary to replace the 5 inch frac string required for the stimulation operation with 2 7/8 inch production grade tubing. Attempts to set a blanking plug in the lower completion in the well (to isolate the reservoir interval) using coil tubing were abandoned following a mechanical failure of the injector head on the coil tubing unit causing damage to the coil tubing, plug and upper completion string. A wireline unit was mobilised from Baku to reset the plug. This was successfully completed, but on extraction of the frac string by CanArgo Georgia it became apparent that damage had also been caused to the completion which resulted in a modification to the final well completion being required. The production tubing is now in place and pressure tested, however, operations to retrieve the mechanical plug have encountered further complications and additional equipment will need to be mobilised to Georgia to complete the operation. Once the plug is removed, well testing operations will continue. As part of the planned testing program, a wireline-conveyed production logging tool will be run in the well to help locate fluid entry points to the well and provide downhole flow rate and pressure data during the test. This data will assist in the evaluation of well conditions and reservoir performance and help assess the overall potential of the well.

In order to fully evaluate the potential of the Manavi prospect as a whole, significant additional drilling and analysis will be required As part of this analysis, we are also evaluating the technical feasibility of acquiring a 3-D seismic data survey over the Manavi structure. All these exploratory activities are, however, dependent upon the

Company securing additional funding.

If commercial production can be established at M12, the well would be put into longterm test production and consideration would be given to performing a similar acid fracture stimulation of the M11z well which remains suspended.

Norio

The second phase of the preliminary work program under the Norio PSA commenced in January 2002 when the first exploration well named MK72 was spudded on the Norio prospect using the CanArgo Ural Mash rig. Norio is a large prospect identified at Middle Eocene level and is analogous in size to the nearby Samgori and Ninotsminda Field complex immediately to the south and east of the block. It has been reported that the Samgori Oil Field alone has produced approximately 180 million barrels of oil to date.

Completion of the MK72 well was delayed as a result of technical problems encountered whilst drilling, and the need to farm out a portion of the equity in the block in order to partly fund the drilling. In September 2003, CNL signed a farm-in agreement relating to the Norio PSA with a wholly owned subsidiary of Georgian Oil, the Georgian State Oil Company. This farm-in agreement obligated Georgian Oil to pay up to $2.0 million to deepen, to a planned depth of 16,733 feet (5,100 metres), the MK-72 well in return for a 15% interest in the contractor share of the Norio PSA. Georgian Oil also had an option, exercisable for a limited period after completion of the well, to increase its interest to 50% of the contractor share of the Norio PSA on payment to CNL of $6.5 million. Due to Georgian Oil s inability to continue to fund the drilling of the well, operations were subsequently suspended and only resumed after May 2005 when we repaid to Georgian Oil the investment it had made in the MK72 well to terminate the farm-in agreement and option and secure a 100% working interest in the Norio PSA.

In August 2005 the Saipem drilling rig and Baker oil-based mud system was mobilized to the MK72 exploration well as our Ural Mash rig had difficulty drilling through a highly over-pressured section of swelling clays above the prognosed target zone. On December 29, 2005, we announced that the MK72 well reached a depth of 16,076 feet (4,900 metres) in the Middle Eocene reservoir having encountered very good oil and gas shows. Before the well could be drilled to the planned depth and tested, the bottom hole assembly (BHA) became stuck due to hole collapse. Subsequent attempts to retrieve the BHA were not successful and we decided to abandon the lower target due to a limited chance of sidetracking the well at this depth in a small diameter hole and to focus our attention on the shallower oil discovery in the overlying Oligocene sands which were the secondary target for the well. From the data obtained from the Middle Eocene (the primary target for the well) we believe that an oil discovery has been made at this level, and that the reservoir has exhibited both permeability and the presence of movable light oil. As such, even though the Middle Eocene has not been fully evaluated, the MK72 well has encountered the Middle Eocene reservoir on prognosis, and with hydrocarbons thus achieving many of the objectives of this wildcat exploration well.

A comprehensive testing program on the oil bearing Oligocene sandstones encountered in the Norio MK72 well commenced in mid-March 2006 when a total of 322 feet (98 metres) of net sands were perforated over the interval 12,096 feet (3,687 metres) to 13,622 feet (4,152 metres). These sands had good oil shows whilst drilling, with oil to surface and with hydrocarbons being interpreted on the electric logs which also indicated a substantial thickness of net pay sands. Following an extensive testing program, the well sustained flow on a small choke size with low average gross fluid rates of approximately 13 barrels per day consisting of light 48.6ºAPI oil, gas and water.

A number of surge clean up flows, a re-perforation of selected intervals, and a low pressure hydrofrac using our own pumping unit have been attempted but these have not improved reservoir deliverability. It is believed that the current flow is limited to a thinner, less permeable, interval whilst the better quality reservoir remains isolated due to potential reservoir damage caused by the invasive fluid damage of the drilling mud. The lower zones in the well, which would have been in communication with the Oligocene interval through the well-bore, were drilled with a 1.9 to 2.2 Specific Gravity (SG) mud due to anticipated reservoir pressures while the results from the testing program indicate that the mid interval reservoir pressure for the Oligocene whilst still over pressured, is lower at 1.7 SG equivalent. As a result of possible mud damage, the current perforations may have not penetrated deep enough beyond the damaged zone to allow proper communication between the more permeable formations and the well-bore.

We considered mobilising a more powerful fraccing unit and equipment to Georgia in order to pump a propant and fluid into the well at high pressure and volume, but the potential for this technology is limited due to a lack of a cement bond behind the casing and the large interval which has been perforated. The well has been left on test production for the past several months but there has been no discernable increase in gross fluid production rate. As we would appear to have exhausted all the low cost options available to us at this time to bypass any damage that may exist in the near-well-bore area and establish better communication between the well-bore and the reservoir, we believe that the only effective option remaining is to sidetrack the well or to drill a new well. The latter, of course, would enable us to attempt to test both the Oligocene and Middle Eocene intervals both of which are considered to have significantly reduced geological risk.

We plan, subject to financing being available from internal resources or through a farm out arrangement, to drill an appraisal well to fully evaluate these attractive discoveries, with the well being designed to enter the Middle Eocene reservoir with a larger hole size. In 2007, several companies undertook a technical review of the Norio area and a number of these have expressed an interest in further evaluating a farm-in to this acreage. We will continue to progress our negotiations with potential farm in partners.

Kumisi

Following an undertaking by the government to purchase any gas produced from the Kumisi prospect on agreed commercial terms, we drilled a well to appraise this prospect in 2007 up-dip of the WR16 well. The Kumisi #1 well is located within the Nazvrevi PSC area and is approximately 7.5 miles (12 Km) southeast of Tbilisi. It is close to the domestic gas transportation grid and the route of the new South Caucasus gas trunkline from Azerbaijan to Turkey. The well commenced drilling in February 2007 and reached a total depth of 11,841 feet (3,609 metres) in June in the Cretaceous.

An extensive testing program was conducted over the Cretaceous section where six separate intervals totalling 482 feet (147 metres) were perforated and tested. Despite elevated gas readings being recorded during drilling, these tests resulted in no discernable flow from the formation and without any hydrocarbons being detected. It is, therefore, reasonable to assume that the Cretaceous reservoir at this location is tight unlike the rocks encountered in other wells in the area. This conclusion was confirmed by a low pressure hydro squeeze which was performed over two separate zones with the data obtained suggesting that these rocks are tight and lack permeability.

Further tests were carried out of potential reservoir units in the overlying Middle and Lower Eocene sequences. Three separate tests were conducted with a total of 79 feet (24 metres) of sandstones being perforated and flow tested. These tests produced water with gas flow to surface in flareable quantities, but non commercial volumes. Each interval was flow tested for a number of days over which there was no increase in the amount of gas produced and the testing was subsequently terminated.

On October 18, 2007 we announced that the Kumisi #1 was being plugged and abandoned. The well results, particularly for the Cretaceous interval, will be reviewed and incorporated into our technical evaluation of the area in order to fully understand the remaining potential of the Kumisi area. As part of this analysis, consideration will be given to acid fracture stimulation techniques as a means by which to enhance permeability within the prospect. As no water has been recovered from the well, management believes that potential for a large gas prospect may still exist up-dip of the WR16 well given better reservoir quality.

In 2008, we have budgeted approximately $12.0 million for our exploration and appraisal work in Georgia, primarily for the testing and appraisal of the Manavi discovery and a short term production enhancement program at the Ninotsminda Field subject to available financing.

To pursue existing projects beyond our immediate development plan and to pursue new opportunities, we will require additional capital. While expected to be substantial, without further exploration work and evaluation the exact amount of funds needed to fully develop all of our oil and gas properties cannot at present be quantified. Potential sources of funds include additional sales of equity securities, project financing, debt financing (subject to certain restrictions under our Convertible Loan agreements) and the participation of other oil and gas entities in our projects. Although we have been successful in the past in raising capital there can be no assurance that we will be successful in securing the necessary funding or if such funding is available that it

will be offered on attractive or acceptable terms. Should such funding not be forthcoming and we are unable to sell some or all of our non-core assets, or, if sold, such sales realize insufficient proceeds, we may have to delay or abandon such projects.

Development of the oil and gas properties and ventures in which we have interests involves multi-year efforts and substantial cash expenditures. Full development of our oil and gas properties and ventures will require the availability of substantial additional financing from external sources. We may also, where opportunities exist, seek to transfer portions of our interests in oil and gas properties and ventures to entities in exchange for such financing. We generally have the principal responsibility for arranging financing for the oil and gas properties and ventures in which we have an interest. There can be no assurance, however, that we or the entities that are developing the oil and gas properties and ventures will be able to arrange the financing necessary to develop the projects being undertaken or to support our corporate and other activities. There can also be no assurance that such financing as is available will be on terms that are attractive or acceptable to or are deemed to be in the best interest of CanArgo, such entities and their respective stockholders or participants.

Ultimate realization of the carrying value of our oil and gas properties and ventures will require production of oil and gas in sufficient quantities and marketing such oil and gas at sufficient prices to provide positive cash flow to us. Establishment of successful oil and gas operations is dependent upon, among other factors, the following:

- mobilization of equipment and personnel to implement effectively drilling, completion and production activities;
- raising of additional capital;
- achieving significant production at costs that provide acceptable margins;
- reasonable levels of taxation, or economic arrangements in lieu of taxation in host countries; and
- the ability to market the oil and gas produced at or near world prices.

Subject to our ability to raise additional capital, we have plans to mobilize resources and achieve levels of production and profits sufficient to recover the carrying value of our oil and gas properties and ventures. However, if one or more of the above factors, or other factors, are different than anticipated, these plans may not be realized, and we may not recover the carrying value of our oil and gas properties and ventures.

Commencing in September 2009 through June 2010 an aggregate of $15,250,000 million in indebtedness under the Company s Subordinated Notes and the 12% Subordinated Notes (collectively, the Notes) will come due and be payable. Unless such Notes are converted into shares of common stock in accordance with their respective terms, the Company will be required to repay or refinance such outstanding indebtedness. There can be no assurance at this time that Company will have the resources to repay such Notes or if it will be in a position to refinance such indebtedness. Repayment of the Notes has been guaranteed by various subsidiaries of the Company which hold substantially all of the assets of the Company on a consolidated basis.

Availability of Capital

As described more fully under Liquidity and Capital Resources below, our sources of capital are primarily cash on hand, cash from operating activities, project financing, debt financing (subject to certain restrictions under our Convertible Loan agreements), the participation of other oil and gas entities in our projects, and the proceeds from the sale of certain assets. We may also attempt to raise additional capital through the issuance of debt or equity securities although no assurances can be made that we will be successful in any such efforts.

As of March 7, 2008, the Company had an aggregate of 242,120,974 shares of common stock issued and outstanding and 500,000,000 authorized shares of common stock. During 2007, we issued 4,975,000 shares of our common stock of which 1,000,000 shares were in connection with the exercise of warrants, 1,475,000 shares were in connection with exercise of stock options and 2,500,000 shares were in connection with a private placement. During 2008, we have to date issued no shares of our common stock. As of March 7, 2008, an aggregate of 67,119,215 shares are reserved for issuance under various stock option plans, warrants and other contractual commitments, including the Senior Secured Notes, the Subordinated Notes and the 12% Subordinated Note.

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Liquidity and Capital Resources
General

We currently have sufficient cash on hand to support our operations through to the third quarter 2008. In order to fund our planned capital expenditure program and to continue our operations after the third quarter 2008, we need to raise substantial funds. As noted elsewhere we are pursuing raising additional funds through private placements of our equity or debt securities or a possible rights offering to shareholders. We are also actively pursuing the farming out a number of our exploration projects. We are required under the covenants of our existing Convertible Notes to obtain the approval of a majority of our debt holders in order to incur additional indebtedness in excess of $2.5 million, which approval we cannot guarantee. In the event we attempt to raise funds through an equity offering, we would more than likely be required to offer our equity securities at a substantial discount to the current public market price in order to attract investors. In the event that we were to do so, provisions in our outstanding Convertible Notes and Warrants would cause their exercise prices to reset to the lower price in any offering. If low enough, this could effect a significant dilution to current shareholders or possibly to a change of control event.

There can be no assurance of our success in raising these funds. In the event that we are unable to raise additional funds on terms acceptable to us, we will be required to significantly curtail our operations in Georgia and to abandon our currently planned capital expenditure program.

The crude oil and natural gas industry is a highly capital intensive and cyclical business. Our current capital requirements are driven principally by our obligations to fund the following costs:

- the development of existing properties, including drilling and completion costs of wells; and
- acquisition of interests in crude oil and natural gas properties.

The amount of capital available to us will affect our ability to continue to grow the business through the development of existing properties and the acquisition of new properties and, possibly, our ability to service any future debt obligations, if any. Our sources of capital are primarily cash on hand, cash from operating activities, project financing, debt financing, the participation of other oil and gas entities in our projects, and the sale of certain assets. Our overall liquidity depends heavily on the prevailing prices of crude oil and natural gas and our production volumes of crude oil and natural gas. We do not hedge our crude oil production. Accordingly, future crude oil and, to a lesser extent, natural gas price declines would have a material adverse effect on our overall results and therefore our liquidity. Low crude oil and natural gas prices could also negatively affect our ability to raise capital on terms favorable to us and could also reduce our ability to borrow in the future. If the volume of crude oil we produce decreases, our cash flow from operations will decrease. Our production volumes will decline as reserves are produced. We sold properties in 2003 and 2004 which reduced potential future reserves and, in the future, we may sell additional properties and other assets, which could further reduce our production volumes and income from oil well drilling and servicing. To offset the loss in production volumes resulting from natural field declines and sales of producing properties, we must conduct successful exploration, exploitation and development activities, acquire additional producing properties as we did with our acquisition of a 50% interest in the Samgori Field in 2004 or identify additional behind-pipe zones or secondary recovery reserves.

Should our current exploration, exploitation and development wells in Georgia prove unsuccessful and we were unable to raise additional debt or equity finance, we might have to cut back on our capital spending plans and or modify our operating plans to conserve cash.

As of December 31, 2007, we had working capital of $715,000 compared to working capital of $11,628,000 as of December 31, 2006. The $10,913,000 decrease in working capital from December 31, 2006 to December 31, 2007 is principally due to expenditures in the period to fund the cost of development activities at the Ninotsminda Field, our appraisal activities at the Manavi oil discovery and the Kumisi appraisal well in Georgia and net cash used by operating activities partially offset by cash received pursuant to a private placement and the maturing of a deposit previously recorded as restricted cash.

Certain Asset Sales

On May 28, 2004, we announced that pursuant to a signed agreement between CanArgo Acquisition Corporation, our wholly owned subsidiary, and Stanhope Solutions Ltd., we had completed a transaction to sell our interest in the Bugruvativske Field in Ukraine through the disposal of our wholly owned subsidiary, Lateral Vector Resources, for $2,000,000. We received $250,000 as an initial payment and should receive the remaining $1,750,000 based upon certain production targets being achieved on the project. As of December 31, 2007, no additional payments have been made.

In December 2007, we disposed of CanArgo Rig #1 for $500,000.

Financing

On February 11, 2004, we entered into a Standby Equity Distribution Agreement (SEDA) that allowed us, at our option, periodically to issue shares of our common stock to US-based investment fund Cornell Capital Partners, LP (Cornell Capital) up to a maximum value of $20,000,000 (Cornell Facility). Under the terms of the SEDA, Cornell Capital provided us with an equity line of credit for 24 months from the Effective Date (as defined in the SEDA). The maximum aggregate amount of the equity placements pursuant to the SEDA was $20,000,000. Subject to this limitation, we could draw down up to $600,000 in any seven-day trading period (a Put). The Cornell Facility could be used in whole or in part entirely at our discretion, subject to effective registration of the shares under the Securities Act. Shares issued to Cornell Capital were priced at a 3% discount to the lowest daily Volume Weighted Closing Bid Price (VWAP) of CanArgo common shares traded on the Oslo Stock Exchange (OSE) for each of the five consecutive trading days immediately following a draw down notice by CanArgo. For each share of common stock purchased under the SEDA, Cornell Capital received a substantial discount to the current market price of CanArgo common stock. The level of the total discount varied depending on the market price of our stock and the amount drawn down under the SEDA. On the basis of the average high and low price for common stock as reported on the American Stock Exchange on January 27, 2005 of $1.37, Cornell Capital received a total discount of 13.87% to the market price of our stock. Such discount comprised (1) 3% discount to, the lowest volume weighted average price of our common stock; (2) 5% of the proceeds that we received for each advance under the SEDA; and (3) a commitment fee of 5.87%. The commitment fee, which was paid, consisted of $10,000 in cash (paid in two tranches) and 850,000 shares of our common stock (issued in three tranches). The 850,000 shares of common stock issued in respect of the commitment fee represented nearly 4% of the estimated 23 million shares of common stock that could have been issued by us under the SEDA. In February 2004, we engaged Newbridge Securities Corporation, a registered broker dealer, to advise us and to act as our exclusive placement agent in connection with the Cornell Facility pursuant to the Placement Agent Agreement dated February 11, 2004. For its services, Newbridge Securities Corporation received 30,799 restricted shares of our common stock which were included in the Registration Statement on Form S-3 (Reg. No. 333-115261) filed on May 6, 2004. On February 3, 2005, the SEC declared effective the registration statement on Form S-3 (Reg. No. 333-115261) originally filed by us on May 6, 2004 in respect of the shares issuable under the Cornell Facility.

On February 21, 2005, we sold 380,836 shares of CanArgo common stock at $1.31 per share under the Cornell Facility. The proceeds of this sale of $500,000 were used to reduce the promissory note to Cornell Capital from $1,500,000 to $1,000,000.

On February 28, 2005, we sold 335,653 shares of CanArgo common stock at $1.47 per share under the Cornell Facility. The proceeds of this sale of $500,000 were used to reduce the promissory note to Cornell Capital from $1,000,000 to $500,000. The proceeds included additional proceeds attributable to 5,179 shares of CanArgo common stock issued pursuant to the takedown under the Equity Line completed on February 21, 2005 proceeds of which should have been credited to us under the February 21, 2005 draw down.

On March 7, 2005, we sold 344,758 shares of CanArgo common stock at $1.54 per share under the Cornell Facility. The interest owed on the note of $32,548 was included in the proceeds. The proceeds of this sale of $500,000 were used to reduce the promissory note to Cornell Capital from $500,000 to $0.

On March 14, 2005, we sold 370,599 shares of CanArgo common stock at $1.62 per share under the Cornell Facility. This provided net proceeds of $600,000 to CanArgo.

On April 26, 2005 we signed a promissory note with Cornell Capital whereby Cornell Capital agreed to advance us the sum of $15 million (Promissory Note). Pursuant to the terms of the Promissory Note the $15 million and interest at a rate of 7.5% per annum was repayable either in cash or using the net proceeds of drawdowns under the SEDA, within 270 calendar days from the date of the Promissory Note. Pursuant to the terms of the Promissory Note, we escrowed 25 requests for advances under the SEDA each in an amount not less than $600,000 and one advance of $289,726.03 (representing estimated interest) together with 16,938,558 shares of CanArgo common stock. As at the agreement date, 664,966 shares were already in escrow.The escrow agent released requests every 7 calendar days from May 2, 2005 provided we had not previously made a payment to Cornell Capital in cash. We had the ability at our sole discretion upon 24 hours prior written notice to Cornell Capital to repay all and any amounts due under the Promissory Note in immediately available funds and withdraw any advance notices yet to be effected.

On August 1, 2005, we made a payment of $7,422,410.96 being the outstanding principal and accrued interest amount payable to Cornell Capital under the terms of both the SEDA and the Promissory Note. Furthermore, all escrowed advances were cancelled and 7,260,647 shares of CanArgo common stock were returned from escrow and duly cancelled on October 5, 2005. In accordance with Section 6 of the Promissory Note, upon receipt of such outstanding sums the Promissory Note was deemed cancelled. On July 25, 2005 notice was given to Cornell Capital to terminate the SEDA with effect as of August 24, 2005.

We received $12,332,548 proceeds net of $285,749 of discounts (excluding the commitment fee of $10,000 and 850,000 shares of common stock previously paid to Cornell Capital) pursuant to twenty one takedowns under the SEDA in which we issued a total of 13,012,945 shares of our common stock to Cornell Capital at an average price of $0.9477 per share. From these proceeds, $1,532,548 was used to repay the promissory note of $1,500,000 plus accrued interest on the note of $32,548 to Cornell Capital and partially repay the promissory note of $15,000,000.

On July 25, 2005, we announced that we had closed the private placement of a $25,000,000 issue of Senior Secured Notes due July 25, 2009 (Senior Secured Note) with a group of investors arranged through Ingalls & Snyder LLC of New York City.

The proceeds of this financing, after the payment of all professional and placing expenses and fees, had been used to redeem short term debt and accrued interest in the amount of approximately $7,400,000 under the Promissory Note with Cornell Capital, to fund the appraisal of a new gas project in Georgia, to fund the development of the Kyzyloi Gas Field in Kazakhstan and adjacent exploration areas, and for additional working capital for our development, appraisal and exploration activities in Georgia. In addition, we terminated the SEDA which we had with Cornell Capital with effect as of August 24, 2005.

See Note 9 to the consolidated financial statements included herein for a description of the terms and conditions of the Senior Secured Notes.

On March 3, 2006, we finalised a private placement with a limited group of investors arranged by Ingalls & Snyder LLC of New York City of a $13,000,000 issue of Senior Subordinated Convertible Guaranteed Notes due September 1, 2009 (the Subordinated Notes) and warrants to purchase an aggregate of 13,000,000 shares of our common stock (Subordinated Note Warrant Shares) at an exercise price of $1.37 per share, subject to adjustment, and expiring on March 3, 2008 or sooner under certain circumstances (Subordinated Note Warrants).

The proceeds of this financing, after the payment of all placing expenses and professional fees were used exclusively to fund the development of the Kyzyloi Gas Field in Kazakhstan and on the commitment exploration programs in Kazakhstan through Tethys Petroleum Limited (Tethys), a former subsidiary of CanArgo. CanArgo disposed of its entire interest in Tethys on August 3, 2007 and no longer has any Kazakhstan assets.

See Note 9 to the consolidated financial statements included herein for a description of the terms and conditions of the Subordinated Notes and associated Subordinated Note Warrants.

On June 28, 2006, we announced that we had entered into the private placement with Persistency of a $10,000,000 issue of a 12% Subordinated Convertible Guaranteed Note due June 28, 2010 (the 12% Subordinated Note) and warrants to purchase an aggregate of 12,500,000 shares of CanArgo common stock (12% Note Warrant Shares), at an exercise price of $1.00 per share, subject to adjustment, and expiring on June 28, 2008 or sooner under certain circumstances (the 12% Note Warrants).

The proceeds of this financing, after the payment of all placing expenses and professional fees were used to fund our appraisal and development activities in Georgia including further development of the Ninotsminda Field and appraisal of the Kumisi gas discovery.

See Note 9 to the consolidated financial statements included herein for a description of the terms and conditions of the 12% Subordinated Note and associated 12% Note Warrants.

On October 13, 2006, we announced the completion of a private placement in Norway by way of the issue of an aggregate of 12,263,368 shares of common stock at a purchase price of NOK 9.10 per share (the Reg. S Shares) for aggregate gross proceeds of NOK 111,596,239 ($16,687,039 equivalent based upon a conversion rate of NOK 6.6876 per dollar) before placing fees and expenses estimated at NOK 6,695,774 ($1,001,022). The shares were issued in a transaction intended to qualify for the exemption from registration afforded by Section 4(2) of the Securities Act and Regulation S promulgated thereunder. CanArgo agreed to register the Shares for resale under the Securities Act and the Company filed a Registration Statement on Form S-3 with the SEC on October 13, 2006, which included these shares. The Registration Statement on Form S-3 was declared effective on January 19, 2007. As a result of the delays incurred in registering the Shares we have paid subscribers a cash liquidity penalty of 5% of the subscription price of their Shares in the aggregate amount of NOK 5,579,812 ($834,352 equivalent). The net proceeds of the placement will be used by the Company for working capital; future capital expenditures in Georgia, including, without limitation, securing drilling equipment; and other related activities.

On August 10, 2007, we entered into a subscription agreement with three accredited investors in terms of which we issued those investors by way of a private placement 2,500,000 shares of CanArgo common stock at $1.00 per share, resulting in gross proceeds of $2,500,000. In consideration for the investors agreeing to make the subscription, we also issued to the investors warrants to subscribe for an aggregate of 5 million shares of common stock of CanArgo. The warrants have an exercise price of $1.00 per share, subject to adjustment, and are exercisable up to the end of August 2009.

During 2007, we continued to progress our exploration, appraisal and development plans in our core area of operation in Georgia. Up until the end of July, operations also continued on our interests in Kazakhstan, but our Kazakhstan assets were discontinued with our disposition of our interest in Tethys Petroleum Limited, which held such assets, on August 3, 2007.

The Next Twelve Months

We currently have sufficient cash on hand to support our operations to the third quarter of 2008.

In order to continue with all of our currently planned development activities in Georgia on our Ninotsminda Field and the appraisal of our Manavi oil discovery, we will need to raise additional funds via debt or equity financing.

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While a considerable amount of infrastructure for the Ninotsminda Field has already been put in place, we cannot provide assurance that:

funding of a field development plan will be timely;

our development plan will be successfully completed or will increase production; or

field operating revenues after completion of the development plan will exceed operating costs.

Under the terms of each of the Note issues, we are restricted from incurring future indebtedness and from issuing additional senior or *pari passu* indebtedness, except with the prior consent of the Required Holders or in limited permitted circumstances. The definition of indebtedness encompasses all customary forms of indebtedness including, without limitation, liabilities for the deferred consideration, liabilities for borrowed money secured by any lien or other specified security interest, liabilities in respect of letters of credit or similar instruments (excluding letters of credit which are 100% cash collateralised) and guarantees in relation to such forms of indebtedness (excluding parent company guarantees provided by the Company in respect of the indebtedness or obligations of any of the Company s subsidiaries under its Basic Documents (as defined in the respective Note Purchase Agreements). Pursuant to the terms of the Note Purchase Agreements, permitted future indebtedness is (a) indebtedness outstanding under the Notes; (b) any additional unsecured indebtedness, the aggregate amount outstanding thereunder at any time not exceeding certain specified amounts and; (c) certain unsecured intra-group indebtedness (in the case of the Subordinated Notes and the 12% Subordinated Notes this is limited to the indebtedness of a CanArgo Group Member (as defined in the relevant Note Purchase Agreements) to a direct or indirect subsidiary of the Company which is not deemed to be a Material Subsidiary (under the Note Purchase Agreements the aggregate amount outstanding under the particular indebtedness shall not exceed certain specified levels at any time). See Note 9 to the consolidated financial statements included herein.

To pursue existing projects for our immediate appraisal and development plans, pay operating expenses and to pursue new opportunities, we will require additional capital in 2008. While expected to be substantial, without further exploration work and evaluation the exact amount of funds needed to fully develop all of our oil and gas properties cannot at present, be quantified. Potential sources of funds include additional sales of equity securities, project financing, debt financing and the participation of other oil and gas entities in our projects. Based on our past history of raising capital and continuing discussions, we believe that such required funds may be available. However, there is no assurance that such funds will be available, and if available, will be offered on attractive or acceptable terms. Should such funding not be forthcoming, we may not be able to pursue projects beyond our current appraisal and development plans or to pursue new opportunities. As discussed above, under the terms of the Notes, we are restricted from incurring additional indebtedness.

Development of the oil and gas properties and ventures in which we have interests involves multi-year efforts and substantial cash expenditures. Full development of our oil and gas properties and ventures may require the availability of substantial additional financing from external sources. We may also, where opportunities exist, seek to transfer portions of our interests in oil and gas properties and ventures to entities in exchange for such financing. We generally have the principal responsibility for arranging financing for the oil and gas properties and ventures in which we have an interest. There can be no assurance, however, that we or the entities that are developing the oil and gas properties and ventures will be able to arrange the financing necessary to develop the projects being undertaken or to support the corporate and other activities of CanArgo. There can also be no assurance that such financing will be available on terms that are attractive or acceptable to or are deemed to be in the best interest of CanArgo, such entities and their respective stockholders or participants.

Ultimate realization of the carrying value of our oil and gas properties and ventures will require production of oil and gas in sufficient quantities and marketing such oil and gas at sufficient prices to provide positive cash flow to CanArgo. Establishment of successful oil and gas operations is dependent upon, among other factors, the following:

mobilization of equipment and personnel to implement effectively drilling, completion and production activities;

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raising of additional capital;
achieving significant production at costs that provide acceptable margins;
reasonable levels of taxation, or economic arrangements in lieu of taxation in host countries; and
the ability to market the oil and gas produced at or near world prices.

Subject to our ability to raise additional capital, we have plans to mobilize resources and achieve levels of production and profits sufficient to recover the carrying value of our oil and gas properties and ventures. However, if one or more of the above factors, or other factors, are different than anticipated, these plans may not be realized, and we may not recover the carrying value of our oil and gas properties and ventures.

