REAL RESOURCES INC.

INITIAL ANNUAL INFORMATION FORM

YEAR ENDED DECEMBER 31, 2001

NOVEMBER 21, 2002

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GLOSSARY OF TERMS AND ABBREVIATIONS

Terms used in this Annual Information Form and not otherwise defined have the meanings set forth below:

"**ABCA**" means the *Business Corporations Act* (Alberta), R.S.A. 2000, c.B-9, as amended, and the regulations thereunder, and any successor laws or regulations thereto.

"**API**" means American Petroleum Institute;

"**ARTC**" means Alberta Royalty Tax Credit;

"**boe**" means barrels of oil equivalent, with natural gas converted at 6 mcf of natural gas per bbl of oil, unless otherwise stated; and NGLs are converted to oil on the basis of one barrel of NGLs to one bbl of oil;

"**boepd**" means boe per day;

"**Common Shares**" means common shares in the share capital of the Corporation;

"**Corporation**" and "**Real**" means Real Resources Inc., a corporation amalgamated under the ABCA;

"**M$**" means thousands of dollars;

"**NGLs**" means natural gas liquids, including condensate, propane, butane and pentane;

"**Paddock**" means Paddock Lindstrom & Associates Ltd., independent oil and gas reservoir engineers, Calgary, Alberta;

"**Paddock Report**" means the independent engineering evaluation of Real's oil, NGLs and natural gas interests prepared by Paddock dated October 25, 2002 and effective September 30, 2002;

"**TCGSL**" means Trans Canada Gas Services Limited;

"**TSX**" means The Toronto Stock Exchange;

"**WTI**" means West Texas Intermediate, the benchmark North American crude oil;

"**$**" means Canadian dollars.

ABBREVIATIONS AND CONVERSION

In this Annual Information Form, the following abbreviations have the indicated meanings.

bbl and bbls	barrel and barrels, each barrel representing 34.972 Imperial gallons or 42 U.S. gallons
Bcf	one billion cubic feet
Mbbls	thousand barrels
BTU	British thermal unit
MMBTU	one million BTU
Mmbbls	million barrels
bbls/d	barrels per day
mbbls/d	thousands of barrels per day
km and kms	kilometre and kilometres
Mcf	one thousand cubic feet
mcf/d	one thousand cubic feet per day
Mmcf	one million cubic feet
mmcf/d	one million cubic feet per day

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

To convert from	**To**	**Multiply by**
Bbls	cubic metres	0.l59
cubic metres	bbls	6.293
Miles	kms	1.609
Kms	miles	0.621

CORPORATE STRUCTURE

Real was incorporated in 1978 pursuant to the ABCA. In recent years the Corporation has made several corporate acquisitions by merging or amalgamating with certain targets, including an amalgamation with Blue Ridge Resources Inc. on July 1, 1995, amalgamations with Flatland Energy Inc. and Flatland Resources Ltd. on January 31, 1997, an amalgamation with Tri-Ex Oil & Gas Ltd. on January 9, 1998, an amalgamation with ABCOG Corporation on November 12, 1998, an amalgamation with Flatland Resources Inc. on January 7, 2000, an amalgamation with Prism Petroleum Inc. on October 2, 2000 and an amalgamation with Embo Petroleum Inc. on April 1, 2001. The Corporation has continued under the name of "Real Resources Inc." following each amalgamation.

At the 1998 Annual General and Special Meeting held on May 21, 1998, the Corporation approved certain amendments to its Articles, including amendments to increase the maximum number of directors to 10 and allow the board of directors to appoint additional directors between annual general meetings. On May 18, 2000, the Corporation amended its Articles to consolidate the Common Shares on the basis of 1 new Common Share for every four previously issued and outstanding Common Shares.

On October 31, 2002, the Corporation formed a wholly-owned subsidiary, Real Oil Corporation, incorporated under the ABCA, which changed its name to Real Oil & Gas Corp. on November 14, 2002.

The Common Shares of Real trade on the TSX under the symbol "RER".

The head office of Real is located at 700, 555 - 4th Avenue S.W., Calgary, Alberta, T2P 3E7. The registered office is located at 3500, 855 - 2nd Street S.W., Calgary, Alberta, T2P 4J8.

