CANARGO ENERGY CORP
Form 10-K/A
August 31, 2004

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**UNITED STATES SECURITIES AND EXCHANGE COMMISSION**

**Washington, D.C. 20549**

**FORM 10-K/A**

(Amendment No. 3)

FOR ANNUAL AND TRANSITION REPORTS
PURSUANT TO SECTIONS 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

[ X ] ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE FISCAL YEAR ENDED DECEMBER 31, 2003

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 **0001-32145**

**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:
**None**

Securities Registered Pursuant to Section 12(g) of the Act:

**Common Stock, par value $0.10 per share**

(Title of Class)

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 [X] 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 herein by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

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, 105,798,421 shares outstanding as of February 29, 2004.

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Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act).

YES [ ] NO [X]

The aggregate market value of the Registrant s common stock held by-non-affiliates was approximately $16.5 million as of June 30, 2003, based upon the last reported sales price of such stock on the Over The Counter Bulletin Board on that date. For this purpose, the Registrant considers Dr. David Robson and Nils Trulsvik to be its only affiliates.

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the Registrant s definitive Proxy Statement issued in connection with its 2004 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.

**EXPLANATORY NOTE**

CanArgo Energy Corporation is hereby amending this Annual Report on Form 10-K for the fiscal year ended December 31, 2003 to amend in full Item 1 *Business* and Item 2 *Properties* of Part I and Item 7 *Management s Discussion and Analysis of Financial Condition and Results of Operations* of Part II of the Report.

Except for the foregoing items, no other information included in the original Annual Report on Form 10-K is amended by this amendment.

## PART I

Item 1 *Business* of this Annual Report on Form 10-K is hereby amended and restated in full as follows:

## ITEM 1. BUSINESS

### General Development of Business

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

Our principal activities are oil and gas exploration, development and production of oil and gas, principally in the Republic of Georgia, and to a lesser extent in Kazakhstan and Ukraine although in 2003 we approved a plan to dispose of our interests in Ukraine. However in late 2000 CanArgo also began to engage in oil and gas marketing and refining activities in Georgia. In November 2000, CanArgo acquired a 51% interest in Georgian American Oil Refinery company which owns a refurbished American refinery with a design capacity of approximately 4,000 barrels per day. Shortly thereafter, in December 2000, CanArgo expanded its interest in Georgia to include a 50% controlling interest in CanArgo Standard Oil Products with the objective of developing within Georgia a chain of retail petrol stations. These have now been sold, conditional upon receiving the agreed purchase price from the buyer. Regardless of these investments, CanArgo continues to direct most of its efforts and resources to the development of its Georgian exploration program and the Ninotsminda Field. In February 2004, CanArgo disposed of its interest in the Georgian American Oil Refinery.

**Exploration, Development and Production Activities**

In Georgia our exploration, development and production activities are carried out under four production sharing contracts ( PSC ), 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.

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Ninotsminda Oil Company Limited is a wholly owned subsidiary of CanArgo. This PSC covers an area of approximately 27,739 acres (113 $km^2$);

2. The Nazvrevi and Block XIII Production Sharing Contract ( Nazvrevi PSC ) 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 388,450 acres (1,572 $km^2$);

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 will be reduced to 85% following completion of a farm-in by the state oil company, Georgian Oil, to the MK72 well, and potentially to 50% if Georgian Oil exercises its option under that farm-in agreement. CanArgo Norio Limited is currently 75% owned by CanArgo. This PSA covers an area of approximately 378,523 acres (1,542 $km^2$); and

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 currently 75% owned by CanArgo. This PSC covers an area of approximately 119,843 acres (485 $km^2$).

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 States taxes, levies and duties. PSCs are a common form of oil and gas exploration and production contract in many parts of the world.

**Ninotsminda Field**

Since completion of the business combination with CanArgo Oil & Gas Inc., our resources have, through our wholly owned subsidiary Ninotsminda Oil Company, been focused on the development of the

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Ninotsminda Field and related exploration activities. 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. The Ninotsminda Field was discovered later than the Samgori Field and has experienced substantially less development activity. Georgian Oil and others, including Ninotsminda Oil Company, have drilled thirty-six wells in the Ninotsminda Field, of which nine are currently producing.

We believe the Ninotsminda PSC area both outside of and beneath the currently producing reservoirs of the Ninotsminda Field has significant additional exploration potential and we have invested substantial funds in exploring this area.

### Other Projects

We also have additional exploratory and developmental oil and gas properties and prospects in Georgia and Ukraine and we own interests in other oil and gas projects in the former Soviet Union. However, during 2003, the company decided to dispose of its Ukrainian assets in order to focus on its business in Georgia. At the end of 2003, CanArgo had sold its interest in its west Ukrainian project and was in negotiations with a buyer for the sale of its interest in the Bugruvativske Field in eastern Ukraine. Our principal product is crude oil, and the sale of crude oil and crude oil products is our principal source of revenue.

### Business Structure

CanArgo and its principal active subsidiaries are as follows:

CanArgo s activities at the Ninotsminda Field are conducted through Ninotsminda Oil Company Limited, a Cypriot corporation ( NOC ). Initially CanArgo had a partner in NOC named JKX Oil & Gas plc ( JKX ) however in May 2000, we reached an agreement with JKX to acquire its final 21.2% interest in NOC for a direct equity interest in CanArgo. In July 2000, this transaction was completed and NOC became our

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wholly owned subsidiary. In November 1999, we increased our percentage ownership of NOC from 68.5% to 78.8% when JKX chose not to subscribe for it s pro rata portion of shares being offered to increase NOC capital.

NOC obtained its rights to the Ninotsminda Field, including all existing wells, one other field 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 CanArgo 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 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 2006 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 $XI^E$. NOC pays 100% of the costs incurred in the project as the sole contractor party under the Ninotsminda PSC. The balance of Production is allocated on a 70/30 basis between Georgian Oil and NOC respectively. While NOC continues to have unrecovered costs, it will receive 65% of Production (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 Republic 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 gas is marketed jointly.

Until the end of 2001, Georgian Oil had a priority right to receive oil representing a projection of what the Ninotsminda Field would have yielded based upon the wells and equipment in use at the time the contract was entered into. This priority right has now ceased.

Pursuant to the terms of CanArgo s PSCs in Georgia, including the Ninotsminda PSC, a Georgian not-for-profit company must be appointed as field operator. Currently there are three such field operating companies, relating to CanArgo s four PSC s: 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. The field operator provides the operating personnel and is responsible for day-to-day operations. 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. Georgian British Oil Company Ninotsminda currently has 114 full time employees and substantially all of its activities relate to the development of the Ninotsminda Field. The use of such Georgian companies as field operator gives us less control of operations than we might otherwise have if we were conducting operations directly, although we do have board control of these field operating companies.

Operations under each of the PSCs are determined by a governing body ( Co-ordinating Committee ) composed of members designated by the respective CanArgo company and Georgian Oil, with the deciding vote on field development issues allocated to us. If Georgian Oil believes that action proposed by CanArgo with which Georgian Oil 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.

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**Ninotsminda, Manavi and West Rustavi Production Sharing Contract**

Production from the Ninotsminda Field was minimal when NOC assumed developmental responsibility for the Field in 1996. We believed that the development and production obtainable from the Ninotsminda Field had in the past been hampered by, among other factors, a lack of funding, civil strife and utilization of old technology and methods.

NOC s initial approach to the Ninotsminda Field development was to produce oil from one zone or underground formation, the Middle Eocene. This development included repairing and adding perforations to existing wells, obtaining additional seismic data and a limited drilling program. The first new well (named N96) was completed in October 1997 and initially produced at the rate of 400 to 600 barrels of oil per day and has recently been re-completed as a horizontal producer. A second well (N98) was completed in October 1998, and sidetracked as a horizontal producer in 2000 and has produced 279,690 barrels of oil to date.

A third oil well commenced in October 1998 (named N97) but drilling was suspended in December 1998 at a depth of 3,258 feet (993 meters) as a result of an undependable supply of electricity. Drilling of this well recommenced in July 2000 as a potential gas condensate exploration well for the deep Cretaceous zone but in October 2000, we announced that as a result of difficult drilling conditions, the well could not be completed to the Cretaceous target as originally planned but rather would be tested in the newly identified shallower Sarmatian zone. This well tested at rates up to 130 barrels of oil per day, but production declined quickly, and this zone requires further analysis to assess its full potential. This well awaits either further completion in the shallow zones utilizing other completion techniques, or else utilization as a horizontal producer in the Middle Eocene zone. We undertook further work to assess the potential of these shallow zones in the Ninotsminda Field, with the sidetracking of the previously mechanically suspended N78 well (Oligocene formation), and the recompletion of the N59 well (Upper Eocene formation). N78z initially flowed at some 660 barrels of oil per day, but has since declined significantly due to a decrease in reservoir pressure and sand production similarly N59 has also declined and is currently shut-in. Further analysis is required to assess the full potential of these oil bearing upper zones in the Ninotsminda Field, in particular on completion techniques for these formations. Such studies may, however, also open up new potential in the upper zones of this and other areas currently under license in Georgia.

In January 2003, in order to increase production at the Ninotsminda Field and further improve working capital, drilling of a new horizontal sidetrack well, N4H, commenced targeting an existing producing reservoir of Middle Eocene age. The well is a horizontal sidetrack from an existing well bore in the Middle Eocene reservoir at approximately 2,356 meters. The horizontal production section extends for a total distance of 400 meters in the west central area of the Field between the N4 and N9 wells. The well was successfully completed and originally put on production at over 1,000 barrels of oil per day (bopd) in April 2003. It was later reduced to approximately 500 bopd to ensure optimal total production produced from the well on the advice of an independent petroleum engineering consultant. Drilling commenced on an additional horizontal sidetrack well, N100H, in August 2003. This well was successfully completed in September 2003. It was drilled along a similar orientation to the N4H well along the crestal part of the Ninotsminda Field where the most fracturing is believed to occur, and into an area of the reservoir that has not yet been drained. The well tested at rates of over 2,000 bopd but has been put on production at a lower rate. In December 2003, a third horizontal well, N96H horizontal well drilled in the west central part of the Field was completed with test flow rates in excess of 1,200 bopd.

Independent petroleum engineering specialists recommend that the optimal long-term production rate for horizontal wells be of the order of 500 bopd per well. In order to maximise productivity and recoverability from the Field, wells are being choked back to the approximate recommended levels while it is planned that future horizontal wells should be drilled under-balanced (i.e., producing while drilling). This requires a specialist unit, and discussions are underway with several international service companies who supply such equipment.

Once the under-balanced specialist drilling equipment is on the Field, several additional horizontal well bores will be drilled. These include N22H and N30H, which were previously planned to be drilled using conventional drilling techniques. A second horizontal well (N100H2 east horizontal) will be drilled from the N100 well bore, and a decision is currently being made as to whether this will be drilled using conventional techniques (CanArgo Rig#2 is mobilized to the well), or using under-balanced coiled tubing drilling. The N100H1 (west horizontal), which is currently producing approximately 500 bopd, was drilled from the N100 well in 2003. We believe that the planned N100H2 (east horizontal) will be the first multilateral well to be drilled in the Caucasus. A new well (N99) is included in the program; this well will be designed so as to have up to three multilateral horizontal wells drilled from it. These will be drilled into the eastern part of the Field, an area that is currently largely undeveloped. It is expected that a suitable under-balanced drilling unit will arrive in Georgia by August 2004. The advancement of the horizontal program is being rescheduled until such a unit is in place.

The completion of a dynamic reservoir model during the year and the implementation of the successful development program based on horizontal drilling have resulted in a significant increase in recoverable oil reserves at the Ninotsminda Field. A report prepared by Oilfield Production Consultants, an independent firm of consulting petroleum engineers dated January 1, 2004 shows year-end 2003 gross total proved oil reserves at the Ninotsminda Field were 6.762 million barrels (MMbbl) up 63% from 2002 s 4.15 MMbbl. Over the same period, gross total proved natural gas reserves, on an energy equivalent basis, decreased from 1.34 million barrels of oil equivalent (MMboe) to 0.51 MMboe. See Properties-*Reserves* and Business Risks Associated with CanArgo s Oil and Gas Activities below for a discussion of the inherent possibility of imprecision in estimating reserves. The recovery of these reserves is dependent on application of optimal production levels for the Ninotsminda wells and further application of horizontal drilling techniques utilizing under-balanced drilling techniques.

While most of the exploration and development of the Ninotsminda Field prior to 2000 focused on oil, a layer of gas above the oil or gas cap was known to exist above the principal producing zone. In December 1999, NOC began commercial production of this gas cap following regulatory approval from the Georgian government. This production was sold pursuant to a gas contract with AES Telasi, a subsidiary of the US based AES Corporation, for delivery to the Gardabani thermal power plant. Under terms of the gas contract, AES-Telasi had agreed to purchase all the gas produced from the Ninotsminda Field in priority to all other suppliers with no maximum or minimum volume. AES continued to purchase gas from NOC on similar contractual terms during 2000 and into 2001.

