RENEWAL ANNUAL INFORMATION FORM

For the year ended December 31, 2002

May 16, 2003

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GLOSSARY OF TERMS

In this Annual Information Form, the following words and phrases have the meanings set forth below, unless the context otherwise requires:

"**AIF**" means the Annual Information Form of the Company dated May 16, 2003;

"**Canadian Property Acquisition**" means the purchase by the Company of certain western Canadian oil and natural gas properties from ConocoPhillips Canada Limited (formerly Conoco Resources Canada Limited and formerly Gulf Canada Resources Limited) for $72 million on February 26, 1999;

"**Common Share**" means a common share in the capital of the Company;

"**Common Share Purchase Warrant**" means a warrant to acquire Common Shares at an exercise price of $2.08 per share, expiring on December 14, 2005;

"**Company**" or "**Resolute**" means Resolute Energy Inc., a corporation continued under the laws of the Province of Alberta;

"Cost Recovery Oil" means the amount of Indonesian production, as defined in the TAC, which is applied to recover PERTAMINA's share of all drilling and operating costs funded by the Company's subsidiaries;

"Crown" means Her Majesty the Queen in Right of Canada or a Province thereof;

"crude oil" or **"oil"** means a mixture, consisting mainly of pentanes and heavier hydrocarbons that may contain sulphur compounds, that is liquid at the conditions under which its volume is measured or estimated, but excluding such liquids obtained from the processing of natural gas;

"**EEII**" means Equatorial Energy (Indonesia) Inc., a corporation incorporated under the laws of the British Virgin Islands and an indirect wholly-owned subsidiary of the Company;

"**EQII**" means Equatorial Energy (International) Inc., a corporation incorporated under the laws of Barbados and a wholly-owned subsidiary of the Company;

"Equatorial Acquisition" means the acquisition by the Company (formerly Equatorial Energy Inc. ("Equatorial")) of the securities of RII on June 14, 2002, which was accounted for as a reverse take-over;

"**GLJ**" means Gilbert Laustsen Jung Associates Ltd., independent petroleum consultants, Calgary, Alberta;

"**GLJ Canada Report**" means the report dated March 5, 2003, prepared by GLJ evaluating the Company's petroleum and natural gas reserves in Canada as of December 31, 2002;

"**GLJ Indonesia Report**" means the report dated January 31, 2003, prepared by GLJ evaluating the Company's subsidiaries' petroleum and natural gas reserves in Indonesia as of December 31, 2002;

"**Government Share**" means PERTAMINA's interest in the Company's subsidiaries' Indonesian properties other than income taxes;

"**gross acres**" means the total number of acres in which the Company has an interest;

"natural gas" means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions is essentially a gas, but which may contain liquids. Natural gas reserve estimates are reported on a marketable basis, that is gas which is available to a transmission line after removal of certain hydrocarbons and non-hydrocarbon compounds present in the raw natural gas and which meets specifications for use as a domestic, commercial or industrial fuel;

"natural gas liquids" or **"NGL"** means those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants or recovered from field separators, scrubbers of other gathering facilities. These liquids include the hydrocarbon components ethane, propane, butanes and pentanes plus, or a combination thereof;

"**net acres"** means gross acres multiplied by the Company's percentage working interest therein;

"**net producing wells"** means the Company's working interest multiplied by the number of producing wells;

"**Performance Warrant"** means a warrant to acquire Common Shares, expiring December 10, 2008;

"**Perkasa"** means Perkasa Equatorial Sembakung Ltd., a corporation incorporated under the laws of the British Virgin Islands and an indirect 80% owned subsidiary of the Company;

"**Perkasa TAC"** means Perkasa's 100% interest in an Indonesian TAC dated May 1, 1994 with PERTAMINA;

"**PERTAMINA"** means Perusahaan Pertambangan Minyak Dan Gas Bumi Negara, the state oil and gas company of Indonesia;

"**Pilona"** means Pilona Petro Tanjung Lontar Ltd., an indirect wholly-owned subsidiary of the Company organized under the laws of the British Virgin Islands;

"**Pilona TAC"** means Pilona's 100% interest in an Indonesian TAC dated October 7, 1996 with PERTAMINA;

"**Profit Oil"** means the amount of Indonesian production that is shared, as defined in the TAC, with PERTAMINA after the Company recovers PERTAMINA's share of all drilling and operating costs funded by the Company's subsidiaries. This amount, before tax, is 28.8642% for the Perkasa TAC and 26.786% for the Pilona TAC;

"**RII"** means Resolute Investments Inc., formerly Resolute Energy Corporation, a wholly-owned subsidiary of the Company incorporated under the laws of the Province of Alberta;

"**SWS"** means the Second White Speckled Shale Formation;

"**TAC"** means technical assistance contract. Such arrangements are made in accordance with Law No. 44 Prp/1960 and Law No. 8/1971 of the Republic of Indonesia. TACs are signed by PERTAMINA as the holder of the oil and natural gas mining authority granted by the Republic of Indonesia and are approved by the Indonesian Minister of Mines and Energy;

"200 Day Period" means the 200 day period following the Equatorial Acquisition on June 14, 2002. Due to the application of reverse take-over accounting, the Company reported in its financial statements the operating results of Equatorial for the 200 days after the Equatorial Acquisition and the operating results of RII from the commencement of RII's operations in October, 2001; and

"**working interest"** means the net interest held by the Company in an oil and natural gas property which normally bears its proportionate share of the costs of exploration, development and operation as well as any royalties or other production burdens.

ABBREVIATIONS

The following abbreviations are used in this AIF to represent the following terms:

"**API**"	means the American Petroleum Institute;
"**API gravity**"	means the method of expressing the specific gravity of crude oil in degrees;
"**bbl**"	means barrel; **"bbls"** means barrels; and **"bbls/d"** means barrels per day;
"**bcf**"	means billion cubic feet;
"**boe**"	means barrels of oil equivalent, with natural gas converted at 6 mcf per barrel of oil equivalent (6:1) unless otherwise stated; and **"boe/d"** means barrels of oil equivalent per day;
"**mbbls**"	means 1,000 barrels;
"**mboe**"	means 1,000 boe;
"**Mmboe**"	means 1,000,000 boe;
"**mcf**"	means 1,000 cubic feet; and **"mcf/d"** means 1,000 cubic feet per day;
"**mmbtu**"	means 1,000,000 British thermal units;
"**mmcf**"	means 1,000,000 cubic feet; and **"mmcf/d"** means 1,000,000 cubic feet per day;
"**NGL**"	means natural gas liquids; and
"**WTI**"	means West Texas Intermediate crude oil delivered at Cushing, Oklahoma.

FORWARD-LOOKING INFORMATION

This document contains certain forward-looking statements relating, but not limited, to operations, anticipated financial performance, business prospects and strategies of the Company. Forward-looking information typically contains statements with words such as "anticipate", "believe", "expect", "plan", "intend" or similar words suggesting future outcomes or statements regarding an outlook on, without limitation, commodity prices, estimates of future production, the estimated amounts and timing of capital expenditures, anticipated future debt levels and royalty rates, or other expectations, beliefs, plans, objectives, assumptions or statements about future events or performance.

Shareholders are cautioned not to place undue reliance on forward-looking information. By its nature, forward-looking information of the Company involves numerous assumptions, inherent risks and uncertainties both general and specific that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur. These factors include, but are not limited to: the availability and price of energy commodities; the effects of competition and pricing pressures; risks and uncertainties involving the geology of crude oil and natural gas; operational risks in exploring for, developing and producing crude oil and natural gas; the uncertainty of estimates and projections relating to production, costs and expenses; shifts in market demands; risks inherent in the Company's marketing operations; industry overcapacity; the strength of the Canadian economy in general; currency and interest rate fluctuations; general global and economic and business conditions; changes in business strategies; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserves estimates; various events which could disrupt operations, including severe weather conditions, technological changes, and the Company's anticipation of and success in managing the above risks; potential increases in maintenance expenditures; changes in laws and regulations, including trade, fiscal, environmental and regulatory laws, particularly in Indonesia; and health, safety and environmental risks may affect projected reserves and resources and anticipated earnings or assets. See also the information set forth under the headings "Industry Conditions" and "Indonesian Operations Risks". Statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future.

The Company cautions that the foregoing list of important factors is not exhaustive. The Company undertakes no obligation to update or revise the forward-looking information provided in this document, whether as a result of new information, future events or otherwise, or the foregoing list of factors affecting this information.

THE COMPANY

General

The Company was incorporated under the laws of the Province of British Columbia on October 29, 1981 under the name Laurel Explorations Ltd. and the Common Shares began trading on the Vancouver Stock Exchange on August 8, 1984. On February 22, 1991, the Company's name was changed to Linden Explorations Inc. ("Linden") and the Common Shares were consolidated on a four for one basis.

On May 13, 1996, Linden acquired all of the issued and outstanding shares of Australian Oilfields Pty. Ltd., a private corporation incorporated under the laws of the Province of Alberta ("Subco"), in exchange for the issuance of 9.025 million common shares of Linden. This acquisition resulted in a change of control of the Company and was accounted for as an acquisition of the Company by Subco. The Company became the legal parent of Subco and all of the assets of Subco were subsequently transferred to the Company and Subco was voluntarily dissolved. On May 23, 1996, the Company's name was changed to Australian Oilfields Pty. Ltd.

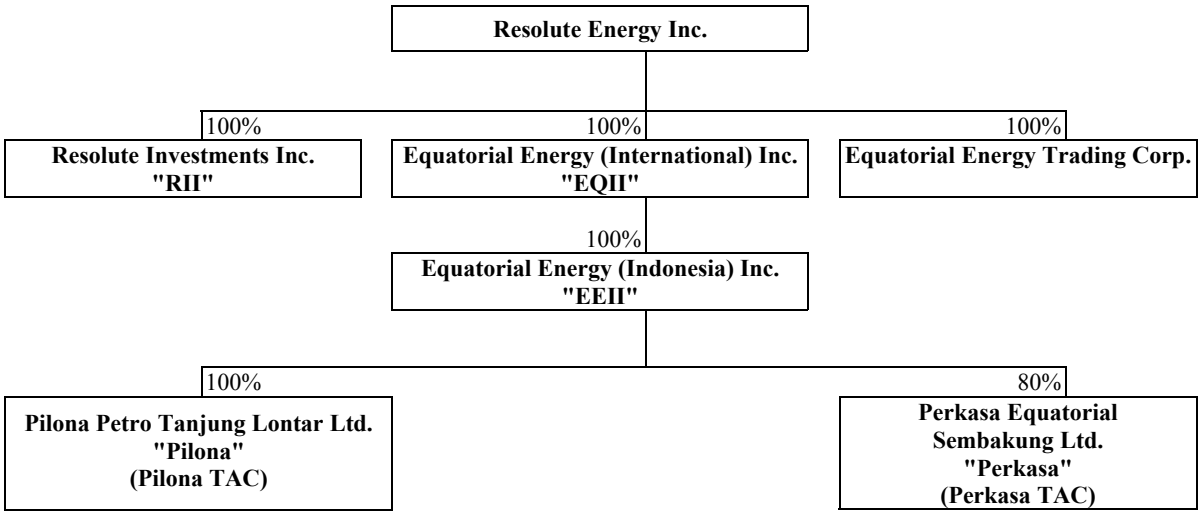
On June 10, 1997, the Company was continued under the laws of the Province of Alberta as Equatorial Energy Inc. and its share capital was reorganized. On July 6, 1999, the Company amended its articles to consolidate its Common Shares on a four for one basis. Accordingly, any reference to the historical number of Common Shares has been adjusted to reflect this consolidation. On June 7, 1999, the Common Shares of the Company commenced trading on The Toronto Stock Exchange.