GENERAL DEVELOPMENT OF THE BUSINESS

Real is an independent Alberta oil and gas company which carries on the business of exploring for, developing, acquiring and producing petroleum and natural gas reserves in Alberta, Saskatchewan and Manitoba. The Corporation's strategy for growth is based on certain guiding principles including the pursuit of oil and gas prospects in the Western Canadian sedimentary basin, generation of prospects internally, managing debt levels and assembling and maintaining large land interests in diversified core areas and maintaining operatorship of such areas.

During 1999, the Corporation drilled a total of 22 gross (13.7 net) wells resulting in 9 gross (5.4 net) oil wells, 3 gross (1.5 net) gas wells, 3 gross (2.3 net) service wells and 7 gross (4.5 net) dry and abandoned wells.

During 2000, the Corporation drilled a total of 45 gross (32.1 net) wells resulting in 11 gross (9.0 net) oil wells, 22 gross (15.5 net) gas wells and 12 gross (7.6 net) dry and abandoned wells.

On September 7, 2000, the Corporation acquired all the shares of Prism Petroleum Inc. ("**Prism**"), a public company, for total consideration of $18,402,000, comprised of 2,408,532 Common Shares with an attributed value of $7,917,000 and $10,485,000 cash. The acquisition of Prism added daily production of approximately 600 boe to Real. The acquired production was approximately 80% natural gas concentrated in three properties: Atlee-Buffalo, West Provost and Ricinus. The acquisition added significantly to the Corporation's cash flow from operations, natural gas sales and natural gas reserves. Prism's reserve life index of over 11 years also improved Real's reserve life index to over 10 years.

During 2001, the Corporation drilled a total of 86 gross (53.2 net) wells resulting in 33 gross (20.7 net) oil wells, 35 gross (23.9 net) gas wells, 0 gross (0 net) service wells and 18 gross (8.6 net) dry and abandoned wells.

On March 1, 2001, the Corporation acquired all of the shares of Embo Petroleum Inc. ("**Embo**") for total cash consideration of $2,888,250 plus a severance payment in the amount of $70,000.

On December 21, 2001, Real issued, on a private placement basis, 1.0 million flow-through Common Shares at a price of $4.00 per share. The gross proceeds from the offering were used to fund the Corporation's exploration program.

On June 17, 2002, the Corporation announced its intention to make a normal course issuer bid (the "**Bid**") through the facilities of the TSX to acquire for cancellation up to 950,000 Common Shares, which represented approximately 5% of the Corporation's issued and outstanding Common Shares. The Bid commenced on June 19, 2002 and will terminate on June 18, 2003.

On November 18, 2002, the Corporation, through its wholly-owned subsidiary, Real Oil & Gas Corp., acquired certain petroleum and natural gas assets in East Central Alberta from The Wiser Oil Company of Canada for an aggregate consideration of approximately $10,000,000.

Trends, Commitments, Events or Uncertainties

The Corporation is engaged in the exploration, development, production and acquisition of crude oil and natural gas. Real's business is inherently risky and there is no assurance that hydrocarbon reserves will be discovered and economically produced. Financial risks associated with the petroleum industry include fluctuations in commodity prices, interest rates and currency exchange rates. Operational risks include competition, environmental factors, reservoir performance uncertainties, a complex regulatory environment and safety concerns. The Corporation minimizes its business risks by operating a large number of its properties. This enables Real to control the timing, direction and costs related to exploration and development opportunities. The geological focus is on areas in which the prospects are well understood by management. Technological tools are regularly used to reduce risk and increase the probability of success. The Corporation closely follows all government regulations and has an up to date emergency response plan that has been communicated to all field operations by management. Real also carries insurance coverage to protect itself against potential losses. Maintaining a highly motivated and talented staff of petroleum and natural gas professionals further minimizes the business risk. The Corporation is exposed to commodity price and market risk for its principal products of petroleum and natural gas. Commodity prices are influenced by a wide variety of factors of which most are beyond the control of Real. To manage this risk, the Corporation has entered into a number of short-term financial derivatives for hedging purposes. These derivatives include contracts related to oil and gas prices, as well as foreign exchange rates. Real has also minimized its exposure to increases in interest rates by entering into short-term contracts for interest rate swaptions. The Corporation is committed to maximizing shareholder value in an environmentally and socially responsible and safe manner. To this end, Real is actively involved in the Canadian Association of Petroleum Producers ("CAPP") Stewardship initiative. This voluntary initiative encourages members to continually improve their environment, health and safety performance and to report their progress to all stakeholders. CAPP has recognized Real's participation at a Silver level which acknowledges an open and transparent account of our environment, health and safety performance on a yearly basis and a leadership role in the improvement of these issues.