With increases in demand for natural gas produced in Georgia, in 2001 NOC commenced the first and second wells of a planned three-well exploration program to explore and determine the future development potential of gas condensate prospects in the Ninotsminda area, particularly focused on the potential in the deeper Cretaceous sequence.

In 2000, the Cretaceous exploration program was initiated under a Participation Agreement with AES Gardabani (also a subsidiary of AES Corporation) relating to the exploration and potential future development of Sub Middle Eocene gas prospects in parts of the Ninotsminda PSC. Under the Participation Agreement, AES Gardabani was to earn a 50% interest in identified prospects at the Sub Middle Eocene stratigraphic level (rocks older than the Middle Eocene sequence i.e., below the producing horizons of the Ninotsminda Field) by funding two thirds of the cost of a three-well exploration program. However, prior to completion of the exploration program as defined in the Participation Agreement, AES indicated in January 2002 that it wished to withdraw from the Participation Agreement in order to focus on its core business. In February 2002, the Participation Agreement with AES was terminated without AES earning any rights to any of the Ninotsminda Field reservoirs. Under a separate Letter Agreement, if gas from the Sub Middle Eocene is discovered and produced, AES will be entitled to recover at the rate of 15% of future gas sales from the Sub Middle Eocene, net of operating costs, their funding under the Participation Agreement. AES also has an option to enter into a five year take or pay gas sales agreement for a quantity up to 200 million cubic meters per year at an initial contract price of $1.30 per thousand cubic feet ($46.00 per thousand cubic meters).

In January 2002, the first well drilled under the Participation Agreement, N100, reached a depth of 16,165 feet (4,927 meters) without having reached the targeted Cretaceous zone. The well was terminated at this depth because of lack of funding caused by the withdrawal of AES from the project, and for mechanical reasons, having penetrated a significant thickness of hydrocarbon bearing sandstones belonging to the

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Lower Eocene and Palaeocene sequences. Three formation tests were carried out on these sandstones, these tests recovering 35° API (SG 0.85) oil, but without commercial flow, despite the installation of a down hole progressive cavity pump. We have concluded that the reason for the lack of commercial flow was either that the zone was of low permeability, or that it suffered formation damage due to the mud used to drill the well. Potential still remains in this sequence but the N100 well was recompleted in 2003 as a Middle Eocene horizontal oil producer. Future plans are to drill a further horizontal well in the Middle Eocene from the N100 well bore, this then becoming the first multi-lateral drilling carried out in Georgia.

*Manavi*

The second well drilled under the Participation Agreement, Manavi well M11, was targeting a large Cretaceous prospect in the Manavi area, east of the Ninotsminda Field, with further potential in the Middle Eocene. This well was suspended for financial reasons in 2002 at a depth of 4,182meters, but re-started following a farm-in by a local oil service company (GBOSC) in September 2003. This well was drilled to a total depth of 14,765 feet (4,500 meters), and encountered the Cretaceous limestone target at 14,265 feet (4,348 meters). Drilling data and wire line logs indicated the presence of hydrocarbons in the Cretaceous and a production liner was set for testing. After initially very encouraging clean-up flows of drilling fluid accompanied by good quality 34.4° API oil, and gas, flow stopped due to a mechanical collapse of the production tubing. This is the first discovery of oil in the Cretaceous sequence in Georgia, however, this sequence is a prolific producer in nearby Chechnya and Dagestan. Regional outcrop studies in east-central Georgia indicate that the Cretaceous reservoir unit to be over 300 meters (~1,000 feet) thick. Although over 490 feet (150 meters) of hydrocarbons were encountered in the Manavi well, no oil-water contact was identified on the logs. An earlier well, the Manavi M7 well, drilled to the south of the M11 location, encountered hydrocarbons in the Cretaceous limestone sequence over 4,265 feet (1,300 meters) deeper, before this well was abandoned without testing being completed.

Mapping of the Manavi Cretaceous oil discovery indicates a substantial potential oilfield might be present. In addition, the shallower Middle Eocene sequence encountered in the well also had hydrocarbon indications, and awaits testing. This is approximately 3,280 feet (1,000 meters) deeper than the currently assumed oil-water contact for eastern Ninotsminda, and may indicate deeper oil in this area. Following the initial testing of the M11 well, CanArgo and NOC agreed with its farm-in partner GBOSC, to buy out its 50% interest in the well by issuing to GBOSC two million shares of CanArgo common stock. As such NOC has now regained its 100% interest in the well, subject only to the possible gas sales related arrangements with AES mentioned above.

Work to retrieve the damaged tubing from M11 and continue the testing program was delayed due to sourcing the necessary equipment from outside Georgia, but we should be ready to recommence operations shortly. However, it is entirely possible that the well will need to be sidetracked to complete the evaluation of the discovery. Regardless of the continuation of the testing on the M11 discovery, we plan to move ahead quickly with appraisal of Manavi. An appraisal well location has been chosen, and discussions are underway to commence drilling this appraisal well (M12) in June/July 2004. Some additional seismic is required to firm up the location for the second appraisal well, but we would hope that this well could commence before the end of the year, while at the same time implementing an early production scheme for the field. Although management is excited about the potential of the Manavi prospect, a fair amount of additional drilling and analysis is still required before we will be able to fully evaluate the reserves and productive possibilities of this prospect.

On the Ninotsminda Field, we have not yet fully evaluated the reserves and economics of production from the upper oil zones, the gas cap or from the hydrocarbon bearing zones below the Middle Eocene. To fully evaluate these zones, further seismic, technical interpretation and drilling will be required.

With respect to gas production, only limited short duration gas supply contracts currently exist for production directly from the gas cap. Gas currently produced from the Middle Eocene and upper zones is subject to market conditions and environmental constraints within Georgia and the ability of NOC to arrange short-term gas supply agreements as required.

*West Rustavi and Kumisi*

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In addition to the Ninotsminda Field and Manavi prospect, under the Ninotsminda PSC NOC has rights to one other field, West Rustavi and an underlying gas prospect named Kumisi.

The West Rustavi Field is located approximately 25 miles (40 km) southeast 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 what is found in 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. One of the ten wells drilled in the West Rustavi Field was completed in the deeper Cretaceous/Paleocene horizon. This well was tested and produced 1 million cubic feet of gas and 3,500 barrels of water per day, and is interpreted to have tested the down dip extent of a Cretaceous gas deposit named Kumisi. Additional seismic data has been acquired by NOC over this structure, but further geo-technical work is required on this horizon to determine its potential size, which could be significant. Given a positive outcome from this work, NOC has potential plans to appraise this discovery dependent on this technical work and on commercial sales contracts for gas off take.

In addition to the horizons discussed above, seismic and well data are currently being interpreted to identify further prospects in the Ninotsminda area at several different stratigraphic levels.

## GLOSSARY OF CERTAIN INDUSTRY 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.

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

Bopd Barrels of oil produced per day.

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.

Mcf One thousand cubic feet of natural gas.

MMbbl One million barrels.

Net acres or net wells The sum of the fractional working interests owned in gross acres or gross wells.

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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.

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.

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.

Item 2 *Properties* of this Annual Report on Form 10-K is hereby amended and restated in full as follows:

## ITEM 2. PROPERTIES

### *Production History*

The Ninotsminda Field was discovered and initial development began in 1979. Average gross oil production for January and February 2004 was 1,711 barrels of oil per day. A testing program implemented to test the optimal production level for individual wells resulted in the temporary shut-in of certain wells thus negatively affecting the production in February. Current production as of March 18, 2004 was approximately 2,000 bopd. Gross and net production from the Ninotsminda Field for the past three years was as follows:

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| Year Ended December 31, | Oil (Barrels) Gross | Oil (Barrels) Net (PSC Entitlement)[1] | Gas (mcf) Gross | Gas (mcf) Net (PSC Entitlement)[1] |
|---|---|---|---|---|
| 2003 | 695,174 | 451,863 | 108,630 | 70,610 |
| 2002 | 292,289 | 189,988 | 212,499 | 138,124 |
| 2001 | 413,724 | 268,921 | 1,110,390 | 721,754 |

(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.

***Productive Wells and Acreage***

The following table summarizes as of December 31, 2003 with respect to Ninotsminda Oil Company 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 Ninotsminda Oil Company.

| | Gross Number of Wells | Gross Acreage |
|---|---|---|
| Ninotsminda Field | 9 | 3,276 |

On December 31, 2003, there were no productive wells or developed acreage on any of our other Georgian properties, except for one gross well on the West Rustavi Field which was shut-in at that date.

***Reserves***

The following table summarizes net hydrocarbon reserves for the Ninotsminda Field. This information is derived from a report dated as of January 1, 2004 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.

| Oil Reserves | Oil Reserves Gross (Million Barrels) | PSC Entitlement Volumes (1) (Million Barrels) |
|---|---|---|
| Proved Developed | 3.593 | 2.336 |

| | | |
|---|---|---|
| Proved Undeveloped | 3.169 | 2.059 |
| **Total Proven** | 6.762 | 4.395 |

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| Gas Reserves | Gas Reserves Gross (Billion Cubic Feet) | PSC Entitlement Volumes (1) (Billion Cubic Feet) |
|---|---|---|
| Proved Developed | 1.742 | 1.133 |
| Proved Undeveloped | 1.243 | 0.808 |
| **Total Proven** | 2.985 | 1.941 |

(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.

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 net oil and gas price used in the report by OPC as of January 1, 2004 were $20.07 per barrel and $1.25 per mcf respectively. 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.

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

***Undeveloped Acreage***

The following table summarizes the gross and net undeveloped acreage held under the Ninotsminda, Nazvrevi/Block XIII and Norio/North Kumisi production sharing contracts as of December 31, 2003. The information regarding net acreage represents our interest based on our 100% interest in Ninotsminda Oil Company and the subsidiary holding the Nazvrevi/Block XIII contract and its current 75% interest in the subsidiary holding the Norio/North Kumisi contract.

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| PSC | Gross Acreage | Gross Square Kilometers | Net Acreage | Net Square Kilometers |
|---|---|---|---|---|
| Ninotsminda, Manavi and West Rustavi covering Block XI$^E$ | 27,739 | 113 | 27,739 | 113 |
| Nazvrevi and Block XIII | 388,450 | 1,572 | 388,450 | 1,572 |
| Norio (Block XI$^C$) and North Kumisi. | 378,523 | 1,542 | 283,892 | 1,157 |
| Block XI$^G$ and XI$^H$ | 119,843 | 485 | 119,843 | 485 |
| Total | 914,555 | 3,712 | 819,924 | 3,327 |

We lease office space in London, England; Guernsey, Channel Islands; Calgary, Alberta; and Tbilisi, Republic of Georgia. The leases have remaining terms varying from eight months to six years and six months and annual rental charges ranging from $16,000 to $262,000.

***Processing, Sales and Customers***

Georgian Oil built a considerable amount of infrastructure in and adjacent to the Ninotsminda Field prior to entering into the production sharing contract with Ninotsminda Oil Company. Ninotsminda Oil Company now uses that infrastructure, including initial processing equipment.

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 eleven kilometers either in a pipeline or by truck to Georgian Oil s central processing facility at Sartichala for further treatment. The gas is transported to Sartichala in a separate pipeline where some is used for fuel and the rest is piped 34 kilometers to Rustavi where it is delivered to the Rustavi industrial complex for sale to a number of customers.

At Sartichala, the water is separated from the oil. Ninotsminda Oil Company then sells oil in this state to buyers at Sartichala for local consumption or transfers it by pipeline 20 kilometers 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.

Ninotsminda Oil Company sells its oil directly to local and international buyers. In 2003, Ninotsminda Oil Company sold its oil production to eleven customers. Of these customers, three customers represented sales greater than 10% of oil revenue:

| Customer | Percent of Oil Revenue |
|---|---|
| Crownhill | 42.4% |
| Baslam | 32.3% |

| | |
|---|---|
| Sveti | 16.9% |

Management believes that the loss of any of the foregoing customers should not materially adversely affect our production 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.

In 2002, Ninotsminda Oil Company sold its oil production to eight customers of which four customers represented sales greater than 10% of oil revenue:

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| Customer | Percent of Oil Revenue |
|---|---|
| Caspian Trading | 28.4% |
| Sveti | 26.4% |
| Crownhill | 20.1% |
| Trafigura | 19.9% |

In 2001, Ninotsminda Oil Company sold its oil production to eight customers of which three customers represented sales greater than 10% of oil revenue:

| Customer | Percent of Oil Revenue |
|---|---|
| Caspian Trading | 63.8% |
| Georgian American Oil refinery (1) | 23.5% |
| MS | 12.7% |

(1) 51% owned by CanArgo effective November 2000

Sales to both the domestic and international markets are based on the average of a number of quotations for Dated Brent Mediterranean with an appropriate discount for transportation and other charges. Sales in 2003 were at an average discount of $7.70 to the price of Brent crude oil as quoted in the Platts Crude Oil Marketwire for Brent Dated Mediterranean compared to an average discount to the Brent price of $5.09 and $6.29 for sales in 2002 and 2001, respectively. The higher discount in 2003 is due to significant upfront security payments being made by the buyer to Ninotsminda Oil Company in return for the option to lift oil over a twelve-month period (described more fully under Liquidity and Capital Resources). For the period of the option, Ninotsminda Oil Company will retain the security for its own use and account.