Working Capital

At December 31, 2007, our current assets of $8,173,000 exceeded our current liabilities of $7,458,000 resulting in a working capital surplus of $715,000. This compares to a working capital surplus of $11,628,000 as of December 31, 2006. Current liabilities as of December 31, 2007 consisted of trade payables of $482,000, accrued liabilities of $6,640,000 and liabilities to be disposed of $336,000.

Capital Expenditures

Capital expenditures in cash in 2007, 2006 and 2005 were $11,710,000, $24,339,000 and $29,957,000, respectively. The table below sets forth the components of these capital expenditures for the three years ended December 31, 2007, 2006 and 2005.

	December 31,		
Expenditure category:	**2007**	**2006**	**2005**
Development	$ 858,271	$ 1,998,556	$ 12,976,649
Exploration	7,509,999	19,130,777	11,872,694
Facilities and other	3,341,904	3,209,541	5,107,998
Total	11,710,174	24,338,874	29,957,341

During 2007, 2006 and 2005 capital expenditures were primarily for the development and exploration of existing properties. We currently have a contingent planned minimum capital expenditure budget of $12.0 million subject to financing being available for 2008, all of which is allocated to our Georgian development and appraisal projects. During 2008, we plan to participate in the workover of two wells on the Ninotsminda Field and complete the testing of the Manavi appraisal well, M12. Further drilling at Norio will be subject to securing financing for this project which may be by way of a farm-out of part of our interest in the PSA in exchange for the drilling of an appraisal well. We have no material long-term capital commitments and are consequently able to adjust the level of our expenditures as circumstances dictate. Additionally, the level of capital expenditures will vary during future periods depending on the results of our development and appraisal programs, market conditions and other related economic factors. Should the prices of crude oil and natural gas decline from current levels; our cash flows will decrease which may result in a reduction of the capital expenditures budget. If we decrease our capital expenditures budget, we may not be able to offset crude oil and natural gas production volume decreases caused by natural field declines and sales of producing properties.)

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Commencing in September 2009 through June 2010 an aggregate of $15,250,000 in indebtedness under the Company s Subordinated Notes and the 12% Subordinated Notes (collectively, the Notes) will come due and be payable. Unless such Notes are converted into shares of common stock in accordance with their respective terms, the Company will be required to repay or refinance such outstanding indebtedness. There can be no assurance at this time that Company will have the resources to repay such Notes or if it will be in a position to refinance such indebtedness. The Notes are secured by all the assets of the Company.

Sources of Capital

The net funds provided by and/or used in each of the operating, investing and financing activities are summarized in the following table and discussed in further detail below:

	December 31,		
	2007	**2006**	**2005**
Net cash used in operating activities	$ (1,762,730)	$ (2,516,083)	$ (9,771,682)
Net cash provided (used) in investing activities	(9,521,847)	(25,395,262)	(26,952,117)
Net cash provided (used) in financing	3,560,600	38,885,118	35,888,797
Net cash flows from assets and liabilities held for sale and to be disposed	(1,859,192)	(13,061,781)	(5,241,488)
Total	(9,583,169)	(2,088,008)	(6.076,489)

Operating activities for the year ended December 31, 2007 used $3,461,000 of cash. Investing activities provided us $11,952,000 during 2007. Financing activities used $16,314,000 during 2007. These funds were used primarily to continue to fund and develop our Georgian projects. In 2007, cash used in operating activities was used principally for production purposes on the Ninotsminda Fields in Georgia and to fund selling, general and administrative overhead. In 2007, cash provided in investing activities was mainly due to the disposition of our investment in Tethys ($21,340,000) partially offset by capital expenditures principally in Georgia ($11,077,000) and prepaid expenditures relating to our Georgian projects ($1,688,000).

Future Capital Resources

We will have four principal sources of liquidity going forward: (i) cash on hand, (ii) cash from operating activities, (iii) industry participation in our projects, and (iv) sales of producing properties. We may also attempt to raise additional capital through the issuance of additional debt or equity securities in public offerings or through further private placements, however, our ability to secure additional debt financing is restricted under the terms of our Subordinated Notes and 12% Subordinated Notes.

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Balance Sheet Changes

All balances represent results from continuing operations, unless disclosed otherwise.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Cash and cash equivalents decreased $7,820,000 from $14,689,000 at December 31, 2006 to $6,869,000 at December 31, 2007. The decrease was due to expenditures in the period to primarily fund the cost of development activities at the Ninotsminda Field and our appraisal activities at the Manavi oil discovery and Kumisi gas discovery in Georgia and net cash used by operating activities partially offset by cash received from the maturing of deposits previously recorded as restricted cash

Restricted cash decreased to $0 at December 31, 2007 from $300,000 at December 31, 2006 due to the maturing of a deposit funding a letters of credit as required under a drilling service contract we entered into with Baker Hughes International.

Accounts receivable decreased from $504,000 at December 31, 2006 to $379,000 at December 31, 2007 primarily due to the settlement in January of this year of an insurance claim in connection with our Georgian exploration activities partially offset by a partial amount due from a December oil sale and some general and administrative costs owed by Tethys. The amounts owed for the sale of oil and by Tethys were settled in full in the first quarter of 2008.

Crude oil inventory decreased to $374,000 at December 31, 2007 from $453,000 at December 31, 2006 primarily as a result of increased sales from storage in the period.

Prepayments to oil and gas equipment suppliers decreased from $2,255,000 at December 31, 2006 to $312,000 at December 31, 2007 as a result of timing differences in respect of prepayments for materials and services related to our appraisal activities at the Manavi oil discovery and Kumisi gas discovery. Upon receipt of the materials and services, those amounts will be transferred to capital assets. This increase is included in the statement of cash flows as an investing activity.

Capital assets net, decreased to $51,305,000 at December 31, 2007 from $87,308,000 at December 31, 2006, due to an impairment of $42,000,000 on our capital assets as a result of the Company performing its annual assessment of costs classified as unproved property to determine if they should be transferred to the cost pool. After evaluating a number of factors including the length of time that these costs remained classified as unproved property, the Company determined that approximately $49,100,000 of costs principally relating to the drilling of exploration wells should be moved to the cost pool. The quarterly ceiling test determined that the net capitalized costs in the cost pool exceeded the 10% net present value of cash flows generated from the Company s proved reserves resulting in an impairment of $42,000,000 million in 2007.

Accounts payable decreased to $482,000 at December 31, 2007 from $3,673,000 at December 31, 2006 primarily due to timing differences in respect of payments to suppliers in connection with our appraisal activities at the Manavi oil discovery and Kumisi gas discovery.

Deferred revenue of $485,000 at December 31, 2006 related to the receipt of a deposit in December 2006 for the sale of oil in Georgia that was delivered in 2007.

Accrued liabilities decreased from $6,918,000 as at December 31, 2006 to $6,640,000 at December 31, 2007 due primarily to a decrease in non cash loan interest at the end of the period as a result of the various long term debt repayments partially offset by increased accrued professional fees and an amount of approximately $396,000 owed to Tethys for our pro rata share of the Tethys IPO costs. Approximately $4,931,000 relates to the disputed Weatherford invoices referred to in Notes 11 and 12 of these consolidated financial statements.

Long term debt net of discounts decreased from $37,264,000 at December 31, 2006 to $11,697,000 due to the repayment of $19,875,000 of long term debt from the sale of CanArgo s remaining Tethys shareholding, the exchange/conversion of $15,000,000 of long term debt into 6,000,000 shares of Tethys previously held by CanArgo partially offset by the amortization of debt discounts associated with the detachable warrants and beneficial conversion features in connection with the issuance of the $13,000,000 in Subordinated Notes in March 2006 and the $10,000,000 issue of the 12% Notes in June 2006 and the issue to the Noteholders of further Notes of $2,125,000 aggregate principal amount on June 30, 2007 in substitution of the aggregate amount of interest of $2,125,000 due and payable to the Noteholders on June 30, 2007. The repayment comprised a repayment of the remaining $16,125,000 in aggregate principal amount of the Senior Secured Notes (together with interest thereon) and the repayment of $3,750,000 in aggregate principal amount of the Subordinated Notes. The exchange/conversion comprised the exchange/conversion of $10,000,000 in aggregate principal amount of the Senior Secured Notes and exchange/conversion of $5,000,000 in aggregate principal amount of the Subordinated Notes. The further Notes issued comprised $1,125,000 in aggregate principal amount of Senior Secured Notes, $400,000 in aggregate principal amount of Subordinated Notes and $600,000 in aggregate principal amount of 12% Notes.

Other non current liabilities decreased to $38,000 at December 31, 2007 from $1,260,000 at December 31, 2006 as a result of reducing the effective interest amount due to the debt repayments and exchange/conversions on the $25,000,000 in Senior Secured Notes and the $13,000,000 in Subordinated Notes and amortizing some of the difference in computing interest using the actual interest rate and the effective interest rate due on both of these notes.

Provision for future site restoration increased to $230,000 at December 31, 2007 from $205,000 at December 31, 2006 due to changes estimates for the provision for future site restorations in our oil and gas properties in Georgia and accretion.

Results of Continuing Operations

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

We recorded operating revenue from continuing operations of $7,209,000 during the year ended December 31, 2007 compared with $6,527,000 for the year ended December 31, 2006. The increase is attributable to a higher price per barrel for oil realized by the Company in 2007 partially offset by lower sales volumes of oil achieved from the Ninotsminda Field in 2007. Ninotsminda Oil Company Limited (NOC) sold 105,111 barrels of oil for the year ended December 31, 2007 compared to 120,413 barrels of oil for NOC for the year ended December 31, 2006.

NOC generated $7,209,000 of oil and gas revenue in the year ended December 31, 2007 compared with $6,527,000 for the year ended December 31, 2006 due to a higher average net sales price partially offset by lower sales volumes. Its net share of the 162,800 bbls (446 bopd) of gross oil production for sale from the Ninotsminda Field in the period amounted to 105,820 bbls. In the period, 709 bbls of oil were added to storage. For the year ended December 31, 2006, NOC s net share of the 178,474 bbls (489 bopd) of gross oil production was 116,008 barrels.

NOC s entire share of production was sold under international contracts or added to storage. Net sale prices for Ninotsminda oil sold during the year ended December 31, 2007 averaged $67.97 per barrel as compared with an average of $53.69 per barrel during the year ended December 31, 2006. NOC s net share of the 17,776 Mcf of gas delivered was 11,554 Mcf at an average net sale price of $0.70 per Mcf of gas for the year ended December 31, 2007. However, due the uncertainty of collectibility of gas revenues under these contracts, the Company has decided in accordance with its revenue recognition policy, to record gas revenues on a cash basis. Gas revenues recorded for the year ended December 31, 2007 were $65,000 compared with $61,000 for the year ended December 31, 2006. For the year ended December 31, 2006, NOC s net share of the 20,094 Mcf of gas delivered was 13,061 Mcf at an average net sale price of $0.66 per Mcf of gas.

The operating loss from continuing operations for the year ended December 31, 2007 amounted to $46,581,000 compared with an operating loss of $48,519,000 for the year ended December 31, 2006. The decrease in operating loss is attributable to increased oil and gas revenues and decreased field operating expenses, direct project costs, selling, general and administration costs, depreciation, depletion and amortization partially offset by an increased impairment charge in 2007 of our oil and gas properties, ventures and other assets.

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Field operating expenses decreased to $1,370,000 for the year ended December 31, 2007 as compared to $1,703,000 for the year ended December 31, 2006. The decrease is primarily a result of lower operating costs in Georgia in 2007 compared to 2006.

Direct project costs decreased to $662,000 for the year ended December 31, 2007, from $812,000 for the year ended December 31, 2006 primarily due to reduced costs directly associated with non operating activity at the Ninotsminda Field.

Selling, general and administrative costs decreased to $7,164,000 for the year ended December 31, 2007 from $9,732,000 for the year ended December 31, 2006. The decrease is mainly attributable to reduced travel costs, office costs, professional fees, insurances and non cash stock compensation expense in 2007 compared to 2006.

The decrease in depreciation, depletion and amortization expense to $2,593,000 for the year ended December 31, 2007 from $3,799,000 for the year ended December 31, 2006 is attributable principally to decreased production in 2007 compared to 2006 and from the reduction in our amortization base resulting from the impairment at year end 2006 of $38,400,000.

The increase in impairment of oil and gas properties, ventures and other assets to $42,000,000 for the year ended December 31, 2007 from $39,000,000 for the year ended December 31, 2006 is as a result of the Company performing its annual assessment of costs classified as unproved property to determine if they should be transferred to the cost pool. After evaluating a number of factors including the length of time that these costs remained classified as unproved property, the Company determined that approximately $49,100,000 of costs principally relating to the drilling of exploration wells should be moved to the cost pool. The quarterly ceiling test determined that the net capitalized costs in the cost pool exceeded the 10% net present value of cash flows generated from the Company s proved reserves resulting in an impairment of $42,000,000 million in 2007.

The increase in other expense to $18,734,000 for the year ended December 31, 2007, from $5,913,000 for the year ended December 31, 2006 is primarily a result of the loss on debt extinguishment of $12,127,000 arising from the issue of an aggregate of 37,777,778 compensatory warrants to the Noteholders in connection with the repayment of $18,750,000 of long term debt and the exchange/conversion of $15,000,000 of long term debt into Tethys shares and the write off of the portion of debt discount related to the repayment of $3,750,000 and $5,000,000 of the debt exchange/conversion. These are partially offset by the reduced effective interest amount as a result of the debt extinguishment, increased levels of debt discount amortisation, the commission paid to the brokers on the sale of the remaining Tethys shareholding and reduced interest income partially offset by lower interest expense as a result of the debt exchange/conversion, reduced foreign exchange losses and the realised gain recorded on selling the remaining holding of Tethys shares in August 2007.

The loss from continuing operations of $65,315,000 or $0.27 per share for the year ended December 31, 2007 compares to a net loss from continuing operations of $54,432,000 or $0.27 per share for the year ended December 31, 2006. The weighted average number of common shares outstanding was higher during the year ended December 31, 2007 than during the year ended December 31, 2006, principally due to the issue of shares in respect a warrants exercise in 2007, the exercise of share options in 2007 and a private placement in 2007.

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

We recorded operating revenue from continuing operations of $6,527,000 during the year ended December 31, 2006 compared with $5,279,000 for the year ended December 31, 2005. The increase is attributable to a higher price per barrel for oil realized by the Company in 2006 and higher sales volumes of oil achieved from the Ninotsminda Field in 2006. Ninotsminda Oil Company Limited (NOC) sold 120,413 barrels of oil for the year ended December 31, 2006 compared to 118,268 barrels of oil for NOC for the year ended December 31, 2005.

NOC generated $6,527,000 of oil and gas revenue in the year ended December 31, 2006 compared with $5,279,000 for the year ended December 31, 2005 due to a higher average net sales price and higher sales volumes. Its net share of the 178,474 bbls (489 bopd) of gross oil production for sale from the Ninotsminda Field in the period amounted to 116,008 bbls. In the period, 4,405 bbls of oil were sold from storage. For the year ended December 31, 2005, NOC s net share of the 184,952 bbls (507 bopd) of gross oil production was 120,219 barrels.

NOC s entire share of production was sold under international contracts or added to storage. Net sale prices for Ninotsminda oil sold during the year ended December 31, 2006 averaged $53.69 per barrel as compared with an average of $44.78 per barrel during the year ended December 31, 2005. NOC s net share of the 20,094 Mcf of gas delivered was 13,061 Mcf at an average net sale price of $0.66 per Mcf of gas for the year ended December 31, 2006. However, due the uncertainty of collectibility of gas revenues under these contracts, the Company has decided in accordance with its revenue recognition policy, to record gas revenues on a cash basis. Gas revenues recorded for the year ended December 31, 2006 were $61,000. For the year ended December 31, 2005, NOC s net share of the 71,241 Mcf of gas delivered was 46,307 Mcf at an average net sale price of $0.53 per Mcf of gas.

The operating loss from continuing operations for the year ended December 31, 2006 amounted to $48,519,000 compared with an operating loss of $11,015,053 for the year ended December 31, 2005. The increase in operating loss is attributable to increased field operating expenses, increased depreciation, depletion and amortization, an impairment of our oil and gas properties, ventures and other assets, partially offset by increased oil and gas revenue, increased selling, general and administration costs, and reduced direct project costs.

Field operating expenses increased to $1,703,000 for the year ended December 31, 2006 as compared to $1,110,000 for the year ended December 31, 2005. The increase is primarily a result of increased oil processing fees in the period and costs attached to oil sales from storage in the period.

Direct project costs decreased to $812,000 for the year ended December 31, 2006, from $1,084,000 for the year ended December 31, 2005 primarily due to reduced costs directly associated with non operating activity at the Ninotsminda Field.

Selling, general and administrative costs decreased to $9,732,000 for the year ended December 31, 2006 from $10,824,000 for the year ended December 31, 2005. The decrease is primarily as a result of reduced non cash stock compensation expense partially offset by a general increase in corporate activity.

The increase in depreciation, depletion and amortization expense to $3,799,000 for the year ended December 31, 2006 from $3,276,000 for the year ended December 31, 2005 is primarily attributable to a downward revision in proved developed oil reserves from the Ninotsminda Field following the 2006 assessment by the Company s independent Petroleum Engineers.

The impairment of $39,000,000 of oil and gas properties, ventures and other assets for the year ended December 31, 2006 was primarily attributable to a downward revision in proved developed oil reserves from the Ninotsminda Field following the 2006 assessment by the Company s independent Petroleum Engineers and also an impairment to the 3 megawatt generator held for sale.

The increase in other expense to $5,913,000 for the year ended December 31, 2006, from $1,507,000 for the year ended December 31, 2005 is primarily a result of lower interest income received due to having lower amounts of surplus cash available to place on term deposit, higher loan interest payable and amortised debt discount and expense, higher foreign exchange losses and fees incurred in respect of a private placement in 2006.

The loss from continuing operations of $54,432,000 or $0.27 per share for the year ended December 31, 2006 compares to a net loss from continuing operations of $12,522,000 or $0.06 per share for the year ended December 31, 2005. The weighted average number of common shares outstanding was higher during the year ended December 31, 2006 than during the year ended December 31, 2005, principally due to the issue of shares in respect of the forced conversion of a convertible Loan with Detachable Warrants in 2006, the exercise of share options in 2006 and a private placement in 2006.

Results of Discontinued Operations

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

On August 1, 2007 we announced that we sold our entire shareholding of 8 million shares in Tethys for gross proceeds before commissions, expenses and payment of a pro rata share of the Tethys IPO costs to Tethys of C$23,600,000. Net proceeds of approximately $20,800,000 were used to repay outstanding indebtedness.

On February 17, 2006 we issued a press release announcing that our subsidiary, CSL, was not proceeding with further investment in the Samgori (Block XI B) Production Sharing Contract (Samgori PSC) in Georgia and associated farm-in which became effective in April 2004, and accordingly we terminated our 50% interest in the Samgori PSC with effect from February 16, 2006.

The net income from discontinued operations, net of taxes and minority interest, for the year ended December 31, 2007 of $11,537,000 compares to a loss of $6,109,000 for the year ended December 31, 2006 due to the activities of Tethys and CSL and the $15,567,000 of realized gains on securities held for sale.

CSL generated no oil and gas revenues for the year ended December 31, 2007 compared with $1,003,000 for the year ended December 31, 2006 due to the withdrawal of our interest in the Samgori PSC on February 16, 2006. CSL s entire share of production was either sold locally in Georgia in 2006 under international contracts or added to storage.

CanArgo recorded an equity loss of approximately $4,000,000 from its investment in Tethys during the year ended December 31, 2007. CanArgo s ownership of Tethys diluted during the period from 100% ownership on December 31, 2006 to approximately 67% on February 15, 2007 due to a Tethys private placement, to approximately 52% on May 9, 2007 due to a Tethys share exchange for the 30% minority interest in BN Munai LLP, a subsidiary of Tethys wholly owned subsidiary Tethys Kazakhstan Limited, to approximately 30% on June 13, 2007 due to a CanArgo debt exchange/conversion and to approximately 18% on June 27, 2007 due to the Tethys initial public offering. On August 3, 2007, we sold our remaining interest in Tethys. We no longer have any shareholding in Tethys. A realized gain on Tethys securities held for sale of $15,567,000 was recorded during the period through to the Tethys initial public offering date of June 27, 2007.

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

On August 1, 2007 we announced that we sold our entire shareholding of 8 million shares in Tethys for gross proceeds before commissions, expenses and payment of a pro rata share of the Tethys IPO costs to Tethys of C$23,600,000. The net proceeds of approximately $20,800,000 were used to repay outstanding indebtedness.

On February 17, 2006 we issued a press release announcing that our subsidiary, CSL, was not proceeding with further investment in the Samgori (Block XI B) Production Sharing Contract (Samgori PSC) in Georgia and associated farm-in which became effective in April 2004, and accordingly we terminated our 50% interest in the Samgori PSC with effect from February 16, 2006.

The net loss from discontinued operations, net of taxes for the year ended December 31, 2006 of $6,109,000 compares to an income of $187,000 for the year ended December 31, 2005 due to the activities of Tethys and CSL.

CSL generated $1,003,000 of oil and gas revenue in the year ended December 31, 2006 compared with $2,303,000 for the year ended December 31, 2005 primarily due to a higher average net sales price achieved in the year ended December 31, 2006 offset by lower sales volumes. Its net share of the 10,226 bbls (218 bopd) of gross oil production for sale from the Samgori Field in the period up to February 16, 2006, the date of withdrawal, amounted to 3,835 bbls. In the period, 5,141 bbls of oil were added to storage. For the year ended December 31, 2005, CSL s net share of the 166,298 bbls (456 bopd) of gross oil production was 62,362 bbls

CSL s entire share of production was either sold locally in Georgia under international contracts or added to storage. Net sale prices for CSL oil sold during the period up to February 16, 2006, the date of withdrawal, averaged $59.57 per barrel as compared with an average of $46.12 per barrel for the year ended December 31, 2005.

Tethys recorded a loss from operations of $6,782,000 for the year ended December 31, 2006 compared to $416,000 for the year ended December 31, 2005. The increased loss in 2006 is mainly attributable to consolidating the results of Tethys for the full year in 2006 compared to consolidating the results of Tethys for the last six months only of 2005 and increased levels of professional fees and interest expense in 2006 compared to 2005.

Contractual Obligations and Commercial Terms

Our principal business and assets are derived from production sharing contracts in Georgia. The legislative and procedural regimes governing production sharing contracts and mineral use licenses in Georgia have undergone a series of changes in recent years resulting in certain legal uncertainties.

Our production sharing contracts and mineral use licenses, entered into prior to the introduction in 1999 of a new Petroleum Law governing such agreements have not, as yet, been amended to reflect or ensure compliance with current legislation. As a result, despite references in the current legislation grandfathering the terms and conditions of our production sharing contracts, conflicts between the interpretation of our production sharing contracts and mineral use licenses and current legislation could arise. Such conflicts, if they arose, could cause an adverse effect on our rights under the production sharing contracts. However, the Norio PSA and the Tbilisi PSC were concluded after enactment of the Petroleum Law, and under the terms and conditions of this legislation.

To confirm that the Ninotsminda PSC and the mineral usage license issued prior to the introduction in 1999 of the Petroleum Law were validly issued, in connection with its preparation of a convertible loan agreement with us, the International Finance Corporation, an affiliate of the World Bank received in November 1998 confirmation from the State of Georgia, that among other things:

- The State of Georgia recognizes and confirms the validity and enforceability of the production sharing contract and the license and all undertakings the State has covenanted with NOC thereunder;
- the license was duly authorized and executed by the State at the time of its issuance and remained in full force and effect throughout its term; and
- the license constitutes a valid and duly authorized grant by the State, being and remaining in full force and effect as of the signing of this confirmation and the benefits of the license fully extend to NOC by virtue of its interest in the license holder and the contractual rights under the production sharing contract.

Despite this confirmation and the grandfathering of the terms of existing production sharing contracts in the Petroleum Law, subsequent legislative or other governmental changes could conflict with, challenge our rights or otherwise change current operations under the production sharing contract. No challenge has been made to date.

In 2002, a participation agreement for the three well exploration program on the Ninotsminda / Manavi area with AES was terminated without AES earning any rights to any of the Ninotsminda / Manavi area reservoirs. The Company therefore has no present obligations in respect of AES. However, under a separate letter of agreement, if gas from the sub Middle Eocene is discovered and produced from the exploration area covered by the participation agreement, AES with be entitled to recover at the rate of 15% of future gas sales from the sub Middle Eocene, net of operating costs, approximately $7,500,000, representing their prior funding under the participation agreement.

Under the Production Sharing Contract for Blocks XI^G and XI^H (the Tbilisi PSC) our subsidiary CanArgo Norio Limited had a commitment to acquire additional seismic data within three years of the effective date of the contract which is September 29, 2003. The State Agency for Oil & Gas Regulation in Georgia (the Agency) has consented to an extension to the period within which the data should be acquired and we are working with the Agency to amend the Tbilisi PSC accordingly. The total commitment over the remaining period is $350,000.

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We have contingent obligations and may incur additional obligations, absolute or contingent, with respect to the acquisition and development of oil and gas properties and ventures in which we have interests that require or may require us to expend funds and to issue shares of our common stock.

Upon completion of the acquisition of an interest in the Samgori PSC we had a contractual obligation to issue four million shares of CanArgo common stock to Europa Oil Services Limited (Europa), an unaffiliated company in connection with a consultancy agreement with Europa in relation to this acquisition. On April 16, 2004 Europa was issued with four million restricted shares of CanArgo common stock in an arms length transaction. A further 12 million shares of CanArgo common stock are issuable upon certain production targets being met from future developments under the Samgori PSC. As we have withdrawn from the Samgori PSC effective February 16, 2006, we have no continuing obligation to issue further shares of CanArgo common stock to Europa. On March 14, 2006, we signed an agreement with Europa formally terminating the consultancy agreement.

At December 31, 2007, we had a contingent obligation to issue a maximum of 187,500 shares of common stock to Fielden Management Services PTY, Ltd (a third party management services company) upon satisfaction of conditions relating to the achievement of specified Stynawske Field project performance standards, an oil field in Ukraine in which we had a previous interest.

In September 2004, a blow-out occurred at the N100 well on the Ninotsminda Field. Our insurers will cover 80% of the costs associated with the blow out up to a maximum cover of $2,500,000. We received $800,000 from our insurers in the second quarter of 2005 and $560,000 in the third quarter of 2006, in respect of costs incurred to date.

The following table sets forth information concerning the amounts of payments due under specified contractual obligations for periods of less than one year, one to three years, three to five years and more than five years as at December 31, 2007:

Contractual Obligations		**Due in less than 1 year**	**Due in 1 to 3 years**	**Due in 3 to 5 years**	**Due in more than 5 years**
Operating lease obligations	$	461,655	654,029	134,188	117,415
Long term debt		-	15,250,000	-	**-**
Long term debt interest		1,737,000	2,207,400	-	**-**
Other long-term liabilities (1)		**-**	**-**	**-**	230,720
	$	**2,198,655**	**18,111,429**	**134,188**	**348,135**

(1) Other long-tem liabilities represent costs provided for future site restoration.

(2) CanArgo has no contractual obligations in respect of capital leases or purchase obligations.

Related Party Transactions

CanArgo s ownership of Tethys was diluted in stages during the year ended December 31, 2007 from 100% ownership on December 31, 2006 through to disposing of its remaining shareholding on August 3, 2007. On June 27, 2007 Tethys announced that it had completed its initial public offering through the issuance of approximately 18.2 million shares on the Toronto Stock Exchange reducing the Company s ownership to approximately 17.7% and Dr. David Robson stepped down from the position of Chief Executive Officer of the Company but remained as Chairman of the Company. Dr David Robson is Chairman, President and Chief Executive Officer of Tethys. CanArgo s former Corporate Secretary, Elizabeth Landles, is Administration Director of Tethys. CanArgo and Tethys shared some common resources in 2007 including corporate secretarial and investor relations services.

Dr. David Robson, Chief Executive Officer of CanArgo until June 27, 2007, provided all of his services to CanArgo through Vazon Energy Limited, a corporation organized under the laws of the Bailiwick of Guernsey (Vazon),

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of which he is the sole owner and Managing Director. In addition a management services agreement exists between CanArgo and Vazon Energy whereby the services of Mrs. Landles (former Corporate Secretary and Executive Vice President), amongst others, are provided to CanArgo. Approximately $775,000 was paid to Vazon in 2007 in respect of these services which included flow through costs for employees and consultants.

On February 7, 2008, we announced that Dr. David Robson had tendered his resignation from the positions of Non-Executive Chairman and Non-Executive Director of the Board of CanArgo with immediate effect. Vazon received a payment of approximately $60,000 in settlement of the remaining six month advance notice period required under Dr. Robson s service agreement. In addition, the expiration of Dr. Robson s outstanding stock options was extended until December 31, 2008.

Effective February 11, 2008, Elizabeth Landles, resigned from the position of Corporate Secretary and Executive Vice President of the Company. In accordance with the terms of her service agreement, Ms Landles will continue to work with the Company throughout a three month notice period at her current salary but in the capacity of Assistant Corporate Secretary.

Mr. Russell Hammond, a non-executive director of CanArgo and Tethys, is also an investment advisor to Provincial Securities Limited who became a minority shareholder in the Norio PSA through a farm-in agreement to the Norio MK72 well. On September 4, 2003 we concluded a deal to purchase Provincial Securities Limited s minority interest in CanArgo Norio Limited by a share swap for shares in CanArgo. Provincial Securities Limited received 2,234,719 shares of CanArgo common stock in relation to the transaction. Provincial Securities Limited also had an interest in Tethys Petroleum Limited which was sold in June 2005 to us by a share exchange for shares in CanArgo. Provincial Securities Limited received 5,500,000 shares of CanArgo common stock in relation to the transaction. Mr Hammond did not receive any compensation in connection with these transactions and disclaims any beneficial ownership of Provincial Securities Limited or any of the Company s common stock owned by Provincial Securities Limited.