There are a number of trends that have been developing in the oil and gas industry during the past 18 months that appear to be shaping the near future of the business. The first trend is the consolidation phase that the industry has been going through. This has affected companies of all sizes from the small emerging companies to the senior integrated organizations. This trend appears to be accelerating as a number of publicly traded companies are trading below asset or break-up value and as a result it is less expensive for companies to grow by acquiring companies than by focusing entirely on drilling and prospect generation. At a time of high commodity prices and relatively low stock valuations there appears to be a valuation disconnect that has resulted in increased merger and acquisition activity.

The second trend relates to the size of companies that investors are focusing on. The larger market capitalization companies provide for greater liquidity and as result appear to be more attractive, however the smaller companies may present potentially larger returns as they have not yet appreciated in value in relation to the strong commodity prices that the industry is currently experiencing. This may change in the near future as investors look for higher rates of returns, which may encourage them to consider investment in smaller oil and gas companies.

The third trend is the current influence of foreign exploration and production on the Canadian oil and gas industry. The main influence has been from American companies that are acquiring companies and assets in Canada in order to build on long-term natural gas supplies to the United States. This trend will continue to influence valuation parameters of Canadian assets and will result in global values for Canadian companies.

A fourth trend is the continuing volatility in the prices for both natural gas and crude oil. Natural gas is a commodity influenced by factors in North America, including the strength of the economy, weather and demand for electrical generation. Natural gas prices have risen recently with prospects remaining positive for the forthcoming winter. Crude oil is influenced by a world economy and OPEC's ability to adjust supply to world demand. Recent success by OPEC and uncertainty in the Middle East and Venezuela has kept crude oil prices high.

The Canadian/U.S. exchange rate also influences commodity prices for Canadian producers as there is a high correlation between Canadian and U.S. oil and natural gas prices. The weakening of the Canadian dollar is a positive trend and with recent significant weakening, the positive effect on pricing is growing in significance.

In 1994, the United Nations' Framework on Climate Change came into force and three years later led to the Kyoto Protocol which requires nations to reduce their emissions of carbon dioxide and, therefore, greenhouse gases. The Government of Canada has ratified the Kyoto Protocol. Reductions in greenhouse gases from oil and gas producers may be required which could result in, among other things, increased operating and capital expenditures for those producers which may make certain production of crude oil or natural gas by those producers uneconomic, resulting in reductions in such production. We are unable to predict the effect on the future earnings of the Corporation as a result of the ratification of the Kyoto Protocol by the Government of Canada.

DESCRIPTION OF THE BUSINESS

General

The business of the Corporation is the acquisition of interests in petroleum and natural gas rights and the exploration for, and the development, production and marketing of, petroleum and natural gas. Real's principal properties are located in Alberta and Saskatchewan.

Exploration and Development

Real's growth strategy gained momentum in 2001, as the Corporation set a new record by drilling 86 wells (53.2 net). Real continued to move forward with a more balanced approach between exploration and development. Exploration represented 36% of the Corporation's drilling activity, while development drilling accounted for 64%. Overall drilling success increased to 84%, while the average working interest per well decreased slightly to 62%.

Real continued the pursuit of a more even split between oil and gas opportunities. In keeping with this objective, during 2001 the Corporation successfully drilled 33 oil wells (20.7 net) and 35 gas wells (23.9 net), along with 18 dry holes (8.6 net).

During the first nine months of 2002, Real drilled 64 (51.0 net) wells. The emphasis in the first two quarters was on developing the Corporation's Dina oil discoveries in the Neutral Hills area of East Central Alberta. The third quarter saw Real shift its focus from development to exploration and from oil to gas.

Exploration represented 28% of the Corporation's drilling activity, while development drilling accounted for 72%. Real successfully drilled and cased 37 (30.2 net) oil wells and 7 (5.9 net) gas wells, along with 20 (14.9 net) dry holes. Overall drilling success decreased slightly to 71%, while the average working interest increased to 80%. The Corporation continued to maintain a high emphasis on hands-on management, operating 54 of the 64 wells.