The average sales price and the average production cost per unit of oil and gas produced for each of the last three years was as follows:

| | Average Sales Price | | |
|---|---|---|---|
| Year Ended December 31, | Oil $/boe | Gas $/mcf | Unit Production Cost $/boe |
| 2003 | 20.07 | 1.25 | 2.59 |
| 2002 | 17.09 | 1.25 | 4.69 |
| 2001 | 19.43 | 1.14 | 2.62 |

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 Licences**

*Nazvrevi and Block XIII Production Sharing Contract (  Nazvrevi PSC  )*

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In February 1998, we entered into a second production sharing contract with Georgian Oil and the State of Georgia. This contract covers the Nazvrevi and Block XIII areas of East Georgia, an approximately 492, 914 acre (2,008 $km^2$) exploration area adjacent to the Ninotsminda and West Rustavi Fields and containing existing infrastructure ( Nazvrevi PSC ). 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, of the southern part of the area, reducing the area to approximately 388,450 acres (1,572 $km^2$).

Under the Nazvrevi PSC, CanArgo pays all operating and capital costs. CanArgo first recovers its cumulative operating costs from production. After deducting production attributable to operating costs, 50% of the remaining production (profit petroleum), considered on an annual basis, is applied to reimburse CanArgo for its cumulative capital costs. While cumulative capital costs remain unrecovered, the other 50% of remaining production is allocated on a 50/50 basis between Georgian Oil and CanArgo. After all cumulative capital costs have been recovered by CanArgo, remaining production after deduction of operating costs is allocated on a 70/30 basis between Georgian Oil and CanArgo, respectively. Thus, while CanArgo is responsible for all of the costs associated with the Nazvrevi 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 CanArgo of all obligations it would otherwise have to pay the Republic of Georgia for taxes and similar levies related to activities covered by the production sharing contract. Both Georgian Oil and CanArgo will take their respective shares of oil production under the Nazvrevi PSC in kind but will jointly market any available gas production.

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 continue to be interpreted, with a view towards defining possible oil and gas prospects and exploration drilling locations. 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 we have met the requirements of the work program defined in the production sharing agreements. The Kumisi gas discovery may extend into Block XIII, 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.

*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 ( CanArgo Norio ), 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 Kumisi blocks of East Georgia, an exploration area of approximately 378,523 acres (1,542 $km^2$) 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. 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. CanArgo Norio has determined production from these fields to be uneconomic, and the fields are currently being operated by Georgian Oil under a service agreement with CanArgo Norio, whereby Georgian Oil takes all production to compensate it for its costs under what is effectively a social program. If CanArgo Norio 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 CanArgo Norio, remaining production after deduction of operating costs is allocated on a 60/40 basis between Georgian Oil and CanArgo Norio, respectively. Thus, while CanArgo

Norio 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. We currently own a 75% controlling interest in CanArgo Norio with the remainder held by private investors.

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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 with the first exploration well named MK72 drilled on a large prospect identified at Middle Eocene level which is the productive horizon in both the Ninotsminda and Samgori Fields to the south and east. The Samgori Oil Field has produced approximately 180 million barrels of oil to date.

The MK72 well was initially drilled to a depth of 9,620 feet (2,932 meters), at which depth the well was suspended in August 2002 due to lack of available funding at that time. Downhole seismic data acquired in the well bore indicated the target may be at a depth of approximately 13,780 feet (4,200 meters), and CanArgo Norio did not have sufficient funding to complete the well to that depth. However the State Agency for the Regulation of Oil and Gas Resources in Georgia confirmed that CanArgo Norio had satisfied all drilling and work obligations under the terms of the Norio PSA by the initial phase of drilling of the MK72 well.

In connection with this initial phase of drilling, which cost a total of $4.3 million, CanArgo s partner in CanArgo Norio sought to farm-out to CanArgo and to third party investors part of its interest in CanArgo Norio to partly fund the drilling of the MK72 well. One of these third party investors was Provincial Securities Limited, an investment company to which Mr. Russell Hammond, a non-executive director of CanArgo, is an Investment Advisor. CanArgo Norio s total share of these drilling costs was $3.1 million. In November 2002, shareholders of CanArgo Norio agreed to adjust the ownership of CanArgo Norio to reflect the funding for the MK72 well, and capitalization of certain loans and management fees that CanArgo had made to CanArgo Norio. Under this agreement, CanArgo s interest increased from 50% to 64.2% in CanArgo Norio. CanArgo Norio then sought a partner to assist with the financing to deepen the MK72 well.

In September 2003, CanArgo Norio signed a farm-in agreement relating to the Norio PSA with a wholly owned subsidiary of Georgian Oil, the Georgian State Oil Company. CanArgo Norio had previously been in negotiations with a large third party energy company to farm-in to the Norio PSA, but Georgian Oil exercised its pre-emption rights under the Norio PSA. Georgian Oil is already a party to the Norio PSA as the commercial representative of the State. The farm-in agreement obligates Georgian Oil to pay up to $2.0 million to deepen, to a planned depth of 16,400 feet (5,000 meters) the MK-72 well in return for a 15% interest in the contractor share of the Norio PSA. Georgian Oil also has an option (the Option ), exercisable for a limited period after completion of the well, to increase its interest to 50% of the contractor share of the Norio PSA on payment to CanArgo Norio of US$ 6.5 million. If Georgian Oil exercises this Option under the farm-in agreement, it loses its rights to exercise the PSA Option under the Norio PSA itself.

Co-incident with the Georgian Oil farm-in, CanArgo concluded a deal to purchase some of the minority interests in CanArgo Norio by a share swap for shares in CanArgo. Through this exchange CanArgo has acquired an additional 10.8% interest in CanArgo Norio, giving CanArgo a 75% interest in CanArgo Norio at present. This approximately maintains CanArgo s effective interest in the Norio PSA after Georgian Oil has completed the first stage of the farm-in at 63.7%. The purchase was achieved by issuing 6 million restricted CanArgo common shares to the minority interest holders in CanArgo Norio. Of the interests in CanArgo Norio, Provincial Securities Limited owned 4%. In the event that Georgian Oil exercises the Option and pays the required $6.5 million, CanArgo (which would have received some $4.8 million of this payment with its previous interest) would receive a further $1.2 million, resulting in a total payment to CanArgo of approximately $6 million. If Georgian Oil exercises this Option CanArgo will issue a further 3 million restricted shares to the minority interest holders.

Drilling at the MK72 well, funded by Georgian Oil, recommenced in December 2003 and by March 16, 2004 total depth had reached approximately 4,200 meters.

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This is an important well in management s opinion since several additional high potential prospects may exist on trend within the licence area.

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, CanArgo s subsidiary, CanArgo Norio, won the tender for the oil and gas exploration and production rights to the Tbilisi PSC an area of approximately 119,843 acres (485 $km^2$) in eastern Georgia adjacent to the Norio, Block XIII and West Rustavi areas. In July 2003, it was announced that CanArgo Norio, 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 the Company has made a commercial discovery in which case the Contract will continue in full force in effect until September 29, 2028. CanArgo Norio views these blocks as having good potential, being adjacent to productive acreage and with some existing wells on the blocks. 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. CanArgo Norio will evaluate existing seismic and geological data during the first year and acquire additional seismic data within three years of the effective date of the Contract which was set as 29 September 2003. The total commitment over the next four years is $350,000. The abovementioned Georgian Oil farm-in to the Norio PSA does not apply to the Tbilisi PSC.

*Block $XI^B$ Production Sharing Contract ( Samgori PSC )*

In February 2004 CanArgo announced that it has obtained State regulatory approval to an agreement to obtain 50% of the Contractor s interest in the Samgori PSC in Georgia and a 50% interest in the licence holder for Block $XI^B$ covering the Samgori Oil Field. Regulatory approval was a key condition to the agreement and the other conditions are expected to be satisfied in due course. The Samgori PSC came into effect on September 1, 2001 and extends for an initial period of twenty years with the final year of the contract being September 1, 2021 this period may be extended subject to commercial production for up to a further fifteen years until 2036.

This interest is being acquired from Georgian Oil Samgori Limited ( GOSL ), a company wholly owned by the Georgian Oil. Under the terms of the agreement, up to 10 horizontal wells will be drilled on the Samgori Field, which is the largest oilfield discovered to date in Georgia and lies adjacent to CanArgo s Ninotsminda Field. We have been advised that Samgori has produced over 180 million barrels (MMbbl) of oil to date at rates up to 70,000 barrels of oil per day (bopd).

The Samgori Field complex was discovered in 1974 and produces from the same Middle Eocene sequence as the Ninotsminda Field. Current production from the Field is approximately 700 bopd. Under the proposed farm-in, CanArgo will be entitled to an immediate share of this production upon completion of the farm-in agreement. In addition, Block $XI^B$ which covers an area of approximately 169,514 acres (634 $km^2$) contains several identified prospects and discoveries in other horizons, notably the Upper Eocene and Cretaceous.

**Refining and Other Activities**

CanArgo also engages in oil and gas, refining and other activities in Georgia. Segment and geographical information including revenue from continuing operations from external customers, operating profit (loss) from continuing operations and total assets is incorporated herein by reference from note 18 to the consolidated financial statements.

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*Georgian American Oil Refinery*

The Georgian American Oil Refinery ( GAOR ) remained in a care and maintenance condition during 2003 and we disposed of our 51% interest in the refinery in February 2004. During 2003, a debit balance of $1,274,895 in minority interest was written-off due to a change in the intentions of our minority interest owner and plan to dispose of the asset. In 2004, CanArgo came to an agreement to sell the refinery.

*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 three drilling rigs, pumping equipment and ancillary machinery. In addition, we have signed an agreement to sell our mobile 3-megawatt duel fuel power plant for $600,000 and have received a nonrefundable deposit of $300,000. It is expected that transfer of title for this equipment and the final payment of $300,000 will take place during the second quarter 2004. This asset is classified and reflected in our financial statements in Assets held for sale for all periods presented. The rigs and related equipment are used in our Georgian operations, and from time to time have also been leased out to other operators on a service basis or used by the company to perform drilling services for other operators.

In September 2001, we entered into an agreement to provide drilling services to a third party using one of our rigs. Commercial drilling operations commenced in October 2001 and continued through February 2002. The company subsequently established a wholly owned well services subsidiary (Argonaut Well Services Limited) and at the end of March 2003 concluded a new drilling service contract with an operating company in Georgia. We will continue to bid in appropriate tenders for drilling contracts in order to utilise drilling equipment not otherwise used in our own operations.

*Potential Caspian Exploration Project*

In May 1998, CanArgo led a consortium which submitted a bid in a tender for two large exploration blocks in the Caspian Sea, located off the shore of the autonomous Russian Republic of Dagestan. The consortium was the successful bidder in the tender and was awarded the right to negotiate licenses for the blocks. Following negotiations, licenses were issued in February 1999 to a majority-owned subsidiary of CanArgo. During 1999 CanArgo concluded that it did not have the resources to advance this project. Accordingly, in November 1999, CanArgo reduced its interest to a 9.5%. Subsequent to this, a restructuring of interests in the project took place with CanArgo increasing its interest slightly to 10%, and with Rosneft, the Russian State owned oil company, becoming the majority owner of the project with 75.1%. Seismic was acquired as part of this restructuring and future plans include interpretation of this data and possible drilling. However our small interest in this project, and the lack of an effective joint operating agreement, means that we have little control of the operator for the project, and any further investment by CanArgo will take this into account.

*Potential Kazakhstan Project*

In December 2003, we announced details of the acquisition of oil and gas interests in Kazakhstan which were previously owned by the UK public company Atlantic Caspian Resources plc ( ACR ). We intend to acquire these interests through a newly established associated company, Tethys Petroleum Investments Limited ( TPI ) which will acquire ACR s 70% interest in BN Munai LLP ( BNM ), a Kazakh limited liability partnership on certain conditions being satisfied. BNM s interests center on the Akkulkovsky exploration area and the Kyzyloy Gas Field, located in western Kazakhstan, just to the west of the Aral Sea. Registration of TPI s interest in BNM is underway and should be completed in the near future. Until this registration is completed, TPI rights to BNM are not finalized. In addition, the license position with regard to the Akkulkovsky exploration area is currently subject to review by the Kazakh authorities and further negotiation is required to potentially secure this. The consideration for the acquisition involved ACR taking a fully paid 10% interest in TPI, but with no cash consideration from CanArgo. Provincial Securities Limited, an investment company to which Mr. Russell Hammond, one of our non-executive directors, is an Investment Advisor, was involved in negotiating the acquisition and the potential future development of TPI, and as such has a significant minority shareholding in TPI. We operate TPI under a

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Management Services Agreement, however it is intended that the further development of TPI will be primarily funded by third party investment. We expect to retain a significant minority shareholding in TPI. Under ACR s ownership BNM has drilled two deep exploration wells in the Akkulkovsky area over the past three years, both of these wells being plugged and abandoned with hydrocarbon shows. However, we believe that the short term potential may lie in the shallower Kyzyloy Gas Field. This is a discovered shallow gas field, located approximately 35 km from the main Bukhara Urals gas pipeline system, and close to the Bazoy gas storage and compression facility. Additional, shallow gas indicators are apparent on seismic data, which, if successfully tested, potentially could be added to any development of the Kyzyloy Field.