Transactions with affiliates or other related parties including management of affiliates are to be undertaken on the same basis as third party arms-length transactions. Transactions with affiliates are reviewed and voted on solely by non-interested directors.

Critical Accounting Policies

Natural Gas and Oil Properties

We utilize the full cost method of accounting for costs related to our natural gas and oil properties. We review the carrying value of our natural gas and oil properties under the full cost accounting rules of the SEC. Under these rules, all such costs excluding significant acquisition, exploration and development costs related to unproved properties, are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test, however, which limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved gas and oil reserves discounted at 10 percent plus the lower of cost or market value of unproved properties. If the net capitalized costs of natural gas and oil properties exceed the ceiling, we will record a ceiling test write-down to the extent of such excess. A ceiling test write-down is a non-cash charge to earnings. If required, it reduces earnings and impacts shareholders equity in the period of occurrence and results in lower depreciation, depletion and amortization expense in future periods. The write-down may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling.

The risk that we will be required to write-down the carrying value of our natural gas and oil properties increases when natural gas and oil prices are depressed or if there are substantial downward revisions in estimated proved reserves. Application of these rules during periods of relatively low natural gas or oil prices due to seasonality or other reasons, even if temporary, increases the probability of a ceiling test write-down. Based on natural gas and oil prices in effect on December 31, 2005, the unamortized cost of our natural gas and oil properties did not exceed the ceiling of proved natural gas and oil reserves. Natural gas pricing has historically been unpredictable and any significant declines could result in a ceiling test write-down in subsequent quarterly or annual reporting periods.

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Natural gas and oil reserves used in the full cost method of accounting cannot be measured exactly. Our estimate of natural gas and oil reserves requires extensive judgments of reservoir engineering data and is generally less precise than other estimates made in connection with financial disclosures. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. The uncertainties inherent in the disclosure are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves. We engage the services of an independent petroleum consulting firm to calculate reserves.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with generally accepted accounting principles requires management 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 reporting period. Actual results could differ from those estimates.

Management believes that it is reasonably possible the following material estimates affecting the financial statements could significantly change in the coming year: (1) estimates of proved oil and gas reserves, (2) estimates as to the expected future cash flow from proved oil and gas properties and (3) estimates of future dismantlement and restoration costs.

Concentration of Credit Risk

Although our cash and temporary investments and accounts receivable are exposed to potential credit loss, we do not believe such risk to be significant. Even though a substantial amount of funds were in accounts at financial institutions which were not covered under bank guarantees, management does not believe that maintaining balances in excess of bank guarantees resulted in a significant risk to the Company.

Foreign Operations

Our future operations and earnings will depend upon the results of our operations in Georgia. There can be no assurance that we will be able to successfully conduct such operations, and a failure to do so would have a material adverse effect on the our financial position, results of operations and cash flows. Also, the success of our operations will be subject to numerous contingencies, some of which are beyond management control. These contingencies include general and regional economic conditions, prices for crude oil and natural gas, competition and changes in regulation. Since we are dependent on international operations, specifically those in Georgia, we will be subject to various additional political, economic and other uncertainties. Among other risks, our operations may be subject to the risks and 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.

Recently Issued Pronouncements

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS No. 157) which defines fair value, establishes a framework for measuring fair value in accordance with accounting principles generally accepted in the United States, and expands disclosures about fair value measurements. SFAS No. 157 is effective for financial assets and liabilities for fiscal years beginning after November 15, 2007. In February 2008, the FASB issued FSP FAS 157-2, Effective Date of FASB Statement No. 157. FSP 157-2 delays the effective date of SFAS No. 157 for all non-financial assets and non-financial liabilities that are not re-measured at fair value on a recurring basis until fiscal years beginning after November 15, 2008. Any amounts recognized upon adoption of this rule as a cumulative effect adjustment will be recorded to the opening balance of retained earnings in the year of adoption. The Company has evaluated SFAS No. 157 and has determined that it will not have a material impact on its Consolidated Financial Statements.

In December 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 141(R), Business Combinations (SFAS 141(R)), which replaces SFAS 141. SFAS 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. The Statement also establishes disclosure requirements, which will enable users to evaluate the nature and financial effects of the business combination. SFAS 141(R) is effective for fiscal years beginning after December 15, 2008. The adoption of SFAS 141(R) will have an impact on accounting for business combinations once adopted, but the effect is dependent upon acquisitions at that time.

In December 2007, FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of Accounting Research Bulletin No. 51 (SFAS 160), which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent s ownership interest and the valuation of retained non-controlling equity investments when a subsidiary is deconsolidated. The Statement also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. SFAS 160 is effective for fiscal years beginning after December 15, 2008. The Company has not determined the effect that the application of SFAS 160 will have on its Consolidated Financial Statements.

The Company has reviewed all other recently issued, but not yet adopted, accounting standards in order to determine their effects, if any, on its consolidated results of operations, financial position and cash flows. Based on that review, the Company believes that none of these pronouncements will have a significant effect on current or future earnings or operations.

Forward-Looking Statements

The forward-looking statements contained in this Item 7 and elsewhere in this Annual Report on Form 10-K are subject to various risks, uncertainties and other factors that could cause actual results to differ materially from the results anticipated in such forward-looking statements. Included among the important risks, uncertainties and other factors are those hereinafter discussed.

Few of the forward-looking statements in this Annual Report deal with matters that are within our unilateral control. Joint venture, acquisition, financing and other agreements and arrangements must be negotiated with independent third parties and, in some cases, must be approved by governmental agencies. These third parties generally have objectives and interests that may not coincide with ours and may conflict with our interests. Unless we are able to compromise these conflicting objectives and interests in a mutually acceptable manner, agreements and arrangements with these third parties will not be consummated.

Operating entities in various foreign jurisdictions must be registered by governmental agencies, and production licenses for development of oil and gas fields in various foreign jurisdictions must be granted by governmental agencies. These governmental agencies generally have broad discretion in determining whether to take or approve various actions and matters. In addition, the policies and practices of governmental agencies may be affected or altered by political, economic and other events occurring either within their own countries or in a broader international context. Finally, due to the developing nature of the legal regimes in many former Soviet Union countries where we operate, our contractual rights and remedies may be subject to certain legal uncertainties.

Our ability to finance all of its present oil and gas projects and other ventures according to present plans is dependent upon obtaining additional funding. An inability to obtain financing could require us to scale back or abandon part of all of our project development, capital expenditure, production and other plans. The availability of equity or debt financing to us or to the entities that are developing projects in which we have interests is affected by many factors, including:

- world economic conditions;
- the state international relations;
- the stability and policies of various governments located in areas in which we currently operate or intend to operate;
- fluctuations in the price of oil and gas, the general outlook for the oil and gas industry and competition for available funds; and
- an evaluation of us and specific projects in which we have an interest.

Rising interest rates might affect the feasibility of debt financing that is offered. Potential investors and lenders will be influenced by their evaluations of us and our projects and comparisons with alternative investment opportunities.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Our principal exposure to market risk is due to changes in oil and gas prices and currency fluctuations. As indicated elsewhere in this Report, as a producer of oil and gas we are exposed to changes in oil and gas prices as well as changes in supply and demand which could affect our revenues. We do not engage in any commodity hedging activities. Due to the ready market for our production in Georgia, we do not believe that any current exposures from this risk will materially affect our financial position at this time, but there can be no assurance that changes in such market will not affect us adversely in the future.

Also as indicated elsewhere in this Report, because all of our operations are being conducted in the former Soviet Union, we are potentially exposed to the market risk of fluctuations in the relative values of the currencies in areas in which we operate. At present we do not engage in any currency hedging operations since, to the extent we receive payments for our production and marketing activities in local currencies, we are utilizing such currencies to pay for our local operations. In addition, our contracts to sell our production from the Ninotsminda Field in Georgia is denominated in US dollars with all export contracts providing for payment in dollars, although we may not always be able to continue to demand payment in U.S. dollars.

We had no material interest in investments subject to market risk during the period covered by this Report.

Because the majority of all revenue to us is from the sale of production from the Ninotsminda Field a change in the price of oil or a change in the production rates could have a substantial effect on this revenue and therefore profits.

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Assuming the same production in 2008 as 2007 but decreasing the net oil price we receive from sales by $5.00 and $10.00 respectively would change the total annual revenue from oil sales as follows. The total annual revenue from oil sales for 2007 based on an average net oil price received of $67.97 was approximately $7,144,000. If the average net oil price received was $5.00 less at $62.97 then the total annual revenue from oil sales would be reduced by approximately $526,000 to approximately $6,618,000. If the average net oil price received was reduced by $10 per barrel then the total annual revenue from oil sales realised would be reduced by approximately $1,051,000 to approximately $6,093,000, assuming all other factors are constant.

Assuming constant oil prices a reduction in annual production by 20% and 50% would have the following effect on total annual revenues. In 2007 total oil sales were 105,111 bbls of oil producing revenue of approximately $7,144,000. If this was reduced by 20% then the annual revenue from oil sales would be reduced to approximately $5,715,000. If the total annual oil sales were reduced by 50% or 52,555 bbls then the total annual revenue from oil sales would be approximately $3,572,000, assuming all other factors are constant.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The Financial Statements required to be filed in this Report begin at Page F-1 of this Report.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A. CONTROLS AND PROCEDURES.

Management s Responsibility for Financial Statements

Our management is responsible for the integrity and objectivity of all information presented in this Annual Report. The consolidated financial statements were prepared in conformity with accounting principles generally accepted in the United States of America and include amounts based on management s best estimates and judgments. Management believes the consolidated financial statements fairly reflect the form and substance of transactions and that the financial statements fairly represent the Company s financial position and results of operations. The Audit Committee of the Board of Directors, which is composed solely of independent directors, meets regularly with the independent auditors, L J Soldinger Associates LLC and representatives of management to review accounting, financial reporting, internal control and audit matters, as well as the nature and extent of the audit effort. The Audit Committee is responsible for the engagement of the independent auditors. The independent auditors have free access to the Audit Committee.

Evaluation of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our chief executive officer and chief financial officer, we evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2007. Based on that evaluation, our chief executive officer and chief financial officer have concluded that our disclosure controls and procedures are not effective to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 (Exchange Act) is recorded, processed, summarized and reported within the time periods specified in the Commission s rules and forms and to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosure.

Management s Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in the rules promulgated under the Exchange Act as a process designed by, or under the supervision of, the Company s principal executive and principal financial officers and effected by the Company s Board, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting procedures (GAAP) and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the Company;

- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with US GAAP, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and Directors of the Company; and

- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company s assets that could have a material effect on the financial statements.

A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, control may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

Under the supervision and with the participation of our management, including our principal executive, financial and accounting officers, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2007 based on the framework in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

The effectiveness of our internal control over financial reporting as of December 31, 2007 has been audited by L J Soldinger Associates, LLC, an independent registered public accounting firm, as stated in their report as set forth at the end of this section.

A material weakness is a control deficiency, or combination of control deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements would not be prevented or detected on a timely basis. As of December 31, 2007, we have concluded that our internal control over financial reporting was ineffective as of December 31, 2007 and that we have material weaknesses in each of the following areas:

1. Disclosure Controls

The Company s disclosure controls and procedures were not effective to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Commission s rules and forms and to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including chief executive officer and chief financial officer, as appropriate to allow timely decisions. Inadequate controls include the lack of procedures used for

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identifying, determining, and calculating required disclosures and other supplementary information requirements.

2. Information Technology

The Company did not adequately implement certain controls over information technology, including certain spreadsheets, used in its core business and financial reporting. These areas included logical access security controls to financial applications, segregation of duties and backup and recovery procedures. The Company s controls over the completeness, accuracy, validity, restricted access, and the review of certain spreadsheets used in the period-end financial statement preparation and reporting process was not designed appropriately. This material weakness affects the Company s ability to prevent improper access and changes to its accounting records and misstatements in the financial statements could occur and not be prevented or detected by the Company s controls in a timely manner.

As a result, misappropriation of assets and misstatements in the financial statements could occur and not be prevented or detected by the Company s controls in a timely manner. In light of the review, Management, in consultation with the Audit Committee, is reviewing the most cost effective way to address the issues raised.

CEO and CFO Certifications The Certifications of our CEO and CFO which are attached as Exhibits 31(1) and 31(2) to this Report include information about our disclosure controls and procedures and internal control over financial reporting. These Certifications should be read in conjunction with the information contained in this Item 9A for a more complete understanding of the matters covered by the Certifications.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control in the fourth quarter.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and
Stockholders of CanArgo Energy Corporation

We have audited CanArgo Energy Corporation s internal control over financial reporting as of 31 December 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organization of the Treadway Commission (COSO). CanArgo Energy Corporation s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report Over Financial Reporting. Our responsibility is to express an opinion on the company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

A material weakness is a control deficiency, or combination of control deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. The following material weaknesses have been identified and included in management s assessment.

Information Technology

The Company did not adequately implement certain controls over information technology, including certain spreadsheets, used in its core business and financial reporting. These areas included logical access security controls to financial applications, segregation of duties and backup and recovery procedures. The Company s controls over the completeness, accuracy, validity, restricted access, and the review of certain spreadsheets used in the period-end financial statement preparation and reporting process was not designed appropriately. This material weakness affects the Company s ability to prevent improper access and changes to its accounting records and misstatements in the financial statements could occur and not be prevented or detected by the Company s controls in a timely manner.

Disclosure

The Company s disclosure controls and procedures were not effective in providing reasonable assurance that information required to be disclosed in reports filed or submitted under The Securities Exchange Act of 1934 is recorded, processed, summarized and reported, within the time periods specified in the SEC s rules and forms and to ensure that information required to be disclosed by the Company in the reports that it files or submits under The Securities Exchange Act of 1934 is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. Inadequate controls include the lack of procedures used for identifying, determining and calculating required disclosures and other supplementary information requirements.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2007 consolidated financial statements of CanArgo Energy Corporation and our report dated 13 March 2008 expressed an unqualified opinion.

These material weaknesses were considered in determining the nature, timing, and extent of audit tests applied in our audit of the 2007 financial statements, and this report does not affect our report dated 13 March 2008 on those financial statements.

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In our opinion, because of the effect of the material weaknesses described above on the achievement of the objectives of the control criteria, CanArgo Energy Corporation has not maintained effective internal control over financial reporting as of 31 December 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

L J Soldinger Associates LLC
Deer Park, Illinois USA
13 March, 2008

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ITEM 9B. OTHER INFORMATION

On March 14, 2006, we entered into an agreement (Termination Agreement) with Europa Oil Services Limited (Europa), an unaffiliated company, formally terminating the consultancy agreement between CanArgo and Europa dated January 8, 2004. Under the terms of the consultancy agreement, CanArgo had an outstanding obligation to issue up to 12 million shares of CanArgo common stock to Europa upon certain production targets being met from future developments under the Samgori PSC. With effect from February 16, 2006, we have withdrawn from the Samgori PSC. Pursuant to the terms of the Termination Agreement the parties accordingly agreed that the consultancy agreement had terminated with effect from February 16, 2006. CanArgo has not incurred any material early termination penalties as a result of the termination of the consultancy agreement.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

The information required by this Item is hereby incorporated by reference from our definitive proxy statement to be mailed to stockholders in connection with our 2008 Annual Meeting of Stockholders and filed with the SEC within 120 days after the close of our fiscal year.

ITEM 11. EXECUTIVE COMPENSATION.

The information required by this Item is hereby incorporated by reference from our definitive proxy statement to be mailed to stockholders in connection with our 2008 Annual Meeting of stockholders and filed with the SEC within 120 days after the close of our fiscal year.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The information required by this Item is hereby incorporated by reference from our definitive proxy statement to be mailed to stockholders in connection with our 2008 Annual Meeting of Stockholders and filed with the SEC within 120 days after the close of our fiscal year.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

The information required by this Item is hereby incorporated by reference from our definitive proxy statement to be mailed to stockholders in connection with our 2008 Annual Meeting of Stockholders and filed with the SEC within 120 days after the close of our fiscal year.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by this Item is hereby incorporated by reference from our definitive proxy statement to be mailed to stockholders in connection with our 2008 Annual Meeting of Stockholders and filed with the SEC within 120 days after the close of our fiscal year.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) Financial Statements

The following financial statements and related notes of the Company contained on pages F-1 through F-60 are filed as part of this Report:

Reports of Independent Auditors
Consolidated Balance Sheets December 31, 2007 and 2006.
Consolidated Statements of Operations Years Ended December 31, 2007, 2006, and 2005.
Consolidated Statements of Cash Flows Years Ended December 31, 2007, 2006, and 2005.
Consolidated Statements of Stockholders Equity Years ended December 31, 2007, 2006 and 2005.
Notes to Consolidated Financial Statements

(2) Financial Statements Schedules

None

All other schedules are omitted because of the absence of conditions under which they are required or because the required information is included in the consolidated financial statements or notes thereto.

(b) Exhibits

Management Contracts, Compensation Plans and Arrangements are identified by an asterisk (*) Documents filed herewith are identified by a cross ( ).

1(1) Engagement Agreement with Sundal Collier & Co ASA dated August 13, 2001. (Incorporated herein by reference from Post-Effective Amendment No. 2 to Form S-1 Registration Statement, File No. 333-85116 filed on September 10, 2002)).

1(2) Placement Agent Agreement dated September 22, 2004 by and between ABG Sundal Collier, Norge ASA and CanArgo Energy Corporation (Incorporated herein by reference from Amendment No 2 to Registration Statement on Form S-3 filed August 31, 2004 (Reg. No. 333-115645)).

1(3) Placement Agent Agreement dated September 22, 2004 by and between ABG Sundal Collier Inc. and CanArgo Energy Corporation (Incorporated herein by reference from Amendment No 1 to Registration Statement on Form S-3 filed July 1, 2004 (Reg. No. 333-115645)).

1(4) Engagement letter between ABG Sundal Collier Norge ASA and CanArgo Energy Corporation dated March 23, 2004 (Incorporated herein by reference from September 30, 2004 Form 10-Q).

1(5) Mandate Agreement dated September 19, 2006 by and among CanArgo Energy Corporation, Terra Securities ASA and Orion Securities ASA as amended by Addendum No. 1 dated September 21, 2006. (Incorporated herein by reference from December 31, 2006 Form 10-K).

2(4)	Memorandum of Agreement between Fielden Management Services Pty, Ltd., A.C.N. 005 506 123 and Fountain Oil Incorporated dated May 16, 1995 (Incorporated herein by reference from December 31, 1997 Form 10-K/A).
3(1)	Registrant s Certificate of Incorporation and amendments thereto (Incorporated by reference from the Company s Proxy Statements filed May 10, 1999 and May 9, 2000 and Form 8-K filed July 24, 1998 and May 23, 2006 and March 31, 2004 Form 10-Q filed on May 17, 2004).
3(2)	Registrant s Amended and Restated Bylaws as amended (Incorporated herein by reference to Form 8-K dated March 2, 2007).
3(3)	Certificate of Amendment of the Certificate of Incorporation as filed with the Office of the Secretary of State of the State of Delaware on June 5, 2007 (Incorporated herein by reference from Form 8-K dated June 11, 2007).
*4(1)	Amended and Restated 1995 Long-Term Incentive Plan (Incorporated herein by reference from September 30, 1998 Form 10-Q).
*4(2)	Amended and Restated CanArgo Energy Inc. Stock Option Plan (Incorporated herein by reference from March 31, 1998 Form 10-Q).
*4(3)	CanArgo Energy Corporation 2004 Long Term Incentive Plan (Incorporated herein by reference from Form 8-K dated May 19, 2004 and Company s definitive Proxy Statement filed March 17, 2006).
4(4)	Note and Warrant Purchase Agreement dated March 3, 2006 among CanArgo Energy Corporation and the Purchasers party thereto (Incorporated herein by reference from Form 8-K dated March 8, 2006).
4(5)	Registration Rights Agreement dated March 3, 2006 among CanArgo Energy Corporation and the Purchasers party thereto (Incorporated herein by reference from Form 8-K dated March 8, 2006).
4(6)	Note and Warrant Purchase Agreement dated June 28, 2006 among CanArgo Energy Corporation and the Purchaser party thereto (Incorporated by reference from Form 8-K dated June 28, 2006).
4(7)	Registration Rights Agreement dated June 28, 2006 among CanArgo Energy Corporation and the Purchaser party thereto (Incorporated by reference from Form 8-K dated June 28, 2006).
4(8)	Form of Subscription Agreement dated as of September 19, 2006 by and between CanArgo Energy Corporation and the Purchaser named therein (Incorporated by reference from Form 8-K dated October 12, 2006).
4(9)	Subscription letter agreement dated as of August 10, 2007 to offer the right to subscribe for an aggregate of 2,500,000 shares of common stock, of the Company and an aggregate of 5,000,000 common stock purchase warrants (Incorporated by reference from Form 8-K dated August 14, 2007).
10(1)	Production Sharing Contract between (1) Georgia and (2) Georgian Oil and JKX Ninotsminda Ltd. dated February 12, 1996 (Incorporated herein by reference from Form S-1 Registration Statement, File No. 333-72295 filed on June 7, 1999).

*10(2) Management Services Agreement between CanArgo Energy Corporation and Vazon Energy Limited

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relating to the provisions of the services of Dr. David Robson dated June 29, 2000 (Incorporated herein by reference from September 30, 2000 Form 10-Q). As amended by Deed of Variation of Management Services Agreement between CanArgo Energy Corporation and Vazon Energy Limited dated May 2, 2003 (Incorporated herein by reference to Form 8-K dated May 13, 2003).

10(3) Tenancy Agreement between CanArgo Energy Corporation and Grosvenor West End Properties dated September 8, 2000 (Incorporated herein by reference from September 30, 2000 Form 10-Q).

10(4) Production Sharing Contract between (1) Georgia and (2) Georgian Oil and CanArgo Norio Limited dated December 12, 2000 (Incorporated herein by reference from December 31, 2000 Form 10-K).

*10(5) Service Agreement between CanArgo Energy Corporation and Vincent McDonnell dated December 1, 2000 (Incorporated herein by reference from December 31, 2001 Form 10-K).

10(6) Sale agreement of CanArgo Petroleum Products Limited between CanArgo Limited and Westrade Alliance LLC dated October 14, 2002. (Incorporated herein by reference from September 30, 2002 Form 10-Q)

10(7) Stock Purchase Agreement dated September 24, 2003 regarding the sale of all of the issued and outstanding stock of Fountain Oil Boryslaw (Incorporated herein by reference from March 31, 2003 Form 10-Q)

10(8) Agreement between CanArgo Samgori Limited and Georgian Oil Samgori Limited dated January 8, 2004 (Incorporated herein by reference from Form S-3 filed May 6, 2004 (Reg. No. 333-115261)).

10(9) Agreement dated March 17, 2004 between CanArgo Acquisition Corporation and Stanhope Solutions Ltd for the sale of Lateral Vector Resources Ltd. (Incorporated herein by reference from Form 8-K dated May 19, 2004).

10(10) Master Service Contract dated June 1, 2004 between CanArgo Energy Corporation and WEUS Holding Inc. (Incorporated herein by reference from Form 8-K dated June 1, 2004).

10(11) Agreement between Ninotsminda Oil Company Limited and Saipem S.p.A. dated January 27, 2005 (Incorporated herein by reference from Form 8-K dated January 27, 2005).

10(12) Agreement between Ninotsminda Oil Company Limited and Primrose Financial Group dated February 4, 2005 (Incorporated herein by reference from Form 8-K dated February 4, 2005).

10(13) Subordinated Subsidiary Guaranty dated March 3, 2006 by and among Ninotsminda Oil Company Limited, CanArgo (Nazvrevi) Limited, CanArgo Norio Limited, CanArgo Limited, Tethys Petroleum Investments Limited, Tethys Kazakhstan Limited and CanArgo Ltd for the benefit of the holders of the Subordinated Notes (Incorporated herein by reference from Form 8-K dated March 8, 2006).

10(14) Subordinated Subsidiary Guaranty dated June 28, 2006 by and among Ninotsminda Oil Company

Limited, CanArgo (Nazvrevi) Limited, CanArgo Norio Limited, CanArgo Limited, Tethys Petroleum Investments Limited, Tethys Kazakhstan Limited and CanArgo Ltd for the benefit of the holder of the 12% Subordinated Note (Incorporated herein by reference from Form 8-K dated June 28, 2006).

10(15) Waiver, Consent and Amendment Agreement dated March 3, 2006 by and among CanArgo Energy Corporation and the Purchasers party thereto (Incorporated herein by reference from Form 8-K dated March 8, 2006).

10(16) Waiver, Consent and Amendment Agreement dated June 28, 2006, by and among CanArgo Energy Corporation and the Senior Secured Noteholders party thereto (Incorporated by reference from September 30, 2006 Form 10-Q).

10(17) Waiver, Consent and Amendment Agreement dated June 28, 2006, by and among CanArgo Energy Corporation and the Senior Secured Noteholders party thereto (Incorporated by reference from September 30, 2006 Form 10-Q).

10(18) Conversion Agreement dated June 28, 2006, by and among CanArgo Energy Corporation, the Subordinated Noteholders and Persistency (Incorporated by reference from Form 8-K dated June 28, 2006).

10(19) Memorandum of Understanding dated as of March 2, 2006 by and between the Ministry of Energy of Georgia and CanArgo (Nazvrevi) Limited (Incorporated herein by reference from Form 8-K dated March 8, 2006)

10(20) Form of Management Services Agreement for Elizabeth Landles, Executive Vice President and Corporate Secretary dated February 18, 2004 (Incorporated by reference from Form 10-K dated March 16, 2006).

10(21) Service Contract between CanArgo Energy Corporation and Jeffrey Wilkins dated August 22, 2006 (Incorporated by reference from September 30, 2006 Form 10-Q).

10(22) Amendment, Consent, Waiver and Release Agreement dated February 9, 2007 by and among CanArgo Energy Corporation and the Purchasers party thereto (Incorporated by reference from Form 8-K dated January 24, 2007).

10(23) Certificate of Discharge dated February 9, 2007 between Ingalls & Snyder LLC and CanArgo Limited (Incorporated by reference from Form 8-K dated January 24, 2007).

10(24) Security Interest Agreement, dated as of February 9, 2007, among Tethys Petroleum Limited, Ingalls & Snyder LLC and the Secured Parties, as defined herein (Incorporated by reference from Form 8-K dated January 24, 2007).

10(25) Amendment, Consent, Waiver and Release Agreement dated February 9, 2007 by and among CanArgo Energy Corporation and the Purchasers party thereto (Incorporated by reference from Form 8-K dated January 24, 2007).

10(26) Amendment, Consent, Waiver and Release Agreement dated February 9, 2007 by and among CanArgo Energy Corporation and Persistency (Incorporated by reference from Form 8-K dated January 24, 2007).

10(27)

Tethys Shareholders Agreement dated as of January 24, 2007 by and among CanArgo Limited, the Investors party thereto and Tethys Petroleum Limited (Incorporated herein by reference from December 31, 2006 Form 10-K).

10(28) Share Exchange Agreement relating to BN Munai LLP between Coin Investments Limited, Tethys Petroleum Limited and Tethys, Kazakhstan Limited (Incorporated herein by reference from

December 31, 2006 Form 10-K).

10(29) Consent and Conversion Agreement dated as of June 5, 2007 by and among CanArgo Energy Corporation, CanArgo Limited and the Purchasers party thereto, including the form of the Senior Compensatory Warrants to purchase up to 11,111,111 shares of CanArgo common stock issuable thereunder (Incorporated by reference from Form 8-K dated June 11, 2007).

10(30) Registration Rights Agreement dated as of June 5, 2007 by and among CanArgo Energy Corporation and the Purchasers party thereto (Incorporated by reference from Form 8-K dated June 11, 2007).

10(31) Conversion Agreement dated as of June 5, 2007 by and among CanArgo Energy Corporation, CanArgo Limited and Persistency, including the form of the Persistency Compensatory Warrants to purchase up to 5 million shares of CanArgo common stock issuable thereunder (Incorporated by reference from Form 8-K dated June 11, 2007).

10(32) Registration Rights Agreement dated as of June 5, 2007 by and among CanArgo Energy Corporation and Persistency (Incorporated by reference from Form 8-K dated June 11, 2007).

10(33) Amendment, Consent, Waiver and Release Agreement dated June 5, 2007 by and among CanArgo Energy Corporation and the Purchasers party thereto (Incorporated by reference from Form 8-K dated June 11, 2007).

10(34) Certificate of Discharge dated June 5, 2007 between Ingalls & Snyder LLC, Tethys Petroleum Limited and CanArgo Limited (Incorporated by reference from Form 8-K dated June 11, 2007).

10(35) Amendment, Consent, Waiver and Release Agreement dated June 5, 2007 by and among CanArgo Energy Corporation and the Purchasers party thereto (Incorporated by reference from Form 8-K dated June 11, 2007).

10(36) Amendment, Consent, Waiver and Release Agreement dated June 5, 2007 by and among CanArgo Energy Corporation and Persistency (Incorporated by reference from Form 8-K dated June 11, 2007).

10(37) Amendment, Consent and Waiver Agreement dated June 13, 2007 by and among CanArgo Energy Corporation and the Purchasers party thereto (Incorporated by reference from Form 8-K dated June 18, 2007).

10(38) Amendment, Consent and Waiver Agreement dated June 13, 2007 by and among CanArgo Energy Corporation and the Purchasers party thereto (Incorporated by reference from Form 8-K dated June 18, 2007).

10(39) Amendment, Consent and Waiver Agreement dated June 13, 2007 by and among CanArgo Energy Corporation and Persistency (Incorporated by reference from Form 8-K dated June 18, 2007).

10(40) Agency Agreement dated June 18, 2007 (Incorporated by reference from Form 8-K dated June 27, 2007).

*10(41) Management Services Agreement between CanArgo Energy Corporation and Vazon Energy Limited relating to the provisions of the services of Dr. David Robson dated June 27, 2007 (Incorporated by reference from Form 8-K dated July 3, 2007).