On June 14, 2002, the Company acquired all of the issued and outstanding shares and other securities of RII, a private corporation. Concurrent with the transaction, the Company underwent a significant reorganization of management and the Board of Directors, with former officers and directors of RII occupying the majority of positions. As a result, the transaction was accounted for as a reverse take-over.

On November 14, 2002, the Company changed its name to Resolute Energy Inc.

Corporate Structure

A schematic diagram of the corporate structure of the Company and its material subsidiaries is set out below, with ownership of voting securities set out as a percentage.



GENERAL DEVELOPMENT OF THE BUSINESS

General

Resolute Energy Inc. is an independent oil and gas company based in Calgary, Alberta. The Company actively pursues petroleum and natural gas exploration, development and production in western Canada. The Company also owns and operates two TACs in Indonesia.

The Company has three material wholly-owned subsidiaries, Equatorial Energy Trading Corp., a Barbados company incorporated on December 20, 2000, EQII, a Barbados company incorporated on November 5, 1997 and RII, a company incorporated under the laws of the Province of Alberta on June 6, 2001. EQII has one wholly-owned subsidiary, EEII, a British Virgin Islands company incorporated on September 29, 1993. EEII has one wholly-owned subsidiary, Pilona, a company incorporated in the British Virgin Islands on February 7, 1996, and continued in Barbados in 1999, and owns 80% of the issued and outstanding common shares of Perkasa, a British Virgin Islands company incorporated on October 4, 1993.

The Company has been active in Indonesia since November 1996, developing the Pilona TAC. The Company acquired the Perkasa TAC in September 1998. In February 1999, the Company acquired assets in western Canada. In June 2002, the Company acquired all of the issued and outstanding shares and other securities of RII.

Significant Acquisitions

Canada

Canadian Property Acquisition

On February 26, 1999, the Company purchased certain oil and natural gas properties in western Canada from ConocoPhillips Canada Limited for approximately $72 million (the "Canadian Property Acquisition"). The majority of the Company's Canadian properties described in this AIF were acquired in the Canadian Property Acquisition.

Equatorial Acquisition

On June 14, 2002, in a transaction that was accounted for as a reverse takeover, the Company acquired all of the issued and outstanding shares and other securities of RII in exchange for 26,973,650 Common Shares, 3,645,091 Common Share Purchase Warrants, 3,310,005 Performance Warrants and 2,368,250 options to acquire Common Shares. Each Common Share Purchase Warrant has a term of 42 months from the date of issue and entitles the holder to acquire one Common Share at an exercise price of $2.08. The Performance Warrants expire on December 10, 2008 (having exercise prices of $2.16 (as to 413,752), $2.70 (as to 413,752), $3.24 (as to 620,625), $3.78 (as to 830,502) and $4.32 (as to 1,034,374)). The options to acquire Common Shares have an exercise price of $2.16 and expire on various dates six years from the date of the original grant that range from January 1, 2002 to March 15, 2002.

As a result of the acquisition, an aggregate of 36,296,996 Common Shares were issued, or made issuable upon the exercise of convertible securities, to RII securityholders. The 26,973,650 Common Shares issued to RII securityholders represented approximately 46.5% of all Common Shares issued and outstanding immediately following the Equatorial Acquisition, and the 36,296,996 Common Shares issued (or made issuable upon the exercise of convertible securities to RII securityholders) represented approximately 52.5% of all Common Shares on a diluted basis following the Equatorial Acquisition.

At the time of the acquisition, RII had approximately $55.3 million in cash (its only material asset), and the Company had approximately $53 million of debt as well as hedges with a negative mark-to-market value of approximately $13 million. The debt and unfavourable hedge position were related to the Company's financing of the Canadian Property Acquisition. The Equatorial Acquisition allowed the Company to reduce its net debt to approximately $13 million and to terminate its hedge position at a cost of approximately $13 million. This

reorganization and related management changes have enabled the Company to be more active in its exploration and development activities and to pursue potential acquisitions more vigorously.

Recent Developments

On April 17, 2003, the Company acquired additional land, reserves, production and facilities in the Berry/Kirkpatrick area of eastern Alberta for $7.8 million (subject to final post-closing adjustments). The acquisition comprised 4.7 bcf of proved natural gas reserves and an additional 60,000 barrels of associated oil and natural gas liquids. Established reserves of 5.5 bcf of natural gas and 70,000 barrels of oil and liquids were independently evaluated by GLJ and are adjusted for production to the April 17 closing and effective date. Current production is 1,700 mcf/d of natural gas and 18 bbls/d of liquids, or approximately 300 boe/d in total, excluding approximately 30 boe/d of production that is presently shut-in as a result of minor well-site facilities optimization. The transaction also included 16,700 net acres of land and 23% to 25% working interests in two natural gas plants with combined capacity of 3,600 mcf/d. The all-in cost of the reserves, without allocating value for undeveloped land and facilities, was approximately $9.20/boe for proved reserves and $7.90/boe for established reserves. The reserve life index for the properties is 7.0 years for proved reserves and 8.2 years for established reserves.

Indonesia

Acquisition of Pilona TAC

On November 22, 1996, the Company acquired all of the shares of Antrim International Energy Inc. ("Antrim"), a private company, for approximately $3.2 million. Antrim's principal asset was the right to acquire 75% of the shares of Pilona, the holder of the Pilona TAC. The Company exercised Antrim's right to acquire 75% of Pilona for approximately $2.7 million. All of the assets of Antrim were subsequently transferred to the Company and Antrim was wound up. The remaining 25% of the Pilona shares were acquired by the Company on March 14, 1997 for approximately $2.3 million.

The Pilona TAC gives the Company an exclusive right until the end of the life of the contract to execute an oil field rehabilitation and exploitation program on the Tanjung Lontar, Sengkuang and Arahan-Banjarsari oil fields located approximately 100 kilometres southwest of the city of Palembang, South Sumatra.

Acquisition of Perkasa TAC

On September 29, 1998, EQII purchased all of the shares of EEII from First Dynasty Mines Ltd. for approximately US$20.0 million. EEII owns 80% of Perkasa, which is a party to a TAC with PERTAMINA to develop the Sembakung oil field in northeast Kalimantan, Indonesia. The Perkasa TAC gives the Company rights to execute an exploration, development and exploitation program on the Sembakung oil field in northeast Kalimantan, Indonesia.

DESCRIPTION OF THE BUSINESS

General

Resolute Energy Inc. is an independent oil and gas company based in Calgary, Alberta. The Company actively pursues petroleum and natural gas exploration, development and production in western Canada. The Company, through its subsidiaries, also owns and operates two TACs in Indonesia.

In Canada, the Company's strategy is to increase production and reserves within the Western Canadian Sedimentary Basin by building new core areas through a combination of exploration and development activities, property acquisitions with exploratory or development upside, and strategic corporate acquisitions. In Indonesia, the Company (through its subsidiaries) has undertaken to seek opportunities over the medium term to maximize the value of these properties, while at the same time reinvesting a portion of the cash flows from the Indonesian production to enhance their overall value.

As of December 31, 2002, the Company had 24 employees in Canada and, through its subsidiaries, 140 employees in Indonesia.

Principal Producing Properties

The Company has producing properties in western Canada and, an indirect interest in properties in Indonesia. The majority of the western Canadian properties were acquired pursuant to the Canadian Property Acquisition and the Company's subsidiaries' interests in the Indonesian properties are comprised of the Perkasa TAC and the Pilona TAC.

Production Summary

The following table summarizes production by area from the Company's properties. RII did not have production prior to the Equatorial Acquisition. Accordingly, due to the application of reverse take-over accounting, the following results are those of Equatorial for the 200 Day Period as reflected in the Company's financial statements.

	Average Production Rates – 200 Day Period			
Property	**Natural Gas (mcf/d)**	**Crude Oil (bbls/d)**	**NGL (bbls/d)**	**Oil Equivalent (boe/d)**
Alberta				
Berry/Kirkpatrick	4,720	165	22	974
Southeast Alberta	2,325	431	2	821
Bigoray	3,440	—	152	725
Kaybob	337	391	17	464
Northwest Alberta	1,843	79	10	396
Willesden Green	1,558	40	35	335
Malmo	1,397	—	5	238
Other	3,553	24	2	618
Saskatchewan	30	217	—	222
Total Canada	19,203	1,347	245	4,793
Sembakung	—	1,844	—	1,844
Tanjung Lontar	—	300	—	300
Total Indonesia [(1)]	—	2,144	—	2,144
Total	**19,203**	**3,491**	**245**	**6,937**

Note:

(1) Indonesian amounts are a proportionate interest equal to the Company's subsidiaries' interest in Profit Oil as defined in each TAC. Effective June 14, 2002, the date of the Equatorial Acquisition, the Company began reporting its subsidiaries' proportionate interest in their Indonesian operations in its financial statements.

Reserves Summary

The following table summarizes the reserves attributed to the Company's and its subsidiaries' properties as at December 31, 2002.

December 31, 2002	Crude Oil Reserve Volumes (mbbls)			NGL Reserve Volumes (mbbls)		
Property	Proved	Risked Probable	Established	Proved	Risked Probable	Established
Alberta	2,143	351	2,494	932	260	1,192
Saskatchewan	425	61	486	—	—	—
Other [(1)]	183	—	183	2	1	3
Total Canada	2,751	412	3,163	934	261	1,195
Sembakung	3,500	1,967	5,467	—	—	—
Tanjung Lontar	255	43	298	—	—	—
Total Indonesia [(2)]	3,755	2,010	5,765	—	—	—
Total	**6,506**	**2,422**	**8,928**	**934**	**261**	**1,195**

December 31, 2002	Natural Gas Reserve Volumes (mmcf)			Oil Equivalent Reserve Volumes (mboe)		
Property	Proved	Risked Probable	Established	Proved	Risked Probable	Established
Alberta	50,053	17,589	67,642	11,417	3,543	14,960
Saskatchewan	95	12	107	441	63	504
Other [(1)]	760	—	760	312	1	313
Total Canada	50,908	17,601	68,509	12,170	3,607	15,776
Sembakung	—	—	—	3,500	1,967	5,467
Tanjung Lontar	—	—	—	255	43	298
Total Indonesia [(2)]	—	—	—	3,755	2,010	5,765
Total	**50,908**	**17,601**	**68,509**	**15,925**	**5,617**	**21,541**

Notes:

(1) These are minor Alberta and Saskatchewan properties evaluated by Resolute, included in the GLJ Canada Report, and not allocated to provinces.

(2) Indonesian amounts are a proportionate interest equal to the Company's subsidiaries' interest in Profit Oil as defined in each TAC. Effective June 14, 2002, the date of the Equatorial Acquisition, the Company began reporting its proportionate interest of its subsidiaries' Indonesian operations in its financial statements.