**Discontinued Operations**

*CanArgo Standard Oil Products*

In September 2002, CanArgo approved a plan to sell CanArgo Standard Oil Products to finance 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. CanArgo agreed subsequently to re-schedule this payment in return for, the purchaser paying some of the funds early and paying interest on the outstanding balance at a an annual rate of 16% payable monthly. To date a total of $2,200,000 has been received with a further $1,800,000 to be paid by end of June 2004. Discontinued Operation activity is incorporated herein by reference from note 17 to the consolidated financial statements.

CanArgo Standard Oil Products sells several different grades of petrol to a broad range of corporate and retail customers. No one customer purchases more than 10% of total sales.

*GAOR*

In 2003, CanArgo approved a plan to dispose of its interest in GAOR as the refiner had remained closed since 2001 and neither CanArgo nor its partners could find a commercially viable option to putting the refinery back into operation. In February 2004, we reach agreement with a local Georgian company to sell our 51% interest in GAOR for a nominal price of one US dollar and the assumption of all the obligations and debts of GAOR to the State of Georgia including deferred tax liabilities of approximately $380,000. In 2003 we announced publicly that we were re-evaluating our treatment in our 2001 and 2002 financial statements of our minority interest in GAOR. After reviewing the basis for our accounting for our interest in GAOR and after discussions with our former auditors we have concluded that our interest was properly accounted for in those statements.

*Bugruvativske Field, Ukraine*

In April 2001, we acquired approximately 82% (77% on a fully diluted basis) of the outstanding common shares of Lateral Vector Resources Inc. ( LVR ) pursuant to an unsolicited offer to purchase all of its outstanding common shares. According to publicly available information at the time we made our offer in March 2001, LVR negotiated and concluded with Ukrnafta, the Ukrainian State Oil Company, a Joint Investment Production Activity ( JIPA ) agreement in 1998 to develop the Bugruvativske Oil Field located in Eastern Ukraine. In July 2001, we completed the acquisition of the remaining outstanding common shares and LVR became a wholly owned subsidiary of CanArgo. The appointed operator under the JIPA agreement and party to the JIPA (0.1%) is IPEC, a local Ukrainian company, owned 85% by LVR. In July 2002, LVR acquired the remaining 15% in IPEC and IPEC became a wholly owned subsidiary of LVR.

In September 2002, we agreed terms with Ukrnafta on revisions to the existing JIPA agreement and reached an agreement with an unaffiliated local Ukrainian oil and gas company on the terms of a farm-in to the JIPA. The terms of the farm-in, arrived at in arms-length negotiations, were that the local Ukrainian oil and gas company through its acquisition of IPEC would invest approximately $3 million in the Bugruvativske Field over the course of 12 months in order to drill two new wells while bearing the financial risk under the JIPA during this period. LVR could match up to the amount invested by IPEC prior to December 31, 2003. The revised JIPA provided that (assuming LVR matched IPEC s initial expenditure) LVR would be entitled to approximately 34.5% of net profits generated under the JIPA (or a proportionally smaller amount if the amount invested was less than that invested by IPEC). LVR had no obligation to invest in the JIPA, however in the event that LVR decided not to invest in the project by December 31, 2003 and IPEC satisfied the terms of the farm-in, it would still receive an ongoing project fee of between 3 - 4 % of the net profits generated under the JIPA in recognition of its earlier involvement in the project.

As of September 30, 2003, IPEC had transferred only $1 million to the JIPA account and drilling operations under the JIPA had not yet commenced due to ongoing disagreements that IPEC and LVR have with Ukrnafta where the latter is conducting independent operations on a well that was to be the subject of joint activity under the JIPA. At December 31, 2003, the dispute with Ukrnafta remained unresolved and there are no assurances that the dispute with Ukrnafta can be resolved to the satisfaction of the company.

Due to the lack of progress with the implementation of the JIPA in 2003, and failure to reach a negotiated agreement with Ukrnafta, management reached the decision to dispose of its interest in the Bugruvativske project and withdraw from Ukraine. The company is currently in negotiations with a potential buyer for the disposal of its 100% interest in LVR. Consequently, CanArgo recorded in 2003 a write-down in respect to the LVR deal and the acquisition of the Bugruvativske Field of approximately $4.8 million.

CanArgo has now effectively withdrawn from Ukraine, in order to focus on its Georgian activities, having disposed of its interest in the Stynawske Field in Western Ukraine in 2003. In September 2003, CanArgo announced it had reached conditional agreement to sell its interest in Boryslaw Oil Company ( BOC ), the joint venture in West Ukraine which operates the Stynawske Field. Fountain Oil Boryslaw ( FOB ), CanArgo s wholly owned subsidiary which holds its 45% interest in BOC, was sold for $1,000,000 payable in eight equal tranches. Final payment was received in November 2003 and ownership in FOB was transferred to the buyer. The buyer has also acknowledged BOC s debts to CanArgo for earlier loans in the total amount of $160,000.

*3-megawatt duel fuel power generator*

In 2003, CanArgo signed a sales agreement disposing of a 3-megawatt duel fuel power generator for $600,000. Following receipt of a non-refundable deposit of $300,000, the unit was shipped to the US for testing. The test is due to be completed in the near future at which time the generator will be delivered to the buyer following receipt of the final payment.

**Employees**

As of December 31, 2003, CanArgo had 279 full time employees. Of its full time employees, the entity acting as operator of the Ninotsminda Field for Ninotsminda Oil Company has 114 full time employees, and substantially all of that company s activities relate to the production and development of the Ninotsminda Field. CanArgo Standard Oil Products has 153 full time employees at its office and petrol stations. We have not experienced any strikes, work stoppages or other labour disputes and management believes the company s relations with its employees are satisfactory.

**Risks Associated with CanArgo s Activities**

*CanArgo s 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 reducing costs, generating funds from internal sources including the sale of certain non-core assets, external sources and, ultimately, maintaining sufficient positive cash flows from operating activities.

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Our financial statements have been prepared on a basis which assumes that operating cash flows, additional funding and/or proceeds from the sale of non-core assets received meet our cash flow needs. If these operating cash flows, additional financings, and in particular the receipt of the final $1,800,000 payment from the sale of CSOP are not received, adjustments may have to be made to our business plan which will limit our development and exploration activities.

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 these properties will require the availability of substantial funds from internal and/or external sources. We believe that we will be able to generate funds from quasi-governmental financing agencies, conventional lenders, equity investors and other oil and gas companies that may desire to participate in our oil and gas projects. Although funds are not yet available, in February 2004, we announced that we had signed a Standby Equity Distribution Agreement that allows us, at our option, to issue shares to US-based investment fund Cornell Capital Partners LP up to a maximum value of $20 million over a period of up to two years. This facility cannot be exercised until the SEC has declared a Registration Statement effective (See Item 7- Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources for a more detailed discussion).

*Current Operations Dependent on Success of the Ninotsminda Field and Georgian Exploration*

We have directed substantially all of our efforts and most of our available funds to the development of the Ninotsminda Field in the Republic of Georgia, exploration in that area and some ancillary activities closely related to the Ninotsminda Field project. This decision is based on management s assessment of the potential of the Ninotsminda Field area. However, the company s focus on the Ninotsminda Field has over the past several years resulted in overall losses for us and we have yet to be profitable. There can be no assurances 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 to justify the investments made and the planned future investments for 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 and appraisal program is an important factor for future success and this program may not be successful, as it carries substantial technical risk.

*Minimum Investment Requirements in the Bugruvativske Field in Ukraine Have Not Been Met*

Under the terms of the farm-in agreement signed in September 2002 with us, a local Ukrainian oil and gas company was required to invest approximately $3 million in the Bugruvativske Field in Ukraine under the Joint Investment Production Activity (JIPA) agreement over the course of 12 months in order to drill two new wells and would bear the financial risk during this period. We could match up to the amount invested by the farminee, prior to December 31, 2003 in order to be entitled to approximately 34.5% of net profits generated from the project (or a proportionally smaller amount if the amount invested was less than that invested by the farminee). In the event that we decided not to invest in the project by December 31, 2003, we would receive an ongoing project fee of between 3-4 % of the net profits generated under the JIPA in recognition of our earlier involvement in the project. At December 31, 2003, neither the farminee nor we had met their respective investment requirements under the JIPA due to an ongoing dispute with Ukrnafta, the other participant to the JIPA. At the present time, there are no assurances that the dispute with Ukrnafta can be resolved to the satisfaction of the company and consequently hydrocarbon reserves are classified as unproved until the dispute is resolved and our investment is made. We are currently trying to sell our interest in this project.

*Write Off of 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

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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.

*Possible Inability to Finance Present Oil and Gas Projects*

Our ability to finance all 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 could require us to scale back or abandon part or all of our project development, capital expenditures, production and other plans. Apart from the evaluation of the economics of specific investment proposals, 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 legal, regulatory, fiscal and tax policies of various governments in 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 also be influenced by their evaluations of us and our projects, including their technical difficulty, and the comparison with available alternative investment opportunities.

*Additional Funds Needed For Long-Term Oil and Gas Development Plans*

It will take many years and substantial cash expenditures to develop fully our oil and gas properties. The company generally has the principal responsibility to provide financing for its oil and gas properties and ventures. Accordingly, we need to raise additional funds from outside sources in order to pay for project development costs beyond those currently budgeted through 2004. We may not be able to obtain that additional financing, or such funds may only be available on commercially unattractive terms. If, in either such case, adequate funds are not available, it will be necessary to scale back or even suspend operations. 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.

*Oil and Activities Involve Risks, Many of Which Are Beyond Our Control*

Our exploration, appraisal, development and production activities are subject to a number of factors and risks, many of which may be beyond our control. First, we must successfully identify commercial quantities of oil and gas. The exploration and 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, equipment and personnel to support operations;

local and global oil prices; and

government regulation and legal uncertainties.

The company s activities can also be affected by a number of hazards, such as:

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- labour disputes;
- 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 hazards could result in damage, losses or liability for the company. There is also an increased risk of some of these hazards in connection with operations that involve the rehabilitation of fields where less than optimal practices and technology were employed in the past, as was often the case in the former Soviet Union. We do not purchase insurance covering all of the risks and hazards that are involved in oil and gas exploration, development and production.

*Risk of Political Instability with Respect to Foreign Operations*

Our principal oil and gas properties and activities are in the Republic of Georgia, which is located in the former Soviet Union. Operation and development of these assets is subject to a number of conditions endemic to former Soviet Union countries, including political instability. The present governmental arrangements in the former Soviet Union in which CanArgo operates 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 themselves replace these governments. Our operations typically involve joint ventures or other participatory arrangements with the national government or state-owned companies.

The PSC covering the Ninotsminda Field is an example of such an arrangement. As a result of such dependency on government participants, our operations could be adversely affected by political instability, 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. We are not insured against such political risks because management deems the premium costs of such insurance to be currently prohibitively expensive.

*Risk of Social, Economic and Legal Instability*

The political institutions in the countries which comprise the former Soviet Union have recently become more fragmented, and the economic institutions of many of these countries have only recently converted to a market economy from a planned economy. New laws have been introduced, and the legal and regulatory regimes in such regions are often vague, containing gaps and inconsistencies, and are constantly 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 following:

- uncertainty as to the enforceability of contracts;
- sudden or unexpected changes in demand for crude oil and or natural gas;
- the lack of trained personnel; and
- the lack of equipment and services and the presence of other factors that could significantly change the economics of production.

In early 2002, the Georgian government requested assistance from the United States to combat terrorism in the Pankisi Gorge, a region of Georgia bordering the separatist Chechnya region of Russia. Social, economic and legal instability have accompanied these changes due to many factors which include:

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

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This instability can make continued operations in affected regions difficult or impossible.

*Inadequate or Deteriorating Infrastructure in the Former Soviet Union*

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, the lack of a reliable electrical power supply caused Ninotsminda Oil Company to suspend drilling of one well and the testing of a second well during the 1998-1999 winter season, although the availability of electrical power supplies has been more regular since that time.

*Currency Risks in the Former Soviet Union*

Payment for oil and gas products sold in the 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. Although most former Soviet Union country currencies are presently convertible into U.S. dollars, there is no assurance that 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 the 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. The company 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.

*Tax Risks in the Former Soviet Union*

Countries in the former Soviet Union frequently add to or amend existing taxation policies in reaction to economic conditions including state budgetary and revenue shortfalls. 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 agreements in Georgia and all current taxes are payable from the State s share of petroleum produced under the production sharing contracts.

*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 those of the company 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 former Soviet Union, even though we may be the designated operator of the oil or gas field. In such circumstances, the concurrence of co-ventures 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 the same objectives. Demands by or expectations of governments, co-venturers, customers, and others may affect our strategy regarding the various projects. Failure to meet such demand or expectations

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could adversely affect our participation in such projects or its ability to obtain or maintain necessary licenses and other approvals.