*10(42)	Amendment No. 1 to the Statement of Terms and Conditions of Employment between Vazon Energy Limited and Elizabeth Landles (Incorporated by reference from Form 8-K dated July 3, 2007).
10(43)	Letter Agreement With Agents (Incorporated by reference from Form 8-K dated July 11, 2007).

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10(44)	Placement Agreement dated July 22, 2007 by and between CanArgo Limited and Jennings Capital Inc (Incorporated by reference from Form 8-K dated July 27, 2007).
10(45)	Amendment, Consent and Waiver Agreement dated as of August 9, 2007 by and among CanArgo Energy Corporation, Ingalls & Snyder LLC, and the Purchasers party thereto, including the form of the Senior Note Compensatory Warrants to purchase up to 17,916,667 shares of CanArgo common stock issuable thereunder (Incorporated by reference from Form 8-K dated August 14, 2007).
10(46)	Amendment, Consent and Waiver Agreement dated as of August 13, 2007 by and among CanArgo Energy Corporation, Ingalls & Snyder LLC and the Purchasers party thereto, including the form of the Subordinated Note Compensatory Warrants to purchase certain shares of CanArgo common stock issuable thereunder (Incorporated by reference from Form 8-K dated August 14, 2007).
10(47)	Transfer Agency and Service Agreement dated December 18, 2007 by and among CanArgo Energy Corporation, Computershare Trust Company, N.A. and Computershare, Inc (Incorporated by reference from Form 8-K dated December 28, 2007).
14	Code of Ethics (Incorporated herein by reference from December 31, 2004 Form 10-K).
21	List of Subsidiaries (Incorporated herein by reference from September 30, 2007 Form 10-Q).
23(a)	Consent of LJ Soldinger Associates, LLC, Independent Public Accountants.
23(c)	Consent of Oilfield Production Consultants (OPC) Limited, Independent Petroleum Consultants.
31(1)	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer of CanArgo Energy Corporation.
31(2)	Rule 13a-14(c)/15d-14(a) Certification of Chief Financial Officer of CanArgo Energy Corporation.
32	Section 1350 Certifications.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CanArgo Energy Corporation
(Registrant)

By: /s/Jeffrey Wilkins — Date: March 13, 2008

Chief Financial Officer and Director
(Principal Financial and Accounting Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

By: /s/Vincent McDonnell — Date: March 13, 2008

Vincent McDonnell, Acting Chairman of the Board,
President, Chief Executive Officer and Director
(Principal Executive Officer)

By:	/s/Michael Ayre	Date: March 13, 2008
	Michael Ayre, Director	
By:	/s/Russell Hammond	Date: March 13, 2008
	Russell Hammond, Director	

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EXHIBIT INDEX

23(a)	Consent of L J Soldinger & Associates, LLC, Independent Public Accountants.
23(c)	Consent of Oilfield Production Consultants (OPC) Limited, Independent Petroleum Consultants.
31(1)	Rule 13a-14(a)/15d-14(a) Certification of Chief Executive Officer of CanArgo Energy Corporation.
31(2)	Rule 13a-14(c)/15d-14(a) Certification of Chief Financial Officer of CanArgo Energy Corporation.
32	Section 1350 Certifications.

CANARGO ENERGY CORPORATION
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REPORT ON MANAGEMENT S RESPONSIBILITIES

To the Stockholders of CanArgo Energy Corporation:

CanArgo s management is responsible for the integrity and objectivity of the financial information contained in this Annual Report. The financial statements included in this report have been prepared in accordance with accounting principles generally accepted in the United States and, where necessary, reflect the informed judgements and estimates of management.

Management maintains and is responsible for systems of internal accounting control designed to provide reasonable assurance that all transactions are properly recorded in the Company s books and records, that procedures and policies are adhered to, and that assets are safeguarded from unauthorized use.

The financial statements for 2007 and 2006 have been audited by the independent accounting firm of L J Soldinger Associates LLC, as indicated in their report. Management has made available to its outside auditors all the Company s financial records and related data and minutes of directors and audit committee meetings.

CanArgo s audit committee, consisting solely of directors who are not employees of CanArgo, is responsible for: reviewing the Company s financial reporting; reviewing accounting and internal control practices; recommending to the Board of Directors and shareholders the selection of independent accountants; and monitoring compliance with applicable laws and company policies. The independent accountants have full and free access to the audit committee and meet with it, with and without the presence of management, to discuss all appropriate matters. On the recommendation of the audit committee, the consolidated financial statements have been approved by the Board of Directors.

/s/ Vincent McDonnell	/s/ Jeffrey Wilkins
Chief Executive Officer	Chief Financial Officer

March 13, 2008

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
CanArgo Energy Corporation
St Peter Port, Guernsey, British Isles

We have audited the accompanying consolidated balance sheets of CanArgo Energy Corporation as of December 31, 2007 and 2006, and the related consolidated statements of operations and comprehensive loss, stockholders equity, and cash flows for each of the years in the three-year period ended December 31, 2007. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statements presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of CanArgo Energy Corporation as of December 31, 2007 and 2006, and its consolidated results of operations, changes in stockholders equity and its cash flows for each of the years in the three-year period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America.

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 to the financial statements, the Company has incurred net losses since inception and does not have sufficient funds to execute its business plan or fund operations through the end of 2008. Management estimates its current cash will last through to the third quarter 2008. In addition, the Company is restricted from incurring additional debt obligations unless it receives permission from its current lenders. These conditions raise substantial doubt about the Company s ability to continue as a going concern. Management s plans regarding those matters are also described in Note 1. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of CanArgo Energy Corporation internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated 13 March, 2008 expressed an adverse opinion on the effectiveness of internal control over financial reporting.

L J SOLDINGER ASSOCIATES LLC
Deer Park, Illinois, USA
March 13, 2008

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CANARGO ENERGY CORPORATION
Consolidated Balance Sheets

	December 31, 2007	2006
	(Expressed in United States dollars)	
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 6,869,381**	$ 14,689,289
Restricted cash		299,777
Accounts receivable	**379,268**	503,953
Crude oil inventory	**373,770**	452,500
Prepayments	**311,537**	2,254,563
Assets to be disposed	**71,294**	5,965,341
Other current assets	**167,404**	163,561
Total current assets	**$ 8,172,654**	$ 24,328,984
Non Current Assets		
Prepaid financing fees	**74,804**	288,632
Assets to be disposed		24,560,166
Capital assets, net (including unevaluated amounts of $9,444,742 and $55,097,099, respectively)	**51,304,619**	87,307,700
Total Assets	**$ 59,552,077**	$ 136,485,482
LIABILITIES AND STOCKHOLDERS EQUITY		
Accounts payable trade	**$ 481,665**	$ 3,672,731
Deferred revenue		484,515
Accrued liabilities	**6,639,887**	6,918,468
Liabilities to be disposed	**336,446**	1,625,282
Total current liabilities	**$ 7,457,998**	$ 12,700,996
Long term debt	**11,697,231**	37,264,270
Other non current liabilities	**37,778**	1,260,079
Provision for future site restoration	**230,720**	205,200
Liabilities to be disposed		3,566,055
Total Liabilities	**$ 19,423,727**	$ 54,996,600
Temporary Equity	**$ 2,119,530**	$ 2,119,530

Stockholders equity:		
Common stock, par value $0.10; authorized 500,000,000 shares at December 31, 2007 and 375,000,000 at December 31, 2006; shares issued, issuable and outstanding 242,120,974 at December 31, 2007 and 237,145,974 at December 31, 2006	**24,212,096**	23,714,596
Capital in excess of par value	**245,316,295**	233,397,113
Accumulated deficit	**(231,519,571)**	(177,742,357)
Total stockholders equity	**$ 38,008,820**	$ 79,369,352
Total Liabilities, Temporary Equity and Stockholders Equity	**$ 59,552,077**	$ 136,485,482

The accompanying notes are an integral part of the consolidated financial statements

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CANARGO ENERGY CORPORATION
Consolidated Statements of Operations and Comprehensive Loss

	For Year Ended December 31,		
	December 31, 2007	December 31, 2006	December 31, 2005
	(Expressed in United States dollars)		
Operating Revenues from Continuing Operations:			
Oil and gas sales	**$ 7,208,666**	$ 6,526,660	$ 5,278,912
	7,208,666	6,526,660	5,278,912
Operating Expenses:			
Field operating expenses	**1,370,153**	1,702,679	1,109,588
Direct project costs	**662,798**	811,795	1,084,330
Selling, general and administrative	**7,163,951**	9,732,142	10,824,494
Depreciation, depletion and amortization	**2,592,531**	3,798,727	3,275,553
Impairment of oil and gas properties, ventures and other assets	**42,000,000**	39,000,000	
	53,789,433	55,045,343	16,293,965
Operating Loss from Continuing Operations	**(46,580,767)**	(48,518,683)	(11,015,053)
Other Income (Expense):			
Interest income	**315,302**	426,816	829,895
Interest and amortization of debt discount and expense	**(6,208,660)**	(5,112,471)	(1,899,522)
Loss/Cost on debt extinguishment	**(12,127,494)**		
Foreign exchange gains (losses)	**(73,863)**	(314,853)	(230,176)
Other	**(639,104)**	(912,506)	(52,618)
Equity Loss from investments			(155,016)
Total Other Expense	**(18,733,819)**	(5,913,014)	(1,507,437)
Loss from Continuing Operations Before Taxes	**(65,314,586)**	(54,431,697)	(12,522,490)
Income taxes			
Loss from Continuing Operations	**(65,314,586)**	(54,431,697)	(12,522,490)
Net Income (Loss) from Discontinued Operations, net of taxes	**11,537,372**	(6,109,154)	187,176
Net Loss	**$ (53,777,214)**	$ (60,540,851)	$ (12,335,314)
Weighted average number of common shares outstanding			

Basic		**239,442,275**		227,001,672		211,586,953
Diluted		**239,442,275**		227,001,672		211,586,953
Basic Net Income (Loss) Per Common Share						
from continuing operations	**$**	**(0.27)**	$	(0.24)	$	(0.06)
from discontinued operations	**$**	**0.05**	$	(0.03)	$	0.00
Basic Net Income (Loss) Per Common Share	**$**	**(0.22)**	$	(0.27)	$	(0.06)
Diluted Net Income (Loss) Per Common Share						
from continuing operations	**$**	**(0.27)**	$	(0.24)	$	(0.06)
from discontinued operations	**$**	**0.05**	$	(0.03)	$	0.00
Diluted Net (Income) Loss Per Common Share	**$**	**(0.22)**	**$**	**(0.27)**	**$**	**(0.06)**

The accompanying notes are an integral part of the consolidated financial statements

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CANARGO ENERGY CORPORATION
Consolidated Statements of Cash Flows

	For Year Ended December 31,		
	2007	2006	2005
	(Expressed in United States dollars)		
Operating activities:			
Net Loss	**(53,777,214)**	(60,540,851)	(12,335,314)
Net income (loss) from discontinued operations, net of taxes and minority interest	**11,537,372**	(6,109,154)	187,176
Loss from continuing operations	**(65,314,586)**	(54,431,697)	(12,522,490)
Adjustments to reconcile net loss from continuing operations to net cash used by operating activities:			
Non-cash stock compensation expense	**627,791**	1,924,076	2,374,578
Non-cash interest expense and amortization of debt discount	**4,445,716**	3,543,938	1,277,878
Non-cash debt extinguishment expense	**12,127,494**		
Common stock issued for services			53,600
Non-cash miscellanous expenses			193,000
Depreciation, depletion and amortization	**2,592,531**	3,831,472	3,275,553
Impairment of oil and gas ventures and other assets	**42,000,000**	39,000,000	
Equity loss (income) from investments			155,016
Gain on disposition of assets	**138,157**		
Allowance for doubtful accounts			145,829
Trading gain on securities	**1,624,732**		
Changes in assets and liabilities:			
Restricted cash	**299,777**	2,881,895	(1,781,672)
Accounts receivable	**124,685**	(892,782)	1,299,761
Inventory	**78,730**	433,750	(632,392)
Prepayments	**254,699**	12,911	(202,801)
Other current assets	**(3,843)**	(12,849)	(178,323)
Accounts payable	**(703,498)**	785,178	400,540
Deferred revenue	**(484,515)**	484,515	(3,081,367)
Accrued liabilities	**429,400**	(76,490)	(548,391)
Net cash used by continuing operating activities	**(1,762,730)**	(2,516,083)	(9,771,681)
Investing activities:			
Capital expenditures	**(11,710,714)**	(24,338,874)	(29,957,341)
Proceeds from disposition of assets	**500,000**		
Acquisitions, net of cash acquired			609,553
Proceeds from disposition of security investments			
Change in oil and gas supplier prepayments	**1,688,327**	(1,056,388)	2,395,671
Net cash used in investing activities	**(9,521,847)**	(25,395,262)	(26,952,117)

Financing activities:			
Proceeds from sale of common stock	**3,560,600**	17,267,280	4,429,303
Share issue costs		(1,146,237)	(191,876)
Proceeds from loans		23,000,000	39,237,000
Repayment of loans			(7,200,000)
Deferred loan costs		(235,925)	(385,630)
Net cash provided by financing activities	**3,560,600**	38,885,118	35,888,797
Discontinued activities:			
Net cash generated by operating activities	**(97,782)**	(6,225,093)	1,502,892
Net cash used in investing activities	**(1,761,409)**	(11,783,380)	(6,744,380)
Net cash provided by financing activities		4,946,692	
Net cash flows from assets and liabilities held for sale and to be disposed	**(1,859,192)**	(13,061,781)	(5,241,488)
Net increase (decrease) in cash and cash equivalents	**(9,583,169)**	(2,088,008)	(6,076,489)
Cash and cash equivalents, beginning of period	**16,452,550**	18,540,558	24,617,047
Amounts reclassified to discontinued operations	**(1,763,261)**	(438,751)	
Cash and cash equivalents, beginning of period as stated	**14,689,289**	18,101,807	24,617,047
Cash and cash equivalents, end of period	**$ 6,869,381**	$ 16,452,550	$ 18,540,558

The accompanying notes are an integral part of the consolidated financial statements

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CANARGO ENERGY CORPORATION
Consolidated Statements of Stockholders Equity

	Common Stock Number of Shares Issued and Issuable	Par Value	Additional Paid-In Capital	Deferred Compensation Expense	Accumulated Deficit	Total Stockholders Equity
			Expressed in United States Dollars			
Total, December 31, 2004	**195,212,089**	**$19,521,208**	**$183,418,338**	**$(1,976,102)**	**$(104,866,192)**	**$96,097,252**
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	380,836	38,084	469,514			507,598
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	335,653	33,565	458,837			492,402
Exercise of stock options	1,067,833	106,783	255,850			362,633
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	344,758	34,476	498,072			532,548
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	370,599	37,060	562,940			600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	381,170	38,117	561,883			600,000
Shares Issued pursuant to Standby Equity Distribution agreement	495,745	49,574	550,426			600,000

(Cornell Capital)				
Exercise of stock options	1,570,000	157,000	11,000	168,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	552,639	55,264	544,736	600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	473,634	47,363	552,637	600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	837,054	**83,705**	516,295	600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	813,670	**81,367**	518,633	600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	872,854	**87,285**	512,715	600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	847,458	**84,746**	515,254	600,000
Shares Issueable pursuant to consultancy agreement (CEOCast)	80,000	8,000	45,600	53,600
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	801,068	**80,107**	519,893	600,000
	812,348	**81,235**	518,765	600,000

Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)					
Shares Issued pursuant to Tethys buy-out	11,000,000	1,100,000	7,260,000		8,360,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	639,591	**63,959**	536,041		600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	596,421	**59,642**	540,358		600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	613,246	**61,325**	538,675		600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	630,120	**63,012**	536,988		600,000

The accompanying notes are an integral part of the consolidated financial statements

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CANARGO ENERGY CORPORATION
Consolidated Statements of Stockholders Equity continued

	Common Stock Number of Shares Issued and Issuable	Par Value	Additional Paid-In Capital	Deferred Compensation Expense	Accumulated Deficit	Total Stockholders Equity
			Expressed in United States Dollars			
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	669,568	**66,957**	533,043			600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	761,325	**76,133**	523,867			600,000
Shares Issued pursuant to Standby Equity Distribution agreement (Cornell Capital)	783,188	**78,319**	521,681			600,000
Exercise of stock options	360,000	36,000	481,320			517,320
Exercise of stock options	284,000	28,400	352,950			381,350
Stock based compensation under SFAS 148			1,222,625	(244,297)		978,328
Share issue costs			(1,186,633)			(1,186,633)
Net Loss					(12,335,314)	(12,335,314)
Total, December 31, 2005	**222,586,867**	**$22,258,685**	**$202,892,303**	**$(2,220,399)**	**$(117,201,506)**	**$105,729,083**

The accompanying notes are an integral part of the consolidated financial statements

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CANARGO ENERGY CORPORATION
Consolidated Statements of Stockholders Equity continued

	Common Stock Number of Shares Issued and Issuable	Par Value	Additional Paid-In Capital	Deferred Compensation Expense	Accumulated Deficit	Total Stockholders Equity
Total, December 31, 2005	**222,586,867**	**$22,258,685**	**$202,892,303**	**$(2,220,399)**	**$(117,201,506)**	**$105,729,083**
Shares Issued pursuant to amended loan agreement dated August 27, 2004. (Salahi Ozturk)	1,521,739	152,174	897,826			1,050,000
Adoption of FAS 123R stock based compensation on effective date			(2,220,399)	2,220,399		
Discount recorded for Beneficial conversion feature and Issue of warrants to purchase 13 million shares persuant to a convertible loan agreement			10,166,000			10,166,000
Discount recorded for Beneficial conversion feature and Issue of warrants to purchase 12.5 million shares persuant to a convertible loan agreement			2,700,000			2,700,000
Stock based compensation under SFAS 123R			1,924,076			1,924,076
			2,220,000			2,220,000

Discount recorded for Issue of warrants to purchase 5 million shares persuant to a loan agreement						
Exercise of stock options	774,000	77,400	511,700			589,100
Shares Issued persuant to private placement October 2006	12,263,368	1,226,337	15,451,843			16,678,180
Share issuance costs			(1,146,236)			(1,146,236)
Net Loss					(60,540,851)	(60,540,851)
Total, December 31, 2006	**237,145,974**	**$23,714,596**	**$233,397,113**	**$ 0**	**$(177,742,357)**	**$ 79,369,352**

The accompanying notes are an integral part of the consolidated financial statements

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CANARGO ENERGY CORPORATION
Consolidated Statements of Stockholders Equity continued

	Common Stock Number of Shares Issued and Issuable	Par Value	Additional Paid-In Capital	Deferred Compensation Expense	Accumulated Deficit	Total Stockholders Equity
Total, December 31, 2006	**237,145,974**	**$23,714,596**	**$233,397,113**	**$ 0**	**$(177,742,357)**	**$ 79,369,352**
Stock based compensation under SFAS 123R			627,791			627,791
Issue of shares under Exercise of Warrants	1,000,000	100,000	530,000			630,000
Additional discount recorded for issue of warrants to purchase 5 million shares persuant to a loan agreement			237,875			237,875
Exercise of stock options	1,475,000	147,500	283,100			430,600
Discount recorded for Issue of compensatory warrants to purchase 5 million shares persuant to the modification to a loan agreement			1,283,500			1,283,500
Discount recorded for Issue of compensatory warrants to purchase 11,111,111 shares persuant to the modification to a loan agreement			2,953,333			2,953,333
Shares Issued persuant to private placement August 2007	2,500,000	250,000	2,250,000			2,500,000

Discount recorded for Issue of compensatory warrants to purchase 17,916,667 shares persuant to the modification to a loan agreement			3,180,208			3,180,208
Discount recorded for Issue of compensatory warrants to purchase 3,750,000 shares persuant to the modification to a loan agreement			573,375			573,375
Net Loss					(53,777,214)	(53,777,214)
Total, December 31, 2007	**242,120,974**	**$24,212,096**	**$245,316,295**	**$ 0**	**$(231,519,571)**	**$ 38,008,820**

The accompanying notes are an integral part of the consolidated financial statements

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NOTE 1 NATURE OF OPERATIONS AND GOING CONCERN

CanArgo Energy Corporation, headquartered in Guernsey, British Isles, and its consolidated subsidiaries (collectively CanArgo , we , our , us), is an integrated oil and gas company operating predominately within Georgia. Our principal activity is the acquisition of interests in and development of crude oil and natural gas fields.

Our ability to continue to pursue our principal activities of acquiring interests in and developing oil and gas fields is dependent upon generating funds from internal sources, external sources and, ultimately, maintaining sufficient positive cash flows from operating activities. Our financial statements have been prepared in accordance with U.S. GAAP, which contemplates continuation of the Company as a going concern. The Company incurred net losses from continuing operations to common stockholders of approximately $65,315,000 $54,432,000 and $12,522,000 for the years ended December 31, 2007, 2006 and 2005 respectively. These net losses included non-cash charges related to depreciation and depletion, impairments, loan interest, amortization of debt discount, extinguishment of debt and stock-based compensation of approximately $61,936,000, $48,213,000 and $7,175,000 for the years ended December 31, 2007, 2006 and 2005 respectively.

In the years ended December 31, 2007 and 2006, the Company s revenues from its Georgian operations did not cover the costs of its operations. At December 31, 2007 the Company had unrestricted cash and cash equivalents available for general corporate use or for use in the Georgian operations of approximately $6,869,000. In 2007 the Company experienced a net cash outflow from operations of approximately $1,800,000 in Georgia. In addition, the Company has a planned capital expenditure budget in 2008 of approximately $12,000,000 in Georgia. The exploration and development wells currently undergoing or waiting to undergo production testing in Georgia currently do not produce enough commercially available quantities of oil and or gas and the Company will not have sufficient working capital and may have to delay or suspend its capital expenditure plans and possibly make cutbacks in its operations. There are no assurances the Company could raise additional sources of equity financing and the covenants contained in the Note Purchase Agreements to which the Company is a party (see Note 9 of the consolidated financial statements) restrict the Company from incurring additional debt obligations unless it receives consent from Noteholders holding at least 51% in aggregate outstanding principal amount of the of the Notes covered by such Agreements.

Consequently, the aforementioned items raise substantial doubt about the Company s ability to continue as a going concern.

We currently have sufficient cash on hand to support our operations through to the third quarter 2008. In order to fund our planned capital expenditure program and to continue our operations after the third quarter 2008, we need to raise substantial funds. As noted elsewhere we are pursuing raising additional funds through -private placements of our equity or debt securities or a possible rights offering to shareholders. We are also actively pursuing the farming out a number of our exploration projects. We are required under the covenants of our existing Convertible Notes to obtain the approval of a majority of our debt holders in order to incur additional indebtedness in excess of $2.5 million, which approval we cannot guarantee. In the event we attempt to raise funds through an equity offering, we would more than likely be required to offer our equity securities at a substantial discount to the current public market price in order to attract investors. In the event that we were to do so, provisions in our outstanding Convertible Notes and Warrants would cause their exercise prices to reset to the lower price in any offering. If low enough, this could effect a significant dilution to current shareholders or possibly to a change of control event.

There can be no assurance of our success in raising these funds. In the event that we are unable to raise additional funds on terms acceptable to us, we will be required to significantly curtail our operations in Georgia and to abandon our currently planned capital expenditure program.

The Company s ability to continue as a going concern is dependent upon raising capital through debt and equity financing on terms desirable to the Company. If the Company is unable to obtain additional funds when they are required or if the funds cannot be obtained on terms favorable to the Company, management will be required to delay, scale back or eliminate its well development program or license third parties to develop or market products that the Company would otherwise seek to develop or market itself, or even be required to relinquish its interest in the properties or in the extreme situation, cease operations. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The consolidated financial statements and notes thereto are prepared in accordance with accounting principles generally accepted in the United States. All amounts are in U.S. dollars. Certain items for prior years in the consolidated financial statements have been reclassified to conform to the current year s presentation. There was no effect on the reported net loss as a result of these reclassifications.

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Consolidation

The consolidated financial statements include the accounts of CanArgo Energy Corporation and its majority owned subsidiaries. All significant intercompany transactions and accounts have been eliminated. Investments in less than majority owned corporations and corporate like entities in which we exercise significant influence are accounted for using the equity method. Entities in which we do not have significant influence are accounted for using the cost method.

Equity Method

Under the guidance of Emerging Issue Task Force D-46, Accounting for Limited Partnership Investments the Company uses the equity method to account for all of its limited partnership interests in oil and gas ventures that exceed 5% and is less than 50%. Under the equity method of accounting, the Company s proportionate share of the investees net income or loss is included in Equity Income from Investments in the consolidated statements of operations. Any excess of the carrying value of the investment and loan advances over the underlying net equity of the investee is evaluated each reporting period for impairment.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates, judgements 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 reporting period. Actual results could differ from those estimates.

Management believes that it is reasonably possible the following material estimates affecting the financial statements could significantly change in the coming year: (1) estimates of proved oil and gas reserves, (2) estimates as to the expected future cash flow from proved oil and gas properties and (3) estimates of future dismantlement and restoration costs.

Cash and Cash Equivalents

Cash and cash equivalents include all liquid investments with an original maturity of three months or less.

Fair Value of Financial Instruments

The carrying amounts reflected in the consolidated balance sheets for cash and equivalents, short-term receivables and short-term payables approximate their fair value due to the short maturity of the instruments. For the balances in 2007, the carrying value of $11,697,231 of long-term debt reflects discounts for the value of detachable warrants and beneficial conversion features, net of amortization, of $3,552,769. The face amount of long-term debt outstanding as of December 31, 2007 was $15,250,000. For the balances in 2006, the carrying value of $37,264,271 of long-term debt reflects discounts for the value of detachable warrants and beneficial conversion features, net of amortization, of $10,735,729. The face amount of long-term debt outstanding as of December 31, 2006 was $48,000,000. Please refer to Note 9 Loans Payable and Long Term Debt for a more detailed discussion of the accounting treatment of the long-term debt.

Concentration of Credit Risk

Although our accounts receivable are exposed to potential credit loss, we do not believe such risk to be significant.

During the year ended December 31, 2007, oil produced in Georgia was sold to two customers with sales to each of these customers representing more than 10% of revenues. During the year ended December 31, 2006, oil produced in Georgia was sold to two customers with sales to one of these customers representing more than 10% of revenues. During the year ended December 31, 2005, oil produced in Georgia was sold to four customers with sales to two of these customers representing more than 10% of revenues.

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As an independent oil and gas producer, our revenue, profitability and future rate of growth are substantially dependent upon prevailing prices for oil and gas, which are dependent upon numerous factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. The energy markets have historically been very volatile, and there can be no assurance that oil and gas prices will not be subject to wide fluctuations in the future. A substantial or extended decline in oil and gas prices could have a material adverse effect on our financial position, results of operations, cash flows and our access to capital and on the quantities of oil and gas reserves that may be economically produced.

Reclassification

Certain items in the consolidated financial statements have been reclassified to conform to the current year presentation. There was no effect on reported net loss as a result of these reclassifications.

Accounts Receivable and Allowance for Doubtful Debts

Accounts receivable are carried at the amount owed by customers, reduced by an allowance for estimated amounts that may not be collectible in the future. The allowance for doubtful accounts is estimated based upon historical write-off percentages, known problem accounts, and current economic conditions. Accounts are written off against the allowance for doubtful accounts when we determine that amounts are not collectable and recoveries of previously written-off accounts are recorded when collected.

Inventories

Inventories of crude oil are valued at the lower of average cost or net realizable value. Inventory costs include expenditures and other charges (including depreciation, depletion and amortization) directly and indirectly incurred in bringing the inventory to its existing condition and location. Selling expenses and general and administrative expenses are reported as period costs and excluded from inventory cost.

Capital Assets

Capital assets are recorded at cost less accumulated provisions for depreciation, depletion and amortization unless the carrying amount is viewed as not recoverable in which case the carrying value of the assets is reduced to the estimated recoverable amount. See Impairment of Long-Lived Assets below. Expenditures for major renewals and betterments, which extend the original estimated economic useful lives of applicable assets, are capitalized. Expenditures for normal repairs and maintenance are charged to expense as incurred. The cost and related accumulated depreciation of assets sold or retired are removed from the accounts and any gain or loss thereon is reflected in operations. Unproved properties are not deemed to be impaired until the right to drill on those properties is lost and/or planned development has ceased.

Oil And Gas Properties CanArgo accounts for oil and gas properties and interests under the full cost method. Under the full cost method, all acquisition, exploration and development costs, including certain directly related employee costs incurred for the purpose of finding oil and gas are capitalized and accumulated in pools on a country by country basis. Capitalized costs include the cost of drilling and equipping productive wells, including the estimated costs of dismantling and abandoning these assets, dry hole costs, lease acquisition costs, seismic and other geological and geophysical costs, delay rentals and costs related to such activities. Employee costs associated with production and other operating activities and general corporate activities are expensed in the period incurred.

Where proved reserves are established, capitalized costs are limited on a country by country basis (the ceiling test). The ceiling test is calculated as the sum of the present value of future net cash flows related to estimated production of proved reserves, using end of the-current-period prices, discounted at 10%, and takes into account expected future costs to develop proved reserves, and operating expenses and income taxes. Under the ceiling test, if the capitalized cost of the full cost pool exceeds the ceiling limitation, the excess is charged as an impairment expense.

Unit-of-production depreciation is applied to capitalized costs of the full cost pool. Unit-of-production rates are based on the amount of proved developed reserves of oil, gas and other minerals that are estimated to be recoverable from existing facilities using current operating methods.

We utilize a single cost center for each country where we have operations for amortization purposes. Any conveyances of properties are treated as adjustments to the cost of oil and gas properties with no gain or loss recognized unless the operations are suspended in the entire cost center or the conveyance is significant in nature.

The costs of investments in unproved properties and portions of costs associated with major development projects are excluded from the depreciation, depletion and amortization (DD&A) calculation until the project is evaluated.