Western Canadian Properties

Strategy

In 2002, the primary focus in western Canada was development and expansion of the Company's existing properties, particularly the Berry/Kirkpatrick project in eastern Alberta and the Winnifred project in Southeast Alberta. In 2003, the Company's target is to establish two to three new core areas – areas having a minimum potential of 1,000 boe/d of production and 2 mmboe of recoverable reserves. Prior to the Canadian Property Acquisition, the Company had no properties in western Canada. Historical information relating to these properties prior to the Equatorial Acquisition is described in the Company's 2001 Annual Information Form filed on February 25, 2003. The following discussion relates to the subsequent 200 Day Period, unless otherwise stated.

Approximately 25% to 30% of the total 2003 capital budget will be invested in new prospect generation and exploration activities. Our primary focus is on natural gas. We are building land positions in areas of interest in northwest, central and southern Alberta. In Southern Alberta, the Company has acquired a sizable land base and has identified several multi-zone Cretaceous and Mississippian targets. The prospects are located within reasonable

proximity to our existing Southeast Alberta core area. In Northwest Alberta, the Company has acquired a significant seismic database and is actively acquiring land in the area, pursuing drilling targets with multiple horizons. New prospects are also being generated in the west central regions of Alberta and Saskatchewan. In total, Resolute anticipates drilling approximately 10 to 15 exploration targets in these new areas during 2003.

Overview

At December 31, 2002, Resolute's Canadian proved reserve base is 70% natural gas and 30% oil and NGL (on a boe basis). In addition, the Company owns 209,341 net acres of undeveloped land. Excluding Kaybob and certain of the Other properties, Resolute operates all of its major producing properties. The Company holds an average working interest of 60% in its properties on a proved reserves basis and 72% on a total land basis.

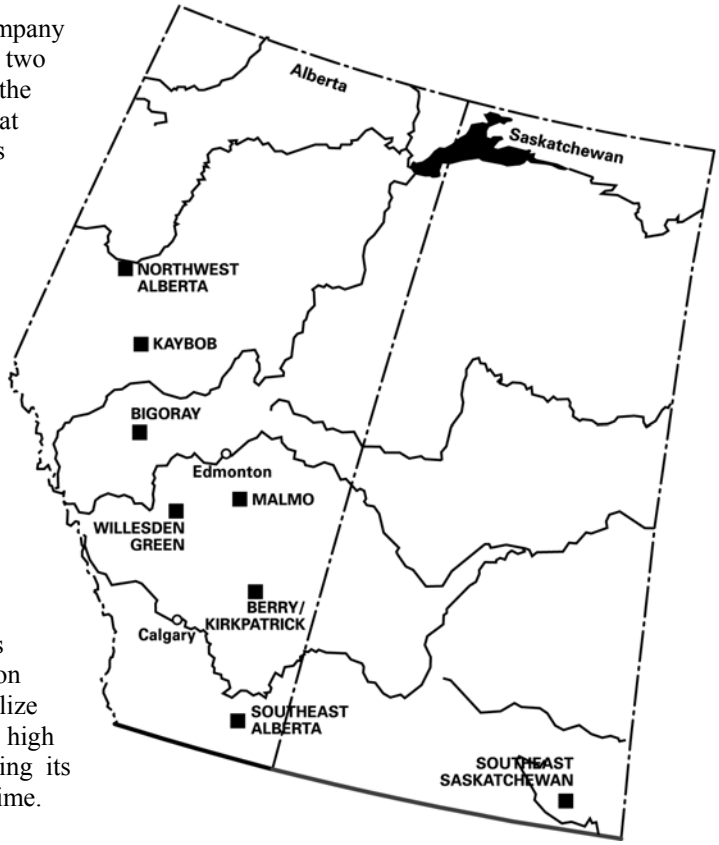
During the second half of 2002, the Company drilled 58 gross wells (53.6 net), resulting in three gross oil wells (2.0 net), 50 gross natural gas wells (47.6 net) and five gross dry holes (4.0 net). Average Canadian production volumes for the 200 Day Period was 4,793 boe/d, of which 67% was natural gas and 33% was light and medium gravity oil and NGL.

The operated properties of Berry/Kirkpatrick, Bigoray, Northwest Alberta, Malmo, Southeast Saskatchewan, Southeast Alberta and Willesden Green and the non-operated Kaybob Unit No. 2 generated 87% of Canadian production and represented 92% of Canadian proved reserve volumes (on a boe basis) at December 31, 2002.

During the second half of 2002, the Company focused the bulk of its Canadian activities in two areas. Forty wells were drilled during the development of a SWS play in Southeast Alberta at Winnifred. At Berry/Kirkpatrick, the Company's activities in the second half of 2002 concentrated on Mannville aged regional sands and channel sands natural gas and oil plays. Resolute will continue to be active in both of these areas in 2003.

In the second half of 2002, the Company invested $5 million or 25% of its capital expenditures in land acquisition and seismic to establish prospects for 2003 and future years both on existing properties and in new areas of interest. The Company anticipates the creation of two to three new core areas in 2003.

The Company is reviewing its properties to evaluate exploitation and cost reduction opportunities. In 2003, the Company may rationalize selected mature assets, particularly those with high operating costs, towards the goal of consolidating its activities in more focused geographic areas over time.



Reference is also made to the information under the heading "Focus on Western Canada" on pages 7-9, inclusive, of the Company's 2002 Annual Report, which pages are incorporated herein by reference.

Alberta

Berry/Kirkpatrick

The Berry/Kirkpatrick area is located approximately 150 kilometres northeast of Calgary, bounded on the south by the Berry property and on the north by the Kirkpatrick property. As at December 31, 2002, Resolute held various working interests in the area, ranging from 28% to 100%, with an average interest of approximately 69% in 82,265 acres. Through purchases and farm-ins, the Company acquired interests in 5,600 acres of land in the area during the second half of 2002. The Company drilled 11 wells (10.0 net) in the second half of 2002, resulting in seven natural gas wells (7.0 net) and three oil wells (2.0 net). Continuing an exploration approach begun in 2000, Resolute has been very successful in identifying Mannville aged regional and channel sands, and Viking aged sands with the use of three-dimensional (3-D) seismic technology. Production is from a number of zones within the Mannville Group and Resolute's net production averaged 4,720 mcf/d of natural gas and 187 bbls/d of oil and NGL from the area during the second half of 2002. Berry wells are tied into the Resolute Berry 2-4-27-13 W4M battery or to third party operated natural gas plants in the area. Kirkpatrick wells are tied-in through a third party midstream facility at 5-30-32-10 W4M. Situated between the Berry and Kirkpatrick properties, the $7.8 million property acquisition in April 2003 augments existing production in the area. It brings the Company's total land position at Berry/Kirkpatrick to approximately 85,000 net acres, of which approximately 42,000 net acres are classed as undeveloped, and provides both immediate and longer term exploration and development potential. In the near term, five net recompletion candidates and seven net drilling locations have been identified on the acquired lands for both shallow gas and deeper Manville targets. Longer term, the acquisition sets up further land purchases and exploration in the area. In 2003, Resolute's plans include approximately 20 net drilling locations and 10 net well recompletions in the Berry/Kirkpatrick area.

Southeast Alberta

Resolute holds an approximately 87% working interest in 90,530 acres of land in the Winnifred, Grassy Lakes, Grand Forks, Hays, Enchant producing areas (collectively referred to as Southeast Alberta). The majority of the lands within Southeast Alberta are located approximately 200 kilometres southeast of Calgary, with production coming from the SWS, Bow Island, Glauconite and Sawtooth formations. Total production in the area averaged 433 bbls/d of oil and 2,325 mcf/d of natural gas during the last half of 2002.

The main focus of the Company's activities in 2002 was in the Winnifred area, where 40 shallow wells were drilled for SWS natural gas. The Company's natural gas gathering and processing facilities south of the South Saskatchewan River were expanded to accommodate increased production. The drilling program added approximately 2,000 mcf/d to the area in December 2002, doubling net deliverability. The SWS wells provide long-life reserves after typical initial declines of 30% to 40% in the first year of production. In 2003, royalty rates are expected to be approximately 15% and operating costs should be below $4.50/boe. Resolute anticipates drilling more than 50 additional shallow natural gas wells south of the South Saskatchewan River in order to fully utilize the Company's compressor station at 2-17-11-10 W4M.

Plans for Southeast Alberta in 2003 include at least 10 delineation locations for SWS natural gas north of the South Saskatchewan River at Winnifred and a horizontal drilling location at Cherry, targeting Mannville oil. In the second half of 2002, the Company acquired a sizeable land base within reasonable proximity to existing Southeast Alberta properties. The Company has identified several multi-zone Cretaceous and Mississippian prospects, some of which will be drilled in 2003.

Bigoray

The Bigoray property is located approximately 300 kilometres northwest of Calgary. The Company owns an average 57% working interest in 19,451 acres.

There are 15 producing wells (9.0 net) on the Bigoray property. They contain long-life reserves and produce liquids-rich sweet natural gas and NGL from the Glauconite and Ostracod formations. Natural gas and NGL is processed at a third-party facility. Production averaged 3,440 mcf/d of natural gas and 152 bbls/d of NGL in

the second half of 2002. Area activity in 2002 included the installation of four plunger lifts to increase productivity on some of the wells. Resolute plans to restimulate one to two wells in this area in 2003.

Kaybob South Triassic Unit No. 2

Resolute owns a 29.94% non-operated working interest in the Kaybob South Triassic Unit No. 2, located approximately 250 kilometres northwest of Edmonton. Production consists of light, slightly sour, 42 degree API gravity oil, with associated natural gas and NGL. The Kaybob unit commenced production in 1967 and is currently under a mature pressure maintenance program. In 2002, the property exhibited moderate decline rates of approximately 15%. Production is from 29 oil wells (9.0 net) in the Montney Formation with pressure support provided by 13 water injectors in a peripheral pressure maintenance scheme. Total production from the area averaged 408 bbls/d of oil and NGL and 337 mcf/d of natural gas during the second half of 2002.

Northwest Alberta

Resolute holds various interests, ranging from 6.25% to 100% in Northwest Alberta. This property is located approximately 300 kilometres northwest of Edmonton. Production in the second half of 2002 averaged 1,843 mcf/d of natural gas and 89 bbls/d of oil and NGL. Presently, the majority of the production is at Gordondale, which contains both oil and natural gas reserves, with oil production from wells in the Halfway "K" oil pool and natural gas production from multiple formations.

Northwest Alberta is a key focus area for new exploration because of its multi-zone, natural gas prone opportunities and longer reserve life. Resolute has acquired access to a significant seismic database in Northwest Alberta and is currently expanding its land holdings. The Company expects to drill three exploratory wells on working interest lands in the area in 2003.

Willesden Green

Resolute holds interests ranging from 53% to 100% in the Willesden Green area, located 50 kilometres west of Red Deer. Production from this property averaged 1,558 mcf/d of natural gas and 75 bbls/d of oil and NGL in the second half of the year. Activity during 2002 consisted of restimulating one Cardium oil well and reactivating one Mannville oil well. Plans for 2003 include two drilling locations and more recompletion work in the Cardium and Mannville zones.