Demands by or expectations of governments, co-venturers, customers and others may also affect our strategy regarding 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.

*Governmental Registration*

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.

*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 CanArgo s control, including:

- global 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.

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. In 2002, the spot price for Brent crude oil increased from $19.29 per barrel at December 31, 2001 to $31.98 per barrel at December 31, 2002. We may also not benefit from continued increases in oil prices as have occurred during 2003 as the market for the levels of crude oil produced in Georgia by Ninotsminda Oil Company can in such an environment be relatively inelastic and contract prices are often set at a specified price determined with reference to Brent oil prices when the contract is entered into or over a short period when the crude oil is delivered.

*Oil and Gas Production Could Vary Significantly From Reserve Estimates*

Oil and natural gas reserves and their values as determined by petroleum engineers are estimates only. Proved oil and gas reserves are the estimated quantities of natural gas and crude oil reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under period-end economic and operating conditions. These estimates are based on professional judgments about a number of elements:

- the amount of recoverable crude oil and natural gas present in a reservoir;
- the costs that will be incurred to produce, transport and market 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;

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- 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 most recent report on our oil and gas reserves prepared by OPC as of January 1, 2004. 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.

*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;
- labour 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 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.

*Competition*

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

*Operations are Dependent on Chairman of the Board and Chief Executive*

Dr. David Robson, the Chairman of the Board and Chief Executive Officer of CanArgo, is our executive who has the most experience in the oil and gas industry and who has the most extensive business relationships in the former Soviet Union. Our business and operations could be significantly harmed if Dr. Robson were to leave the company or become unavailable because of illness or death. Dr. Robson through his company, Vazon Energy Limited, has signed a comprehensive Management Services Agreement with a rolling six-month notice period and a two-year non-competition clause effective from the date of termination of the agreement. We do not carry key employee insurance on any of our employees.

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## PART II

Item 7 *Management s Discussion and Analysis of Financial Condition and Results of Operations* is hereby amended and restated in full as follows:

## 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 Qualifying Statement With Respect To Forward-Looking Information 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 1 Business-Risks Associated with CanArgo s Activities may have a significant impact on our future financial condition and results of operations.

### 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 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;
- 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 6.762 million barrels (MMbbl) up 63% from 2002 s 4.15 MMbbl. Over the same period, gross total proved natural gas reserves, on an energy equivalent basis, decreased from 1.34 million barrels of oil equivalent (MMboe) to 0.51 MMboe.

The significant increase in recoverable oil reserves results primarily from the completion of a dynamic reservoir model during the year and the implementation of a successful development program based on horizontal drilling. However, recovery of these reserves is dependent on application of optimal production levels for the Ninotsminda wells and further application of horizontal drilling techniques.

Because our proved reserves will decline as crude oil, and, to a lesser extent, natural gas and natural gas liquids are produced (since our natural gas and natural gas liquid production is currently incidental to our crude oil production), 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

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available funds for acquisition, exploitation and development projects. For more information on the volumes of crude oil, natural gas liquids and natural gas we have produced during 2001, 2002 and 2003, please refer to the information under the caption Results of Operations below.

*Exploitation and Development Activity*

During 2003, we continued exploitation activities on our Georgian properties. We participated in the drilling of 3 successful wells on the Ninotsminda Field. The Company invested $4.5 million in capital spending on these activities during 2003. In December 2003, as a result of these activities, our average daily production was approximately 3120bbls, a 372% increase from the daily production rate at the beginning of the year (excluding production from the property sold in 2003).

We have budgeted $6.4 million for drilling expenditures in 2004. If crude oil and, to a lesser extent, natural gas prices return to depressed levels or if our production levels continue to decrease, our revenues, cash flow from operations and financial condition will be materially adversely affected. For more information, see Liquidity and Capital Resources .

*Recent Acquisitions of Interests*

In December 2003, CanArgo announced details of the acquisition of oil and gas interests in Kazakhstan which were previously owned by the UK public company Atlantic Caspian Resources plc ( ACR ). We intend to acquire these interests through a newly established associated company, Tethys Petroleum Investments Limited ( TPI ) which will acquire ACR s 70% interest in BN Munai LLP ( BNM ), a Kazakh limited liability partnership on certain conditions being satisfied. BNM s interests centre on the Akkulkovsky exploration area and the Kyzyloy Gas Field, located in western Kazakhstan, just to the west of the Aral Sea. Registration of the TPI interest in BNM is underway and should be completed in early 2004. The licence position with regard to the Akkulkovsky exploration area is currently subject to review by the Kazakh authorities and further negotiation is required to secure this. The consideration for the acquisition involves ACR taking a fully paid 10% interest in TPI, but with no cash consideration from CanArgo. We will operate TPI, however it is intended that the further development of TPI will be primarily funded by third party investment. We expect to retain a significant minority shareholding in TPI. Under ACR s ownership BNM have drilled two deep exploration wells in the Akkulkovsky area over the past three years, both of these wells being plugged and abandoned with hydrocarbon shows. However, CanArgo believe that the short term potential may lie in the shallower Kyzyloy Gas Field. This is a discovered shallow gas field, located approximately 35 km from the main Bukhara Urals gas pipeline system, and close to the Bazoy gas storage and compression facility. Additional shallow gas indicators are apparent on seismic data, which potentially could be added to any development of the Kyzyloy Field.

In February 2004, CanArgo announced that it has obtained Georgian State regulatory approval to an agreement to obtain 50% of the Contractor s interest in the Samgori PSC in Georgia and a 50% interest in the licence holder for Block $XI^{B}$ covering the Samgori Oil Field. Regulatory approval was a key condition to the agreement and the other conditions are expected to be satisfied in due course.

This interest is being acquired from Georgian Oil Samgori Limited ( GOSL ), a company wholly owned by Georgian Oil. Under the terms of the agreement, up to 10 horizontal wells will be drilled on the Samgori Field, which is the largest oilfield discovered to date in Georgia and lies adjacent to CanArgo s Ninotsminda Field. Samgori has produced over 180 million barrels (MMbbl) of oil to date at rates up to 70,000 barrels of oil per day (bopd).

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The Samgori Field complex was discovered in 1974 and produces from the same Middle Eocene sequence as the Ninotsminda Field. Current production from the Field is approximately 700 bopd. We will be entitled to an immediate share of this production upon completion of the farm-in agreement. In addition, Block $XI^B$ which covers an area of approximately 169,514 acres (634 $km^2$) contains several identified prospects and discoveries in other horizons, notably the Upper Eocene and Cretaceous. As part of the farm-in terms, we will be obliged to fund 100% of the cost of the first horizontal well section to be drilled on the Samgori Field, the anticipated cost of this well is $1.2 million. Thereafter, it is anticipated that up to a further ten horizontal development wells will be drilled on the Samgori complex over the next three years which will be funded jointly by CanArgo and GOSL pro rata their interest in the PSC.

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

- funding of a Field development plan will be timely;
- that the development plan will be successfully completed or will increase production; or
- that Field operating revenues after completion of the development plan will exceed operating costs.

To pursue existing projects beyond CanArgo s immediate development plan and to pursue new opportunities, CanArgo 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 and the participation of other oil and gas entities in CanArgo s projects. Based on CanArgo s past history of raising capital and continuing discussions, management believes 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 and we are unable to sell some or all of our non-core assets, or, if sold, such sales realize insufficient proceeds, further cost reductions and additional funding will be required in order for us to remain a going concern.

Development of the oil and gas properties and ventures in which CanArgo has interests involves multi-year efforts and substantial cash expenditures. Full development of CanArgo s oil and gas properties and ventures will require the availability of substantial additional financing from external sources. CanArgo may also, where opportunities exist, seek to transfer portions of its interests in oil and gas properties and ventures to entities in exchange for such financing. CanArgo generally has the principal responsibility for arranging financing for the oil and gas properties and ventures in which it has an interest. There can be no assurance, however, that CanArgo 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 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 CanArgo s 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;
- 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.

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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.

*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, the participation of other oil and gas entities in our projects, funding from the sale of our equity securities under a Standby Equity Distribution Agreement with Cornell Capital (the Cornell Equity Facility ) described below, 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 23, 2004, the Company had an aggregate of 109,284,724 shares of common stock outstanding. On March 23, 2004, shareholders approved an increase in the authorized number of shares of common stock from 150,000,000 to 300,000,000, leaving an aggregate of 165,622,189 of uncommitted shares available for future issuance by the Company.

**Liquidity and Capital Resources**

**General**

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, funding under the Cornell Equity Facility 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. Significant downturns in commodity prices, such as that experienced in the last nine months of 2001 and the first quarter of 2002, can reduce our cash from operating activities. 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 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 or identify additional behind-pipe zones or secondary recovery reserves.

As of December 31, 2003, we had working capital of $3,235,000, compared to working capital of $10,646,000 as of December 31, 2002. The $7,410,000 decrease in working capital from December 31, 2002 to December 31, 2003 is principally due to the change in assets and liabilities held for sales resulting from the impairment of the Bugruvativske field in the period, an increase in loan facilities undertaken by the retail operation in Georgia and the part receipt of funds in respect of a farm-in agreement on the Norio project.

In May 2003, NOC entered into a new 12-month crude oil sales agreement whereby the buyer will provide a security payment of $1.75 million in return for the right to lift up to 5,000 metric tons of oil per month for the 12-month period commencing August 2003. At the end of the 12 months, the security payment will be repaid through the delivery of additional crude oil equal to the value of the security. This agreement replaces an existing crude oil sales agreement, where the buyer had already provided $1million security. Following the success of the N100H well, NOC entered into a further oil sales agreement with the buyer for an additional monthly quantity of 2,500 metric tons of oil. The agreement runs to the end of 2004 and as security for payment and for having the option to lift oil on a monthly basis the buyer will provide additional security in the amount of $550,000. The security will be repaid in oil at the end of the contract period.

*Certain Asset Sales*

In September 2003, CanArgo announced it had reached conditional agreement to sell its interest in Boryslaw Oil Company ( BOC ), the joint venture in West Ukraine currently operating the Stynawske Oil Field. Fountain Oil Boryslaw ( FOB ), CanArgo s wholly owned subsidiary which holds its 45% interest in BOC, was sold for $1,000,000 payable in eight equal tranches. The buyer has also acknowledged BOC s debts to CanArgo for earlier loans in the total amount of $160,000. On November 10, 2003 CanArgo announced that the full payment had been received early and that CanArgo s interest in FOB had been transferred to the buyer. Management has concluded that the sale of our interest in BOC does not constitute the disposition of a material asset of the Company.

In 2003, CanArgo signed a sales agreement disposing of a 3-megawatt duel fuel power generator for $600,000. Following receipt of a non-refundable deposit of $300,000, the unit was shipped to the US for testing. The test is due to be completed in the near future at which time the generator will be delivered to the buyer following receipt of the final payment.

**Cornell Equity Facility**

In December 2003, CanArgo announced that it had signed a Standby Equity Distribution Agreement that allowed it, at its option, to issue shares to US-based investment fund Cornell Capital Partners LP ( Cornell Capital ) up to a maximum value of $6 million. Under the terms of the Agreement, CanArgo could, at its discretion, issue shares to Cornell Capital at any time over the next two years. The maximum aggregate amount of the equity placements pursuant to the Agreement was $6 million. Subject to this limitation, CanArgo could draw down up to $200,000 in any seven-day period (a Put ). The facility could be used in whole or in part entirely at CanArgo s discretion, subject to effective registration of the shares under the Securities Act of 1933, as amended ( Securities Act ). Shares issued to Cornell Capital would be priced at a 3% discount to the lowest daily Volume Weighted Average Price ( VWAP ) of CanArgo common shares traded on each of the five days following a drawdown notice by CanArgo. A commission of 5% would apply to each issue of CanArgo shares under the Agreement and would be payable to Cornell Capital at the time of issue. The net effect of the 5% commission and the 3% discount is that Cornell Capital would pay 92.15% of the applicable lowest weighted price for each share of the company s common stock. The shares to be issued to Cornell Capital would be restricted securities as defined in rule 144 under the Securities Act. We agreed to prepare and file a registration statement under the Securities Act registering the shares to be issued under the facility for resale under such Act. This facility was terminated on February 11, 2004 when we entered into a further standby equity distribution agreement with Cornell ( New Cornell Facility ). No funds had been drawn down under the original facility when it was terminated.

Under the terms of the New Cornell Facility, Cornell Capital will provide us with an equity line of credit for 24 months. The New Cornell Facility allows us at our discretion to periodically issue and sell to Cornell Capital up to $20 million of shares of our common stock. The terms of the New Cornell Facility are materially the same as those for the original facility, with the exception that the New Cornell Facility has been increased to $20 million and the maximum amount of each advance is set at $600,000. No exercise of a Put will be made until the SEC has declared effective a registration statement registering the issuable shares under the Securities Act for resale. By way of fees and expenses, we shall issue Cornell

Capital a restricted stock certificate evidencing restricted shares of common stock in an amount equal to 2.07% of the Commitment Amount ($20,000,000) based upon the Market Price (as defined in the Agreement) for the common stock. The total amount of shares to be issued to Cornell Capital was 850,000 shares of which an aggregate of 425,000 shares were issued upon execution of the original and New Cornell Facilities. Cornell Capital will earn the remaining 425,000 restricted shares of common stock once the SEC declares the Registration Statement effective.