Unproved property costs include leasehold costs, seismic costs and other costs incurred during the exploration phase. In areas where proved reserves are established, significant unproved properties are evaluated periodically, but not less than annually, for impairment. If a reduction in value has occurred, these property costs are considered impaired and are transferred to the related full cost pool. Unproved properties whose acquisition costs are not individually significant are aggregated, and the portion of such costs estimated to be ultimately nonproductive, based on experience, is amortized to the full cost pool over an average holding period.

In countries where the existence of proved reserves has not yet been determined, leasehold costs, seismic costs and other costs incurred during the exploration phase remain capitalized in unproved property cost centers until proved reserves have been established or until exploration activities cease or impairment and reduction in value occurs. If exploration activities result in the establishment of a proved reserve base, amounts in the unproved property cost center are reclassified as proved properties and become subject to depreciation, depletion and amortization and the application of the ceiling test. If exploration efforts in a country are unsuccessful in establishing proved reserves, it may be determined that the value of exploratory costs incurred there have been permanently diminished in part or in whole. Therefore, based on the impairment evaluation and future exploration plans, the unproved property cost centers related to the area of interest could be impaired, and accumulated costs charged against earnings.

Property and Equipment Depreciation of property and equipment is computed using the straight-line method over the estimated useful lives of the assets ranging from three to five years for office furniture and equipment to three to fifteen years for oil and gas related equipment.

Revenue Recognition

Continuing operations We recognize revenues when hydrocarbons have been produced and delivered and payment is reasonably assured.

Discontinued operations We recognize revenues when hydrocarbons have been produced and delivered and payment is reasonably assured.

Foreign Operations

Our future operations and earnings will depend upon the results of our operations in the Georgia. There can be no assurance that we will be able to successfully conduct such operations, and a failure to do so would have a material adverse effect on our financial position, results of operations and cash flows. Also, the success of our operations will be subject to numerous contingencies, some of which are beyond management control. These contingencies include general and regional economic conditions, prices for crude oil and natural gas, competition and changes in regulation. Since we are dependent on international operations, specifically those in Georgia, we will be subject to various additional political, economic and other uncertainties. Among other risks, our operations may be subject to the risks and 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.

Foreign Currency Translation

The U.S. dollar is the functional currency for our upstream operations and the Lari is the functional currency for marketing operations. All monetary assets and liabilities denominated in foreign currency are translated into U.S. dollars at the rate of exchange in effect at the balance sheet date and the resulting unrealized translation gains or losses are reflected in operations. Non-monetary assets are translated at historical exchange rates. Revenue and expense items (excluding depreciation and amortization which are translated at the same rates as the related assets) are translated at the average rate of exchange for the year.

Income Taxes

We recognize deferred tax liabilities and assets for the expected future tax consequences of events that have been included in the financial statements or tax returns. Deferred tax liabilities and assets are determined based on the difference between the financial statement and the tax bases 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 realized.

Impairment of Long-Lived Assets

The Company evaluates its long-lived assets for impairment using the guidance of Statement of Financial Accounting Standard (SFAS) No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. SFAS No. 144 establishes a single accounting model for long-lived assets to be disposed of by sale and requires that those long-lived assets be measured at the lower of carrying amount or fair value less cost to sell, whether reported in continuing operations or in discontinued operations.

Dismantlement, Restoration and Environmental Costs

Effective January 1, 2003, we recognize liabilities for asset retirement obligations associated with tangible long-lived assets, such as producing well sites, with a corresponding increase in the related long-lived asset. The asset retirement cost is depleted along with the property and equipment in the full cost pool. The asset retirement obligation is recorded at fair value and accretion expense, recognized over the life of the property, increases the liability to its expected settlement value. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded for both the asset retirement obligation and the asset retirement cost. As at December 31, 2007 and December 31, 2006, the asset retirement obligation, which is included on the consolidated balance sheet in provision for future site restoration, was $230,000 and $205,000, respectively.

	2007	2006
Beginning balance, January 1	$ 205,000	$ 167,000
New obligations incurred in 2007		21,000
Liabilities settled in 2007		
Accretion of expense	20,000	22,000
Revision in estimates, including timing	5,000	(5,000)
Balance at December 31	230,000	205,000

Stock-Based Compensation Plans

Effective January 1, 2006 the Company adopted Statement of Financial Accounting Standard (SFAS) No. 123 (revised 2004), Share Based Payment (SFAS No. 123(R)). Generally, the fair value approach in

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SFAS No. 123(R) is similar to the fair value approach described in SFAS No. 123. In 2005, we used the Black-Scholes option pricing model to estimate the fair value of stock options granted to employees. We adopted SFAS No. 123(R), using the modified-prospective method, beginning January 1, 2006. We also elected to continue to estimate the fair value of stock options using the Black-Scholes-option pricing model. Total compensation cost related to non-vested awards not yet recognized was approximately $140,950 as of December 31, 2007 and the weighted average period over which this cost will be recognized is approximately 6 months.

Recently Issued Pronouncements

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS No. 157) which defines fair value, establishes a framework for measuring fair value in accordance with accounting principles generally accepted in the United States, and expands disclosures about fair value measurements. SFAS No. 157 is effective for financial assets and liabilities for fiscal years beginning after November 15, 2007. In February 2008, the FASB issued FSP FAS 157-2, Effective Date of FASB Statement No. 157. FSP 157-2 delays the effective date of SFAS No. 157 for all non-financial assets and non-financial liabilities that are not re-measured at fair value on a recurring basis until fiscal years beginning after November 15, 2008. Any amounts recognized upon adoption of this rule as a cumulative effect adjustment will be recorded to the opening balance of retained earnings in the year of adoption. The Company has evaluated SFAS No. 157 and has determined that it will not have a material impact on its Consolidated Financial Statements.

In December 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 141(R), Business Combinations (SFAS 141(R)), which replaces SFAS 141. SFAS 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. The Statement also establishes disclosure requirements, which will enable users to evaluate the nature and financial effects of the business combination. SFAS 141(R) is effective for fiscal years beginning after December 15, 2008. The adoption of SFAS 141(R) will have an impact on accounting for business combinations once adopted, but the effect is dependent upon acquisitions at that time.

In December 2007, FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of Accounting Research Bulletin No. 51 (SFAS 160), which establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, changes in a parent s ownership interest and the valuation of retained non-controlling equity investments when a subsidiary is deconsolidated. The Statement also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. SFAS 160 is effective for fiscal years beginning after December 15, 2008. The Company has not determined the effect that the application of SFAS 160 will have on its Consolidated Financial Statements.

The Company has reviewed all other recently issued, but not yet adopted, accounting standards in order to determine their effects, if any, on its consolidated results of operations, financial position and cash flows. Based on that review, the Company believes that none of these pronouncements will have a significant effect on current or future earnings or operations.

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NOTE 3 RESTRICTED CASH

Restricted cash consisted of the following at December 31:

	2007	2006
Restricted Cash Secured deposits	$	$ 299,777
	$	$ 299,777

In the third quarter of 2005, we deposited approximately $300,000 to secure the issuance of a letter of credit as required under the drilling contract we entered into with Baker Hughes International. This deposit became unrestricted in January 2007.

NOTE 4 ACCOUNTS RECEIVABLE

Accounts receivable consisted of the following at December 31:

	2007	2006
Trade receivables before allowance for doubtful debts	$ 208,732	$
Insurance receivable		474,665
Other receivables	170,536	29,288
	$ 379,268	$ 503,953

Bad debt expense for 2007, 2006 and 2005 was nil, nil and $145,829 respectively, and is reflected under other income in the statement of operations.

The trade receivable of $208,732 at December 31, 2007 related to a partial amount owed from an oil sale and was received in full in January 2008.

Included in other receivables of $170,536 is an amount of $106,585 due from Tethys Petroleum Limited (Tethys) for Tethys selling, general and administrative expenses paid by the Company after we sold our entire Tethys shareholding. The amount owed by Tethys was settled in full in February 2008.

In the second quarter of 2006 we filed a claim with our insurance carrier for recovery of drilling equipment lost in the Manavi 12 well. As of December 31, 2006, $474,665 was recorded as a receivable in connection with this claim. This claim was settled in full by our insurance carrier in February 2007.

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NOTE 5 INVENTORY

Inventory of crude oil consisted of the following at December 31:

	2007	2006
Crude oil	$ 373,770	$ 452,500
	$ 373,770	$ 452,500

NOTE 6 PREPAYMENTS

Prepayments consisted of the following at December 31:

	2007	2006
Drilling Contractors	$ 161,297	$ 1,849,624
Financing Fees	46,721	157,372
Other	103,519	247,567
	$ 311,537	$ 2,254,563

NOTE 7 CAPITAL ASSETS

Capital assets, net of accumulated depletion, depreciation and amortization (DD&A) and impairment, include the following at December 31, 2007:

	Cost	Accumulated DD&A And Impairment	Net Capital Assets
Oil and Gas Properties			
Proved properties	$ 145,983,558	$ (111,567,391)	$ 34,416,167
Unproved properties	9,444,742		9,444,742
	155,428,300	(111,567,391)	43,860,909
Property and Equipment			
Oil and gas related equipment	10,938,820	(3,816,173)	7,122,647
Office furniture, fixtures and equipment and other	1,125,733	(804,670)	321,063
	12,064,553	(4,620,843)	7,443,710
	$ 167,492,853	$ (116,188,234)	$ 51,304,619

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Capital assets, net of accumulated depletion, depreciation and amortization and impairment (DD&A), include the following at December 31, 2006:

	Cost	Accumulated Depreciation And Impairment	Net Capital Assets
Oil and Gas Properties			
Proved properties	$ 91,539,624	$ (67,608,087)	$ 23,931,537
Unproved properties	55,097,099		55,097,099
	146,636,723	(67,608,087)	79,028,636
Property and Equipment			
Oil and gas related equipment	13,474,127	(5,598,712)	7,875,415
Office furniture, fixtures and equipment and other	1,027,289	(623,640)	403,649
	14,501,416	(6,222,352)	8,279,064
	$ 161,138,139	$ (73,830,439)	$ 87,307,700

We expensed $2,592,531, $3,798,727 and $3,275,553 in respect of depletion, depreciation and amortization for the years ended December 31, 2007, 2006 and 2005, respectively.

Depletion per Barrel of Oil Equivalent on a Units of Production basis was $1,959,304 ($18.04), $3,174,586 ($45.57) and $2,651,053 ($18.67) for the years ended December 31, 2007, 2006 and 2005, respectively. All production in the periods presented related to Georgia. Production from our Samgori Field attracted depletion from the date of acquisition in April 2004 to December 31, 2005. Production from our Ninotsminda Field attracted depletion for all years presented.

During 2007 we transferred approximately $3,800,000 of capital asset costs, into the full cost pool from unproved properties, relating to the plugging and abandoning of the Kumisi #1 well drilled and tested in 2007. As a result of performing our annual assessment of costs classified as unproved property to determine if they should be transferred to the cost pool, we determined that approximately $49,100,000 of further costs principally relating to the drilling of exploration wells at the Manavi and Norio Fields should be moved to the cost pool. We considered a number of factors in our evaluation including the length of time that these costs remained classified as unproved property.

Oil and Gas Properties

Ultimate realization of the carrying value of our oil and gas properties will require production of oil and gas in sufficient quantities and marketing such oil and gas at sufficient prices to provide positive cash flow to CanArgo, which is dependent upon, among other factors, achieving significant production at costs that provide acceptable margins, reasonable levels of taxation from local authorities, and the ability to market the oil and gas produced at or near world prices. In addition, we must mobilize drilling equipment and personnel to initiate drilling, completion and production activities. If one or more of the above factors, or other factors, are different than anticipated, we may not recover our carrying value.

As a result of application of the ceiling test limitation, CanArgo recorded a write-down of oil and gas properties, relating to Georgia, of $42,000,000 in 2007 and $38,400,000 in 2006. In 2005, CanArgo did not need to write-down oil and gas properties due to the ceiling test.

We generally have the principal responsibility for arranging financing for the oil and gas properties and ventures in which we have an interest. There can be no assurance, however, that we or the entities that are developing the oil and gas properties and ventures will be able to arrange the financing necessary to develop the projects being undertaken or to support our corporate and other activities or that such financing as is available will be on terms that are attractive or acceptable to or are deemed to be in the best interests of the Company, such entities or their respective stockholders or participants.

The consolidated financial statements of CanArgo do not give effect to any additional impairment in the value of our investment in oil and gas properties and ventures or other adjustments that would be necessary if financing cannot be arranged for the development of such properties and ventures or if they are unable to achieve profitable operations. Failure to arrange such financing on reasonable terms or failure of such properties and ventures to achieve profitability would have a material adverse effect on our financial position, including realization of assets, results of operations, cash flows and prospects.

Unproved property additions relate to our exploration activity in the period.

We plan to test a portion of our unproved properties for oil and gas in 2008. In the event that we do not find oil and gas, we could incur substantial impairments were the amounts to exceed our ceiling test.

Costs Not Being Amortised

Oil and gas property costs not being amortized at December 31, 2007, for both Georgia by year that the costs were incurred are as follows:

Year Ended December 31:	Exploration	Acquisition	Total Capital
2007	$ 3,620,091	$	$ 3,620,091
2006			
2005			
Prior	2,299,003	3,525,648	5,824,651
	$ 5,919,094	$ 3,525,648	$ 9,444,742

During 2007 we transferred $3,841,159 of capital asset costs, into the full cost pool from unproved properties, relating to the plugging and abandoning of the Kumisi #1 well drilled and tested in 2007. As a result of the performing our annual assessment of costs classified as unproved property to determine if they should be transferred to the cost pool, we determined that approximately $49,100,000 of further costs principally relating to the drilling of exploration wells at the Manavi and Norio Fields should be moved to the cost pool. We considered a number of factors in our evaluation including the length of time that these costs remained classified as unproved property.

Unevaluated costs as at December 31, 2007 include $5,620,091 for the Ninotsminda Field. $2,000,000 was allocated to the Cretaceous on acquisition prior to 2003. An appraisal well, M12, was drilled in 2006, tested in 2007 and now awaits further testing after the successful acid fracturing operation.

Unevaluated costs as at December 31, 2007 include $22,500 for the Norio Field.

Unevaluated costs as at December 31, 2007 include $3,802,151 for the Nazvrevi Field. $2,695,145 was allocated to the Field on acquisition prior to 2003. It also includes the significant Kumisi Cretaceous gas where we commenced drilling in February 2007.

Property and Equipment

Property and Equipment, Oil and gas related equipment includes related equipment currently in use by us in the development of the Ninotsminda Field.

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NOTE 8 PREPAID FINANCING FEES

Prepaid financing fees at December 31:

	2007	2006
Commission and Professional fees	$ 74,804	$ 288,632
	$ 74,804	$ 288,632

Prepaid financing fees as at December 31, 2007 are corporate finance fees incurred in respect of a $13,000,000 issue of Senior Subordinated Convertible Guaranteed Notes due September 1, 2009 and a $10,000,000 issue of a 12% Subordinated Convertible Guaranteed Note due June 28, 2010, with a group of investors, discussed in Note 9, which are to be amortized as interest payable over the term of the loans. Professional fees of $135,948 were amortized on a straight-line basis in 2007 in connection with the Notes. There was additional amortization incurred in 2007 when one of the notes was retired.

Prepaid financing fees as at December 31, 2006 are corporate finance fees incurred in respect of the private placement of a $25,000,000 issue of Senior Convertible Secured Notes due July 25, 2009, a $13,000,000 issue of Senior Subordinated Convertible Guaranteed Notes due September 1, 2009, and a $10,000,000 issue of a 12% Subordinated Convertible Guaranteed Note due June 28, 2010 with a group of investors, discussed in Note 9 and which are to be amortized as interest expense over the term of the loans. Professional fees of $133,238 were amortized on a straight-line basis in 2006 in connection with the Notes.

NOTE 9 LOANS PAYABLE AND LONG TERM DEBT

Loans payable at December 31 consisted of the following:

	2007	2006
Long term debt		
Senior Secured Convertible Loan Notes	$	$ 25,000,000
Senior Subordinated Convertible Guaranteed Loan Notes	4,650,000	13,000,000
12% Subordinated Convertible Guaranteed Loan Notes	10,600,000	10,000,000
Unamortized debt discount	(3,552,769)	(10,735,730)
Long term debt	$ 11,697,231	$ 37,264,270

The maturities of long-term borrowings at December 31, 2007, was as follows:

	2008	2009	2010	2011	2012
Repayments due	$	$4,650,000	$10,600,000	$	$
	$	$4,650,000	$10,600,000	$	$

In order to ensure timely procurement of long lead items for our drilling program in Georgia and for working capital purposes, we have entered into a number of loan agreements of which those outstanding during 2007 are described below. For the years ended December 31, 2007 and December 31, 2006 we paid interest in respect of these loans of $1,762,944 and $3,426,167 respectively.

Senior Secured Convertible Notes: On July 25, 2005, CanArgo completed a private placement of $25,000,000 in aggregate principal amount of our Senior Convertible Secured Loan Notes due July 25, 2009 (the Senior Secured Notes) with a group of private investors (the Purchasers) all of which qualified as accredited investors under Rule 501(a) promulgated under the Securities Act of 1933 as amended, (the Securities Act) arranged through Ingalls & Snyder LLC of New York City, as Placement Agent, pursuant to a Note Purchase Agreement of even date (the Senior Note Purchase Agreement). The Company paid approximately $100,000 of legal fees for the Purchasers and a $250,000 arrangement fee to Orion Securities in connection with the Senior Secured Notes.

The unpaid principal balance under the Senior Secured Notes bore interest (computed on the basis of a 360-day year of twelve 30-day months) (a) at increasing rates ranging from 3% from the date of issuance to December 31, 2005; 10% from January 1, 2006 until December 31, 2006; and 15% from January 1, 2007 until final payment, payable semi-annually, on June 30 and December 30, commencing December 30, 2005, until the principal shall have become due and payable, and (b) at 3% above the applicable rate on any overdue payments of principal and interest,

Pursuant to the provisions of Emerging Issue Task Force 86-15: Increasing-Rate Debt , the Company recognized interest expense using the effective interest rate method, which resulted in the use of a constant interest rate for the life of the Senior Secured Notes. The effective interest rate was approximately 12.3% per annum.

The Company amortised the professional fees incurred in relation to the Senior Secured Notes over the term of the Senior Secured Notes.

The Senior Secured Notes were convertible any time, in whole or in part, at the option of the Note holder, into shares of CanArgo common stock (the Conversion Stock) which was subject to (a) customary anti-dilution adjustments and (b) adjustment if CanArgo issued any equity securities (other than pursuant to the granting of employee stock options pursuant to shareholder approved employee stock option plans or existing outstanding options, warrants and convertible securities), at a price per share of less than $0.90 per share, as adjusted (the CanArgo Conversion Price), determined net of all discounts, fees, costs and expenses incurred in connection with such issuance, in which case the CanArgo Conversion Price would be reset to such lower price.

We could have, at our option without the consent of Note holders, upon not less than 90 days and not more than 120 days prior written notice, prepaid at any time and from time to time after July 31, 2006, all or any part of the Senior Secured Notes, in a principal amount of not less than $100,000 at the following Redemption Prices (expressed as percentages of the principal amount so prepaid): 105% after July 31, 2006; 104% after January 1, 2007; 103% after July 1, 2007; 102% after January 1, 2008; 101% after July 1, 2008, and 100% after January 1, 2009, together with all accrued and unpaid interest.

The Senior Secured Notes were subject to mandatory prepayment due to a change in control of the Company, as defined by the Senior Note Purchase Agreement.

In connection with the execution and delivery of the Senior Note Purchase Agreement, CanArgo entered into a Registration Rights Agreement with the Purchasers pursuant to which it agreed to register the Conversion Stock for resale under the Securities Act and indemnify the Purchasers in connection with the registration. Under the terms of a Registration Rights Agreement the Company provided the Purchasers with certain registration rights with respect to the Conversion Stock. On July 27, 2007 the

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Conversion Stock was no longer restricted, provided the Noteholders were not affiliates, and no longer need to be covered by a Registration Statement.

The Senior Secured Notes were secured by substantially all of the assets of the Company and its subsidiaries and contained certain negative and affirmative covenants and also restricted the ability of the Company to pay dividends to its common stockholders until the loan and all accrued interest had been paid or the Note holders elected to convert their loans to common stock.

The Company evaluated the embedded conversion feature in this debt and determined it did not meet the criteria for bifurcation under SFAS No 133 Accounting for Derivative Instruments and Hedging Activities during the quarter.

Conversion/Exchange of Senior Secured Notes and issue of Senior Secured Note Conversion Compensation Warrants: On June 5, 2007, the Company entered into a consent and conversion agreement (the Consent and Conversion Agreement) with the holders of the Senior Secured Notes and with CanArgo Limited that became effective on June 13, 2007.

Pursuant to the Consent and Conversion Agreement certain holders of Senior Secured Notes agreed to convert/exchange $10 million in aggregate principal amount of the Senior Secured Notes into Tethys common stock. The conversion/exchange was satisfied by the transfer by CanArgo Limited to the converting note holders of 4 million shares of Tethys common stock.

As an inducement for those note holders to exchange $10 million in aggregate principal amount of Senior Secured Notes into Tethys common stock, the Company agreed to issue to those converting note holders 11,111,111 warrants (the Senior Secured Note Conversion Compensation Warrants) to purchase CanArgo common stock at an exercise price of $0.90 per common share in transactions intended to qualify for an exemption from registration under the Securities Act pursuant to Section 4(2) thereof and Regulation D promulgated thereunder.

All of the Senior Secured Note Conversion Compensation Warrants expire on the earlier of: (i) September 1, 2009; (ii) or such sooner date at the election of the Company and upon at least thirty (30) days prior written notice to the Registered Holder in the event that: (a) the Manavi M12 well indicates, by way of an independent engineering report, sustainable production, if developed, in excess of 7,500 barrels of oil per day or (b) all warrants originally issued under that certain Note and Warrant Purchase Agreement dated as of March 3, 2006 by and among the Company and the purchasers listed therein are exercised by the holders thereof and the average closing price for the Company s Common Stock on the American Stock Exchange or, if the Common Stock is not then listed for trading on the American Stock Exchange (AMEX) then the Oslo Stock Exchange, is above $2.00 (or its equivalent in NOK, and in any case adjusted for any stock dividends, stock splits, reverse splits, recapitalizations or reorganizations) for a period of five consecutive trading days (the Expiration Date).

We used the following assumptions to determine the fair value of the Senior Secured Note Conversion Compensation Warrants:

	Additional Loan
Stock price on date of grant	$ 0.74
Risk free rate of interest	5.08%
Expected life of warrant months	25
Dividend rate	
Historical volatility	70.4%

The Company has accounted for the modification and extinguishment of $10 million of principal of the Senior Secured Notes under Emerging Issues Task Force (EITF) 06-16 Debtor s Accounting for a Modification (or Exchange) of Convertible Debt Instruments and EITF 96-19 Debtor s Accounting for a Modification or Exchange of Debt Instruments . The Company determined that the fair value of

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the Tethys shares, issued as consideration paid in satisfaction of the principal balance, was $2.50 per share or $10 million based on sales of shares to outside investors, and thus no gain or loss was recorded. The Company accounted for the issuance of the 11,111,111 Senior Note Conversion Compensation Warrants issued as additional compensation to induce the conversion of the debt to Tethys shares under SFAS 84 Induced Conversions of Convertible Debt, an Amendment of APB 26 and determined the fair value of the warrants using the Black Scholes model to be approximately $2.95 million and has recorded that expense under the line item Loss/Cost on Debt Extinguishment . In addition, the Company reversed long-term accruals made under EITF 86-15 noted above in the amount of approximately $270,000 associated with the debt extinguished against the loss on extinguishment.

Issue of further $1,125,000 Senior Secured Notes in connection with restructuring of short term interest payments: On June 13, 2007, the Company entered into an amendment, consent and waiver (the Senior Secured Note Amendment, Consent and Waiver) with the holders of the Senior Secured Notes in terms of which the holders of the Senior Secured Notes agreed to receive certain interest payments due on the Senior Secured Notes as of June 30, 2007 by payment in kind of additional Senior Secured Notes. As a result, the Company issued a further $1,125,000 in aggregate principal amount of Senior Secured Notes. These additional Senior Secured Notes carried the same rights (including as to conversion into shares of common stock of the Company) as the original $25 million in aggregate principal amount of Senior Secured Notes which were previously issued (see the section above entitled Senior Secured Convertible Notes)**.**

Amendment, Consent and Waiver to Note Purchase Agreement dated July 25, 2005: On July 31, 2007 CanArgo Limited (a wholly owned subsidiary of the Company) sold its remaining interest in Tethys for CDN$23,600,000 (before expenses and commission). On August 3, 2007 the sum of $21,340,397 was remitted to Ingalls and Snyder LLC (the Escrow Agent) to be held in an escrow account (the Escrow Account) and released from the Escrow Account pursuant to an Escrow Agreement (the Escrow Agreement) dated as of August 3, 2007 among CanArgo, CanArgo Limited and the Escrow Agent. On August 9, 2007, CanArgo entered into an Amendment, Consent and Waiver Agreement with the holders of the Senior Secured Notes (the Senior Noteholders), pursuant to which:

CanArgo agreed to use part of the net proceeds received by CanArgo Limited (after commission and certain expenses, including CanArgo Limited s pro rata share of the costs and expenses incurred in relation to the recent initial public offering of shares in Tethys, which pro rata share of costs and expenses of not more than $500,000) to repay to the Senior Noteholders all amounts outstanding on the Senior Secured Notes (and accordingly on or about August 9, 2007 the sum of $16,864,063 was released from the Escrow Account in full repayment of the Senior Secured Notes);

the Senior Noteholders agreed to waive the notice period which the Company would otherwise have required to give the Senior Noteholders on early repayment of the Senior Notes;

the Senior Noteholders agreed that, notwithstanding the date of the Amendment, Consent and Waiver Agreement, interest on the Senior Notes would cease to accrue as of (but including) August 8, 2007;

the parties agreed that following release from the Escrow Account of the monies necessary to repay all amounts owing on the Senior Secured Notes the Escrow Agent would disburse such amounts to the Senior Noteholders in accordance with the respective entitlements of the Senior Noteholders to receive repayment of the Senior Secured Notes;

by waiving the notice period which the Company would otherwise be required to give the Senior Noteholders of an early repayment of the Senior Secured Notes and by agreeing to a variation of the interest provisions attaching to the Senior Secured Notes the Senior Noteholders effectively gave up (a) certain rights to convert their Senior Secured Notes into common stock of CanArgo as an alternative to accepting repayment of their Senior Secured Notes and (b) the right to receive interest on their Senior Secured Notes in respect of the period between, on the one hand, the date on which CanArgo would otherwise have served notice of early repayment and, on the other hand, the date on which repayment (or conversion) would otherwise have taken place;

in order to compensate the Senior Noteholders for giving up the aforesaid rights, CanArgo issued to the Senior Noteholders in the aggregate warrants to purchase up to 17,916,667 shares of common stock, par value $0.10 per share, at an exercise price of $1.00 per share, subject to adjustment, expiring at the close of business on December 6, 2007 (the Senior Note Compensatory Warrants); and

accordingly, CanArgo and the Senior Noteholders amended the Note Purchase Agreement and the Senior Secured Notes to give effect to the foregoing.

the warrants to purchase up to 17,916,667 shares of common stock expired on December 6, 2007.

We used the following assumptions to determine the fair value of the Senior Note Compensatory Warrants:

	Additional Loan
Stock price on date of grant	$ 0.89
Risk free rate of interest	4.64%
Expected life of warrant months	5
Dividend rate	
Historical volatility	92%

The Company has accounted for the extinguishment of the remaining $15 million of principal of the Senior Secured Notes under Emerging Issues Task Force (EITF) 06-16 Debtor s Accounting for a Modification (or Exchange) of Convertible Debt Instruments and EITF 96-19 Debtor s Accounting for a Modification or Exchange of Debt Instruments . The Company accounted for the issuance of the 17,916,667 Senior Note Compensatory Warrants issued, as compensation to the Senior Noteholders for giving up the aforementioned rights, under SFAS 84 Induced Conversions of Convertible Debt, an Amendment of APB 26 and determined the fair value of the warrants using the Black Scholes model to be approximately $3,180,000 and has recorded that expense under the line item Loss/Cost on Debt Extinguishment . In addition, in the third quarter 2007 the Company reversed long-term accruals made under EITF 86-15 noted above in the amount of approximately $794,000 associated with the debt extinguished against the loss on extinguishment.

Senior Subordinated Convertible Guaranteed Notes: On March 3, 2006, we finalised a private placement with a limited group of investors arranged by Ingalls & Snyder LLC of New York City of a $13,000,000 issue of Senior Subordinated Convertible Guaranteed Notes due September 1, 2009 (the Subordinated Notes) and warrants to purchase an aggregate of 13,000,000 shares of our common stock, par value $0.10 per share (Subordinated Note Warrant Shares) at an exercise price of $1.37 per share (which exercise price has, as noted below, now been reset to $1.00 per share), subject to adjustment as defined below, and expiring on March 3, 2008 or sooner under certain circumstances (Subordinated Note Warrants).

The proceeds of this financing, after the payment of all placing expenses and professional fees of approximately $150,000, have been used to fund the development of the Kyzyloi Gas Field in Kazakhstan and on the commitment exploration programs in Kazakhstan through Tethys, the former wholly owned subsidiary of CanArgo which held CanArgo s former Kazakhstan assets. See Note 17.

Pursuant to the provisions of Emerging Issue Task Force 86-15: Increasing-Rate Debt , the Company recognizes interest expense using the effective interest rate method, which results in the use

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of a constant interest rate for the life of the Subordinated Notes. The effective interest rate is approximately 8.3% per annum. The difference between the interest computed using the actual interest rate in effect (3% per annum to December 31, 2006 and 10% from January 1, 2007) and the effective interest rate (8.3% per annum) totalled $114,328 as of December 31, 2007 of which $76,550 has been included as an accrued liability and $37,778 has been accrued as a non-current liability.