Malmo

Resolute holds an average working interest of 81% in 31,171 acres in the Malmo area, located approximately 65 kilometres northeast of Red Deer. In the second half of 2002, production from 28 wells (26.0 net) averaged 1,397 mcf/d of natural gas, primarily from the Edmonton and Belly River zones. Resolute has identified several natural gas prospects on its lands.

Saskatchewan

The Southeast Saskatchewan area consists primarily of oil properties at Wauchope and Arcola. Both properties have been developed extensively. They have long-life reserves and relatively low decline rates. Total production from the area averaged 217 bbls/d of oil and 30 mcf/d of natural gas in the second half of 2002.

Wauchope is approximately 130 kilometres southeast of Regina. Resolute holds a 97% working interest in Wauchope, which produced 131 bbls/d during the second half of 2002. The pool has been developed with both horizontal and vertical wells. The Arcola property is approximately 200 kilometres southeast of Regina. Resolute holds a 50% working interest in the property, which produced 53 bbls/d during the second half of 2002. Resolute expects to drill two to three horizontal oil locations on the property in 2003.

In West Central Saskatchewan, Resolute plans to drill one exploratory Mannville test in 2003.

Other

The Company also has various working interests in other properties throughout Alberta, northeast British Columbia and southwest Saskatchewan. Total production from these properties averaged 3,553 mcf/d of natural gas and 26 bbls/d of oil and NGL in the second half of 2002.

Canadian Facilities

The Company has an interest in over 40 processing facilities in western Canada. These facilities include batteries, natural gas plants, compressors and pipelines typically used in Canadian oil and natural gas operations. The Company's interest in its western Canadian facilities ranges from approximately 7% to 100% and the replacement values of each of these facilities is estimated to range from $13,000 to $1.5 million. At Frog Lake, Kirkpatrick, Malmo, Warwick and Bigoray, Resolute's natural gas production is processed through facilities owned by midstream operators.

Indonesian Properties

Strategy

At the time the Company completed the Equatorial Acquisition, Resolute concluded that the Indonesian properties were not a long-term hold in light of the significant business risks in that country and the relatively small scale of the Company's subsidiaries' operations. The Company has undertaken to seek opportunities over the medium term to maximize the value of these properties, while at the same time reinvesting a portion of the cash flows to enhance their overall value. Such reinvestment is intended to maintain production through exploratory and extension drilling and the implementation of a water injection scheme in the Sembakung property.

Overview

Production from the Indonesian properties is governed by two TACs with PERTAMINA. While Resolute's subsidiaries operate the properties, the oil and mineral rights are retained by PERTAMINA, with a subsidiary owning a Profit Oil interest in oil produced in each contract area. Production is light, sweet crude oil, averaging 38 degrees API and is sold directly to PERTAMINA at Minas prices (Sumatran Light Crude), which is a regional market rate that is typically at a slight discount to WTI prices.

Under the TACs, production is divided into Cost Recovery Oil and Profit Oil. Resolute's subsidiaries are required to fund PERTAMINA's share of all drilling and operating costs and Cost Recovery Oil allows for the recovery of those costs. The remaining production is Profit Oil and this is shared with PERTAMINA. The properties are now in full commercial operation and all original capital commitments under the contracts have been met and recovered. Much of the PERTAMINA carried interest in ongoing discretionary expenditures is billed and recovered on a current basis through Cost Recovery Oil. Accordingly, Resolute has chosen an accounting policy that records its subsidiaries' proportionate interest in Indonesian reserves, production volumes, revenues, operating costs and capital expenditures based on its Profit Oil percentage for each contract area. Government share, administrative costs and Indonesian income taxes are allocated 100% to the account of the Company, and are recorded as such.

Sembakung

Resolute has an indirect 80% interest in the Perkasa TAC. In the latter half of 2002, Perkasa drilled five wells on the southern extension to the Sembakung structure as a follow-up to two successful wells drilled in the first half by Equatorial. All five wells were successfully completed as oil producers and contributed to proved reserve additions at Sembakung of 0.8 mmbbls net to the Perkasa's proportionate interest. During 2003, Perkasa's plans include infill and step-out drilling of the southern field extension and further infill drilling of the main Sembakung field.

Perkasa also initiated a pilot pressure maintenance program for the Sembakung field. One well was converted to water injection and, since October, 2002, has been injecting approximately 2,700 bbls/d of water, restricted by pump capacity. Three adjacent producing wells are being monitored and two are showing increased total fluid production as a result of water injection. The performance is consistent with the expected response. In 2003, further wells may be converted to injection to expand the pressure maintenance scheme. If fully implemented, the program has the potential to significantly increase recoverable reserves over the remaining contract term.

Tanjung Lontar

Resolute has an indirect 100% interest in the Pilona TAC. The TAC is comprised of a group of four mature South Sumatran oil fields discovered by early Dutch explorers at the beginning of the twentieth century. In late 2002, Pilona drilled six wells on the Arahan field, two wells on the Sengkuang field and two wells on the Tanjung Lontar field. Of these wells, five were successful at Arahan, two at Sengkuang and one at Tanjung Lontar. These results provide significant drilling potential at both Arahan and Sengkuang, which will be the focus of drilling activity in 2003.

Indonesian Facilities

All equipment and facilities relating to the Company's subsidiaries' Indonesian operations are owned by PERTAMINA. The Company's subsidiaries typically purchase equipment and facilities on behalf of PERTAMINA and recover their costs through the cost recovery provisions of the applicable TACs. Facilities used in the course of the Company's subsidiaries Indonesian operations include batteries and pipelines typically used in oil exploration and production operations.

Indonesian Production Sharing Arrangements

Production from the Indonesian properties is governed by TACs with PERTAMINA, pursuant to which the Company's subsidiaries provide financing and technical expertise to conduct exploration, development and production activities in a specified geographic area (each a "contract area"). See also "Industry Conditions" and Indonesian Operations Risks".

The following table summarizes key terms of the Company's subsidiaries' TACs:

	Perkasa TAC	**Pilona TAC**
Effective Year	1994	1996
Expiry Year	2014	2016
Remaining Capital Expenditure Obligation	—	—
Non-Shareable Oil Obligation	750 bbls/d [(1)]	—
Cost Recovery	80% of Gross Revenue	75% of Gross Revenue [(2)]
Unrecovered Cost Pools at December 31, 2002	—	—
Investment Credit	17%	15.83%
Income Tax Rate	48%	44%
Post-Cost Recovery Share to Company – After Tax	15%	15%

Notes:

(1) In 2003 and declining at 13.3% per year. PERTAMINA and Perkasa have specified this amount, by mutual agreement, as an amount of crude oil production that PERTAMINA will receive free of any production sharing with Perkasa.

(2) In 2003, reduced by 5% every two years, commencing in 2004, to 65% by 2006.

Marketing

Crude Oil and Natural Gas

The Company sells approximately 90% of its natural gas production on the Alberta spot market, with the remaining 10% of production being sold through natural gas aggregators.

Resolute markets its Canadian crude oil through the services of a crude oil marketing company. Canadian crude oil volumes are generally sold on the spot market at major Canadian transportation hubs through 30-day evergreen contracts.

In Indonesia, Perkasa's and Pilona's crude oil production is sold directly to PERTAMINA at Minas prices (Sumatran Light Crude), which is a regional market rate that is typically at a slight discount to WTI prices.

Hedges

From time to time, the Company may enter into derivative contracts to manage its exposure to commodity price risks. Currently, there are no such contracts in place.

Seasonality

The exploration for and development of oil and natural gas reserves depends on access to areas where operations are to be conducted. Seasonal weather variations, including freeze-up and break-up in Canada and rains in Indonesia, affect access in certain circumstances.

Natural gas is used principally as a heating fuel and for power generation. Accordingly, seasonal variations in weather patterns affect the demand for natural gas. Depending on prevailing conditions, the prices received for sales of natural gas are generally higher in winter than summer months, while prices are generally higher in summer than spring and fall months.

Reserves

GLJ evaluated the oil and natural gas reserves attributable to the Company's Canadian and its subsidiaries' Indonesian petroleum and natural gas properties effective December 31, 2002. The following tables set forth certain information relating to the oil, natural gas and NGL reserves associated with such properties and the present value of the future net cash flows associated with such reserves. The information set forth below is derived from the GLJ Canada Report and the GLJ Indonesia Report. The impact of income taxes on the estimated future net cash flows are as stated in the tables below. All evaluations are stated prior to indirect costs and future site restoration costs and after deduction of royalties and future capital expenditures. It should not be assumed that the future net cash flows shown below are representative of the fair market value of the relevant reserves. GLJ relied upon information provided by the Company in preparing the GLJ Canada Report and by the Company and PERTAMINA in preparing the GLJ Indonesia Report.

As a result of the Equatorial Acquisition, GLJ updated the oil and natural gas reserves attributable to the Company's Canadian and its subsidiaries' Indonesian petroleum and natural gas properties effective June 30, 2002. The June 30, 2002 reserves were previously disclosed in the Company's 2001 Annual Information Form filed on February 25, 2003. Readers are referred to the subsequent reserve reconciliation, which summarizes changes in the Company's reserves from June 30, 2002 to December 31, 2002.

Constant Dollar Economics
December 31, 2002

	Company's Reserves						
	Natural Gas		Crude Oil			NGL	
	Gross (mmcf)	Net (mmcf)	Gross (mbbls)	Net (mbbls)	Contractual Percentage of Gross (mbbls)	Gross (mbbls)	Net (mbbls)
Canada							
Proved Producing	42,546	34,775	2,818	2,384	2,818	771	521
Proved Non-Producing	9,362	7,490	139	121	139	172	117
Total Proved	51,908	42,265	2,957	2,505	2,957	943	638
Risked Probable	17,964	15,013	457	398	457	264	170
Established	69,872	57,278	3,414	2,903	3,414	1,207	808
Indonesia [11]							
Proved Producing	—	—	11,406	4,724	3,276	—	—
Proved Non-Producing	—	—	1,743	806	496	—	—
Total Proved	—	—	13,149	5,530	3,772	—	—
Risked Probable	—	—	7,001	2,838	2,015	—	—
Established	—	—	20,150	8,368	5,787	—	—
All Properties							
Proved Producing	42,546	34,775	14,179	7,108	6,094	771	521
Proved Non-Producing	9,362	7,490	1,927	927	635	172	117
Total Proved	51,908	42,265	16,106	8,035	6,729	943	638
Risked Probable	17,964	15,013	7,458	3,236	2,472	264	170
Established Reserves	**69,872**	**57,278**	**23,564**	**11,271**	**9,201**	**1,207**	**808**

Constant Dollar Economics
December 31, 2002

($000s)	Present Worth Discounted at			
	0%	10%	15%	20%
Canada	Before Tax			
Proved Producing	227,425	148,837	128,644	114,037
Proved Non-Producing	39,305	25,024	20,946	17,878
Total Proved	266,730	173,861	149,590	131,915
Risked Probable	76,840	31,508	23,343	18,134
Established	343,570	205,369	172,933	150,049
Indonesia [11]	After Tax [12]			
Proved Producing	41,777	32,474	29,558	27,226
Proved Non-Producing	6,067	4,418	3,855	3,403
Total Proved	47,244	36,892	33,413	30,629
Risked Probable	25,382	14,173	10,986	8,691
Established	72,626	51,065	44,399	39,320
All Properties	Canadian Values Before Tax and Indonesian Values After Tax [12]			
Proved Producing	268,602	181,311	158,202	141,263
Proved Non-Producing	45,372	29,442	24,801	21,281
Total Proved	313,974	210,753	183,003	162,544
Risked Probable	102,222	45,681	34,329	26,825
Established Reserves	**473,446**	**256,434**	**217,332**	**189,369**