**Working Capital**

At December 31, 2003, our current assets of approximately $15.6 million exceeded our current liabilities of $12.4 million resulting in a working capital surplus of $3.2 million. This compares to a working capital surplus of $10.6 million as of December 31, 2002. Current liabilities as of December 31, 2003 consisted approximately of trade payables of $0.5 million, $1.4 million in a partial receipt of funds from a farm-in partner in respect of an agreement on the Norio project, $3.2 million in revenues due third parties; advanced proceeds, less costs of the sale of subsidiary $1.9m; advanced proceeds from the sale of other assets $0.3m, accrued liabilities $0.3m, income taxes payable $0.1m and loans payable $0.1m.

**Capital Expenditures**

Capital expenditures in 2003, 2002 and 2001 were $5.9 million, $10.7 million and $6.3 million, respectively. The table below sets forth the components of these capital expenditures for the three years ended December 31, 2003 2002 and 2001.

| Expenditure category: | 2003 | December 31, 2002 | 2001 |
|---|---|---|---|
| Development | **$5,200,614** | $ 543,280 | $ 2,054,989 |
| Exploration | **324,467** | 12,167,238 | 5,851,306 |
| Facilities and other | **412,772** | (1,975,366) | (1,589,908) |
| Total | **5,937,853** | 10,735,152 | 6,316,376 |

The negative expenditures recorded in facilities and other recorded in 2002 and 2001 is principally as a result of expenditures being reclassified to development and exploration expenditure from facilities and other when actual work is performed.

During 2003, 2002 and 2001 capital expenditures were primarily for the development and exploration of existing properties. During 2002, capital expenditures were primarily related to the exploration activity. We currently have a contingent planned minimum capital expenditure budget of $10 million subject to financing being available for 2004, of which all is allocated to Georgian development and appraisal projects. We plan to participate in the drilling of at least three horizontal sidetracks from existing wells on the Ninotsminda Field, complete the testing of the Manavi oil discovery well, M11, and drill at least one appraisal well on the Manavi structure. Further capital expenditures may be required following the conclusion of the Samgori farm-in. 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 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

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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.

**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, | |
|---|---|---|---|
| | **2003** | **2002** | **2001** |
| Net cash generated (used in) operating activities | $ **4,430,921** | $ 1,634,629 | $ (6,287,721) |
| Net cash used in investing activities | **(3,883,233)** | (8,431,282) | (12,388,739) |
| Net cash provided in financing | **1,529,791** | 3,174,870 | 3,085,563 |
| Net cash flows from assets and liabilities held for sale | **(190,227)** | (683,308) | (8,215,666) |
| Total | **1,887,252** | (4,305,091) | (23,806,563) |

Operating activities for the year ended December 31, 2003 provided us with $4.4 million of cash. Investing activities used $3.9 million during 2003. Financing activities provided us $1.5 million during 2003. Most of these funds were used to continue to fund and develop our Georgian projects. In 2003, cash generated from operating activities ($4.4m) was principally due to improved production resulting from our successful horizontal well program on the Ninotsminda Field in Georgia. In 2003, cash used in investing activities was due to capital expenditures principally in Georgia ($5.9m) partially offset by the proceeds from disposals of CanArgo Standard Oil Products ($1.4m), Boryslaw Oil Company ($1.0m) and other assets ($0.3m); and receipts from Georgian Oil in respect of the Norio farm-in ($1.4m).

**Future Capital Resources**

We will have five principal sources of liquidity going forward: (i) cash on hand, (ii) cash from operating activities, (iii) funding under the Cornell Capital Equity Facility, (iv) industry participation in our projects, and (v) 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 private placements.

**Balance Sheet Changes**

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

Cash and cash equivalents increased $1,887,000 to $3,472,000 at December 31, 2003 from $1,585,000 at December 31, 2002. The increase was primarily due to an increase in cash generated from operating activities, receipts in respect of the disposal of CanArgo Standard Oil Products and Boryslaw Oil Company, and receipt from the farm-in partner in respect of the Norio exploration program, partially offset by capital expenditures on the Ninotsminda project.

Accounts receivable decreased from $251,000 at December 31, 2002 to $162,000 at December 31, 2003 primarily as a result of an allowance against a number of historic receivables.

Inventory increased from $159,000 at December 31, 2002 to $469,000 at December 31, 2003 primarily as result of increased production of oil by Ninotsminda Oil Company. Ninotsminda Oil Company held approximately 97,000 barrels of oil in storage at December 31, 2003 for sale to the Georgian domestic, regional or international market.

Prepayments increased from $212,000 at December 31, 2002 to $962,000 at December 31, 2003 as a result of prepayment for materials and services related to CanArgo s exploration activities to be transferred to capital assets upon receipt. This increase is included in the statement of cash flows as an investing activity.

Assets held for sale, consisting of assets of CanArgo Standard Oil Products operations, a 3-megawatt duel fuel power generator, the assets of the refinery and the capital assets of the Bugruvativske Field project, decreased by $2,907,000 to $10,346,000 at December 31, 2003 from $13,253,000 at December 31, 2002 primarily due to a net write-down of $4,126,151 in 2003 of which $4,790,727 represented the write down of unproved oil and gas properties to reflect the estimated recoverable amount from the disposal of our interest in the Bugruvativske Field following an approved plan to sell our interest in the project and $667,576 represented a gain on disposal from the sale of CanArgo s interest in the Boryslaw Oil Company, the joint venture in West Ukraine currently operating the Stynawske oilfield. This was partially offset by activity at CanArgo Standard Oil Products relating to the addition of new petrol stations in Georgia.

Other currents assets increased from $176,000 at December 31, 2002 to $207,000 at December 31, 2002 as a result of a deposit to secure professional services.

Capital assets, net increased from $54,642,000 at December 31, 2002 to $58,323,000 at December 31, 2003, primarily as a result of investment of $5,938,000 in capital assets including oil and gas properties and equipment, principally related to the Ninotsminda PSC. During 2002, we wrote down our oil and gas properties in the Ninotsminda Field by an aggregate $1,600,000 on application of the full cost ceiling test as a result of lower reserve quantities following production declines in 2002 and reduced development plans. If oil prices or production levels were to decline in the future, we may experience an additional impairment of this property.

Investments in and advances to oil and gas and other ventures, net deceased from $459,000 at December 31, 2002 to $75,000 at December 31, 2003. The decrease reflects our announcement in 2003, that we had reached conditional agreement to sell our interest in Boryslaw Oil Company, the joint venture in West Ukraine currently operating the Stynawske Oil Field. Fountain Oil Boryslaw, CanArgo s wholly owned subsidiary which holds our 45% interest in Boryslaw Oil Company, was sold for $1,000,000 payable in eight equal tranches. Payment in full was received in December 2003.

Accounts payable increased to $483,000 at December 31, 2003 from $405,000 at December 31, 2002 primarily due to an absolute increase in corporate payables.

Advance from joint venture partner of $1,428,000 at December 31, 2003 relates to an initial receipt from Georgian Oil in accordance with the Norio farm-in agreement.

Loans payable of $102,179 at December 31, 2003 relates to a short-term secured loan facility maturing on February 27, 2004, which a subsidiary of CanArgo entered into, locally in Georgia, at an annual interest rate of 20% in order to fund the drilling of a new horizontal well, N4H, at the Ninotsminda Field in Georgia. No parent company guarantees have been provided by CanArgo with respect to this loan. The loan matured and was paid off in full in February 2004.

Other Liabilities increased from $1,500,000 at December 31, 2002 to $5,474,000 at December 31, 2003 due to advance proceeds received for the sale of CanArgo Standard Oil Products in the period, advance proceeds received for the sale of a 3-megawatt duel fuel power generator and security received resulting from an oil sales agreement entered into during the period whereby the buyer provided a security payment of $1.75 million in return for the right to lift up to 5,000 metric tons of oil per month for the 12 month period commencing August 2003 and a further security payment of $550,000 under an additional oil sales agreement in return for the rights to lift 2,500 metric tons of oil up to the end of December 2004. Proceeds received in respect of CanArgo Standard Oil Products sale are $2,000,000 at December 31, 2003.

Income taxes payable increased from $61,000 from at December 31, 2002 to $97,000 at December 31, 2003 due to the final assessment of income tax payable for Ninotsminda Oil Company Ltd, a CanArgo subsidiary.

Accrued liabilities increased to $349,000 at December 31, 2003 from $204,000 at December 31, 2002 primarily due to an increase in accrued professional fees.

Liabilities held for sale increased by $1,629,000 from $2,819,000 at December 31, 2002 to $4,448,000 at December 31, 2003 due to liabilities held for sale, in respect of discontinued operations, that increased by $1,614,000 to $3,774,000 at December 31, 2003 from $2,160,000 at December 31, 2002 primarily due to additional bank loans drawn by CanArgo Standard Oil Products in Tbilisi at an effective interest rate of 18% per annum, in order to fund the construction of new petrol stations in Georgia.

Minority interest in continuing and discontinued subsidiaries increased by $1,254,000 to $4,773,000 at December 31, 2003 from $3,519,000 at December 31, 2002 due to due to the write down of $1,274,895 of the minority interest share of losses relating to the refinery, minority interest share of income in the period, partially offset by CanArgo purchasing some of the minority interests in CanArgo Norio by a share swap for shares in CanArgo in the period.

The foreign currency translation is due to the Company adopting the self-sustaining method of accounting for CanArgo Standard Oil Products. The fact that CanArgo Standard Oil Products was no longer financially and operationally dependant upon its parent company necessitated the adoption of the self-sustaining method. Under the self-sustaining method of foreign currency translation, assets and liabilities are translated into US dollars at period end exchange rates and income and expenses are translated into US dollars at average rates in effect during the period. Exchange gains and losses on translation are reflected as a separate component of shareholders equity.

On March 23, 2004 at a duly convened special meeting of our stockholders held in Oslo, Norway the requisite majority of our stockholders approved an amendment to Article 4 of our Certificate of Incorporation to increase the number of shares of common stock, par value $.10 per share, that we are authorized to issue from 150,000,000 to 300,000,000.

**Results of Continuing Operations**

*Year Ended December 31, 2003 Compared to Year Ended December 31, 2002*

CanArgo recorded operating revenue of $8,105,000 during the year ended December 31, 2003 compared with $5,486,000 for the year ended December 31, 2002. The increase is primarily attributable to higher oil and gas revenues, being partially offset by lower other revenue being recorded in the twelve month period ended December 31, 2003. Other revenue for the twelve month period ended December 31, 2003 and 2002 represented the provision of drilling services in Georgia.

Ninotsminda Oil Company generated $7,881,000 of oil and gas revenue in the year ended December 31, 2003 compared with $4,163,000 for the year ended December 31, 2002 due to higher volume of sales resulting from increased production from the successful horizontal wells completed in 2003 and a higher average net sales price achieved in 2003. Its net share of the 695,174 barrels (273 barrels per day) of gross oil production for sale from the Ninotsminda Field in the period amounted to 451,863 barrels. In 2003, 64,142 barrels of oil were added to storage**.** For the year ended December 31, 2002, Ninotsminda Oil Company s net share of the 292,289 barrels (801 barrels per day) of gross oil production was 189,988 barrels. The increase in production is due to the successful horizontal development wells completed at the Ninotsminda Field in 2003.

Ninotsminda Oil Company s entire share of production was sold locally in Georgia under both national and international contracts. Net sale prices for Ninotsminda oil sold during 2003 averaged $20.07 per barrel as compared with an average of $17.09 per barrel in 2002. Its net share of the 108,630 thousand cubic feet (mcf) of gas delivered was 70,610 mcf at an average net sale price of $1.25 per mcf of gas. For the year ended December 31, 2002, Ninotsminda Oil Company s net share of the 212,499 mcf of gas delivered was 138,124 mcf at an average net sales price of $1.25 per mcf of gas.

CanArgo had other revenue of $224,000 for the year ended December 31, 2003 compared to other revenue of $1,323,000 for the year ended December 31, 2002. In 2003 and 2002, other revenue consisted of the provision of drilling services. In September 2001, CanArgo entered into an agreement to provide drilling services to a third party using one of CanArgo s rigs. Commercial drilling operations commenced in October 2001 and continued through February 2002. The Company subsequently established a wholly owned well services subsidiary (Argonaut Well services Limited) and at the end of March 2003 concluded a new drilling services contract with an operating company in Georgia. It will continue to bid in appropriate tenders for drilling contracts in order to utilize drilling equipment not otherwise used in its own operations.

The operating loss from continuing operations for the year ended December 31, 2003 amounted to $159,000 compared with an operating loss of $4,902,000 for 2002. The decrease in operating loss is attributable primarily to a reduction in field operating expenses, reduced selling, general and administration expense, reduced direct project costs in the period, and an impairment of oil and gas properties in 2002; partially offset by an increase in depletion and amortization in the period; and stock compensation in expense in 2003.