We entered into a Note and Warrant Purchase Agreement dated as of March 3, 2006 (Subordinated Note Purchase Agreement) with a limited group of private investors (the Purchasers) all of whom qualified as accredited investors under Rule 501(a) promulgated under the Securities Act. Pursuant to the Subordinated Note Purchase Agreement, we issued the Subordinated Notes, one of which was issued to Ingalls & Snyder LLC as nominee for certain Purchasers, and the Subordinated Note Warrants, one of which was also issued to Ingalls & Snyder LLC as nominee for certain Purchasers, in a transaction intended to qualify for an exemption from registration under the Securities Act pursuant to Section 4(2) thereof and Regulation D promulgated thereunder. For purposes hereof each of the Purchasers for whom Ingalls & Snyder LLC acts as nominee is deemed a beneficial holder of the Subordinated Notes and Subordinated Note Warrants issued in Ingalls & Snyder LLC s name and such Purchasers may each be assigned their own Subordinated Note and Subordinated Note Warrant as provided in the Subordinated Note Purchase Agreement.

The principal terms of the Subordinated Note Purchase Agreement and related agreements include the following:

Interest. The unpaid principal balance under the Subordinated Notes bears interest (computed on the basis of a 360-day year of twelve 30-day months) payable semi-annually on June 30 and December 30 in cash at the rate of 3% per annum until December 31, 2006 and 10% per annum thereafter and (b) at the rate of 3% per annum above the applicable rate on any overdue payments of principal and interest.

Optional Prepayments. CanArgo may, at its option, upon at least not less than 60 days and not more than 120 days prior written notice, prepay at any time and from time to time after March 1, 2007, all or any part of the Subordinated Notes, in a principal amount of not less than $100,000 at the following Redemption Prices (expressed as percentages of the principal amount so prepaid): 105% after March 1, 2007; 104% after September 1, 2007; 103% after March 1, 2008; 102% after September 1, 2008; 101% after March 1, 2009, and 100% after September 1, 2009, together with all accrued and unpaid interest.

Mandatory Prepayment. CanArgo will not take any action to consummate a Change of Control (or Change of Control contemplated by a Control Event) unless it shall offer to prepay all, but not less than all, of the Subordinated Notes, on not less than 15 business days prior written notice, in the event of an occurrence of a Change of Control or Control Event. Mandatory prepayment of the Subordinated Notes shall be in an amount equal to 101% of the outstanding principal amount of such Subordinated Notes, together with interest on such Subordinated Notes accrued to the date of prepayment. *Change in Control* is defined to mean (a) if CanArgo shall at any time cease to be a publicly held company or cease to have its capital stock traded on an exchange or (b) a transaction or series of related transactions pursuant to which (i) at least fifty-one percent (51%) of the outstanding shares of CanArgo s common stock or, on a fully diluted basis, shall subsequent to March 3, 2006 be owned by any person which is not related to or affiliated with CanArgo, (ii) if CanArgo merges into or with, consolidates with or effects any plan of share exchange or other combination with any person which is not related to or affiliated with CanArgo, or (iii) if CanArgo disposes of all or substantially all of its assets other than in the ordinary course of business and *Control Event* is defined to mean (i) the execution by CanArgo or any material subsidiary of CanArgo which has guaranteed the indebtedness evidenced by the Subordinated Notes (a CanArgo Group Member) of any agreement or letter of intent with respect to any proposed transaction or event or series of transactions or events which, individually or in the aggregate, may reasonably be expected to result in a Change in Control, or (ii) the execution of any written agreement which, when fully performed by the parties thereto, would result in a Change in Control.

Conversion. The Subordinated Notes are convertible, in whole or in part, into shares of CanArgo common stock (Conversion Stock) at a conversion price per share of $1.00 (the Conversion Price) (the original exercise price of $1.37 having been reset to $1.00), which is subject to adjustment if

CanArgo issues any equity securities (other than pursuant to the granting of employee stock options pursuant to shareholder approved employee stock option plans or existing outstanding options, warrants and convertible securities at a price per share of less than $1.00 (formerly $1.37, the original $1.37 exercise price having been reset to $1.00) per share, as adjusted, determined net of all discounts, fees, costs and expenses incurred in connection with such issuance, in which case the Conversion Price will be reset to such lower price. The Conversion Price shall also be adjusted in connection with any stock split, stock dividend, reverse stock split, reclassification, recapitalization, combination, merger, consolidation or any similar transaction, in which case the Conversion Price and number of shares of Conversion Stock will be appropriately adjusted to reflect any such event, such that the holders of the Subordinated Notes will receive upon conversion the identical number of shares of common stock or other consideration or property to be received by the holders of the common stock as if the holders had converted the Subordinated Notes immediately prior to any such event as such amount would then be adjusted by reason of such stock split, stock dividend, reverse stock split, reclassification, recapitalization, combination, merger, consolidation or other similar transaction; provided, however, in no event shall the number of shares of common stock issuable to the Purchasers upon conversion cause the Purchasers to collectively own in excess of 19.9% of the shares of CanArgo common stock outstanding as of March 3, 2006 absent shareholder approval in accordance with applicable stock exchange requirements. No fractional shares of common stock shall be issued upon any conversion; instead the Conversion Price shall be appropriately adjusted so that holders shall receive the nearest whole number of shares upon any conversion. As a result of entering into the private placement in respect of the 12% Subordinated Notes, the Subordinated Note Purchase Agreement and related agreements dictated that the Conversion Price and the exercise price of the Subordinated Note Warrants be reset to $1.00 from $1.37.

In connection with the execution and delivery of the Subordinated Note Purchase Agreement, CanArgo entered into a Registration Rights Agreement with the Purchasers pursuant to which it agreed to register the Conversion Stock and the Subordinated Note Warrant Shares for resale under the Securities Act. Pursuant to the terms of the Registration Rights Agreement the Company provided the Purchasers with certain registration rights with respect to all shares of the Company s common stock issuable upon conversion of the Subordinated Notes and all shares of the Company s common stock issuable upon exercise of the Subordinated Note Warrants. Under the Registration Rights Agreement the Company had agreed to use all commercially reasonable efforts to file a Registration Statement on Form S-3 or Form S-1 in respect of the CanArgo Conversion Stock by December 31, 2006.

Security. Payment of all amounts due and payable under the Subordinated Note Purchase Agreement, the Subordinated Note and all related agreements (collectively, the Loan Documents) is secured by subordinated guarantees from each other CanArgo Group Member (the Subordinated Subsidiary Guaranty). If CanArgo forms or acquires a Material Subsidiary (as defined in the Subordinated Note Purchase Agreement) it shall cause such Subsidiary to execute a Subordinated Subsidiary Guaranty (other than for certain excepted companies and legal entities) and thereby become a CanArgo Group Member subject to the provisions of the Subordinated Note Purchase Agreement.

Covenants. Under the terms of the Subordinated Note Purchase Agreement CanArgo is subject to certain affirmative and negative covenants, which can be waived by the beneficial holders of at least 51% of the outstanding principal amount of the Subordinated Notes (the Required Holders), including the following affirmative and negative covenants, respectively: (a) providing current information regarding CanArgo and rights of inspection; compliance with laws; maintenance of corporate existence, insurance and properties; payment of taxes; adding new material subsidiaries as additional guarantors under the Subordinated Subsidiary Guaranty; payment of professional fees for the Purchasers (not in excess of US$75,000), and (b) restrictions on: transactions with affiliates; mergers, consolidations and sales of all of CanArgo s assets; liens (except for certain permitted liens); the issuance of additional senior indebtedness; changes in CanArgo s line of business; certain types of payments; sale-and leasebacks; sales of assets other than in the ordinary course of business; future Indebtedness, as defined in the Subordinated Note Purchase Agreement (other than certain permitted indebtedness); cancelling, terminating, waiving or amending provisions of, or selling any interests in (other than under certain circumstances) any of the Basic Agreements (as defined in the Subordinated Note Purchase Agreement); and adopting any anti-take-over defences except as permitted by the

Subordinated Note Purchase Agreement. CanArgo is not subject to any financial covenants, such as the maintenance of minimum net worth or coverage ratios, other than the restriction on its ability to incur additional Indebtedness.

Events of Default. An Event of Default shall exist if one or more of the following occurs and is continuing: (i) failure to pay when due any principal and, after 5 business days, any interest, payable under the Subordinated Note or any Loan Document; (ii) default in the performance of certain enumerated covenants; (iii) default in the performance or compliance with any other terms which remains unremedied for 30 days after the earlier of a Responsible Officer first obtaining actual and not constructive knowledge of the default or the receipt of notice; (iv) any representation or warranty made in writing on behalf of CanArgo or any other CanArgo Group Member proves to have been false or incorrect in any material respect; (v) customary events involving bankruptcy, insolvency or reorganization; (vi) the entry of a final judgment or judgments in excess of $2,500,000 (uncovered by insurance), which is not discharged or settled; (vii) violations of ERISA or the Internal Revenue Code of 1986, as amended, under funding of accrued benefit liabilities and other matters relating to employee benefit plans subject to ERISA or Foreign Pension Plans; (viii) any Loan Document ceases to be in full force and effect (except in accordance with its terms) or its validity is challenged by CanArgo or any affiliate; (ix) CanArgo or any other CanArgo Group Member modifies its Charter Document which results in a Default or Event of Default or will adversely affect the rights of Note holders; or (x) a change occurs in the consolidated financial condition of CanArgo or in the physical, operational or financial status of the Properties (as defined in the Subordinated Note Purchase Agreement), which change has a Material Adverse Effect (as defined in the Subordinated Note Purchase Agreement).

Other than for certain Events of Default that will result in an automatic acceleration without notice, such as bankruptcy, if an Event of Default occurs and is continuing, the Required Holders may at any time at its or their option, by notice to CanArgo, declare all outstanding Subordinated Notes to be immediately due and payable and holders of the Subordinated Note may proceed to enforce their rights under the Loan Documents at law or in equity. CanArgo is responsible for the payment of all costs of collection, including all reasonable legal fees actually incurred in connection therewith.

Warrants. The Subordinated Note Warrants were to expire on March 3, 2008 or such sooner date at the election of the Company and upon at least 30 days prior written notice in the event that the Manavi M12 well indicated, by an independent engineering report, sustainable production, if developed, in excess of 7,500 barrels of oil per day, and were exercisable at an exercise price of $1.00 per share (Exercise Price) (this exercise price having been reset to $1.00 from $1.37 following the issue of the 12% Subordinated Notes), subject to adjustment in connection with any stock split, stock dividend, reverse stock split, reclassification, recapitalization, combination, merger, consolidation or any similar transaction, in which case the Exercise Price and number of Subordinated Note Warrant Shares were to be appropriately adjusted to reflect any such event, such that the holders of the Subordinated Note Warrants would receive upon exercise the identical number of shares of common stock or other consideration or property to be received by the holders of the common stock as if the holders had exercised the Subordinated Note Warrants immediately prior to any such event as such amount would then be adjusted by reason of such stock split, stock dividend, reverse stock split, reclassification, recapitalization, combination, merger, consolidation or other similar transaction. If CanArgo issues any equity securities (other than pursuant to the granting of employee stock options pursuant to shareholder approved employee stock option plans or existing outstanding options, warrants and convertible securities at a price per share of less than $1.00 per share, as adjusted, determined net of all discounts, fees, costs and expenses incurred in connection with such issuance, the Exercise Price would have been reset to such lower price; provided, however, in no event shall the number of Subordinated Note Warrant Shares issuable upon exercise cause Subordinated Note Warrant holders to collectively own in excess of 19.9% of the shares of CanArgo common stock outstanding as of March 3, 2006 absent shareholder approval in accordance with applicable stock exchange requirements. No fractional shares of common stock would have been issued upon any exercise; instead the Exercise Price would have been appropriately adjusted so that holders shall receive the nearest whole number of shares upon any conversion. The Subordinated Note Warrants expired on March 3, 2008.

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Miscellaneous. The execution of the Subordinated Note Purchase Agreement was conditional upon the consent, which was obtained, from 51% of the holders of the Senior Secured Notes pursuant to a Waiver, Consent and Amendment dated as of March 3, 2006 (Waiver, Consent and Amendment Agreement). Under the terms of the Waiver, Consent and Amendment Agreement, the holders of the Senior Secured Notes further consented to certain amendments to the Note Purchase Agreement dated July 25, 2005 among the Company and Ingalls & Snyder Value Partners, L.P together with the other purchasers listed therein to provide for the amendment or termination of the Company s or any of the Subsidiaries interests in the Production Sharing Contract dated May 2001 among the State Agency of Georgia, Georgian Oil and National Petroleum Limited (the Samgori PSC), a Basic Document as defined in the Senior Note Purchase Agreement, including without limitation, a waiver of the negative covenants set forth in Section 11.10 of the Senior Note Purchase Agreement and an increase in the authorized capital stock of the Company to 380 million shares of which 375 million shares shall constitute common stock and 5 million shares shall constitute preferred stock. The Subordinated Note Purchase Agreement, the Subordinated Note, the Subordinated Subsidiary Guaranty and the Registration Rights Agreement are all governed by New York Law and the Warrants are governed by the laws of the State of Delaware; the CanArgo Group Members party thereto subject themselves to the jurisdiction of New York Courts and waive the right to jury trial.

The Company evaluated the embedded conversion feature in this debt and determined it did not meet the criteria for bifurcation under SFAS No 133 Accounting for Derivative Instruments and Hedging Activities during the quarter.

Pursuant to EITF 98-5 Accounting for Convertible Securities with Beneficial Conversion Features or Contingently Adjustable Conversion Ratios and EITF 00-27 Application of Issue No. 98-5 to Certain Convertible Instruments , the Company had initially recorded a discount to the Senior Subordinated Note in the amount of approximately $6,483,000 based on the relative fair value of the beneficial conversion feature and warrants of $2,245,000 and $4,238,000, respectively.

We used the following assumptions to determine the fair value of the Subordinated Notes and Subordinated Note Warrants:

	Additional Loan
Stock price on date of grant	$ 1.16
Risk free rate of interest	4.72%
Expected life of warrant months	24
Dividend rate	
Historical volatility	68.6%

Conversion/Exchange of Subordinated Notes and issue of Subordinated Note Conversion Compensation Warrants: On June 5, 2007, the Company entered into a conversion agreement (the Conversion Agreement) with Persistency (one of the then holders of the Subordinated Notes) and with CanArgo Limited that became effective on June 13, 2007.

Pursuant to the Conversion Agreement Persistency agreed to convert/exchange its holding of $5,000,000 of the Subordinated Notes into Tethys common stock. The conversion exchange was satisfied by the transfer by CanArgo Limited to Persistency of 2 million shares of Tethys common stock.

As an inducement for Persistency to convert its $5 million in aggregate principal amount of Subordinated Notes into Tethys common stock, the Company agreed to issue to Persistency 5,000,000 warrants (the Subordinated Notes Conversion Compensation Warrants) to purchase CanArgo common stock at an exercise price of $1 per common share in transactions intended to qualify for an exemption from registration under the Securities Act pursuant to Section 4(2) thereof and Regulation D promulgated thereunder.

All of the Subordinated Notes Conversion Compensation Warrants expire on the earlier of: (i) September 1, 2009; (ii) or such sooner date at the election of the Company and upon at least thirty (30) days prior written notice to the Registered Holder in the event that: (a) the Manavi M12 well indicates, by way of an independent engineering report, sustainable production, if developed, in excess of 7,500 barrels of oil per day or (b) all Subordinated Note Warrants originally issued under the Subordinated Note and Warrant Purchase Agreement are exercised by the holders thereof and the average closing price for the Company s common stock on the American Stock Exchange or, if the common stock is not then listed for trading on the American Stock Exchange (AMEX) then the Oslo Stock Exchange, is above $2.00 (or its equivalent in NOK, and in any case adjusted for any stock dividends, stock splits, reverse splits, recapitalizations or reorganizations) for a period of five consecutive trading days (the Expiration Date).

We used the following assumptions to determine the fair value of the Subordinated Notes Conversion Compensation Warrants:

	Additional Loan
Stock price on date of grant	$ 0.74
Risk free rate of interest	5.08%
Expected life of warrant months	26
Dividend rate	
Historical volatility	72.3%

The Company has accounted for the modification and extinguishment of $5 million of principal of the Senior Subordinated Notes under Emerging Issues Task Force (EITF) 06-16 Debtor s Accounting for a Modification (or Exchange) of Convertible Debt Instruments and EITF 96-19 Debtor s Accounting for a Modification or Exchange of Debt Instruments . The Company determined that the fair value of the Tethys shares issued as consideration paid in the satisfaction of the principal balance, was $2.50 per share or $5 million based on sales of shares to outside investors and recorded a loss on extinguishment of $2,942,468 which is equal to the $5 million in Tethys common shares less the carrying value of the loan on the date of extinguishment of $2,057,532. The Company accounted for the issuance of 5,000,000 Subordinated Notes Conversion Compensation Warrants issued as additional compensation to induce the conversion of debt to Tethys shares under SFAS 84 Induced Conversions of Convertible Debt, an Amendment of APB 26 and determined the fair value of such Warrants using the Black Scholes model to be approximately $1.28 million and has recorded that expense under the line item Loss/Cost of Debt Extinguishment In addition, the Company reversed long-term accruals made under EITF 86-15 noted above in the amount of approximately $152,000 associated with the debt extinguished against the loss on extinguishment.

Issue of further $400,000 Subordinated Notes in connection with restructuring of short term interest payments: On June 13, 2007, the Company entered into an amendment, consent and waiver (the Subordinated Note Amendment, Consent and Waiver) with the holders of the Subordinated Notes in terms of which the holders of the Subordinated Notes agreed to receive certain interest payments due on the Subordinated Notes as of June 30, 2007 by payment in kind of additional Subordinated Notes. As a result, the Company issued a further $400,000 in aggregate principal amount of Subordinated Notes. These additional Subordinated Notes carry the same rights (including as to conversion into shares of common stock of the Company) as the original $13 million in aggregate principal amount of Subordinated Notes which were previously issued (see the section above entitled *Senior Subordinated Convertible Guaranteed Notes*).

Amendment, Consent and Waiver to Note and Warrant Purchase Agreement dated March 3, 2006: On August 13, 2007, CanArgo entered into an Amendment, Consent and Waiver Agreement with the holders of the Subordinated Notes (the Subordinated Noteholders), pursuant to which:

it was agreed that the balance standing to the credit of the Escrow Account (referred to above in the section entitled Amendment, Consent and Waiver to Note Purchase Agreement dated July 25, 2005) as at the relevant repayment date would be used to repay part of the outstanding Subordinated Notes;

the aggregate principal amount of the Subordinated Notes to be repaid pursuant to the Amendment, Consent and Waiver Agreement would be calculated in accordance with the terms of that agreement (such amount of Subordinated Notes the Repayment Subordinated Notes);

the Subordinated Noteholders agreed that, notwithstanding the date of the Amendment, Consent and Waiver Agreement, interest on the Repayment Subordinated Notes (but not the remaining Subordinated Notes) would cease to accrue as of (but including) August 14, 2007;

by waiving the notice period which CanArgo would otherwise be required to give the Subordinated Noteholders of an early repayment of the Repayment Subordinated Notes and by agreeing to a variation of the interest provisions attaching to the Repayment Subordinated Notes the Subordinated Noteholders effectively gave up (a) certain rights to convert their Repayment Subordinated Notes into common stock of CanArgo as an alternative to accepting repayment of the Repayment Subordinated Notes and (b) the right to receive interest on the Repayment Subordinated Notes in respect of the period between, on the one hand, the date on which CanArgo would otherwise have served notice of early repayment and, on the other hand, the date on which actual repayment (or conversion) of the Repayment Subordinated Notes would otherwise have taken place;

in order to compensate the Subordinated Noteholders for giving up the aforesaid rights, CanArgo agreed to issue to the Subordinated Noteholders warrants to purchase certain shares (subsequently agreed upon as warrants to purchase 3,750,000 shares) at an exercise price of $1.00 per share, subject to adjustment, of CanArgo s common stock, par value $0.10 per share, expiring at close of business on November 13, 2007 (the Subordinated Note Compensatory Warrants), the aggregate number of all such Subordinated Note Compensatory Warrants being calculated in accordance with the terms of the Amendment, Consent and Waiver Agreement; and

accordingly CanArgo and the Subordinated Noteholders agreed to amend the Subordinated Note Purchase Agreement and the Repayment Subordinated Notes to give effect to the foregoing.

The warrants to purchase 3,750,000 shares expired on November 13, 2007.

We used the following assumptions to determine the fair value of the Subordinated Note Compensatory Warrants:

	Additional Loan
Stock price on date of grant	$ 0.89
Risk free rate of interest	4.39%
Expected life of warrant months	4
Dividend rate	
Historical volatility	91.7%

The Company has accounted for the modification and extinguishment of $3,750,000 of principal of the Senior Subordinated Notes under Emerging Issues Task Force (EITF) 06-16 Debtor s Accounting for a Modification (or Exchange) of Convertible Debt Instruments and EITF 96-19 Debtor s Accounting for a Modification or Exchange of Debt Instruments . The Company accounted for the issuance of the Subordinated Notes Compensatory Warrants issued, as compensation to the Subordinated Noteholders for giving up the aforementioned rights, under SFAS 84 Induced Conversions of Convertible Debt, an Amendment of APB 26 and determined the fair value of the warrants using the Black Scholes model to be approximately $573,375 and has recorded that expense under the line item Loss/Cost of Debt Extinguishment . In addition, in the third quarter the Company reversed long-term accruals made under EITF 86-15 noted above in the amount of approximately $127,000 associated with the debt extinguished against the loss on extinguishment.

On June 28, 2006, we announced that we had entered into the private placement with Persistency, a Cayman Islands company, of a $10,000,000 issue of a 12% Subordinated Convertible Guaranteed Note due June 28, 2010 (see

12% Subordinated Convertible Guaranteed Note below) and warrants to purchase an aggregate of 12,500,000 shares of CanArgo common stock (12% Note Warrant Shares), at an exercise price of $1.00 per share, subject to adjustment, and expiring on June 28, 2008 or sooner under certain circumstances (the 12% Note Warrants) which is described more fully below.

As a result of entering into this private placement we issued the 12% Note Warrants at an exercise price below $1.37 and therefore the terms of the Subordinated Note Purchase Agreement and related agreements dictated that the conversion and warrant exercise prices under the Subordinated Note Purchase Agreement be reset to $1.00 per share as described above.

The Company therefore recorded an additional debt discount of $3,683,000 to the Subordinated Note, increasing the total debt discount to approximately $10,166,000 based on the relative fair value of the beneficial conversion feature and warrants of $6,123,000 and $4,043,000, respectively. Debt discount of $1,705,098 has been amortised to interest expense in 2007.

We used the following assumptions in our Black Scholes model to determine the fair value of the Subordinated Notes and Subordinated Note Warrants:

	Additional Loan
Stock price on date of grant	$ 0.74
Risk free rate of interest	5.3%
Expected life of warrant days	1,161
Dividend rate	
Historical volatility	64.3%

12% *Subordinated Convertible Guaranteed Note:* On June 28, 2006, we entered into a $10,000,0000 private placement with Persistency (the Purchaser) of a 12% Subordinated Convertible Guaranteed Note due June 28, 2010 (the 12% Note) and warrants to purchase an aggregate of 12,500,000 shares of CanArgo common stock (12% Note Warrant Shares), at an exercise price of $1.00 per share, subject to adjustment, and expiring on June 28, 2008 or sooner under certain circumstances (the 12% Note Warrants).

The proceeds of this financing, after the payment of placing expenses and professional fees of approximately $168,000, was used to fund our appraisal and development activities in Georgia including further development of the Ninotsminda Field and the appraisal of the Kumisi gas discovery.

We entered into a Note and Warrant Purchase Agreement dated as of June 28, 2006 (12% Note Purchase Agreement) with the Purchaser which qualified as an accredited investor under Rule 501(a) promulgated under the Securities Act. Pursuant to the 12% Note Purchase Agreement, we issued the 12% Note and the 12% Note Warrants in a transaction intended to qualify for an exemption from registration under the Securities Act pursuant to Section 4(2) thereof and Regulation D promulgated thereunder.

The terms of the 12% Note Purchase Agreement and related agreements include the following:

Interest. The unpaid principal balance under the 12% Note bears interest (computed on the basis of a 360-day year of twelve 30-day months) payable semi-annually on June 30 and December 31, commencing December 31, 2006, in cash at the rate of 12% per annum and (b) at the rate of 15% per annum on any overdue payments of principal and interest.

Optional Prepayment. CanArgo may, at its option, upon at least not less than 60 days and not more than 120 days prior written notice, prepay at any time and from time to time after June 28, 2007, any part of the 12% Notes up to an aggregate of $5,000,000 in aggregate principal amount, in multiples of not less than $100,000, and at any time after June 28, 2008 the remaining outstanding principal amount at the following Redemption Prices (expressed as percentages of the principal amount so prepaid): 105% after June 28, 2007 and 103% after June 28, 2008, together with all accrued and unpaid interest.

Mandatory Prepayment. CanArgo will not take any action to consummate a Change of Control (or Change of Control contemplated by a Control Event) unless it shall offer to prepay all, but not less than all, of the 12% Note, on not less than 15 business days prior written notice, in the event of an occurrence of a Change of Control or Control Event. Mandatory prepayment of the 12% Note shall be in an amount equal to 101% of the outstanding principal amount of such 12% Note, together with interest on such 12% Note accrued to the date of prepayment. *Change in Control* is defined to mean

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(a) if CanArgo shall at any time cease to be a publicly held company or cease to have its capital stock traded on an exchange or (b) a transaction or series of related transactions pursuant to which (i) at least fifty-one percent (51%) of the outstanding shares of CanArgo s common stock or, on a fully diluted basis, shall subsequent to June 28, 2006 be owned by any person which is not related to or affiliated with CanArgo, (ii) if CanArgo merges into or with, consolidates with or effects any plan of share exchange or other combination with any person which is not related to or affiliated with CanArgo, or (iii) if CanArgo disposes of all or substantially all of its assets other than in the ordinary course of business; and *Control Event* is defined to mean (i) the execution by CanArgo or any material subsidiary of CanArgo which has guaranteed the indebtedness evidenced by the 12% Note (a CanArgo Group Member) of any agreement or letter of intent with respect to any proposed transaction or event or series of transactions or events which, individually or in the aggregate, may reasonably be expected to result in a Change in Control, or (ii) the execution of any written agreement which, when fully performed by the parties thereto, would result in a Change in Control.

Conversion. The 12% Note is convertible, in whole or in part, into shares of CanArgo common stock (CanArgo Conversion Stock) at a conversion price per share of $1.00 (the CanArgo Conversion Price), which is subject to adjustment if CanArgo issues any equity securities (other than pursuant to the granting of employee stock options pursuant to shareholder approved employee stock option plans or existing outstanding options, warrants and convertible securities, including without limitation the Senior Secured Notes and Senior Subordinated Notes) at a price per share of less than $1.00 per share, as adjusted, determined net of all discounts, fees, costs and expenses incurred in connection with such issuance, in which case the CanArgo Conversion Price will be reset to such lower price. The CanArgo Conversion Price shall also be adjusted in connection with any stock split, stock dividend, reverse stock split, reclassification, recapitalization, combination, merger, consolidation or any similar transaction, in which case the CanArgo Conversion Price and number of shares of CanArgo Conversion Stock will be appropriately adjusted to reflect any such event, such that the holder of the 12% Note will receive upon conversion the identical number of shares of CanArgo common stock or other consideration or property to be received by the holder of the CanArgo common stock as if the holder had converted the 12% Note immediately prior to any such event as such amount would then be adjusted by reason of such stock split, stock dividend, reverse stock split, reclassification, recapitalization, combination, merger, consolidation or other similar transaction; provided, however, in no event shall the number of shares of CanArgo Common Stock issuable to the Purchasers upon conversion cause the Purchasers to collectively own in excess of 19.9% of the shares of CanArgo common stock outstanding as of June 28, 2006 absent shareholder approval in accordance with applicable stock exchange requirements. The 12% Note is subject to mandatory conversion under certain circumstances. No fractional shares of CanArgo common stock shall be issued upon any conversion; instead the CanArgo Conversion Price shall be appropriately adjusted so that holders shall receive the nearest whole number of shares upon any conversion.

In connection with the execution and delivery of the 12% Note Purchase Agreement, CanArgo entered into a Registration Rights Agreement with the Purchasers pursuant to which it agreed to register the CanArgo Conversion Stock and the 12% Note Warrant Shares for resale under the Securities Act. The Registration Rights Agreement gives the holders of the 12% Notes and 12% Note Warrants both demand and piggyback registration rights. In addition the Registration Rights Agreement required us to use our best efforts to have a registration statement declared effective by December 31, 2006 and to maintain that effectiveness for a period of two years in the event that we use a Form S-3 and at least 90 days in the event we use a Form S-1 to register the shares. The conversion stock was registered for resale under the Securities Act and the Company is required to maintain the registration effective until July 2008. There is no penalty associated with our failure to perform under the Registration Rights Agreement.

Security. Payment of all amounts due and payable under the 12% Note Purchase Agreement, the 12% Note and all related agreements (collectively, the Loan Documents) is secured by subordinated guarantees from each other CanArgo Group Member (the 12% Subordinated Subsidiary Guaranty). If CanArgo forms or acquires a Material Subsidiary (as defined in the 12% Note Purchase Agreement) it shall cause such Subsidiary to execute a 12% Subordinated Subsidiary Guaranty (other than for certain excepted companies and legal entities) and thereby become a CanArgo Group Member subject to the provisions of the 12% Note Purchase Agreement.

Subordination. Payments on the 12% Note and under the 12% Subordinated Subsidiary Guaranty is subordinated and junior in right of payment to the prior payment or conversion in full of CanArgo s Senior Indebtedness in the event of the bankruptcy, insolvency or other reorganization of CanArgo. Under the terms of the subordination, holders of the 12% Note agree for the benefit of the holders of the Senior Indebtedness to certain limitations on their right to accelerate or demand payment under the 12% Note or otherwise realize under the 12% Subordinated Subsidiary Guaranty in the event of a default under the Senior Indebtedness. *Senior Indebtedness* is defined to mean (i) all indebtedness under the Senior Secured Notes (which have now been repaid), the Senior Subordinated Notes, or any related agreements; (ii) certain permitted indebtedness now existing or hereafter arising, and (iii) all renewals, refinancings, extensions, modifications and replacements of the then outstanding principal amount owing under any of the foregoing.