The drilling success experienced on the Corporation's gas exploration prospects in the third quarter of 2002 will likely lead to an overall increase in natural gas production for the subsequent winter heating season. With natural gas prices continuing to gain strength during the first quarter of 2003, the Corporation plans to increase drilling activities on gas prospects in West Central Alberta as well as to complete an active shallow multi zone gas drilling program in Southern Alberta.

Two production purchases were completed in the Neutral Hills area of East Central Alberta during the fourth quarter of 2002. These purchases included varying working interests in one inactive and five production oil pools. The first well of a multi-well redevelopment program on the 100% owned inactive oil pool was drilled, completed and put on production during the fourth quarter of 2002. Development plans for the acquired oil pools will enhance the ongoing activities of Real at Neutral Hills where the Corporation expects to follow up with additional wells in the first half of 2003.

An oil pool discovery was made in the Enchant area in early October 2002. The discovery well, in which Real holds a 96% working interest, encountered a 65 foot column of oil in the Arcs formation. This well, which was completed and put on production in the fourth quarter of 2002, will be followed up with development drilling in 2003 and the implementation of a waterflood.

The Corporation initiated an asset rationalization process on non-core properties early in the third quarter of 2002. Proceeds of approximately $4.0 million have been received in connection with the sale of production of 180 barrels of oil equivalent per day.

Real continues to stay the course by effectively integrating exploration, exploitation and development in its four core areas: East Central Alberta, Southern Alberta, West Central Alberta and Saskatchewan.

East Central Alberta

The majority of the Corporation's drilling and seismic activity in 2001 was in East Central Alberta, where a total of 44 wells (10 exploratory and 34 development) were drilled. One key acquisition in this core area enhanced Real's existing land and prospect inventory and led to two significant Dina oil pool discoveries. On the first Neutral Hills discovery, 18 development oil wells were drilled.

A second significant Neutral Hills Dina oil discovery was made during the third quarter of 2001. After drilling three successful oil wells, the Corporation conducted a 3-D seismic survey on 100% working interest lands adjacent to the discovery well. Real drilled three more successful Dina oil wells to confirm the accuracy of the 3-D survey. Up to 10 more locations have been identified on seismic. In the West Provost Unit, the Corporation and its partners drilled nine successful Viking oil/gas wells. Just north of this area, three wells were drilled at Nelson Lake targeting Rex gas. At Oyen, Real drilled two exploratory wells. The first was abandoned, but the second resulted in a new McLaren gas pool discovery. Up to three additional wells have been identified on 2-D trade seismic.

The majority of the Corporation's drilling and seismic activity during the first nine months of 2002 was in East Central Alberta. A total of 50 (41.2 net) wells were drilled, of which 7 were exploratory and 43 were development. This drilling program resulted in 35 (28.9 net) oil wells, 4 (4.0 net) gas wells and 11 (7.0 net) dry and abandoned wells.

During the first nine months of 2002, Real discovered two new Dina oil pools and a pool extension at Neutral Hills. The Corporation drilled 14 development wells to delineate these new discoveries. Real also drilled 22 development wells in order to delineate the Dina oil pool discovered late in 2001.

Elsewhere in East Central Alberta, gas discoveries were made at Highland, Neutral Hills and at Nelson Lake.

Southern Alberta

In the Southern Alberta area in 2001, the Corporation continued an active pace of development drilling where a total of 17 wells were drilled. At Enchant, three development oil wells were drilled in the Arcs and Grotto formations. Subsequent to year end, Real acquired additional interests in the pool. On the Corporation's newly acquired Atlee-Buffalo property, a 100% successful shallow gas development program of 10 wells during the third quarter of 2001 was carried out. These Medicine Hat gas wells are characterized by relatively low production rates, countered by a long and stable reserve life index. Four exploratory wells were drilled during 2001. Three gas wells were drilled at Armada to follow up the discovery made in 2000. These new wells are now on production from the Bow

Island, Glauconitic and Sunburst zones. Real also drilled a dual zone exploratory gas discovery well at its Scandia property.