Field operating expenses decreased to $1,052,000 ($2.59 per BOE) for the year ended December 31, 2003 as compared to $1,538,000 ($4.69 per BOE) for 2002. The decrease is primarily a result of a cost reduction program initiated in the last quarter of 2002 at the Ninotsminda Field and costs relating to increase of oil storage in the year. Operating costs per BOE decreased as day-to-day field operations in Georgia include a proportionately higher fixed to variable cost component combined with a cost reduction program initiated in the last quarter of 2002 at the Ninotsminda Field and higher production rates.

Direct project costs decreased to $1,029,000 for the year ended December 31, 2003, from $1,429,000 for the year ended December 31, 2002, primarily due to costs associated with the provision of drilling services in Georgia in 2002.

Selling, general and administrative costs decreased to $3,229,000 for the year ended December 31, 2003, from $3,494,000 for the year ended December 31, 2002. The decrease is primarily as a result of a corporate cost reduction program initiated in the last quarter of 2002.

Non cash stock compensation expense increased to approximately $277,000 for the year ended December 31, 2003, from nil for the year ended December 31, 2002 due to the Company, effective January 1, 2003, adopting the fair value recognition provisions of SFAS No. 123, Accounting for Stock-Based Compensation, prospectively to all employee awards granted, modified, or settled after December 31, 2002.

The increase in depreciation, depletion and amortization expense to $3,294,000 for the year ended December 31, 2003 from $2,317,000 for the year ended December 31, 2002 is attributable principally to higher production resulting from the successful horizontal wells at the Ninotsminda Field completed in 2003.

We wrote down our oil and gas properties in the Ninotsminda Field by an aggregate $1,600,000 on application of the full cost ceiling test as a result of lower reserve quantities following production declines in 2002. The write-down was a non-cash write-down. If oil prices or production levels declined in the future, we may experience an additional impairment of this property.

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During 2003, CanArgo also announced it had reached conditional agreement to sell its interest in Boryslaw Oil Company, the joint venture in West Ukraine currently operating the Stynawske Oil Field. Fountain Oil Boryslaw, CanArgo s wholly owned subsidiary which holds our 45% interest in Boryslaw Oil Company, was sold for $1,000,000 and a gain on disposal of $665,000 was also recorded in gain on disposition of investments during the period.

CanArgo recorded net other expenses of $605,000 for the year ended December 31, 2003, as compared to net other expense of $576,000 during the year ended December 31, 2002. The increase is primarily due to foreign exchange translation losses during 2003 partially offset by CanArgo s adjusted interest in its share of the carrying net asset value of its subsidiary CanArgo Norio Limited (Norio) giving rise to a non-operating loss of $444,000, in accordance with the application of SAB 51, following agreement with the minority shareholders on the finalization of respective equity interest in Norio in 2002, and a bad debt allowance of $275,000 being recorded in 2002.

Equity income from investments decreased to $66,000 for the year ended December 31, 2003 from an equity income of $86,000 for the year ended December 31, 2002 primarily as a result of only nine months of equity income recorded from production and sales of crude oil by Boryslaw Oil Company prior to its disposal in the last quarter of 2003.

The net loss from continuing operations of $756,000 or $0.01 per share for the year ended December 31, 2003 compares to a net loss from continuing operations of $5,478,000 or $0.06 per share for the year ended December 31, 2002. The weighted average number of common shares outstanding was higher during the year ended December 31, 2003 than during the year ended December 31, 2002, due in large part to share issues in respect of agreements relating to of Norio and Manavi projects during 2003.

The cumulative effect of change in accounting principle of $41,290 at December 31, 2003 relates to the adoption of FASB Statement No. 143 Accounting for Asset Retirement Obligations ( SFAS 143 ) on January 1, 2003. SFAS 143 requires companies to record the discounted fair value of a liability for an asset retirement obligation in the period in which the liability is incurred concurrent with an increase in the long-lived assets carrying value. The increase and subsequent adjustments in the related long-lived assets carrying value is amortised over its useful life. Upon settlement of the liability a gain or loss is recorded for the difference between the settled liability and the recorded amount. The discount associated with the liability is accreted into income over the related asset s useful life. Upon adoption of this standard an entity is required to record the fair value of its existing asset retirement obligations as if the liabilities had been initially accounted for in accordance with SFAS 143 using assumptions present at the date of adoption. The income statement effect of the treatment is recorded as a cumulative effect in accounting principle in the period of adoption, no retroactive restatement is permitted.

*Year Ended December 31, 2002 Compared to Year Ended December 31, 2001*

CanArgo recorded operating revenue of $5,486,000 during the year ended December 31, 2002 compared with $4,575,000 for the year ended December 31, 2001. The increase is primarily attributable to other revenue, representing provision of drilling services in Georgia.

Ninotsminda Oil Company generated $4,163,000 of oil and gas revenue in the year ended December 31, 2002 compared with $3,967,000 for the year ended December 31, 2001 due principally to a lower average net sales price achieved in 2002. Its net share of the 292,289 barrels (801 barrels per day) of gross oil production for sale from the Ninotsminda Field in the period amounted to 189,988 barrels. In 2002, 44,483 barrels of oil were removed from storage and sold**.** For the year ended December 31, 2001, Ninotsminda Oil Company s net share of the 413,724 barrels (1,133 barrels per day) of gross oil production was 247,179 barrels. The decline in production is due to limited workover investment resulting in a natural reservoir rate of decline.

Ninotsminda Oil Company s entire share of production was sold locally in Georgia under both national and international contracts. Net sale prices for Ninotsminda oil sold during 2002 averaged $17.09 per barrel as compared with an average of $19.43 per barrel in 2001. Its net share of the 212,499 thousand cubic feet

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(mcf) of gas delivered was 138,124 mcf at an average net sale price of $1.25 per mcf of gas. For the year ended December 31, 2001, Ninotsminda Oil Company s net share of the 1,110,390 mcf of gas delivered was 721,754 mcf at an average net sales price of $1.14 per mcf of gas. Gas deliveries for the year ended December 31, 2002 declined significantly due to lower oil and gas production and the temporary shutdown by AES of its thermal power generating station following an accident at the facility. Although AES has now re-opened, CanArgo has not sold any further gas to AES since their demand for gas was too great for CanArgo to meet from production.

CanArgo had other revenue of $1,323,000 for the year ended December 31, 2002 compared to other revenue of $608,000 for the year ended December 31, 2002. In 2002 and 2001, all other revenue consisted of the provision of drilling services. In September 2001, CanArgo entered into an agreement to provide drilling services to a third party using one of CanArgo s rigs. Commercial drilling operations commenced in October 2001 and continued through February 2002. No new drilling service contracts have been signed, although the company has established a well services subsidiary, which will bid in local tenders for drilling contracts.

The operating loss from continuing operations for the year ended December 31, 2002 amounted to $4,902,000 compared with an operating loss of $11,838,000 for 2001. The decrease in operating loss is attributable primarily to reduced impairment of oil and gas properties in 2002, profit generated from a drilling services contract, and a reduced depreciation, and reduced depletion and amortization in the period.

Field operating expenses decreased to $1,538,000 ($4.69 per BOE) for the year ended December 31, 2002 as compared to $1,568,000 ($2.62 per BOE) for 2001. The decrease is primarily a result of decreased activity at the Ninotsminda Field offset partially by costs relating to sales of oil from storage in the year. Operating costs per BOE increased as day-to-day field operations in Georgia include a proportionately higher fixed to variable cost component combined with lower production rates.

Direct project costs increased to $1,429,000 for the year ended December 31, 2002, from $1,300,000 for the year ended December 31, 2001, reflecting additional costs associated with the provision of drilling services in Georgia.

Selling, general and administrative costs increased to $3,494,000 for the year ended December 31, 2002, from $3,483,000 for the year ended December 31, 2001. The increase was primarily as a result of the impact of increased costs resulting from business development activity offset partially the impact of a corporate cost reduction program initiated in the last quarter of 2002.

The decrease in depreciation, depletion and amortization expense to $2,317,000 for the year ended December 31, 2002 from $2,746,000 for the year ended December 31, 2001 is attributable principally to lower production, due to limited workover investment resulting in a natural reservoir rate of decline.

During 2002, CanArgo wrote down its oil and gas properties in the Ninotsminda Field by an aggregate $1,600,000 on application of the full cost ceiling test as a result of lower reserve quantities following production declines in 2002. The write-down was a non-cash write-down. In 2001, CanArgo wrote down its oil and gas properties in the Ninotsminda Field by an aggregate $7,300,000 on application of the full cost ceiling test as a result of a decline in Brent oil prices at December 31, 2001, lower reserve quantities following production declines in 2001 and reduced development plans. If oil prices or production levels decline further, CanArgo may experience additional impairment of this property.

CanArgo recorded net other expenses of $576,000 for the year ended December 31, 2002, as compared to net other income of $525,000 during the year ended December 31, 2001. This is primarily due to CanArgo s adjusted interest in its share of the carrying net asset value of its subsidiary CanArgo Norio Limited (Norio) giving rise to a non-operating loss of $444,000, in accordance with the application of SAB 51, following agreement with the minority shareholders on the finalization of respective equity interest in Norio. Additional movements are explained by lower cash balances in 2002, an allowance for doubtful accounts of $275,000 from previous gas sales, and a bad debt write-off of $93,000 relating to the provision of drilling services in Georgia.

Equity income from investments increased to $86,000 for the year ended December 31, 2002 from an equity loss of $160,000 for the year ended December 31, 2001 as a result of increased equity income from production and sales of crude oil by Boryslaw Oil Company and 2001 expenses relating to operation by East Georgian Pipeline Company of the gas pipeline from Ninotsminda to the Gardabani power station.

The net loss from continuing operations of $5,478,000 or $0.06 per share for the year ended December 31, 2002 compares to a net loss from continuing operations of $11,313,000 or $0.16 per share for the year ended December 31, 2001. The weighted average number of common shares outstanding was substantially higher during the year ended December 31, 2002 than during the year ended December 31, 2001, due in large part to private placements in July 2001, February and May 2002.

**Results of Discontinued Operations**

*Year Ended December 31, 2003 Compared to Year Ended December 31, 2002*

The net income from discontinued operations, net of taxes and minority interest for the year ended December 31, 2003 amounted to $6,608,000 compared with net income of $150,000 for the corresponding period in 2002. The increase in net loss from discontinued operations, net of taxes and minority interest relates to the activities of LVR and GAOR, offset partially by the activities of CanArgo standard Oil Products. Losses increased at GAOR as there was no income in the year ended December 31, 2003.

During 2003**,** CanArgo approved a plan to sell its interest in the Bugruvativske Field and recorded a write-down of $4,790,727 in 2003 of unproved oil and gas properties to reflect the estimated recoverable amount from disposal**.**

An impairment of other assets of $1,355,000 for the year ended December 31, 2003, from nil for the year ended December 31, 2002 was due to a write-down of the minority interest share of losses relating to GAOR of $1,274,895 and the a write- down of a generator in the period to its net realizable value by $80,000. During 2003, a debit balance of $1,274,895 in minority interest was written-off due to a change in the intentions of our minority interest owner and a plan to dispose of the asset. In 2004, CanArgo came to an agreement to sell the refinery.

Increased income at CanArgo standard Oil Products is due to higher sales volume during 2003 offset partially by more competitive operating margins for the year ended December 31, 2003 compared with the corresponding period in 2002. Increased income at LVR related to foreign exchange gains in the period for the year ended December 31, 2003 compared with the corresponding period in 2002

*Year Ended December 31, 2002 Compared to Year Ended December 31, 2001*

The net income from discontinued operations, net of taxes and minority interest for the year ended December 31, 2002 increased to $150,000 compared with net loss of $1,905,000 for the corresponding period in 2001. The increase in net income from discontinued operations, net of taxes and minority interest relates mainly to the activities of GAOR and the impairment of a power-generating unit in 2001, offset partially by the activities of CanArgo standard Oil Products and LVR.

During 2001, Georgian American Oil Refinery ( GAOR ) was producing operating losses. Only naphtha, diesel and mazut can be produced and of these products, an excise tax on both naphtha and diesel sales remains in place. In the fourth quarter 2001, GAOR deemed the production of naphtha as commercially uneconomic and suspended refining activity. In 2002, GAOR entered into a short-term lease of the refinery to a third party for nominal revenue. During the lease period, all operating costs of the refinery were borne by the lessee. This lease expired in May 2002 and has not been renewed. In 2003, CanArgo approved a plan to dispose of its interest in GAOR.

In 2001, as a result of both product instability and continued difficulties addressing excise taxes on refined products, refinery and related equipment was written-down by $3,360,000 to reflect, under current conditions, the estimated net recoverable amount of the refinery.

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In 2001, CanArgo wrote down other oil and gas related equipment by $500,000 following a decision to dispose of a power-generating unit. In 2002, a plan was agreed to sell this equipment and it is included in assets held for sale as at December 31, 2002.

CanArgo standard Oil Products income decreased for the year ended December 31, 2002 due to more competitive operating margins for the year ended December 31, 2002 compared with the corresponding period in 2001 and interest on additional bank loans drawn by CanArgo Standard Oil Products in Tbilisi at an effective interest rate of 18% per annum, in order to fund the construction of new petrol stations in Georgia.