Escalated Dollar Economics
December 31, 2002

	Company's Reserves						
	Natural Gas		Crude Oil			NGL	
	Gross (mmcf)	Net (mmcf)	Gross (mbbls)	Net (mbbls)	Contractual Percentage of Gross (mbbls)	Gross (mbbls)	Net (mbbls)
Canada							
Proved Producing	41,458	33,826	2,614	2,229	2,614	762	518
Proved Non-Producing	9,450	7,578	137	119	137	172	117
Total Proved	50,908	41,404	2,751	2,348	2,751	934	635
Risked Probable	17,601	14,686	412	361	412	261	170
Established	68,509	56,090	3,163	2,709	3,163	1,195	805
Indonesia [(11)]							
Proved Producing	—	—	11,361	5,619	3,263	—	—
Proved Non-Producing	—	—	1,727	917	492	—	—
Total Proved	—	—	13,088	6,536	3,755	—	—
Risked Probable	—	—	6,975	3,357	2,010	—	—
Established	—	—	20,063	9,893	5,765	—	—
All Properties							
Proved Producing	41,458	33,826	13,975	7,848	5,877	762	518
Proved Non-Producing	9,450	7,578	1,864	1,036	629	172	117
Total Proved	50,908	41,404	15,839	8,884	6,506	934	635
Risked Probable	17,601	14,686	7,387	3,718	2,422	261	170
Established Reserves	**68,509**	**56,090**	**23,226**	**12,602**	**8,928**	**1,195**	**805**

Escalated Dollar Economics
December 31, 2002

($000s)	Present Worth Discounted at			
	0%	10%	15%	20%
Canada	Before Tax			
Proved Producing	145,091	99,144	87,097	78,280
Proved Non-Producing	26,121	16,441	13,690	11,622
Total Proved	171,212	115,585	100,787	89,902
Risked Probable	53,441	20,846	15,111	11,487
Established	224,653	136,431	115,898	101,389
Indonesia [(11)]	After Tax [(12)]			
Proved Producing	28,073	22,873	21,079	19,621
Proved Non-Producing	3,383	2,354	2,007	1,731
Total Proved	31,456	25,227	23,086	21,352
Risked Probable	15,489	8,438	6,438	5,000
Established	46,945	33,665	29,524	26,352
All Properties	Canadian Values Before Tax and Indonesian Values After Tax [(12)]			
Proved Producing	173,164	122,017	108,176	97,901
Proved Non-Producing	29,504	18,795	15,697	13,353
Total Proved	202,668	140,812	123,873	111,254
Risked Probable	68,930	29,284	21,549	16,487
Established Reserves	**271,598**	**170,096**	**145,422**	**127,741**

Notes:

Definitions

(1) "Gross Reserves" are the total of the Company's and its subsidiaries' working interests and royalty interests share of reserves before deducting Government Share and royalties owned by others.

(2) "Net Reserves" are the total of the Company's and its subsidiaries' working interests and royalty interests share of reserves after deducting Government Share and royalties owned by others.

(3) "Contractual Percentage of Gross" is the Company's gross oil and natural gas reserves for Western Canada, 28.8642% of the gross oil reserves at Sembakung and 26.786% of the gross oil reserves at Tanjung Lontar. The values of 28.8642% and 26.786% for Sembakung and Tanjung Lontar, respectively, were chosen by the Company because they are equal to the Company's subsidiaries' interest in Profit Oil as defined in each TAC. Effective June 14, 2002, the date of the Equatorial Acquisition, the Company began reporting its proportionate interest of its subsidiaries' Indonesian operations in its financial statements.

(4) "Proved" reserves are those reserves estimated as recoverable under current technology and existing economic conditions in the case of constant price and cost assumptions and anticipated economic conditions in the case of escalated price and cost assumptions, 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 economic and technically successful in the subject reservoir.

(5) "Proved Producing" reserves are those proved reserves that are actually on production or, if not producing, that could be recovered from existing wells or facilities and where the reason for the current non-producing status is the choice of the owner rather than the lack of markets or some other reason. An illustration of such a situation is where a well or zone is capable of production but is shut-in because its deliverability is not required to meet contract commitments.

(6) "Proved Non-Producing" reserves are those proved reserves that are not currently producing either due to lack of facilities or markets.

(7) "Probable" reserves are those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery. Probable reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery process which can be reasonably expected to be instituted in the future.

(8) "Risked Probable" reserves are 50% of probable reserves. The volumes and cash flows associated with development and production of probable reserves are 50% of the total assigned to probably reserves to allow for risk associated with the recovery of probable reserves.

(9) "Established" reserves are total proved plus risked probable reserves.

Pricing

(10) The escalated prices and costs case assumes the continuance of laws and regulations in effect on the dates of the GLJ Canada Report and GLJ Indonesia Report. Estimates of capital expenditures and operating costs were deducted in arriving at future net cash flow.

(11) The Tanjung Lontar and Sembakung reported values were converted from US$ to Cdn. $ at the rate of Cdn. $1.5152 per US$.

(12) The TACs are "ring-fenced" for tax purposes and, in the absence of substantial capital investment, future cash flows are fully taxable.

(13) The following tables, used in the GLJ Canada Report and the GLJ Indonesia Report, are the crude oil and natural gas price forecasts as of January 1, 2003. These prices were adjusted for quality, transportation and local market conditions, as applicable, for each property.

Year	Inflation %	Exchange Rate $US/$Cdn	WTI at Cushing, Oklahoma $US/bbl	Light, Sweet Crude Oil (40 degree API, 0.3% sour) at Edmonton $Cdn/bbl	Bow River Crude Oil Stream Quality at Hardisty $Cdn/bbl	Medium Crude Oil (29 degree API, 2.0% sour) at Cromer $Cdn/bbl
2003	1.5	0.650	22.50	38.50	29.50	33.00
2004	1.5	0.660	22.00	32.50	25.50	29.00
2005	1.5	0.670	21.00	30.50	24.50	27.00
2006	1.5	0.670	21.00	30.50	25.00	27.50
2007	1.5	0.680	21.25	30.50	25.00	27.50
2008	1.5	0.680	21.75	31.00	25.50	28.00
2009	1.5	0.680	22.00	31.50	26.00	28.50
2010	1.5	0.680	22.25	32.00	26.50	29.00
2011	1.5	0.680	22.50	32.50	27.00	29.50
2012	1.5	0.680	23.00	33.00	27.50	30.00
2013	1.5	0.680	23.25	33.50	28.00	30.50
2014+	1.5	0.680	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr

Year	Edmonton Propane $Cdn/bbl	Edmonton Butane $Cdn/bbl	Edmonton Pentanes Plus $Cdn/bbl	US Gulf Coast Gas Price at Henry Hub $US/mmbtu	Alberta Plant Gate	
					Spot $Cdn/mmbtu	Aggregator $Cdn/mmbtu
2003	24.75	27.25	39.50	4.20	5.40	5.20
2004	19.75	21.50	33.00	3.80	4.80	4.65
2005	19.50	20.50	31.00	3.60	4.50	4.50
2006	19.50	20.50	31.00	3.65	4.65	4.65
2007	19.50	20.50	31.00	3.70	4.65	4.65
2008	19.75	21.00	31.50	3.75	4.65	4.65
2009	20.25	21.50	32.00	3.80	4.65	4.65
2010	20.50	22.00	32.50	3.90	4.70	4.70
2011	20.75	22.50	33.00	3.95	4.75	4.75
2012	21.00	23.00	33.50	4.00	4.85	4.85
2013	21.50	23.50	34.00	4.05	4.90	4.90
2014+				+1.5%/yr	+1.5%/yr	

Unless otherwise stated, the natural gas price reference point is the receipt point on the applicable provincial natural gas transmission system known as the plant gate. The plant gate price represents the price before raw natural gas gathering and processing charges are deducted. "Spot" refers to weighted average one month price.

(14) The constant price assumptions assume the continuance of current laws, regulations and operating costs in effect on the date of the GLJ Canada Report and GLJ Indonesia Report. The constant prices and costs case utilizes 2002 year-end prices of $31.20 US/bbl for WTI, $49.29 Cdn/bbl for Light, Sweet Crude Oil at Edmonton, $6.02 Cdn/mcf for Alberta Plant Gate spot natural gas. These prices were adjusted for quality, transportation and local market conditions, as applicable, for each property.

Other Information

(15) The GLJ Canada Report and the GLJ Indonesia Report were based upon data supplied by the Company with respect to interests owned, royalties payable and contractual commitments. No field inspection was conducted. Abandonment costs and salvage costs were not included in the evaluation.

(16) Total capital expenditures (undiscounted) associated with developing the Company's existing established reserves to achieve the future net cash flow from the Canadian properties have been estimated by GLJ to be $15,347,000 net to the Company in the escalated price case ($14,776,000 in the constant price case). GLJ has estimated that $8,591,000 of these costs will be incurred in 2003 and $3,212,000 of these costs will be incurred in 2004 in the escalated price case ($8,591,000 in 2003 and $3,165,000 in 2004 in the constant price case).

(17) The Company's subsidiaries' proportionate share, or Profit Oil share, of capital expenditures (undiscounted) associated with developing the Company's subsidiaries' existing established reserves to achieve the future net cash flow from the Indonesian properties have been estimated by GLJ to be $6,386,000 net to the Company in the escalated price case ($6,133,000 in the constant price case). GLJ has estimated that $2,693,000 of these costs will be incurred in 2003 and $2,765,000 of these costs will be incurred in 2004 in the escalated price case ($2,615,000 in 2003 and $2,644,000 in 2004 in the constant price case).