In Southern Alberta, the Corporation drilled 6 (4.1 net) wells in the first nine months of 2002, of which 4 were exploratory and 2 were development. This drilling program resulted in 1 (1.0 net) oil well, 1 (0.5 net) gas well and 4 (2.6 net) dry and abandoned wells.

At Enchant West, the Corporation discovered a new Arcs oil pool. Further seismic and drilling delineation will be necessary to determine the size of this pool. At Scandia, Real made a new Sunburst gas discovery. Further drilling is planned during the fourth quarter for both of these areas.

West Central Alberta

During 2001, the Corporation drilled 21 wells in West Central Alberta. The majority were highly exploratory in nature and were drilled in the first half of the year because of winter only accessibility.

Ten exploratory wells were drilled at the Corporation's W5M project area, which consists of Prairie River, Meekwap and Virginia Hills. As a result of this drilling activity, a 37 km pipeline was constructed and Real's first Prairie River gas began flowing in the fourth quarter. Other exploratory discoveries were drilled at Ricinus and Valleyview.

The Corporation drilled five development wells in West Central Alberta in 2001 to follow up previous discoveries. A second development well at Westerose, in which Real has a 50% working interest, encountered Glauconitic gas.

In the first nine months of 2002, Real drilled 7 (5.4 net) wells in West Central Alberta, of which 6 were exploratory and 1 was development. This drilling program resulted in 2 (1.45 net) gas wells and 5 (3.95) dry and abandoned wells.

At Ferrybank, the Corporation made a 100% working interest multi-zone gas discovery. The well has been production-tested and will go onstream late in the fourth quarter of 2002. Further delineation drilling will be required to test the aerial extent of the new pools encountered in this well. A second gas discovery was made at Thorsby.

Real's first two high impact Devonian test wells were dry and abandoned. Technical results were encouraging and a 3-D seismic program will be carried out in the first quarter of 2003. Further drilling is planned once the new seismic data is interpreted.

Saskatchewan

At Alida West, in which the Corporation continues to operate and hold a 100% working interest, the fourth and fifth successful horizontal oil wells were drilling during 2001. These two wells are now on production and represent the final development phase of the Alida West property. Real also drilled a successful horizontal oil well at Rocanville. Both of these properties produce high quality 40° API oil.

As much of the Corporation's Saskatchewan acreage is mature and developed, only 1 (0.33 net) well was drilled during the first nine months of 2002. This well was a successful Tilston oil well drilled at Ashley Lake. No further drilling or seismic is planned for Saskatchewan for the remainder of the year.

Material Reorganization

The Corporation eliminated its accumulated deficit as at December 31, 1999 by reducing its stated capital, as ratified by the shareholders of the Corporation at the Annual General and Special Meeting of the shareholders held May 18, 2000.

Future Commitments

The Corporation is a party to various conventional oil and gas, foreign exchange and interest rate contracts that are used, in certain cases, to lock in prices, and in other cases to lock in base prices. These contracts are settled monthly and are individually described in their entirety in Note 7 of the Corporation's interim financial statements for the nine month period ended September 30, 2002.

Markets

Real utilizes the services and expertise of various oil and gas marketers to sell its production. Crude oil and natural gas liquids are sold under short term contracts and the majority of gas production is sold at spot market prices. In August of 1999, Real commenced a hedging program to manage the Corporation’s exposure to crude oil price fluctuations. The hedging allows Real to ensure its base capital program can be funded by a threshold cash flow while also realizing increased netbacks from the higher current oil prices. In 2000, the Corporation also commenced a hedging program on a portion of its gas production. The Corporation's hedging program for oil and gas is ongoing.

Seasonability of the Markets, Commodity Pricing and Competitive Conditions

The prices received for oil and gas are governed by a number of factors. For the most part, the major factor in determining the price is the supply of oil and gas versus the demand for the commodities. The demand for oil and gas in North America is strongly influenced by the weather. During the colder winter months, the demand for oil and gas for heating purposes is high compared to the remainder of the year. This resulting increase in demand can be reflected in the prices received and has a seasonability effect in the prices. Most of the major oil exporting nations of the world are members of cartel named the Organization of Petroleum Exporting Countries ("**OPEC**"). One function of OPEC is to establish oil production quotas for its members. By limiting oil production, the cartel can influence the price of oil.