LVR corporate costs for the year ended December 31, 2002 were lower than the corresponding period in 2001 due to less corporate activity.

### Contractual Obligations and Commercial Terms

Our principal business and assets are derived from production sharing contracts in the Republic of 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 production sharing contract 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 the 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 Ninotsminda Oil Company 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 Ninotsminda Oil Company 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.

In 2002, the Participation Agreement for the three well exploration program on the Ninotsminda area with AES was terminated without AES earning any rights to any of the Ninotsminda 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 $7.5 million, representing their prior funding under the Participation Agreement.

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CanArgo has 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 it has interests that require or may require CanArgo to expend funds and to issue shares of its Common Stock.

At December 31, 2003, CanArgo had a contingent obligation to issue 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.

Under the Norio and North Kumisi PSA the shareholders agreement with the other shareholder of Norio calls for a bonus payment of $800,000 to be paid by CanArgo should commercial production be obtained from the Middle Eocene or older strata and a second bonus payment of $800,000 should production from the Block from the Middle Eocene or older strata exceed 250 tons of oil per day over any 90 day period.

In September 2003, CanArgo Norio signed a farm-in agreement relating to the Norio Production Sharing Agreement ( Norio PSA ) with a wholly owned subsidiary of Georgian Oil. CanArgo Norio had previously been in negotiations with a large third party energy company to farm-in to the Norio PSA, but Georgian Oil exercised its pre-emption rights under the Norio PSA. Georgian Oil is already a party to the PSA as the commercial representative of the State. The agreement obligates Georgian Oil to pay up to US$ 2.0 million to complete the MK-72 well on the Norio prospect in return for a 15% interest in the contractor share of the Norio PSA. Georgian Oil will also have an option (the 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 CanArgo Norio of US$ 6.5 million. The well was suspended in 2002 due to lack of available funding at that time. Drilling recommenced on the well in December 2003 and the current depth is approximately 4,200 meters. It is expected that the well will be finished within three months.

Co-incident with the Georgian Oil farm-in, CanArgo concluded a deal to purchase some of the minority interests in CanArgo Norio by a share swap for shares in CanArgo. Through this CanArgo has acquired an additional 10.8% interest in CanArgo Norio, giving CanArgo a 75% interest in CanArgo Norio at present. This approximately maintains CanArgo s effective interest in the Norio PSA after Georgian Oil has completed the first stage of the farm-in at 63.7%. The purchase was achieved by issuing 6 million restricted CanArgo shares to the minority interest holders in CanArgo Norio. 4.0% of these minority interests were owned by Provincial Securities Limited, a company which J.F. Russell Hammond, a non-executive director of CanArgo, is an Investment Advisor. In the event that Georgian Oil exercises the Option and pays the required $6.5 million, CanArgo (which would have received some $4.8 million of this payment with its previous interest) would receive a further $1.2 million, resulting in a total payment to CanArgo of approximately $6 million. If the Option is exercised CanArgo would issue a further 3 million restricted shares to the minority interest holders.

In May 2003, NOC entered into a new 12-month crude oil sales agreement whereby the buyer will provide a security payment of $1.75 million in return for the right to lift up to 5,000 metric tons of oil per month for the 12-month period commencing August 2003. At the end of the 12 months, the security payment will be repaid through the delivery of additional crude oil equal to the value of the security. This agreement replaces an existing crude oil sales agreement, where the buyer had already provided $1million security. Following the success of the N100H well, NOC entered into a further oil sales agreement with the buyer for an additional monthly quantity of 2,500 metric tons of oil. The agreement runs to the end of 2004 and as security for payment and for having the option to lift oil on a monthly basis the buyer will provide additional security in the amount of $550,000. The security will be repaid in oil at the end of the contract period. NOC has a total commitment to repay $2.3m arising from security payments under oil sales agreements signed in May 2003 and October 2003.

On July 2, 2003 CanArgo announced that its subsidiary CanArgo Norio had entered into a new Production Sharing Contract (PSC) for Blocks $XI^G$ and $XI^H$ (Mtskheta, Tetritskaro and Gardabani areas), named the Tbilisi PSC in the

Republic of Georgia. The licence was subsequently issued on 9 July 2003 for a period of 25 years. These areas are located adjacent to CanArgo s existing acreage close to Tbilisi and cover in total approximately 119,843 acres (485 $km^2$). Under the terms of the Tbilisi PSC, CanArgo Norio will evaluate existing seismic and geological data during the first year and acquire additional seismic data within four years of the effective date of the Agreement which is September 29, 2003. The total

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commitment over the next four years is $350,000. The commercial terms of the Tbilisi PSC are similar to those governing CanArgo Norio s other exploration areas.

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, 2003.

| 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 | $261,400 | 683,183 | 440,000 | 220,000 |
| Loans payable | 102,179 | | | |
| Other long-term liabilities (1) | | | | 152,000 |
| | **$363,579** | **683,183** | **440,000** | **372,000** |

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

(2) CanArgo has no contractual obligations in respect of long-term debt, capital leases or purchase obligations.

**Related Party Transactions**

Of the 50% of CanArgo Standard Oil Products not held by CanArgo, 41.65% is held by Standard Oil Products, an unrelated third party entity, and 8.35% is held by an individual, Mr Levan Pkhakadze, who is one of the founders of Standard Oil Products and is an officer and director of CanArgo Standard Oil Products. The majority of refined product purchased by CanArgo Standard Oil Products for resale at its petrol stations is purchased from a company controlled by Standard Oil Products who together with an individual shareholder, own the 50% interest in CanArgo Standard Oil Products not held by CanArgo. Total product purchases from the related company in 2003 were $7,229,000 (2002 $5,263,000).

A company owned by significant employees of Georgian British Oil Company Ninotsminda provides certain equipment to Georgian British Oil Company Ninotsminda. Total rental payments for this equipment in 2003 were $183,428 ($125,729 in 2002). In 2003, the same company provided additional services to Georgian British Oil Company Ninotsminda in accordance with the farm-in agreement in respect of the Manavi well for the value of $450,000.

Dr. David Robson, Chief Executive Officer, provides all of his services to CanArgo through Vazon Energy Limited of which he is the Managing Director.

Mr. Russell Hammond, a non-executive director of CanArgo, is also an Investment Advisor to Provincial Securities who became a minority shareholder in the Norio and North Kumisi Production Sharing Agreement through a farm-in agreement to the Norio MK72 well.

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 (productive and non-productive) 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, 2003, 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.

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.

Concentration of Credit Risk

Although CanArgo s cash and temporary investments and accounts receivable are exposed to potential credit loss, CanArgo does 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

CanArgo s future operations and earnings will depend upon the results of CanArgo s operations in the Republic of Georgia. There can be no assurance that CanArgo will be able to successfully conduct such operations, and a failure to do so would have a material adverse effect on the CanArgo s financial position, results of operations and cash flows. Also, the success of CanArgo s 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 CanArgo is dependent on international operations, specifically those in the Republic of Georgia, CanArgo will be subject to various additional political, economic and other uncertainties. Among other risks, CanArgo s 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.

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**New Accounting Standards**

In January 2003, the FASB issued Interpretation No. 46, Consolidation of Variable Interest Entities, an interpretation of ARB No. 51 ( FIN 46 ). In December 2003, the FASB modified FIN 46 to make certain technical corrections and address certain implementation issues that had arisen. FIN 46 provides a new framework for identifying variable interest entities ( VIEs ) and determining when a company should include the assets, liabilities, noncontrolling interests and results of activities of a VIE in its consolidated financial statements.

In general, a VIE is a corporation, partnership, limited-liability corporation, trust, or any other legal structure used to conduct activities or hold assets that either: (1) has an insufficient amount of equity to carry out its principal activities without additional subordinated financial support; (2) has a group of equity owners that are unable to make significant decisions about its activities; or (3) has a group of equity owners that do not have the obligation to absorb losses or the right to receive returns generated by its operations.

FIN 46 requires a VIE to be consolidated if a party with an ownership, contractual or other financial interest in the VIE ( a variable interest holder ) is obligated to absorb a majority of the risk of loss from the VIEs activities, is entitled to receive a majority of the VIEs residual returns (if no party absorbs a majority of the VIEs losses), or both. A variable interest holder that consolidates the VIE is called the primary beneficiary. Upon consolidation, the primary beneficiary generally must initially record all the VIEs assets, liabilities and noncontrolling interests at fair value and subsequently account for the VIE as if it were consolidated based on majority voting interest. FIN 46 also requires disclosures about VIEs that the variable interest holder is not required to consolidate but in which it has a significant variable interest.

On October 9, 2003, the FASB issued Staff Position No. 46-6 which deferred the effective date for applying the provisions of FIN 46 for interests held by public entities in variable interest entities or potential variable interest entities created before February 1, 2003. On December 24, 2003, the FASB issued a revision to FIN 46. Under the revised interpretation, the effective date was delayed to periods ending after March 15, 2004 for all variable interest entities, other than SPEs. The adoption of FIN 46 is not expected to have an impact on the Company s financial condition, results of operations or cash flows.

The Company does not have an interest in any special purpose entity that is required to be consolidated under FIN 46. The Company s is currently evaluating its involvement in other entities pursuant to the revised guidance; however, the Company does not anticipate a significant effect as a result of its application.

In April 2003, the FASB issued SFAS No. 149, Amendment of Statement No. 133 on Derivative Instruments and Hedging Activities. This statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. SFAS No. 149 requires that contracts with comparable characteristics be accounted for similarly. The statement is effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003. The provisions of SFAS No. 149 generally are to be applied prospectively only. The adoption of SFAS No. 149 did not have a material impact on the Company s results of operations or financial position.

In May 2003, the FASB issued SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity. SFAS No. 150 establishes standards for classification and measurement by an issuer of certain financial instruments with characteristics of both liabilities and equity. The statement requires that an issuer classify a financial instrument that is within its scope as a liability (or asset in some circumstances). Many of those instruments were previously classified as equity. This Statement also addresses questions about the classification of certain financial instruments that embody obligations to issue equity shares. This statement is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003, except as it relates to consolidated limited-life subsidiaries. The FASB indefinitely deferred the effective date of this statement as it relates to certain mandatory redeemable noncontrolling interests in consolidated limited-life subsidiaries. The adoption of the effective provisions of SFAS No. 150 did not have a material impact on the Company s results of operations or financial position.

On December 17, 2003, the Staff of the Securities and Exchange Commission (or SEC) issued Staff Accounting Bulletin No. 104 ( SAB 104 ), Revenue Recognition, which supersedes Staff Accounting Bulletin No. 101, Revenue Recognition in Financial Statements ( SAB 101 ). SAB 104 s primary purpose is to rescind the accounting guidance contained in SAB 101 related to multiple-element revenue arrangements that was superseded as a result of the issuance of EITF 00-21,Accounting for Revenue Arrangements with Multiple Deliverables. Additionally, SAB 104 rescinds the SEC s related Revenue Recognition in Financial Statements Frequently Asked Questions and Answers issued with SAB 101 that had been codified in SEC Topic 13, Revenue Recognition. While the wording of SAB 104 has changed to reflect the issuance of EITF 00-21, the revenue recognition principles of SAB 101 remain largely unchanged by the issuance of SAB 104, which was effective upon issuance. The adoption of SAB 104 did not have a material effect on the Company s financial position or results of operations.

Management has been made aware of a reporting issue regarding the application of provisions of SFAS 141, Business Combinations and SFAS No. 142, Goodwill and Other Intangible Assets (SFAS 142) to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS 142 requires registrants to reclassify costs associated with mineral rights, including both proved and unproved leasehold acquisition costs, as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs. Historically, the Company s and other oil and gas companies have included the cost of these oil and gas leasehold interests as part of oil and gas properties and provided the disclosures required by SFAS No. 69, Disclosures about Oil and Gas Producing Activities (SFAS 69). Also under consideration is whether SFAS 142 requires registrants to provide the additional disclosures prescribed by SFAS 142 for intangible assets for costs associated with mineral rights.

The Emerging Issues Task Force ( EITF ) has recently decided to consider this issue. If the EITF determines that SFAS 142 requires the Company to reclassify costs associates with mineral rights from property and equipment to intangible assets, the Company currently believes that its results of operations and financial condition would not be materially affected, since such intangible assets would continue to be depleted and assessed for impairment in accordance with existing full cost accounting rules and impairment standards. In addition, cost associated with mineral rights would continue to be characterized as oil and gas property costs in the Company s required disclosures under SFAS 69.

**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.

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We do not have a majority of the equity in the entity that is the licensed developer of some projects, , that we may pursue in 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. As a result of all of the foregoing, among other matters, any forward-looking statements regarding the occurrence and timing of future events may well anticipate results that will not be realized. 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 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 hawse 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.

**Commitments**

CanArgo has not filed any of its required 2002 or 2003 income tax or information returns required by various governmental authorities. Failure to file these returns carries significant penalties. CanArgo is taking steps to rectify the matter. CanArgo has not accrued for any penalties it may be required to pay.

## 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)

Date: August 31, 2004

By: /s/ Vincent McDonnell

Chief Financial Officer

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