Covenants. Under the terms of the 12% Note Purchase Agreement CanArgo is subject to certain affirmative and negative covenants, which can be waived by the beneficial holders of at least 51% of the outstanding principal amount of the 12% Notes (the Required Holders), including the following affirmative and negative covenants, respectively: (a) providing current information regarding CanArgo and rights of inspection; compliance with laws; maintenance of corporate existence, insurance and properties; payment of taxes; adding new material subsidiaries as additional guarantors under the 12% Subordinated Subsidiary Guaranty; payment of professional fees for the Purchaser (not in excess of $75,000), and (b) restrictions on: transactions with affiliates; mergers, consolidations and sales of all of CanArgo s assets; liens (except for certain permitted liens); the issuance of additional senior indebtedness; changes in CanArgo s line of business; certain types of payments; sale-and leasebacks; sales of assets other than in the ordinary course of business; future Indebtedness, as defined in the 12% Note Purchase Agreement (other than certain permitted indebtedness); cancelling, terminating, waiving or amending provisions of, or selling any interests in (other than under certain circumstances) any of the Basic Agreements (as defined in the 12% Note Purchase Agreement); and adopting any anti-take-over defences except as permitted by the 12% Note Purchase Agreement. CanArgo is not subject to any financial covenants, such as the maintenance of minimum net worth or coverage ratios, other than the restriction on its ability to incur additional Indebtedness.

Events of Default. An Event of Default shall exist if one or more of the following occurs and is continuing: (i) failure to pay when due any principal and, after 5 business days, any interest, payable under the 12% Note or any Loan Document; (ii) default in the performance of certain enumerated covenants; (iii) default in the performance or compliance with any other terms which remains unremedied for 30 days after the earlier of a Responsible Officer first obtaining actual and not constructive knowledge of the default or the receipt of notice; (iv) any representation or warranty made in writing on behalf of CanArgo or any other CanArgo Group Member proves to have been false or incorrect in any material respect; (v) customary events involving bankruptcy, insolvency or reorganization; (vi) the entry of a final judgment or judgments in excess of $2,500,000 (uncovered by insurance), which is not discharged or settled; (vii) violations of ERISA or the Internal Revenue Code of 1986, as amended, under funding of accrued benefit liabilities and other matters relating to employee benefit plans subject to ERISA or Foreign Pension Plans; (viii) any Loan Document ceases to be in full force and effect (except in accordance with its terms) or its validity is challenged by CanArgo or any affiliate; (ix) CanArgo or any other CanArgo Group Member modifies its Charter Document which results in a Default or Event of Default or will adversely affect the rights of 12% Note holders; or (x) a change occurs in the consolidated financial condition of CanArgo or in the physical, operational or financial status of the Properties (as defined in the Note Purchase Agreement), which change has a Material Adverse Effect (as defined in the Note Purchase Agreement).

Other than for certain Events of Default that will result in an automatic acceleration without notice, such as bankruptcy, if an Event of Default occurs and is continuing, the Required Holders may at any time at its or their option, by notice to CanArgo, declare all outstanding 12% Notes to be immediately due and payable and holders of the 12% Note may proceed to enforce their rights under the Loan

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Documents at law or in equity. CanArgo is responsible for the payment of all costs of collection, including all reasonable legal fees actually incurred in connection therewith.

12% Note Warrants. The 12% Note Warrants may be exercised at an exercise price of $1.00 per share, subject to adjustment (the Exercise Price) in whole or in part at any time during the period (the Exercise Period) commencing on the first Business Day six (6) months after the date of issuance and terminating at the close of business on June 28, 2008 or shall be exercised on such sooner date at the election of the Company (a Mandatory Exercise) and upon at least thirty (30) days prior written notice to the Registered Holder (the Mandatory Exercise Notice) in the event that: (i) the Manavi M12 well indicates, by way of an independent engineering report, sustainable production, if developed, in excess of 7,500 barrels of oil per day or (ii) all the warrants originally issued under that certain Note and Warrant Purchase Agreement dated as of March 3, 2006 by and among the Company and the holders of the Senior Subordinated Notes are exercised by the holders thereof and the average closing price for the CanArgo Common Stock on the American Stock Exchange or, if the CanArgo Common Stock is not then listed for CanArgo s trading on the American Stock Exchange then the Oslo Stock Exchange, is above $1.25 (or its equivalent in NOK, and in any case adjusted for any stock dividends, stock split, its reverse split, recapitalization or reorganization) for a period of five consecutive trading days (the Warrant Expiration Date); except that (a) in the case of a Mandatory Conversion (as defined in the 12% Note Purchase Agreement), any and all outstanding 12% Note Warrants issued under the 12% Note Purchase Agreement and held by Purchaser shall automatically and simultaneously become immediately exercisable on receipt of the Mandatory Conversion Notice, and (b) in the case of a Mandatory Exercise, any and all outstanding 12% Notes issued under the 12% Note Purchase Agreement and held by Purchaser shall automatically and simultaneously become immediately convertible on receipt of the Mandatory Exercise Notice. The Exercise Period may also be extended by the Company s Board of Directors. The Exercise Price is subject to adjustment in connection with any stock split, stock dividend, reverse stock split, reclassification, recapitalization, combination, merger, consolidation or any similar transaction, in which case the Exercise Price and number of 12% Note Warrant Shares will be appropriately adjusted to reflect any such event, such that the holders of the 12% Note Warrants will receive upon exercise the identical number of shares of CanArgo common stock or other consideration or property to be received by the holders of the CanArgo common stock as if the holders had exercised the 12% Note Warrants immediately prior to any such event as such amount would then be adjusted by reason of such stock split, stock dividend, reverse stock split, reclassification, recapitalization, combination, merger, consolidation or other similar transaction. If CanArgo issues any equity securities (other than pursuant to the granting of employee stock options pursuant to shareholder approved employee stock option plans or existing outstanding options, warrants and convertible securities, including without limitation the conversion of the Senior Subordinated Notes) at a price per share of less than $1.00 per share, as adjusted, determined net of all discounts, fees, costs and expenses incurred in connection with such issuance, the Exercise Price will be reset to such lower price; provided, however, in no event shall the number of 12% Note Warrant Shares issuable upon exercise cause 12% Note Warrant holders to collectively own in excess of 19.9% of the shares of CanArgo common stock outstanding as of June 28, 2006 absent shareholder approval in accordance with applicable stock exchange requirements. The 12% Note Warrants may be converted at the election of the holders and with the concurrence of the Company into 12% Note Warrant Shares on a net basis based upon the then spread between the Exercise Price and the market price of the 12% Note Warrant Shares. No fractional shares of CanArgo common stock shall be issued upon any exercise; instead the Exercise Price shall be appropriately adjusted so that holders shall receive the nearest whole number of shares upon any conversion.

Miscellaneous. The execution of the 12% Note Purchase Agreement was conditional upon the consent, which was obtained, from 51% of the holders of the Senior Secured Notes and from 50% of the holders of the Senior Subordinated Notes each pursuant to Waiver and Consent Agreements each dated as of June 28, 2006. Under the terms of their Waiver and Consent Agreement, the holders of 51% in aggregate principal amount of the Senior Secured Notes further agreed to issue to the Purchaser an option to purchase their Senior Secured Notes at par in the event of Default and acceleration of the Senior Secured Notes provided that the Purchaser concurrently offers to purchase the remaining outstanding Senior Secured Notes on identical terms and conditions. The 12% Note Purchase

Agreement, the 12% Note, the 12% Subordinated Subsidiary Guaranty and the Registration Rights Agreement are all governed by New York Law and the 12% Note Warrants are governed by the laws of the State of Delaware; the CanArgo Group Members party thereto subject themselves to the jurisdiction of New York Courts and waive the right to jury trial.

The Company evaluated the embedded conversion feature in this debt and determined it did not meet the criteria for bifurcation under SFAS No 133 Accounting for Derivative Instruments and Hedging Activities during the quarter.

Pursuant to EITF 98-5 Accounting for Convertible Securities with Beneficial Conversion Features or Contingently Adjustable Conversion Ratios and EITF 00-27 Application of Issue No. 98-5 to Certain Convertible Instruments , the Company has recorded a discount to the 12% Note in the amount of approximately $2,700,000 based on the relative fair value of the beneficial conversion feature and warrants of $50,000 be and $2,650,000, respectively.

We used the following assumptions to determine the fair value of the 12% Note and 12% Note Warrants:

	Additional Loan
Stock price on date of grant	$ 0.74
Risk free rate of interest	5.30%
Expected life of warrant days	731
Dividend rate	
Historical volatility	64.3%

The discount is being amortized to interest expense over the life of the 12% Note using an effective interest rate of 10.1%. We amortized $634,000 of debt discount as interest expense in 2007. The total effective interest rate for the 12% Note is 22.1%.

Issue of further $600,000 12% Notes in connection with restructuring of short term interest payments on the 12% Notes: On June 13, 2007, the Company entered into an amendment, consent and waiver (the 12% Note Amendment, Consent and Waiver) with Persistency, the holder of the 12% Notes, in terms of which Persistency agreed to receive the interest payments due on the 12% Notes as of June 30, 2007 with a payment in kind of additional 12% Notes. As a result, the Company issued a further $600,000 in aggregate principal amount of 12% Notes. These additional 12% Notes carry the same rights (including as to conversion into shares of common stock of the Company) as the original $10 million in aggregate principal amount of 12% Notes which were previously issued. The rights attaching to the 12% Notes are set out in the 12% Note Purchase Agreement and related agreements.

NOTE 10 DEFERRED REVENUE

Other liabilities consisted of the following at December 31:

	2007	2006
Prepaid sales	$	$ 484,515
	$	$ 484,515

As of December 31, 2006 prepaid sales related to a deposit received from a customer for a sale of oil that was completed in 2007.

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NOTE 11 ACCRUED LIABILITIES

Accrued liabilities consisted of the following at December 31:

	2007	2006
Drilling contractors	$ 4,931,332	$ 5,039,685
Professional fees	929,628	706,288
Tethys Spin-Out costs	395,611	
Non-cash loan interest	76,550	890,800
Other	306,766	281,695
	$ 6,639,887	$ 6,918,468

Amounts due to drilling contractors at December 31, 2007 and at December 31, 2006, include amounts invoiced by Weatherford of $4,931,332. We have formally notified Weatherford that we dispute the validity of these billings to the Company for work Weatherford performed in the first and second quarter of 2005. We have recorded all amounts billed by Weatherford as of December 31, 2006 pending the outcome of the dispute resolution (see Note 12) following a formal Request for Arbitration with the London Court of International Arbitration against CanArgo Energy Corporation lodged by WEUS on September 12, 2005.

NOTE 12 COMMITMENTS AND CONTINGENCIES

We have contingent obligations and may incur additional obligations, absolute and contingent, with respect to the acquisition and development of oil and gas properties and ventures in which we have interests that require or may require us to expend funds and to issue shares of our Common Stock.

At December 31, 2007, we had the contingent obligation to issue an aggregate of up to 187,500 shares of our Common Stock to Fielden Management Services PTY, Ltd (a third party management services company), subject to the satisfaction of conditions related to the achievement of specified performance standards by the Stynawske Field project, an oil field in Ukraine in which we had a previous interest. As far as management is aware, the project is not progressing at the desired pace of development and consequently, in management s opinion, the chance of having to issue these shares is remote.

Under the Production Sharing Contract for Blocks XI^G and XI^H (the Tbilisi PSC) in Georgia our subsidiary CanArgo Norio Limited had a commitment to acquire additional seismic data within three years of the effective date of the contract which is September 29, 2003. The State Agency for Oil & Gas Regulation in Georgia has given written consent to an extension to the period within which the data should be acquired to July 31, 2008 and we are currently working with the State Agency to amend the Tbilisi PSC accordingly. The total commitment over the remaining period is $350,000. In the event that a commercial discovery is not established, our interest in the Tbilisi PSC would terminate 10 years from the effective date, which will be September 29, 2013.

In 2002, a participation agreement for the three well exploration program on the Ninotsminda / Manavi area with AES Gardabani (a subsidiary of AES Corporation) (AES) was terminated without AES earning any rights to any of the Ninotsminda / Manavi area reservoirs. We therefore have no present obligations in respect of AES. However, under a separate letter of agreement, if gas from the Sub Middle Eocene is discovered and produced from the exploration area covered by the participation agreement, AES will be entitled to recover at the rate of 15% of future gas sales from the Sub Middle Eocene, net of operating costs, approximately

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$7,500,000, representing their prior funding under the Participation Agreement. AES have now withdrawn from Georgia, but hydrocarbons have been discovered in the Manavi area reservoir and in the event of a successful gas development from the Sub Middle Eocene, it is reasonably possible that AES may exercise their rights under the letter of agreement.

In September 2004, a blow-out occurred at the N100 well on the Ninotsminda Field. The Company currently estimates that the total costs attributable to the blow-out, including compensation and cleaning of the environment will be $2,000,000. The Company s insurance policies cover 80% of these costs up to a maximum of $2,500,000 and the remaining 20% insurance retention being payable by the Company. In 2005 we received $800,000, as a first instalment, from our insurers and in 2006 we received a further $560,000, in respect of costs incurred to date and the chance of receiving the remaining amount up to 80% of our total costs, is deemed probable.

On July 27, 2005, GBOC Ninotsminda, an indirect subsidiary of the Company in which the Company has a 50% interest, received a claim raised by certain of the Ninotsminda villagers (listed on pages 1 to 76 of the claim) in the Tbilisi Regional Court in respect of damage caused by the blow-out of the N100 well on the Ninotsminda Field in Georgia on September 11, 2004. An additional claim was received in December 2005 and amended in March 2006, thus bringing the relief sought pursuant to both claims to the sum of approximately GEL 314,000,000 (approximately $198,000,000 at the exchange rate of GEL to US dollars in effect on December 31, 2007). We believe that we have meritorious defences to this claim and intend to defend it vigorously and as a result of discussions with our legal advisors in Georgia, we would consider the chances of the claim being successful to be remote.

On September 12, 2005, WEUS Holding Inc (WEUS) a subsidiary of Weatherford International Ltd lodged a formal Request for Arbitration with the London Court of International Arbitration against CanArgo Energy Corporation in respect of unpaid invoices for work performed under the Master Service Contract dated June 1, 2004 between the Company and WEUS for the supply of under-balanced coil tubing drilling equipment and services during the first and second quarter of 2005. Pursuant to the Request for Arbitration, WEUS demand for relief is $4,931,332.55. Although the Company has recorded all amounts billed by Weatherford as of December 31, 2005 (see Note 11) the Company is contesting the claim and has filed a counterclaim. We believe that we have meritorious defenses to this claim and intend to defend it vigorously. At this point in the proceedings it is not possible to predict the outcome of the arbitration. However, in the event that Weatherford is successful, the extent of the loss to the Company would be limited to the payment of the unpaid invoices and the payment of Weatherford s professional fess in regards to this matter.

The Company has been named in a claim with a group of defendants by former interest holders of the Lelyakov oil field in the Ukraine. The plaintiffs are seeking damages of approx 600,000 CDN (approx $611,000 at December 31, 2007 exchange rates). The former owners of UK-Ran Oil Company disposed of their investment in the field prior to selling the Company to CanArgo. CanArgo believes the claim against it to be meritless. The Company is unable at this time to determine a potential outcome but in general would consider the chances of the claim being successful to be remote.

Under the Ninotsminda PSC, NOC is required to relinquish at least half of the area then covered by the production sharing contract, but not in portions being actively developed, at five year intervals commencing December 1999. In 1998, these terms were amended with the initial relinquishment being due in 2008 and a reduction in the area to be relinquished at each interval from 50% to 25% whereby the Contractor selects the relinquishment portions.

CanArgo Norio Limited currently owns a 100% interest in the Norio (Block XI^C) and North Kumisi Production Sharing Agreement (Norio PSA), although this interest has a 25 year term it may be reduced to 85% should the state oil company, Georgian Oil and Gas Corporation (GOGC), exercise an option available to it under the PSA for a limited period following the submission of a field development plan. Although we are not able to speak for GOGC, in management s opinion it is likely that GOGC would exercise the option available to it in the event of a commercial oil or gas discovery. As a contractor party, GOGC would be liable for all costs and expenses in relation to any interest it may acquire in the PSA. This PSA covers an area of approximately

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265,122 acres (1,061 km^2) following a 25% relinquishment in April 2006 and will be subject to a further 50% relinquishment of the remaining contract area less any development area in April 2011.

Lease Commitments We lease office space under non-cancelable operating lease agreements. Rental expense for the years ended December 31, 2007, 2006 and 2005 was $461,655, $428,088, and $456,908 respectively. Future minimum rental payments over the next five years for our lease obligations as of December 31, 2007, are as follows:

2008	$ 461,655
2009	413,655
2010	240,374
2011	67,094
2012	67,094
Thereafter	117,415*
	$ 1,367,286

* This represents payments for 1 years and 9 months after 2012.

Total sub-rental income due to the Company over the next 2 years and 6 months under sub-leases is $435,254.

No parent company guarantees have been provided by CanArgo with respect to our contingent obligations and commitments.

NOTE 13 TEMPORARY EQUITY

Our 2004 Plan allows for up to 17,500,000 shares of the Company s common stock to be issued to officers, directors, employees, consultants and advisors pursuant to the grant of stock based awards, including qualified and non-qualified stock, options, restricted stock, stock appreciation rights and other stock based performance awards. Stock options may be exercised, in whole or in part, by giving written notice of exercise to the Corporation specifying the number of shares to be purchased. However, in the event of Change of Control (as defined in the 2004 Plan) an optionee (other than an optionee who initiated a Change of Control in a capacity other than as an officer or director of the Corporation) may elect to surrender all or part of the stock option to the Corporation and to receive in cash an amount equal to the amount by which the fair market value per share of the Stock on the date of exercise shall exceed the purchase price per share under the stock option multiplied by the number of shares of the Stock granted under the stock option as to which the right granted by this proviso shall have been exercised.

The company accounts for options issued with redemption features in accordance with SEC Accounting Series Release 268 Presentation in Financial Statements of Redeemable Preferred Stocks and EITF D-98: Classification and Measurement of Redeemable Securities, the Company has calculated and classified the intrinsic value of $2,119,530 as at December 31, 2005 to Temporary Equity, the vested portion of issued share options from our 1995 Long-Term Incentive Plan in accordance with the related guidance. The Company believes that the likelihood of a Change in Control is remote at this point in time and therefore has fixed its Temporary Equity as at the December 31, 2005 level.

NOTE 14 STOCKHOLDERS EQUITY

On July 8, 1998, at a Special Meeting of Stockholders, the stockholders of CanArgo approved the acquisition of all of the common stock of CanArgo Oil and Gas (CAOG) for Common Stock of the Company pursuant to the terms of an Amended and Restated Combination Agreement between those two companies (the Combination Agreement). Upon completion of the acquisition on July 15, 1998, CAOG became a subsidiary

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of CanArgo, and each previously outstanding share of CAOG common stock was converted into the right to receive 0.8 shares (the Exchangeable Shares) of CAOG which are exchangeable generally at the option of the holders for shares of CanArgo s Common Stock on a share-for-share basis.

On January 24, 2002 we announced that we had established May 24, 2002 as the redemption date for all of the Exchangeable Shares of CAOG since the number of outstanding Exchangeable Shares had fallen below the minimum 853,071 share threshold. Each Exchangeable Share was purchased by CanArgo for shares of CanArgo Common Stock on a share-for-share basis resulting in the issuance of an aggregate of 148,826 shares of Common Stock. No cash consideration was issued by CanArgo and the purchase did not increase the total number of shares of Common Stock of CanArgo deemed issued and issuable.

In February 2004, we announced that we had signed a Standby Equity Distribution Agreement that allowed us, at our option, to issue shares to US-based investment fund Cornell Capital Partners LP up to a maximum value of $20,000,000 over a period of up to two years from the date on which the Registration Statement on Form S-3 registering for resale the shares under the Securities Act of 1933, as amended (Securities Act) is declared effective. The Registration Statement was declared effective by the SEC on February 3, 2005

In October 2006, we issued an aggregate of 12,263,368 shares of common stock in connection with a private placement in Norway intended to qualify for the exemption from registration afforded by Section 4(2) of The Securities Act of 1933, as amended (Securities Act) and Regulation S promulgated under the Securities Act, for aggregate gross proceeds of NOK (Norwegian Kroner) 111,596,239 ($16,687,039 equivalent based upon a conversion rate of NOK 6.6876 per dollar) before placing fees and expenses estimated at NOK 6,695,774 ($1,001,222 equivalent). We agreed to register the Shares for resale under the Securities Act. As a result of the delays incurred in registering the Reg. S Shares we have paid subscribers a cash liquidity penalty of 5% of the subscription price of their Shares in the aggregate amount of NOK 5,579,812 ($834,352 equivalent). The Registration statement was declared effective by the SEC on January 19, 2007.

On August 10, 2007, we entered into a subscription agreement with three accredited investors in terms of which we issued those investors by way of a private placement 2,500,000 shares of CanArgo common stock at $1.00 per share, resulting in gross proceeds of $2,500,000. In consideration for the investors agreeing to make the subscription, we also issued to the investors warrants to subscribe for an aggregate of 5 million shares of common stock of CanArgo. The warrants have an exercise price of $1.00 per share, subject to adjustment, and are exercisable up to the end of August 2009.

The total number of shares of common stock authorized was 500,000,000 as of December 31, 2007, 375,000,000 as of December 31, 2006 and 300,000,000 as of December 31, 2005.

As of December 31, 2007 and 2006, we had 5,000,000 shares of $0.10 par value preferred stock authorized, of which none were outstanding. The Board of Directors may at any time issue additional shares of preferred stock and may designate the rights and privileges of a series of preferred stock without any prior approval by the stockholders.

During the years ended December 31, 2007, 2006 and 2005, the following transactions regarding CanArgo s Common Stock were consummated pursuant to authorization by CanArgo s Board of Directors or duly constituted committees thereof.

Year Ended December 31, 2007

In January 2007, 1,000,000 shares of our common stock were issued at $0.63 per share as a result of the exercising of warrants.

In March 2007, 355,000 shares of our common stock were issued at an average of $0.90 per share as a result of an employee exercising stock options.

In June 2007, 20,000 shares of our common stock were issued at $0.14 per share as a result of an employee exercising stock options.

In August 2007, 1,100,000 shares of our common stock were issued at $0.10 per share as a result of employees exercising stock options.

In August 2007, 2,500,000 shares of our common stock were issued at $1.00 per share in relation to a private placement.

Year Ended December 31, 2006

In February 2006, 1,521,739 shares of our common stock were issued converting the Ozturk Long Term Loan with Detachable Warrants.

In September 2006, 774,000 shares of our common stock were issued at an average of $0.76 per share as a result of employees exercising stock options.

In October 2006, 12,263,368 shares of our common stock were issued at $1.36 per share in relation to a private placement in Norway.

Year Ended December 31, 2005

We issued to Cornell Capital Partners, L.P. pursuant to the Standby Equity Distribution Agreement, the following shares at the dates and prices indicated:

In February 2005, 380,836 shares of our common stock were issued at $1.31 per share.

In February 2005, 335,653 shares of our common stock were issued at $1.47 per share.

In March 2005, 344,758 shares of our common stock were issued at $1.54 per share.

In March 2005, 370,599 shares of our common stock were issued at $1.62 per share.

In March 2005, 381,170 shares of our common stock were issued at $1.57 per share.

In March 2005, 495,745 shares of our common stock were issued at $1.21 per share.

In April 2005, 552,639 shares of our common stock were issued at $1.09 per share.

In April 2005, 473,634 shares of our common stock were issued at $1.27 per share.

In May 2005, 837,054 shares of our common stock were issued at $0.72 per share.

In May 2005, 813,670 shares of our common stock were issued at $0.74 per share.

In May 2005, 872,854 shares of our common stock were issued at $0.69 per share.

In May 2005, 847,458 shares of our common stock were issued at $0.71 per share.

In June 2005, 801,068 shares of our common stock were issued at $0.75 per share.

In June 2005, 812,348 shares of our common stock were issued at $0.74 per share.

In June 2005, 639,591 shares of our common stock were issued at $0.94 per share.

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In June 2005, 596,421 shares of our common stock were issued at $1.00 per share.

In July 2005, 613,246 shares of our common stock were issued at $0.98 per share.

In July 2005, 630,120 shares of our common stock were issued at $0.95 per share.

In July 2005, 669,568 shares of our common stock were issued at $0.90 per share.

In July 2005, 761,325 shares of our common stock were issued at $0.79 per share.

In August 2005, 783,188 shares of our common stock were issued at $0.77 per share.

Other Stock issuances were as follows:

In March 2005, 1,067,833 shares of our common stock were issued at an average of $0.34 per share as a result of employees exercising stock options.

In March 2005, 1,570,000 shares of our common stock were issued at an average of $0.11 per share as a result of employees exercising stock options.

In May 2005, 80,000 shares of CanArgo common stock were issueable to CEOcast Inc in relation to a consultancy agreement between CanArgo and CEOcast.

In June 2005, 5,500,000 shares of our common stock were issued at $0.76 per share to Provincial, of which Russell Hammond (one of our non-executive directors) is Investment Advisor and 5,500,000 shares of our common stock were issued at $0.76 per share to Vando, in connection with the Tethys Acquisition.

In August 2005, 360,000 shares of our common stock were issued at an average of $1.44 per share as a result of stock options being exercised.

In September 2005, 284,000 shares of our common stock were issued at an average of $1.34 per share as a result of stock options being exercised

NOTE 15 NET LOSS PER COMMON SHARE

Earnings (loss) per share is calculated in accordance with SFAS No. 128, Earnings Per Share. Basic and diluted earnings per share are provided for continuing operations, discontinued operations, cumulative effect of change of accounting principle and net income (loss). Basic earnings (loss) per share is computed based upon the weighted average number of shares of common stock outstanding for the period and excludes any potential dilution. Diluted earnings per share reflects potential dilution from the exercise of securities (warrants, options and convertible debt) into common stock. Outstanding options and warrants to purchase common stock are not included in the computation of diluted loss per share because the effect of these instruments would be anti-dilutive for the loss periods presented.

Basic and diluted net loss per common share for the years ended December 31, 2007, 2006 and 2005 were based on the weighted average number of common shares outstanding during those periods. Shares issuable upon the conversion of convertible notes, options and warrants to purchase CanArgo s Common Stock were outstanding during the years ended December 31, 2007, 2006 and 2005 but were not included in the computation of diluted net loss per common share because the effect of such inclusion would have been anti-dilutive (i.e. reduce the loss per share). The total number of such shares excluded from diluted net loss per common share were 80,119,215, 97,365,214 and 41,644,516 for each of the years ended December 31, 2007, 2006 and 2005 respectively.

NOTE 16 INCOME TAXES

CanArgo and its U.S. domestic subsidiary file a U.S. consolidated income tax return. No benefit for U.S. income taxes has been recorded in these consolidated financial statements because of CanArgo s inability to recognize deferred tax assets under provisions of SFAS 109. Due to the implementation of the quasi-reorganization as of October 31, 1988, future reductions of the valuation allowance relating to those deferred tax assets existing at the date of the quasi-reorganization, if any, will be allocated to capital in excess of par value.

A reconciliation of the differences between income taxes computed at the U.S. federal statutory rate of 34% and CanArgo s reported provision for income taxes is as follows:

	Year Ended December 31,		
	2007	2006	2005
Income tax benefit at statutory rate	$ (18,284,253)	$ (20,583,889)	$ (4,194,007)
Benefit of losses not recognized	18,284,253	20,583,889	4,194,007
Provision for income taxes	$	$	$
Effective tax rate	0%	0%	0%

The components of deferred tax assets consisted of the following as of December 31:

	2007	2006
U.S. Net operating loss carryforwards	$ 14,062,000	$ 11,059,000
Foreign net operating loss carryforwards	2,357,000	2,794,000
Net timing differences on impairments and accelerated capital allowances	9,553,000	9,553,000
	25,972,000	23,406,000
Valuation allowance	(25,972,000)	(23,406,000)
Net deferred tax asset recognized in balance sheet	$	$

On August 1, 1991, August 17, 1994, July 15, 1998 and June 28, 2000, CanArgo experienced changes in ownership as defined in Section 382 of the Internal Revenue Code (IRC). The effect of these changes in ownership is to limit the utilization of certain existing net operating loss carryforwards for income tax purposes to approximately $2,920,000 per year on a cumulative basis. As of December 31, 2007, total unexpired U.S. net operating loss carryforwards were approximately $57,149,000, approximately $20,312,000 of this amount was incurred prior to the ownership change in 2000 and as a result of IRC Section 382 limitations approximately $15,789,000 of those carry forwards will expire unused.

The U.S. net operating loss carryforwards expire from 2008 to 2027. CanArgo also has approximately $6,931,000 of foreign net operating loss carryforwards. A significant portion of the foreign net operating loss carryforwards may be subject to limitations similar to IRC Section 382.

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CanArgo s available net operating loss carryforwards may be used to offset future taxable income, if any, prior to their expiration subject to the Section 382 limitations described above and potential further limitations as a result of additional changes in ownership.

Effective January 1, 2007 the Company adopted FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in the financial statements if that position is more likely than not of being sustained by the taxing authority. The Company does not believe it has any tax positions that meet this criteria; therefore, no amounts were recognized in the liability for unrecognized tax benefits and its effective tax rate was not impacted by the adoption of FIN 48. The Company did not adjust the opening balance of retained earnings as of January 1, 2007.