Although Real started as a 100% oil producer, one objective of the Corporation has been to become essentially balanced between oil and gas on both a reserve and production basis. Since the prices received for these commodities are influenced separately, for the most part, maintaining a balance between them allows the Corporation to optimize economic returns. The quality of Real’s oil reserves and production is categorized as light-medium. As a result, the price received for this quality of oil is higher than one that is categorized as heavy. The focus of the Corporation’s activities are in areas of light-medium quality oil in order to obtain higher oil prices.

Oil and Gas Reserves

The Paddock Report evaluates the proved and probable crude oil, NGLs and natural gas reserves associated with Real's properties effective as of September 30, 2002.

In preparing its report, Paddock obtained basic information from Real, which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required to conduct the evaluation and upon which the Paddock Report is based, was obtained from public records, other operators and from Paddock's non-confidential files. Information concerning the extent and character of ownership of Real's interests and the accuracy of all factual data supplied to Paddock by third parties was accepted by Paddock as represented.

The following is a summary, as at September 30, 2002, of the oil, NGLs and natural gas reserves of Real and the present worth value of the estimated future net cash flows ascribed to such reserves as evaluated in the Paddock Report, based on escalated and constant price and cost assumptions. **All evaluations of the present worth of estimated future cash flows in the Paddock Report are stated after provision for estimated future capital expenditures and prior to provision for future site restoration and reclamation costs, income taxes and indirect costs and do not necessarily represent the fair market value of the reserves. There is no assurance that the price and cost assumptions used in the Paddock Report will be attained and variances could be material.**

Summary of Corporation Interest Reserves and Present Values (including ARTC)
Based on Escalating $ Economics
Effective September 30, 2002

	Oil		Sales Gas		NGL		Present Value Cash Flow including ARTC			
Reserves Category	**Gross (mstb)**	**Net (mstb)**	**Gross (mmcf)**	**Net (mmcf)**	**Gross (mstb)**	**Net (mstb)**	**PW(0) (M$)**	**PW(10) (M$)**	**PW(15) (M$)**	**PW(20) (M$)**
Proved Producing	5,453	4,877	22,264	19,224	203	162	132,157	87,557	76,169	67,936
Proved Non-Producing	197	165	9,050	6,789	235	155	27,780	19,179	16,645	14,725
Total Proved Developed	5,650	5,042	31,314	26,013	438	317	159,937	106,736	92,814	82,661
Proved Undeveloped	564	505	5,990	5,264	30	23	19,225	8,030	5,697	4,135
Total Proved	6,214	5,547	37,304	31,277	468	340	179,162	114,766	98,511	86,796
Probable Additional Unrisked	2,309	2,065	16,482	13,241	402	275	72,200	32,346	24,565	19,434
Proved + Probable Unrisked	8,523	7,612	53,786	44,518	870	615	251,362	147,112	123,076	106,230
50% Reduction for Risk	(1,154)	(1,032)	(8,241)	(6,620)	(201)	(137)	(40,568)	(20,332)	(16,488)	(13,621)
Proved + Probable Risked	7,369	6,580	45,545	37,898	669	478	210,794	126,780	106,588	92,069

Volumes in Metric Units

	Oil		Sales Gas		NGL		Present Value Cash Flow including ARTC			
Reserves Category	**Gross (e3m3)**	**Net (e3m3)**	**Gross (e6m3)**	**Net (e6m3)**	**Gross (e3m3)**	**Net (e3m3)**	**PW(0) (M$)**	**PW(10) (M$)**	**PW(15) (M$)**	**PW(20) (M$)**
Proved Producing	867	775	627	542	32	26	132,157	87,557	76,169	67,936
Proved Non-Producing	31	26	255	191	38	24	27,780	19,179	16,645	14,725
Total Proved Developed	898	801	882	733	70	50	159,937	106,736	92,814	82,661
Proved Undeveloped	90	81	169	148	4	4	19,225	8,030	5,697	4,135
Total Proved	988	882	1,051	881	74	54	179,162	114,766	98,511	86,796
Probable Additional Unrisked	366	328	464	373	64	44	72,200	32,346	24,565	19,434
Proved + Probable Unrisked	1,354	1,210	1,515	1,254	138	98	251,362	147,112	123,076	106,230
50% Reduction for Risk	(183)	(164)	(232)	(186)	(32)	(22)	(40,568)	(20,332)	(16,488)	(13,621)
Proved + Probable Risked	1,171	1,046	1,283	1,068	106	76	210,794	126,780	106,588	92,069