Reserve Reconciliation

The following summarizes changes in the Company's and its subsidiaries' reserves in the last six months of 2002. **Changes for the first six months of 2002 were disclosed in the Company's 2001 Annual Information Form filed on February 25, 2003.**

	Natural Gas (mmcf)			Crude Oil (mbbls)		
	Proved	Risked Probable	Established	Proved	Risked Probable	Established
Canada						
June 30, 2002	44,571	14,450	59,021	2,665	563	3,228
Production	(3,592)	—	(3,592)	(248)	—	(248)
Acquisitions	400	—	400	—	—	—
Discoveries	10,115	2,599	12,714	66	6	72
Revisions	(586)	552	(34)	268	(157)	111
December 31, 2002	50,908	17,601	68,509	2,751	412	3,163
Indonesia						
June 30, 2002	—	—	—	3,182	2,208	5,390
Production	—	—	—	(405)	—	(405)
Acquisitions	—	—	—	—	—	—
Discoveries	—	—	—	978	(198)	780
Revisions	—	—	—	—	—	—
December 31, 2002	—	—	—	3,755	2,010	5,765
Resolute Total						
June 30, 2002	44,571	14,450	59,021	5,847	2,771	8,618
Production	(3,592)	—	(3,592)	(653)	—	(653)
Acquisitions	400	—	400	—	—	—
Discoveries	10,115	2,599	12,714	1,044	(192)	852
Revisions	(586)	552	(34)	268	(157)	111
December 31, 2002	50,908	17,601	68,509	6,506	2,422	8,928

	NGL (mbbls)			Oil Equivalent (mboe)		
	Proved	Risked Probable	Established	Proved	Risked Probable	Established
Canada						
June 30, 2002	1,014	178	1,192	11,108	3,149	14,257
Production	(44)	—	(44)	(891)	—	(891)
Acquisitions	—	—	—	67	—	67
Discoveries	15	—	15	1,767	439	2,206
Revisions	(51)	83	32	119	18	137
December 31, 2002	934	261	1,195	12,170	3,606	15,776
Indonesia						
June 30, 2002	—	—	—	3,182	2,208	5,390
Production	—	—	—	(405)	—	(405)
Acquisitions	—	—	—	—	—	—
Discoveries	—	—	—	978	(198)	780
Revisions	—	—	—	—	—	—
December 31, 2002	—	—	—	3,755	2,010	5,765
Resolute Total						
June 30, 2002	1,014	178	1,192	14,290	5,357	19,647
Production	(44)	—	(44)	(1,296)	—	(1,296)
Acquisitions	—	—	—	67	—	67
Discoveries	15	—	15	2,745	241	2,986
Revisions	(51)	83	32	119	18	137
December 31, 2002	934	261	1,195	15,925	5,616	21,541

Oil and Natural Gas Wells

The following table sets forth the number and status of wells in which Resolute and each of its subsidiaries has a working or a royalty interest, as at December 31, 2002, which are producing or which the Company considers to be capable of production:

	Producing				Shut-in (1)			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada								
Alberta	137	91	229	169	36	19	118	82
Saskatchewan	21	15	2	—	13	11	2	2
British Columbia	—	—	—	—	—	—	11	8
Total Canada	158	106	231	169	49	30	131	92
Indonesia								
Sambakung	34	10	—	—	2	1	—	—
Tanjung Lontar	26	7	—	—	18	5	—	—
Total Indonesia	60	17	—	—	20	6	—	—
Resolute Total	218	123	231	169	69	36	131	92

Note:

(1) "Shut-in" wells means wells which have encountered and are capable of producing oil or natural gas but which are not producing due to lack of available transportation facilities, available markets or other operational engineering reasons. All shut-in wells are within 15 kilometres of pipeline facilities.

Production History and Netback Analysis

The following table sets forth certain production information and a netback analysis relating to the Company's and its subsidiaries' oil and natural gas interests for the periods indicated. RII did not have production and netback history prior to the Equatorial Acquisition. Accordingly, due to reverse take-over accounting, the following amounts are those of Equatorial for the 16 days ended June 30, 2002 and for 200 Day Period ended December 31, 2002 as reflected in the Company's financial statements. All production volume information is stated before deduction of royalties and Government Share.

	Quarter Ended				
	2002				
	December 31	September 30	June 30	March 31	Total
Volumes					
Natural gas (mcf/d)	19,798	19,044	16,697	—	19,203
Crude oil (bbls/d)	3,721	3,397	2,700	—	3,490
NGL (bbls/d)	231	257	264	—	245
Oil equivalent (boe/d)	7,252	6,828	5,746	—	6,936
Realized prices					
Natural gas ($/mcf)	5.62	2.94	4.08	—	4.34
Crude oil ($/bbl)	42.58	40.77	36.67	—	41.41
NGL ($/bbl)	39.98	27.95	34.59	—	33.73
Royalty / Government Share					
Natural gas ($/mcf)	1.17	0.77	0.73	—	0.96
Crude oil ($/bbl)	8.60	6.70	7.41	—	7.68
NGL ($/bbl)	11.18	8.51	9.24	—	9.73
Operating Costs [(1)]					
Natural gas ($/mcf)	0.96	0.73	1.17	—	0.87
Crude oil ($/bbl)	11.20	9.52	9.54	—	10.34
NGL ($/bbl)	5.71	4.40	8.77	—	5.34
Netbacks					
Natural gas ($mcf)	3.48	1.44	2.17	—	2.51
Crude oil ($/bbl)	22.79	24.54	19.73	—	23.38
NGL ($/bbl)	23.10	15.03	16.58	—	18.66

Note:

(1) Reference is made to the information contained in the table relating to an analysis of Canadian operating costs on page 18 of the Company's 2002 Annual Report, which table is incorporated herein by reference.

Capital Expenditures

The following table summarizes capital expenditures made by the Company and its subsidiaries in exploration and development drilling, production facilities and other equipment for the periods indicated. Due to the application of reverse take-over accounting, the following amounts are those of Equatorial for the 200 Day Period and those of RII from commencement of its operations in October 2001 as reflected in the Company's financial statements.

Capital Expenditures ($000s)	**Quarter Ended**					
	2002					**2001**
	December 31	**September 30**	**June 30**	**March 31**	**Total**	**December 31**
Land acquisition and retention	2,897	1,876	33	156	4,962	—
Geological and geophysical	206	250	32	5	493	—
Exploration drilling	1,888	1,277	—	—	3,165	—
Development drilling	7,528	3,980	603	10	12,121	—
Plant and production facilities	3,289	1,555	—	—	4,844	—
Net property acquisitions	416	170	260	—	846	—
Other	53	188	—	49	290	41
Total	16,277	9,296	928	220	26,721	41

Drilling History

The following sets forth the gross and net wells in which the Company and its subsidiaries participated during the period. RII did not incur drilling activities or expenditures prior to the Equatorial Acquisition. Due to the application of reverse take-over accounting, drilling expenditures were not reported in the Company's financial statements prior to the Equatorial Acquisition. Accordingly, the following history is that of Equatorial for the 200 Day Period.

	Number of Wells					
	Canada		**Indonesia**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Natural gas	50	47.6	—	—	50	47.6
Crude oil	3	2.0	13	3.6	16	5.6
Dry	5	4.0	2	0.5	7	4.5
Total	58	53.6	15	4.1	73	57.7
Average working interest		92%		28%		79%
Success rate	91%		87%		90%	

Land Holdings

The following summarizes the Company's approximate crude oil and natural gas land holdings as at December 31, 2002.

	Total Land		
Property	**Gross Acres**	**Net Acres**	**Average Working Interest**
Alberta	384,769	253,448	66%
Saskatchewan	73,959	62,232	84
British Columbia	51,137	27,522	54
Total	**509,865**	**343,202**	**67%**

The following summarizes the Company's approximate developed and undeveloped crude oil and natural gas land holdings as at December 31, 2002.

	Developed Land			Undeveloped Land		
Property	**Gross Acres**	**Net Acres**	**Average Working Interest**	**Gross Acres**	**Net Acres**	**Average Working Interest**
Alberta	201,918	124,595	62%	182,851	128,853	70%
Saskatchewan	6,451	3,581	56	67,508	58,651	87
British Columbia	9,340	5,685	61	41,797	21,837	52
Total	**217,709**	**133,861**	**61%**	**292,156**	**209,341**	**72%**

The following summarizes changes in the Company's undeveloped land holdings since the date of the Equatorial Acquisition.

Undeveloped Land Reconciliation	**Gross Acres**	**Net Acres**
June 14, 2002	250,162	165,459
Crown and freehold purchases	42,894	42,894
Property acquisition/farm-ins	9,175	7,132
Expiries	(10,075)	(6,144)
December 31, 2002	292,156	209,341

INDUSTRY CONDITIONS

Reference is made to the information under the heading "Management of Business Risks" on pages 21-23, inclusive, of the Company's 2002 Annual Report, which pages are incorporated herein by reference.

Commodity Price Volatility

Crude oil and natural gas prices are volatile and subject to a number of external factors. Prices are cyclical and fluctuate as a result of shifts in the balance between supply and demand for crude oil and natural gas, world and North American market forces, inventory and storage levels, OPEC policy, weather patterns and other factors. In early 2002, the industry initially saw a general weakening of prices for both oil and natural gas. However, through the second half of the year, commodity prices rebounded above historical averages. Currently, tight supply/demand balance has kept prices high for both crude oil and natural gas.

Crude oil is influenced by a world economy and OPEC's ability to adjust supply to world demand. Recent success by OPEC and low North American crude stocks have kept crude oil prices high. However, the Company expects world prices of crude oil to decrease to historical average levels of approximately US $24 per barrel (WTI), but also expect continued global political factors to hold prices at those levels.

Natural gas prices are greatly influenced by market forces in North America. It is generally believed that natural gas has greater stability than crude oil in terms of short-term pricing as there is a shortage of natural gas production and natural gas storage levels are low. The Company expects natural gas prices to moderate somewhat through 2003, but expect the supply of North American natural gas to continue to be constrained by North American production decline rates.

Industry Consolidation and Competition

Over the past few years, consolidation within the Canadian oil and gas industry has resulted in a significant reduction of the number of junior to intermediate-sized exploration and production companies. American companies have also been acquiring companies and assets in Canada. The strong demand for natural gas production

and reserves is expected to result in a continued high level of corporate and asset transactions as buyers strive to increase their natural gas assets and sellers take advantage of high transaction prices.

Along with this merger and acquisition activity, a number of traditional exploration and production companies have recently converted into income or royalty trusts. This trend, which has increased competition for investment dollars and property acquisitions, is expected to continue in the short-term.

As occurred in 2000 and early 2001, the strength of commodity prices resulted in significantly increased operating cash flows and has led to increased drilling activity. The Canadian Association of Oilwell Drilling Contractors forecasts an 11% increase in industry drilling in 2003, approaching the number of wells drilled in 2001, which was a record year. This industry activity will increase competition for oilfield goods and services and may cause drilling and operating costs to increase.

Government Regulation

The oil and natural gas industry is subject to extensive controls and regulation imposed by various levels of government. In western Canada, the various provincial governments have legislation and regulations, which govern land tenure, royalties, production rates, environmental protection, the prevention of waste and other matters. It is not expected that these controls and regulation will affect the operations of the Company in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted.

For Indonesia, see "Indonesia" and "Indonesian Operations Risks".

Pricing and Marketing – Oil and Natural Gas

In Canada, producers of oil and natural gas negotiate sales contracts directly with purchasers, with the result that the market determines the price of oil and natural gas. Exports from Canada may be made pursuant to export contracts with terms not exceeding one year, in the case of light crude, and not exceeding two years, in the case of heavy crude and natural gas, provided that an order approving any such export has been obtained from the National Energy Board ("NEB"). Exports of longer terms require an exporter to obtain an export license from the NEB and the issue of such a license requires the approval of the Governor in Council.

In western Canada, the various provincial governments also regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere, based on such factors as reserve availability, transportation arrangements and market considerations.

Although pipeline expansions are ongoing, the lack of firm natural gas pipeline capacity continues to affect the ability to market natural gas production. The prorating of capacity on the inter-provincial pipeline systems may also affect the ability to market oil production.

The North American Free Trade Agreement

On January 1, 1994 the North American Free Trade Agreement ("NAFTA") among the governments of Canada, the U.S. and Mexico became effective. The NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the U.S. or Mexico will be allowed, provided that any export restrictions do not (i) reduce the proportion of energy resource exported relative to domestic use (based on the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price; or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements and, except as permitted in enforcement of countervailing and antidumping orders and undertakings, minimum or maximum import price requirements.