Accordingly, the Company did not accrue or recognize any amounts for interest or penalties in its financial statements during 2007. The Company will classify interest to be paid on an underpayment of income taxes and any related penalties as income tax expense if it is determined, in a subsequent period that a tax position is more likely than not of being sustained by the taxing authority.

NOTE 17 DISCONTINUED OPERATIONS

Tethys Petroleum Limited

CanArgo s ownership of Tethys was diluted in stages during the year ended December 31, 2007 from 100% ownership on December 31, 2006 through to disposing of its remaining shareholding on August 3, 2007. In the first quarter of 2007, Tethys sold approx 6.8 million shares of its common stock in a private placement offering to outside investors for gross proceeds of approximately $16.8 million. This transaction reduced the Company s interest in Tethys to approximately 67%. In May 2007, Tethys received the approval from the Ministry of Mineral Resources of Kazakhstan to exchange approximately 6 million of Tethys common shares in return for the remaining 30% ownership of BN Munai LLP not previously controlled by Tethys. This transaction reduced the Company s ownership of Tethys to approximately 52%. As more fully described in Note 9 above, on June 13, 2007, the Company, through its wholly owned subsidiary, CanArgo Ltd, transferred 6 million of its Tethys common shares to the CanArgo Noteholders in exchange for the extinguishment of $15 million in principal of outstanding notes payable. This transaction reduced the Company s ownership in Tethys to approximately 30% and resulted in Tethys no longer being a consolidated subsidiary of the Company. On June 27, 2007 Tethys announced that it had completed its initial public offering through the issuance of approximately 18.2 million shares on the Toronto Stock Exchange reducing the Company s ownership to approximately 17.7%. On August 3, 2007 the Company sold its remaining shareholding in Tethys receiving proceeds of approximately $20.8 million net of fees.

The results of discontinued operations in respect of Tethys consisted of the following for the years ended:

	December 31, 2007	December 31, 2006	December 31, 2005
Loss Before Income Taxes and Minority Interest	**$ (3,999,646)**	$ (6,781,987)	$
Realised gain on securities held for sale	**15,566,878**		
Equity Loss on investments			(155,016)
Income Taxes			
Net Income (Loss) from Discontinued Operation	**$ 11,567,232**	$ (6,781,987)	$ (155,016)

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Gross consolidated assets and liabilities in respect of Tethys that are included in assets to be disposed consisted of the following at December 31:

	December 31, 2007	December 31, 2006
Assets to be disposed:		
Cash	$	$ 1,763,261
Accounts receivable		5,368
Prepayments		4,188,854
Prepaid financing fees		30,050
Other assets		1,291,834
Capital assets		23,238,284
	$	$ 30,517,651
Liabilities to be disposed:		
Accounts payable	$	$ 787,581
Accrued liabilities		468,762
Long term debt		3,083,673
Other non current liabilities		31,715
Provision for future site restoration		450,667
	$	$ 4,822,398

Samgori PSC

On February 17, 2006 we issued a press release announcing that our subsidiary, CanArgo Samgori Limited (CSL), was not proceeding with further investment in Samgori (Block XI ^{B}) Production Sharing Contract (Samgori PSC) in Georgia and associated farm-in which became effective in April 2004, and accordingly we terminated our 50% interest in the Samgori PSC with effect from February 16, 2006. The decision by CSL not to proceed with further investment under the current farm-in arrangements was due to the inability of CSL s partner in the project, Georgian Oil Samgori Limited (GOSL), to provide its share of funding to further the development of the Field. We consider that there would have been insufficient time to meet the commitments under the Agreement with National Petroleum Limited (NPL) the previous licence holders and we were not prepared to fund the project, which is not without risk, on a 100% basis without different commercial terms and an extension to the commitment period. It was not possible to negotiate a satisfactory position on either matter. CSL has been informed that NPL has now exercised its right to take back 100% of the Contractor Share in the Samgori PSC from GOSL and, accordingly, effective February 16, 2006 we have withdrawn from the Samgori PSC.

The results of discontinued operations in respect of CSL consisted of the following for the years ended:

	December 31, 2007	December 31, 2006	December 31, 2005
Operating Revenues	**$**	$ 1,002,842	$ 2,303,463
Income (Loss) Before Income Taxes and Minority Interest	**(29,860)**	672,803	603,170
Income Taxes			

Minority Interest in Income			
Net Income (Loss) from Discontinued Operation	**$ (29,860)**	$ 672,803	$ 603,170

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Gross consolidated assets and liabilities in respect of CSL that are included in assets to be disposed consisted of the following at December 31:

	December 31, 2007	December 31, 2006
Assets to be disposed:		
Accounts receivable (net)	$ 71,294	$ 1,120
Other current assets		6,736
	$ 71,294	$ 7,856
Liabilities to be disposed:		
Accounts payable	$ 327,046	$ 361,939
Deposits		
Provision for future site restoration	9,400	7,000
	$ 336,446	$ 368,939

NOTE 18 SEGMENT AND GEOGRAPHICAL DATA

During the three years ended December 31, 2007 Georgia represented the only geographical and operating segment.

Prior to the disposal of the Kazakhstan operations (see Note 17) the Company had multiple geographical segments.

NOTE 19 SUPPLEMENTAL CASH FLOW INFORMATION

	2007	2006	2005
Non-cash transactions:			
Stock compensation expense	$ 627,791	$ 1,924,076	$ 2,374,578
Interest expense and amortization of debt discount	4,445,416	3,543,938	1,277,878
Non cash miscellaneous expense Financing fees			193,000
Debt extinguishment expense	12,127,494		
Issuance of common stock for services			53,600
Issuance of common stock pursuant to SEDA (1)			10,327,305
Issuance of common stock to acquire 55% remaining interest in Tethys Petroleum Investments, Ltd			8,360,000
Interest expense rolled into PIK loans	2,125,000		
Impairment of oil and gas ventures and other assets	42,000,000	39,000,000	
(1) The amount recorded in 2005 included the following			
Repayment of principal of $1.5million Cornell advance from 2004			1,500,000
Repayment of principal of $15million Cornell promissory note from 2005			7,800,000
Payment of offering costs with proceeds from SEDA			994,757
Payment of interest on the $1.5million Cornell advance from 2004			32,548
Issue of common stock pursuant to SEDA			10,327,305
There was no cash for income taxes for the years ended December 31, 2007, 2006 and 2005.			
Reclassification temporary equity			1,396,250
Cash paid for interest expense	1,762,944	3,436,117	621,644

NOTE 20 STOCK-BASED COMPENSATION PLANS

At December 31, 2007, stock options and warrants had been issued from the following stock based compensation plans:

<u>1995 Long-Term Incentive Plan (1995 Plan</u>). The 1995 Plan was approved by our stockholders at the annual meeting of stockholders held on February 6, 1996.This Plan allows for up to 7,500,000 shares of the Company s common stock to be issued to officers, directors, employees, consultants and advisors pursuant to the grant of stock based awards, including qualified and non-qualified stock, options, restricted stock, stock appreciation rights and other stock based performance awards. As of December 31, 2007, options to acquire an aggregate of 739,000 shares of common stock had been granted under this Plan and were outstanding all of which are 100% vested. The Plan expired on November 13, 2005. The awards have a term of 5 years from date of issue and vest immediately.

<u>The Amended and Restated CanArgo Energy Inc. Plan (the CEI Plan</u>). The CEI Plan (also known as the CAOG Plan) was adopted by the Company s Board of Directors on September 29, 1998. All Options outstanding under the Plan as of July 15, 1998 were assumed by the Company pursuant to the terms of an Amended and Restated Combination Agreement between the Company and CanArgo Energy Inc. dated

February 2, 1998 which was approved by the Company s stockholders on July 8, 1998. This Plan allowed for up to 1,250,000 shares (of which only 988,000 shares were registered) of the Company s common stock to be issued to any director or full-time employee of the Company or a subsidiary of the Company. As of December 31, 2007, five year options to acquire an aggregate of

130,000 shares of common stock had been granted under this Plan and were outstanding of which 55,000 are currently 100% vested. The awards have a term of 5 years from date of issue, each award having a special vesting provision defined in the award.

Special Stock Options and Warrants. This plan was created to allow the Company to retain and provide incentives to existing executive officers and directors and to allow retirement of new officers and directors following the Company s decision to relocate finance and administration functions from Calgary, Canada to London, England. As of December 31, 2007, no special stock options and warrants issued under this plan were outstanding.

2004 Long Term Stock Incentive Plan (2004 Plan). The 2004 Plan was approved by our stockholders at the annual meeting of stockholders held on May 18, 2004. This Plan allows for up to 17,500,000 shares of the Company s common stock to be issued to officers, directors, employees, consultants and advisors pursuant to the grant of stock based awards, including qualified and non-qualified stock options, restricted stock, stock appreciation rights and other stock based performance awards. As of December 31, 2007, seven year options to acquire an aggregate of 7,477,000 shares of common stock had been granted under this Plan and were outstanding, 7,050,333 of which vested at that date. The 2004 Plan will expire on May 17, 2014, although the Board of Directors may terminate the 2004 Plan at any time prior to that date. The awards have a term of 7 years from date of issue and vest 1/3 for each year, with the first 1/3 vesting immediately.

The purpose of the Company s stock option plans is to further the interest of the Company by enabling officers, directors, employees, consultants and advisors of the Company to acquire an interest in the Company by ownership of its stock through the exercise of stock options and stock appreciation rights granted under its various stock option plans.

A summary of the status of stock options granted under the Company s plans are as follows:

	Shares Issuable Under Outstanding Options	Weighted Average Exercise Price
Balance, December 31, 2004	10,472,833	0.56
Options (1995 Plan):		
Granted at market		
Exercised	(1,477,500)	0.13
Expired		
CAOG Plan Authorization:		
Granted at market		
Exercised	(305,000)	0.22
Expired		
Special Stock options and warrants:		
Increase in shares available for issue		
Granted at market		
Exercised	(1,118,333)	0.83
Expired	(275,000)	1.44
Options (2004 Plan):		

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	Shares Issuable Under Outstanding Options	Weighted Average Exercise Price
Increase in shares available for issue		
Granted at market	3,129,000	1.03
Exercised	(381,000)	0.65
Expired		
Balance, December 31, 2005	10,045,000	0.72
Options (1995 Plan):		
Granted at market		
Exercised	(220,000)	0.65
Expired		
Options (2004 Plan):		
Increase in shares available for issue		
Granted at market	420,000	1.03
Exercised	(554,000)	0.79
Expired	(60,000)	1.00
Balance, December 31, 2006	9,631,000	0.73
Options (1995 Plan):		
Granted at market		
Exercised	(495,000)	0.10
Expired		
Options (CEI Plan):		
Granted at market		
Exercised	(90,000)	0.10
Expired		
Special Stock options and warrants:		
Granted at market		
Exercised	(535,000)	0.10
Expired		
Options (2004 Plan):		
Increase in shares available for issue		
Granted at market	280,000	0.85
Exercised	(355,000)	0.90
Expired	(90,000)	1.47
Balance, December 31, 2007	8,346,000	0.80

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Shares issuable upon exercise of vested options and the corresponding weighted average exercise price are as follows:

	Shares Issuable Under Exercisable Options	Weighted Average Exercise Price
December 31, 2005	5,938,000	$ 0.63
December 31, 2006	8,458,000	$ 0.68
December 31, 2007	7,844,333	$ 0.79

The weighted average fair value of options granted during the year was $0.54, $1.03 and $0.83 for the years ended December 31, 2007, 2006 and 2005 respectively.

The number and weighted average grant-date fair value of non-vested options as at January 1, 2007 was 1,173,000 and $0.81 respectively. The number and weighted average grant-date fair value of options vested during 2007 was 921,333 and $0.99 respectively. The number and weighted average grant-date fair value of non-vested options as at December 31, 2007 was 501,667 and $0.98 respectively.

The number and weighted average grant-date fair value of non-vested options as at January 1, 2006 was 4,147,000 and $0.68 respectively. The number and weighted average grant-date fair value of options vested during 2006 was 3,249,000 and $0.64 respectively. The number and weighted average grant-date fair value of non-vested options as at December 31, 2006 was 1,173,000 and $0.81 respectively.

The total intrinsic value of options exercised during each of the years ended December 31, 2007, 2006 and 2005 were $779,320, $389,320 and $3,056,721 respectively.

As of December 31, 2007 total compensation cost related to non-vested options not yet recognized is $140,950 and this cost will be recognized over a weighted average period of 9 months.

We received cash proceeds of $430,600 from the exercise of options during the year ended December 31, 2007.

All share options plans are approved by the shareholders and a registration statement is subsequently filed with the SEC resulting in the issue of new shares by the company when options are exercised.

We used the black-scholes option pricing model using the following assumptions to determine the fair value of the options issued under our plans during the following years:

	2007	2006	2005
Stock price on date of grant	$0.77	$ 0.91	$ 0.97
Risk free rate of interest	4.47%	4.88%	4.16%
Expected life of warrant-months	84	84	84
Dividend rate	0%	0%	0%
Historical volatility	74.2%	94.43%	109.49%

The numbers above reflect the weighted average for the options issued during the year.

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The following table summarizes information about stock options outstanding at December 31, 2007:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Shares Outstanding at December 31, 2007	Weighted Average Remaining Term	Weighted Average Exercise Price	Number Of Shares Exercisable at December 31, 2007	Weighted Average Exercise Price
$0.60 to $0.90	5,552,000	3.86	0.66	5,290,333	0.66
$0.90 to $1.42	2,794,000	4.48	1.05	2,554,000	1.05
$0.00 to $1.42	8,346,000	4.07	0.80	7,844,333	0.79

The following table summarizes additional information about stock options outstanding at December 31, 2007:

Range of Exercise Prices	Options Outstanding Aggregate Intrinsic Value of Shares Outstanding at December 31, 2007	Options Exercisable Aggregate Intrinsic Value Of Shares Exercisable at December 31, 2007
$0.60 to $0.90	1,380,682	1,314,499
$0.90 to $1.42		
$0.60 to $1.42	1,380,682	1,314,499

NOTE 21 RELATED PARTY TRANSACTIONS

CanArgo s ownership of Tethys was diluted in stages during the year ended December 31, 2007 from 100% ownership on December 31, 2006 through to disposing of its remaining shareholding on August 3, 2007. On June 27, 2007 Tethys announced that it had completed its initial public offering through the issuance of approximately 18.2 million shares on the Toronto Stock Exchange reducing the Company s ownership to approximately 17.7% and Dr. David Robson stepped down from the position of Chief Executive Officer of the Company but remained as Chairman of the Company. Dr David Robson is Chairman, President and Chief Executive Officer of Tethys. CanArgo s former Corporate Secretary, Elizabeth Landles, is Administration Director of Tethys. CanArgo and Tethys shared some common resources in 2007 including corporate secretarial and investor relations services.

Dr. David Robson, Chief Executive Officer of CanArgo until June 27, 2007 and Non-Executive Chairman thereafter, provided all of his services to CanArgo through Vazon Energy Limited, a corporation organized under the laws of the Bailiwick of Guernsey (Vazon), of which he is the sole owner and Managing Director. In addition management services agreements exists between CanArgo and Vazon Energy whereby the services of Mrs. Landles (former Corporate Secretary & Executive Vice President) amongst others, are provided to CanArgo. Approximately $775,000 was paid to Vazon in 2007 in respect of these services which included flow through costs for employees and consultants.

On June 7, 2005, CanArgo made an offer to acquire 55% of the ordinary share capital of Tethys which was held by Provincial and Vando for consideration of 11,000,000 CanArgo common shares. On June 9, 2005 CanArgo issued 5,500,000 shares to Provincial, of which Russell Hammond (one of our non-executive directors) is Investment Advisor in connection with this transaction.

Mr. Russell Hammond, a non-executive director of CanArgo, is also an Investment Advisor to Provincial Securities Limited who became a minority shareholder in the Norio and North Kumisi Production Sharing Agreement through a farm-in agreement to the Norio MK72 well. On September 4, 2003 we concluded a deal to purchase Provincial Securities Limited s minority interest in CanArgo Norio Limited by a share swap for shares

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in CanArgo. Provincial Securities Limited received 2,234,719 shares of CanArgo common stock in relation to the transaction. Provincial Securities Limited also had an interest in Tethys Petroleum Investments Limited which was sold in June 2005 to us by a share exchange for shares in CanArgo. Provincial Securities Limited received 5,500,000 shares of CanArgo common stock in relation to the transaction, Transactions with affiliates or other related parties including management of affiliates are to be undertaken on the same basis as third party arms-length transactions.

Transactions with affiliates are reviewed and voted on solely by non-interested members of the board of directors.

NOTE 22 SUBSEQUENT EVENTS

On February 7, 2008, the Company announced that Dr. David Robson had tendered his resignation from the positions of Non-Executive Chairman and Non-Executive Director of the Board of CanArgo with immediate effect. Vazon Energy Limited received a payment, through, of approximately $60,000 in settlement of the remaining six month notice period under Dr. Robson s service agreement. Vincent McDonnell became acting Chairman of the Board in addition to his duties as President and Chief Executive Officer.

Effective February 11, 2008, Elizabeth Landles, resigned from the position of Corporate Secretary of the Company. Also Effective February 11, 2008 Jeffrey Wilkins has been appointed to the position of Corporate Secretary in addition to his current duties as Chief Financial Officer and Executive Director.

Effective September 24, 2007, Nils Trulsvik, Non Executive Director, stepped down from the CanArgo Board with immediate effect due to potential conflict of interest in respect of other oil and gas companies in which he is involved. The Company also appointed Mr. Jeffrey Wilkins to the position of Executive Director on the Board of the Company in addition to his current duties as Chief Financial Officer.

On September 27, 2007, the Company advised the American Stock Exchange (the AMEX) by correspondence of its Board changes announced September 24, 2007 and at the same time acknowledged that the Company was not in compliance with Sections 121 (A)(1) and Section 121(B)(2)a of the AMEX Company Guide, which require, respectively, that at least a majority of the directors comprising the Board of Directors are independent and that the Company s audit committee be comprised of at least three independent directors. Specifically, the Company currently only had two independent directors of the five directors on the Company s Board of Directors and an audit committee composed of only two members. On September 27, 2007, the Company also received notice from the AMEX that since the Company was not in compliance with Sections 121 (A)(1) and 121(B)(2)a of the Company Guide, it had until December 27, 2007 to regain compliance with these requirements.

On January 8, 2008, the Company received a deficiency letter from the AMEX advising the Company that in view of its continued non compliance with Section 121(A)(1) and Section 121(B)(2)a of the continued listing standards of the AMEX Company Guide it had until January 18, 2008 to submit a plan to the Exchange of steps it has taken, or will take, in order to regain compliance with these requirements by no later than April 4, 2008. The Company submitted a plan to the Staff of the AMEX, which included an explanation that the Company has been liaising with a specialist recruiting agency and taking independent steps to find candidates with the necessary qualifications to comply with the requirements of the listing standards.

On February 14, 2008 the Company was advised by the AMEX that its listing is being continued until April 4, 2008. As previously disclosed the Company had submitted a plan to the Staff of the AMEX and the AMEX has determined that the Company has made a reasonable demonstration of its ability to regain compliance with the continued listing standards by the end of the plan period. The AMEX determined that the end of the plan period is to be April 4, 2008.

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NOTE 23 QUARTERLY FINANCIAL DATA (Unaudited)

	2007 First Quarter	2007 Second Quarter	2007 Third Quarter	2007 Fourth Quarter
Operating revenue from continuing operations	$ 446,847	$ 2,915,000	$ 32,961	$ 3,813,858
Operating income (loss) from continuing operations	(1,954,861)	(503,907)	(2,197,196)	(41,924,860)
Net income (loss) from continuing operations	(4,091,403)	(8,645,420)	(9,903,798)	(42,673,965)
Net income (loss) from discontinued operations, net of taxes	(2,205,217)	13,389,959	(55,873)	43,687
Net income (loss)	(5,931,803)	4,744,539	(9,959,671)	(42,630,278)
Net income (loss) per common share basic and diluted from continuing operations	(0.02)	(0.04)	(0.04)	(0.18)
Net income (loss) per common share basic and diluted from discontinued operations	(0.00)	0.06	(0.00)	0.00
Net income (loss) per common share basic and diluted	(0.02)	(0.02)	(0.04)	(0.18)

	2006 First Quarter	2006 Second Quarter	2006 Third Quarter	2006 Fourth Quarter
Operating revenue from continuing operations	$ 698,945	$ 1,303,132	$ 2,090,147	$ 2,434,436
Operating income (Loss) from continuing operations	(3,090,043)	(2,694,504)	(2,182,546)	(40,551,589)
Net income (loss) from continuing operations	(4,077,990)	(4,335,303)	(4,226,407)	(41,791,997)
Net income (loss) from discontinued operations, net of taxes	(1,381,152)	1,630,267	(1,491,710)	(4,866,559)
Net income (loss)	(5,459,142)	(2,705,036)	(5,718,117)	(46,658,556)
Net income (loss) per common share basic and diluted from Continuing operations	(0.02)	(0.02)	(0.02)	(0.31)
Net income (loss) per common share basic and diluted from discontinued operations	(0.01)	0.01	(0.01)	(0.04)
Net income (loss) per common share basic and diluted	(0.02)	(0.01)	(0.03)	(0.35)

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NOTE 24 SUPPLEMENTAL OIL AND GAS DISCLOSURE (Unaudited)

ESTIMATED NET QUANTITIES OF OIL AND GAS RESERVES

Users of this information should be aware that the process of estimating quantities of proved and proved developed natural gas and crude oil reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved reserves are estimated quantities of natural gas, crude oil and condensate that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs with existing equipment under existing economic and operating conditions.

Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and under existing economic and operating conditions.

Oil and gas reserves

The following tables set forth our net proved oil and gas reserves, including the changes therein, and net proved developed reserves at December 31, 2006, as estimated by the independent petroleum engineering firm, Oilfield Production Consultants Limited for Georgia:

Net Proved Developed and Undeveloped Reserves Oil (In Thousands of Barrels):

	2007	2006	2005
January 1	2,196	3,514	4,076
Purchase of properties			
Revisions of previous estimates	(552)	(1,198)	(410)
Extension, discoveries, other additions			
Production	(106)	(120)	(152)
Disposition of properties			
December 31	1,538	2,196	3,514
Net Proved Developed Oil Reserves December 31, 2007	901		

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Net Proved Developed and Undeveloped Reserves Gas (In Million Cubic Feet) Georgia

	2007	2006	2005
January 1	1,825	1,599	1,703
Purchase of properties			
Revisions of previous estimates	215	709	
Extension, discoveries, other additions			
Production	(410)	(483)	(104)
Disposition of properties			
December 31	1,630	1,825	1,599
Net Proved Developed Gas Reserves December 31, 2007	1,249		

Net proved oil reserves in Georgia consisted of the following at December 31:

	2007		2006	
	Oil Reserves Gross (MSTB)	PSC Entitlement Volumes (MSTB) (1)	Oil Reserves Gross (MSTB)	PSC Entitlement Volumes (MSTB) (1)
Proved Developed Producing	1,386	901	1,811	1,177
Proved Undeveloped	979	637	1,568	1,019
Total Proven	2,365	1,538	3,379	2,196

Net proved gas reserves in Georgia consisted of the following at December 31:

	2007		2006	
	Gas Reserves Gross (MMCF)	PSC Entitlement Volumes (MMCF) (1)	Gas Reserves Gross (MMCF)	PSC Entitlement Volumes (MMCF) (1)
Proved Developed Producing	1,921	1,249	1,885	1,225
Proved Undeveloped	587	381	923	600
Total Proven	2,508	1,630	2,808	1,825

(1) PSC Entitlement Volumes attributed to CanArgo are calculated using the economic interest method applied to the terms of the production sharing contract. PSC Entitlement Volumes are those produced volumes which, through the production sharing contract, accrue to the benefit of Ninotsminda Oil Company after deduction of Georgian Oil s share which includes all Georgian taxes, levies and duties. As a result of CanArgo s interest in Ninotsminda Oil Company, these volumes accrue to the benefit of CanArgo for the recovery of capital, repayment of operating costs and share of profit.

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Results of continuing operations for oil and gas producing activities

Results of continuing operations for oil and gas producing activities, all in Georgia, for 2007, 2006 and 2005 are as follows:

Year Ended December 31, 2007	Georgia
Revenues	$ 7,208,666
Operating expenses	1,370,153
Depreciation, depletion and amortization	2,411,500
Impairment of oil and gas properties	42,000,000
Operating Income (Loss)	(38,572,987)
Income tax provision	
Results of Continuing Operations for Oil and Gas Producing Activities	$ (38,572,987)

Year Ended December 31, 2006	Georgia
Revenues	$ 6,526,660
Operating expenses	1,702,679
Depreciation, depletion and amortization	3,388,134
Impairment of oil and gas properties	38,400,000
Operating Income (Loss)	(36,964,153)
Income tax provision	
Results of Continuing Operations for Oil and Gas Producing Activities	$ (36,964,153)

Year Ended December 31, 2005	Georgia
Revenues	$ 5,278,912
Operating expenses	1,109,588
Depreciation, depletion and amortization	2,651,053
Impairment of oil and gas properties	
Operating Income (Loss)	1,518,271
Income tax provision	
Results of Continuing Operations for Oil and Gas Producing Activities	$ 1,518,271

Georgia was the only country where we had oil and gas producing activities for 2007, 2006 and 2005.

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Costs incurred for oil and gas property acquisition, exploration and development activities

Costs incurred for oil and gas property acquisition, exploration and development activities for 2007, 2006 and 2005 are as follows:

Year Ended December 31, 2007	Georgia
Property Acquisition	
Unproved (1)	$
Proved	
Exploration	7,509,999
Development	858,271
Total costs incurred	$ 8,368,270

Year Ended December 31, 2006	Georgia
Property Acquisition	
Unproved (1)	$
Proved	
Exploration	21,851,057
Development	1,998,556
Total costs incurred	$ 23,849,613

Year Ended December 31, 2005	Georgia
Property Acquisition	
Unproved (1)	$
Proved	
Exploration	16,012,465
Development	18,828,582
Total costs incurred	$ 34,841,047

(1) These amounts represent costs incurred by CanArgo and excluded from the amortization base until proved reserves are established

or impairment is
determined.

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Aggregate Capitalized Costs

Capitalized costs relating to Oil and Gas Activities is as follows:

December 31, 2007 (in thousands)	Georgia
Proved	$ 145,983
Unproved	9,445
Total capitalized Costs	155,428
Accumulated depreciation, depletion, impairment and amortization	(112,201)
Net capitalized costs	$ 43,227

December 31, 2006 (in thousands)	Georgia
Proved	$ 53,679
Unproved	55,097
Total capitalized Costs	108,776
Accumulated depreciation, depletion, impairment and amortization	(67,608)
Net capitalized costs	$ 41,168

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

The following information has been developed utilizing procedures prescribed by SFAS No. 69 *Disclosure about Oil and Gas Producing Activities* (SFAS 69) and based on crude oil reserve and production volumes estimated by the Company s engineering staff. It may be useful for certain comparative purposes, but should not be solely relied upon in evaluating the Company or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of the Company.

CanArgo believes that the following factors should be taken into account in reviewing the following information: (1) future costs and selling prices will probably differ from those required to be used in these calculations; (2) actual rates of production achieved in future years may vary significantly from the rate of production assumed in the calculations; (3) selection of a 10% discount rate is arbitrary and may not be reasonable as a measure of the relative risk inherent in realizing future net oil and gas revenues; and (4) future net revenues may be subject to different rates of income taxation.

Under the Standardized Measure, future cash inflows were estimated by applying period-end oil prices adjusted for fixed and determinable escalations to the estimated future production of period-end proven reserves. Future cash inflows were reduced by estimated future development, abandonment and production costs based on period-end costs in order to arrive at net cash flow before tax. Future income tax expenses has been computed by

applying period-end statutory tax rates to aggregate future pre-tax net cash flows, reduced by the tax basis of the properties involved and tax carryforwards. Use of a 10% discount rate is required by SFAS No. 69.

Management does not rely solely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proven reserves and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

Standardized measure of discounted future net cash flows relating to proved oil and gas reserves

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves for Georgia is as follows:

	December 31		
(In Thousands)	2007	2006	2005
Future cash inflows	$133,874	$110,443	$179,340
Less related future:			
Production costs	43,518	28,668	26,406
Development and abandonment costs	8,250	7,120	18,808
Future net cash flows before income taxes	82,106	74,655	134,126
Future income taxes		(4,091)	(6,567)
Future net cash flows (1)	82,106	70,564	127,559
10% annual discount for estimating timing of cash flows	(38,657)	(37,419)	(51,056)
Standardized measure of discounted future net cash flows	$ 43,449	$ 33,145	$ 76,503

(1) In Georgia, future cash flows are based on PSC Entitlement Volumes attributed to CanArgo using the economic interest method applied to the terms of the production sharing contract. PSC Entitlement Volumes are those produced volumes which,

through the production sharing contract, accrue to the benefit of Ninotsminda Oil Company Limited after deduction of Georgian Oil s share which includes all Georgian taxes, levies and duties. As a result of our interest in Ninotsminda Oil Company Limited, these volumes accrue to the benefit of CanArgo for the recovery of capital, repayment of operating costs and share of profit.

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A summary of the changes in the standardized measure of discounted future net cash flows applicable to proved oil and gas reserves for Georgia is as follows:

	December 31		
In Thousands	2007	2006	2005
Beginning of year	$ 33,144	$ 76,502	$ 46,411
Purchase (sale) of reserves in place			
Revisions of previous estimates	(33,363)	(38,635)	(13,209)
Development costs incurred during the period	1,988	(9,689)	27,437
Additions to proved reserves resulting from Extensions, discoveries and improved			
Recovery			
Accretion of discount	3,314	7,650	4,641
Sales of oil and gas, net of production costs	(5,839)	(4,824)	(3,495)
Net change in sales prices, net of Production costs	35,731	(8,269)	56,113
Changes in production rates (timing) and other	8,474	10,409	(41,396)
Net increase (decrease)	10,305	(43,358)	30,091
End of year	43,449	$ 33,144	$ 76,502

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