The NAFTA contemplates the reduction of restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The NAFTA also contemplates clearer disciplines on regulators

to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

Land Tenure

Oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments who grant rights to explore for and produce oil and natural gas pursuant to leases, licenses and permits based upon conditions set forth in provincial legislation. Oil and natural gas rights may also be privately owned and rights to explore for and produce such oil and natural gas are generally granted by lease from the freehold owner on such terms and conditions as may be negotiated.

Provincial Royalties and Incentives

The royalty regime is a significant factor in the profitability of crude oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the freehold mineral owner and the lessee, although production from such lands is also subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on the type of product being produced, well productivity, geographical location and field discovery date.

From time to time, the various provincial governments in western Canada have established incentive programs, which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration and development. The trend in recent years has been for provincial governments to eliminate these types of programs in favour of long-term programs that enhance predictability for producers.

Crude oil and natural gas royalty holidays for specific wells and royalty rate reductions lower the amount of Crown royalties paid by the Company to the provincial governments. In Alberta, the Alberta royalty tax credit program also provides a rebate, to certain eligible producers, on Alberta Crown royalties paid in respect of eligible producing properties. These incentives result in increased profitability from operations of the Company.

In Alberta, the amount payable as a royalty in respect of oil depends upon its vintage and whether it is light, medium or heavy. The royalty payable on natural gas, subject to various incentives, is also dependent upon vintage as well as a prescribed or corporate average price.

In Saskatchewan, the fiscal regime for the oil and gas industry was revised effective October 1, 2002. Some royalties on wells existing as of that date will remain unchanged and will therefore be subject to various periods of royalty/tax deduction. The changes include new lower royalty and tax structures applicable to both oil, natural gas and associated natural gas, a new system of volume incentives and a reduced Corporation Capital Tax Surcharge rate on gross Saskatchewan resource sales.

In British Columbia, the amount payable as a royalty in respect of oil depends on the vintage of the oil, the quantity of oil produced in a month and the value of the oil. The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the amount obtained by the producer and prescribed minimum price.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulation pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures. A breach of such legislation may result in the imposition of material fines and penalties, the revocation of necessary licenses and authorizations and civil liability for pollution damage.

In Alberta, environmental compliance is governed by the *Alberta Environmental Protection and Enhancement Act*. In British Columbia, energy projects may be subject to review pursuant to the provisions of the *Environmental Assessment Act*. In Saskatchewan, environmental compliance is governed by the *Environmental Management and Protection Act*.

The Company believes that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. The Company is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and expense nature as a result of increasingly stringent laws relating to the protection of the environment.

Kyoto Protocol

In December 2002, Canada became a signatory to the Kyoto Protocol. This international treaty establishes commitments to reduce emissions of greenhouse gases that are believed to be responsible for increasing the surface temperatures of the Earth and affecting the global climate. The U.S. Government's decision to withdraw from the Kyoto Protocol may have serious implications for Canada in the context of a continental or hemispheric energy market, but the U.S. is expected to develop a strategy to reduce greenhouse gases, perhaps using the NAFTA model. Early indications from the Government of Canada's policy commitments are that Canada's ratification will not significantly penalize the oil and gas industry. Some uncertainty will remain until the Federal government provides its detailed implementation plan and it becomes clearer what the effect will be on business economics, primarily on the cost site. However, the Company does not expect ratification of the Protocol to have a material effect on its performance in 2003.

Indonesia

PERTAMINA is responsible for the management of operations contemplated under all TAC arrangements, and the contractor is responsible to PERTAMINA for the execution of such operations. TACs have a 20 year term and, in addition to a minimum annual work commitment required to be made during the initial six year period of the TAC, the contractor is required, at least three months prior to the beginning of each calendar year (or at other mutually agreed times), to submit for approval to PERTAMINA a plan of development ("POD") and budget of costs.

PERTAMINA is typically responsible for managing all TAC operations, assuming and discharging the contractor from all taxes, other than Indonesian corporate taxes and the tax on interest, dividend and royalties, expediting approvals and permits needed by the project and ensuring that sufficient Rupiah funds will be available to cover Rupiah expenditures under the work program and budget at all times. PERTAMINA holds title to all non-leased capital equipment, inventory and data from hydrocarbon operations. The responsibilities of a contractor under a TAC include advancing necessary funds, including PERTAMINA's portion, furnishing technical aid and preparing and executing the POD and budget. In return, the contractor may freely lift, dispose of and export its share of crude oil and retain abroad its proceeds obtained from its share. After a period of five years starting the month of the first delivery of crude oil produced from each new field in the contract area, the contractor will typically have a domestic market obligation to account for 25% of the Company's subsidiaries' interest crude oil produced from the contract area, at 15% of market price calculated at the point of export. The contractor generally has the right to recover all costs, defined as "operating costs" in each TAC, against available revenues generated by the TAC. Operating costs consist of current year non-capital costs, current year depreciation on capital costs and current year allowed recovery of prior year's unrecovered operating costs. Non-capital costs relate to costs incurred with respect to current year's operations, the cost of geological and geophysical activity and the intangible costs of drilling exploratory, delineation and development wells. Capital costs include expenditures for items which have useful lives in excess of one year and are depreciated commencing in the year the asset is placed into service at rates which vary depending on the type of asset, but generally results in the asset being fully depreciated within five to seven years. Exploration and development costs in a contract area are "ring-fenced", meaning that expenditures for one TAC cannot be offset against revenues from another TAC. However, within any one TAC, these unrecovered costs can be carried forward to future years for cost recovery purposes. Before deducting operating costs, the contractor may typically recover an investment credit amounting to a fixed percentage of the capital investment cost directly required to develop crude oil production facilities (including new secondary recovery projects), subject to certain restrictions.

For crude oil in excess of Cost Recovery Oil, PERTAMINA is entitled to an 85% after-tax Profit Oil share. The contractor is obligated to pay Indonesian corporate taxes on Profit Oil at the Indonesian corporate tax rate in effect at the time the TAC is executed. The contractor's pre-tax profit share is generally the rate that will provide to it an after-tax profit share of 15% of oil production based on the corporate tax rate that applies to the specific TAC.

If PERTAMINA and the contractor consider the processing and utilization of any natural gas produced under the TAC to be economical, then the construction and installation of facilities for such processing and utilization will be carried out pursuant to an approved work program and budget, with all costs and revenue treated as set forth above. If the contractor considers that the processing and utilization of natural gas is not economical, then PERTAMINA may choose to take and utilize the natural gas which would otherwise be flared and is liable for all associated costs.

All crude oil sold by the contractor to third parties is valued at the net realized price, free on board (f.o.b.), Indonesia, received by the contractor. If a more favourable net realized price is available to PERTAMINA for crude oil sold by the contractor to third parties, other than the contractor's share of production, then the contractor must meet such price if notified by PERTAMINA, or PERTAMINA can choose to market the crude oil itself.

The contractor is obligated to pay a signing bonus to PERTAMINA upon approval by the Indonesian government of the TAC and production bonuses after specified daily production goals for the contract area have been reached. PERTAMINA has the right to demand that a 10% undivided interest in the total rights and obligations under the TAC be offered to itself. In return, PERTAMINA must reimburse the contractor for an amount equal to 10% of the sum of the costs incurred under the TAC to the date of the demand, including 10% of the signing bonus and production bonuses previously paid by the contractor to PERTAMINA. These amounts can be paid directly in cash or through production installments. All payments to be made under the TAC to PERTAMINA, the Indonesian government or the contractor must be made in U.S. dollars or in other currency acceptable to the payee. However, the contractor may make payments to PERTAMINA or the Indonesian government in Rupiah to the extent that such currency is realized as a result of the domestic sale of crude oil or natural gas.

Disputes arising between the contractor and PERTAMINA pursuant to the TAC are submitted to arbitration under the Rules of Arbitration of the Budan Arbitrasi Nusional Indonesia for the Pilona TAC and of the International Chamber of Commerce for the Perkasa TAC. The TACs are governed by the laws of the Republic of Indonesia. Either party has the right to terminate the TAC on 90 days' written notice if a major breach of the TAC is committed by the other party, provided that conclusive evidence of such breach is found through arbitration or a final court decision. To the Company's knowledge, no TAC has been terminated in Indonesia.

Indonesia is a civil law jurisdiction based on a code derived from the Code Napoleon. The Indonesian Civil Code stipulates that contracts must be performed and enforced in accordance with principles of fairness and good faith.

On October 23, 2001, the Indonesian Parliament passed the new Indonesian Oil and Gas Law (Law No. 22 of 2001). The new Law transferred PERTAMINA's regulatory control and supervisory activities in the upstream oil and gas sector to BPMIGAS, a new implementing body that reports directly to the Minister of Energy and Mineral Resources. Existing production sharing contracts and related contracts were transferred from PERTAMINA to BPMIGAS. All existing contracts are to remain in effect and unamended notwithstanding the transfer until their scheduled expiration. The Company's subsidiaries' TACs were not transferred under the new law.

While it is premature to attempt to assess the effect of the new law, it is not expected that the new Law will have an adverse effect on current contractors.

INDONESIAN OPERATIONS RISKS

In addition to the general risks faced by Canadian oil and gas companies, the Company is subject to risks related to its subsidiaries' Indonesian operations and interests. A significant portion of the Company's subsidiaries' business is regulated by the laws and regulations of Indonesia, including those relating to the development,

production, marketing, pricing, transportation and storage of natural gas and crude oil, taxation and environmental and safety matters. The Company's subsidiaries' may be adversely affected by changes in governmental policies or social instability or other political, economic or diplomatic developments in or affecting Indonesia which are not within the control of the Company including, among other things, a change in crude oil or natural gas pricing policy, the risks of war, terrorism, expropriation, nationalization, renegotiation or nullification of existing concessions and contracts, taxation policies, foreign exchange and repatriation restrictions, changing political conditions, international monetary fluctuations and currency controls.

A change in government in Indonesia could adversely affect the Company's subsidiaries' existing contractual relationships with Indonesian governmental agencies and its ability to conduct business in Indonesia. There can be no assurance that transitions in governmental control will occur in accordance with specified constitutional procedure or that the current or a successor administration will not implement policies which could have a material adverse effect upon Indonesia's economy or upon the operations of the Company. The Indonesian government has exercised and continues to exercise significant influence over many aspects of the Indonesian economy, including the oil and gas industry. All of the Company's subsidiaries' crude oil production in Indonesia is sold at Minas (Sumatran Light Crude) prices. The Indonesian government could implement policies that result in significant devaluation of the Rupiah. There has been civil unrest in certain areas in Indonesia that could result in government instability or civil conflict. Any of these factors could adversely affect the business climate in Indonesia and the Company's subsidiaries' business.

The Company is also exposed to risks relating to policy changes by the governments of Canada and the United States in respect of changes in Indonesian government policies. Any such policy changes may have a material adverse effect upon the Company's subsidiaries' foreign operations.

The Company's subsidiaries' existing commercial arrangements are, and future ventures may be, subject to complex legal and contractual relationships and the effectiveness of enforcement of such contracts and relationships with parties in these jurisdictions is not known and cannot be assured. The business practices in Indonesia may differ from those in North America and may affect the cost of operations.

All of The Company's subsidiaries' reserves in Indonesia are attributable to TACs, which contain requirements regarding quality of service, capital expenditures, legal status of the concessionaires, restrictions on transfer and encumbrance of assets and other restrictions. Failure to comply with these arrangements could result, under certain circumstances, in the revocation of the TAC. Such an action could have a material adverse effect on the Company's financial condition, results of operations or prospects.

The Company's results of operations will continue to be materially affected by its subsidiaries' relationship with PERTAMINA. The Company's subsidiaries' must obtain approval from PERTAMINA for substantially all material activities undertaken with respect to the TACs, including exploration, development, production, drilling and other operations, sale of oil or natural gas and the hiring or termination of personnel.

SELECTED FINANCIAL INFORMATION

The following table summarizes certain quarterly and annual financial information relating to the Company. Due to the application of reverse take-over accounting, the following amounts are those of Equatorial for the 200 Day Period and those of RII from commencement of its operations in October 2001 as reflected in the Company's financial statements.

Financial Information
(000s except per share amounts)

	Quarter Ended					
	2002					2001
	December 31	September 30	June 30	March 31	Total	December 31
Gross oil and natural gas revenue	$ 25,666	$ 18,559	$ 2,819	—	$ 47,044	—
Net income (loss) [1]	2,882	1,034	(19,235)	(227)	(15,546)	(52)
Per Common Share – basic [2]	0.05	0.02	(0.33)	—	(0.26)	—
Per Common Share – diluted [2]	0.05	0.02	(0.33)	—	(0.26)	—
Cash flow from (used in) operations	9,941	7,743	555	(221)	18,018	(51)
Per Common Share – basic [2]	0.17	0.13	0.01	—	0.31	—
Per Common Share – diluted [2]	0.16	0.13	0.01	—	0.30	—
Total assets	178,232	168,156	160,376	17,703	178,232	18,117
Total long-term liabilities	20,775	19,265	14,637	—	20,775	—

Notes:

(1) This is also net income from continuing operations.

(2) Before the Equatorial Acquisition, RII was a private company and due to the application of reverse take-over accounting the Company was not required to report per share data prior to that event.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The Company's management's discussion and analysis of financial condition and results of operations, including the financial statements and notes thereto for the fiscal year ended December 31, 2002, contained on pages 14 through 23 of the Company's 2002 Annual Report, is incorporated herein by reference.

New Accounting Pronouncements

The Canadian Institute of Chartered Accountants (CICA) has issued a number of accounting pronouncements, some of which may impact the Company's reported results and financial position in future periods. These new pronouncements include the following:

Effective for 2003, the CICA issued an Accounting Guideline "Hedging Relationships" that establishes standards for the documentation and effectiveness of hedging relationships. While the Company has no derivatives contracts currently, from time to time the Company may enter into such contracts to manage its exposure to risk, and this Guideline may impact the Company's financial statements in the future.

Effective for 2003, the CICA issued Accounting Guideline 14, "Disclosure of Guarantees" which elaborates on the disclosures required with respect to any obligations under certain guarantees issued by the Company. This Section is not expected to have a significant impact on the Company's financial statements.

Effective May 1, 2003, the CICA issued Section 3475, "Disposal of Long-Lived Assets and Discontinued Operations". This Section establishes new standards for the recognition, measurement, presentation and disclosure of the disposal of long-lived assets. It also expands the scope of what assets or operations are to be reclassified as discontinued operations and establishes standards for the presentation and disclosure of those operations, whether or not they include long-lived assets. This Section will be effective on a prospective basis for disposal activities initiated on or after May 1, 2003. This Section is not expected to have a significant impact on the Company's financial statements.

Effective for 2004, the CICA issued Section 3063, "Impairment of Long-Lived Assets" which establishes standards for the recognition, measurement and disclosure of the impairment of long-lived assets, and applies to long-lived assets held for use. An impairment loss is recognized when the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. This Section is not expected to have a significant impact on the Company's financial statements.

Effective for 2004, the CICA issued Section 3110, "Asset Retirement Obligations" which requires liability recognition for retirement obligations associated with petroleum and natural gas interests. These obligations are initially measured at fair value when incurred, which is the discounted future value of the liability. This fair value is added to the carrying amount of the related asset and amortized to expense over its useful life. The liability accretes until the retirement obligation is settled. The impact on the Company's financial statements has not yet been determined.

DIVIDEND POLICY

To date, the Company has not paid any dividends on the outstanding Common Shares and has no intention to declare dividends on its Common Shares in the foreseeable future. Any decision to pay dividends on the Common Shares in the future will be dependent upon the financial requirements of the Company to finance future growth, the financial condition of the Company and other factors which the board of directors of the Company may consider appropriate in the circumstances.

MARKET FOR SECURITIES

The Company's Common Shares are listed on The Toronto Stock Exchange and trade under the symbol "RSE".

DIRECTORS AND OFFICERS

Directors

The names, municipalities of residence, positions held with the Company and principal occupations of the directors of the Company are as follows. The term of office of each director will expire at the next annual meeting of the Company, unless his office is earlier vacated.

Name, Present Office Held and Municipality of Residence	Director Since	Five Year History of Principal Occupations
S. Barry Jackson [2][4] Executive Chairman and Director ***Calgary, Alberta***	June 2002	Corporate director since November 2000; prior thereto, President and Chief Executive Officer of Crestar Energy Inc. (oil and gas company).
Douglas D. Baldwin [1][3] Director ***Calgary, Alberta***	June 2002	Corporate director since April 2001; prior thereto, President and Chief Executive Officer of TransCanada Pipelines Limited (energy transmission and power company) from August 1999 to April 2001; prior to December 1998, Senior Vice President and Director of Imperial Oil Limited (integrated energy company).
Donald P. Driscoll [1][2] Director ***Calgary, Alberta***	June 2002	President and Chief Executive Officer of NAL Resources (oil and gas asset management company).
Brian K. Lemke [4] President, Chief Executive Officer and Director ***Calgary, Alberta***	November 2002	President and Chief Executive Officer of the Company since November 2002; prior thereto, Executive Vice President of the Company from June 2002 to November 2002; prior thereto, Vice President and Chief Financial Officer of RII from November 2001 to June 2002; prior thereto, Chief Financial Officer of Crestar Energy Inc. (oil and gas company) from October 1998 to November 2000; prior thereto, Chief Financial Officer of HCO Energy Ltd. (oil and gas company).
Douglas G. Manner [3] Director ***Houston, Texas***	August 1999	Independent businessman since June 2002; prior thereto, Chairman and Chief Executive Officer of Mission Resources from May 2001 to June 2002; prior thereto, Vice President and Chief Operating Officer of Gulf Canada Resources Limited.
Paul G. McDermott [1] Director ***Greenwich, Connecticut***	June 2002	Managing Partner, Energy of RBC Capital Partners (private equity company) since January 2001; prior thereto, principal of Energy Investment Corporation (investment consulting firm).
Robert R. Rooney [2] Director ***Calgary, Alberta***	March 1999	Partner, Bennett Jones LLP (law firm)
Jeffrey T. Smith [3][4] Director ***Calgary, Alberta***	June 2002	Independent Businessman and director of various public oil and gas companies since December 1997; prior thereto, Chief Operating Officer of Northstar Energy Corporation (oil and gas company).
Mac Van Wielingen [1][2] Director ***Calgary, Alberta***	June 2002	Chairman of ARC Financial Corporation (energy investment and management company) and Chairman of ARC Resources Ltd. (oil and gas company) since May 2003; prior thereto, Vice Chairman of ARC Resources Ltd. since June 2000; prior thereto, Chief Executive Officer of ARC Financial Corporation and ARC Resources Ltd.

Notes:

(1) Member of the Audit and Finance Committee.

(2) Member of the Human Resources and Governance Committee.

(3) Member of the Technical Committee. Mr. Lemke is a non-voting member of the Technical Committee.

(4) Member of the Corporate Review Committee.

Executive Officers

The names, municipalities of residence, positions held with the Company and principal occupations of the executive officers of the Company are as follows.

Name, Present Office Held and Municipality of Residence	Officer Since	Five Year History of Principal Occupations
Brian K. Lemke President, Chief Executive Officer and Director ***Calgary, Alberta***	June 2002	See "Directors".
Peter R. Bresee Vice President, Exploration ***Calgary, Alberta***	May 2003	Vice-President, Exploration of the Company since May 2003; prior thereto, Exploration Manager, South Region since June 2002; prior thereto, Exploration Manager, South Region of RII from February to June 2002; prior thereto, President of GeoPete Exploration Ltd. (private oil and gas company) from October 2000 to February 2002; prior thereto, staff geologist promoted to Exploration Manager, South of Edge Energy Inc. (oil and gas company) from January 1999 to September 2000; prior thereto; staff geologist at Crestar Energy Inc. (oil and gas company).
Brian R. Cumming Vice President, Operations ***Calgary, Alberta***	June 2002	Vice President, Operations of the Company since June 2002; prior thereto, Vice President, Operations for RII from December 2001 to June 2002; prior thereto, independent engineering consultant to the oil and gas industry from June 2000 to November 2001; prior thereto, Manager, Engineering of Maxwell Oil & Gas Ltd. (oil and gas company) from February 2000 to June 2000; prior thereto, senior engineer at Crestar Energy Inc. (oil and gas company).
Michael A. Wilhelm Vice President, Finance and Chief Financial Officer ***Calgary, Alberta***	November 2001	Vice President, Finance and Chief Financial Officer of the Company since November 2001; prior thereto, Manager, Finance & Treasury of the Company from March 2001 to November 2001; prior thereto, held financial roles of increasing responsibility with the Company.

As at May 8, 2003, the directors and executive officers of the Company, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 2,442,384 Common Shares, which represented approximately 4.12% of the outstanding Common Shares.

ADDITIONAL INFORMATION

Additional information, including executive compensation, principal holders of the Company's securities, options to purchase securities and interests of insiders in material transactions, is contained in the Management Proxy Circular of the Company dated March 25, 2003. Additional financial information is provided in the Company's audited consolidated financial statements for the year ended December 31, 2002, contained in the Company's 2002 Annual Report.

When the securities of the Company are in the course of a distribution pursuant to a short form prospectus, or a preliminary short form prospectus has been filed in respect of a distribution of its securities, copies of the following documents may be obtained by contacting:

Chief Financial Officer
Resolute Energy Inc.
Suite 2700, 530 – 8 Avenue S.W.
Calgary, Alberta T2P 3S8

Telephone: 403-264-9562

1. one copy of the Company's Annual Information Form, together with one copy of any document, or the pertinent pages of any document, incorporated by reference in the Annual Information Form;

2. one copy of the Company's comparative consolidated financial statements for its most recently completed financial year, together with the accompanying auditors' report and one copy of the most recent interim consolidated financial statements of the Company filed subsequent to its most recently completed financial year;

3. one copy of the Company's Management Proxy Circular in respect of its most recent annual meeting of shareholders; and

4. one copy of any other documents that are incorporated by reference into the preliminary short form prospectus or short form prospectus and are not required to be provided under paragraphs (1), (2) or (3) above.

At any other time, copies of the documents referred to in paragraphs (1) to (4) above may be obtained upon request from the Chief Financial Officer, provided that, if the request is made by a person who is not a shareholder of the Company, payment of a reasonable charge for such copies may be required.