Summary of Corporation Interest Reserves and Present Values (including ARTC)
Based on Constant Price and Cost Assumptions
Effective September 30, 2002

	Oil		Sales Gas		NGL		Present Value Cash Flow including ARTC			
Reserves Category	**Gross (mstb)**	**Net (mstb)**	**Gross (mmcf)**	**Net (mmcf)**	**Gross (mstb)**	**Net (mstb)**	**PW(0) (M$)**	**PW(10) (M$)**	**PW(15) (M$)**	**PW(20) (M$)**
Proved Producing	5,539	4,916	23,111	20,009	204	162	166,358	108,037	93,271	82,631
Proved Non-Producing	194	159	9,072	6,852	235	153	30,604	21,072	18,269	16,147
Total Proved Developed	5,733	5,075	32,183	26,861	439	315	196,962	129,109	111,540	98,778
Proved Undeveloped	567	499	6,100	5,366	30	22	21,454	9,467	6,950	5,251
Total Proved	6,300	5,574	38,283	32,227	469	337	218,416	138,576	118,490	104,029
Probable Additional Unrisked	2,379	2,116	16,611	13,427	402	271	84,222	39,044	30,042	24,060
Total Proved + Probable Unrisked	8,679	7,690	54,894	45,654	871	608	302,638	177,620	148,532	128,089
50% Reduction for Risk	(1,189)	(1,058)	(8,305)	(6,713)	(201)	(135)	(46,497)	(23,608)	(18,976)	(15,868)
Proved + Probable Risked	7,490	6,632	46,589	38,941	670	473	256,141	154,012	129,556	112,221

Volumes in Metric Units

Reserves Category	Oil Gross (e3m3)	Oil Net (e3m3)	Sales Gas Gross (e6m3)	Sales Gas Net (e6m3)	NGL Gross (e3m3)	NGL Net (e3m3)	Present Value Cash Flow including ARTC PW(0) (M$)	PW(10) (M$)	PW(15) (M$)	PW(20) (M$)
Proved Producing	880	781	651	564	32	26	166,358	108,037	93,271	82,631
Proved Non-Producing	31	25	256	193	38	24	30,604	21,072	18,269	16,147
Total Proved Developed	911	806	907	757	70	50	196,962	129,109	111,540	98,778
Proved Undeveloped	90	80	172	151	5	4	21,454	9,467	6,950	5,251
Total Proved	1,001	886	1,079	908	75	54	218,416	138,576	118,490	104,029
Probable Additional Unrisked	378	336	468	378	63	43	84,222	39,044	30,042	24,060
Total Proved + Probable Unrisked	1,379	1,222	1,547	1,286	138	97	302,638	177,620	148,532	128,089
50% Reduction for Risk	(189)	(168)	(234)	(189)	(31)	(21)	(46,497)	(23,608)	(18,976)	(15,868)
Total Proved + Probable Risked	1,190	1,054	1,313	1,097	107	76	256,141	154,012	129,556	112,221

Notes:

(1) *Gross Reserves* are defined as the total remaining recoverable reserves owned by Real before deduction of any royalties. "Net" reserves are defined as those accruing to Real after all interests owned by others, including crown and freehold royalties, have been deducted.

(2) *Proved Reserves* are defined as those reserves estimated as recoverable under current technology and anticipated (existing in the constant price case) economic conditions, from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir.

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

(4) *Proved Non-Producing Reserves* are defined as those proved reserves that are not currently producing either due to lack of facilities and/or markets.

(5) *Proved Undeveloped Reserves* are defined as those proved reserves which are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units, which are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.

(6) *Probable Additional Reserves* are defined as those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and anticipated economic conditions, but where such analysis suggests the likelihood of their existence and future recovery. Probable additional 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 processes which can be reasonably expected to be instituted in the future.

(7) The Paddock Report makes certain assumptions regarding future increases in the prices of oil and gas and takes into account inflation with respect to future operating and capital costs in the escalated price case. Operating and capital costs were escalated by 2% per annum from 2003. All oil prices have been adjusted from the reference price for quality and transportation and all gas prices have been adjusted for heating value.

The product prices used in the escalating price and cost evaluations include the following:

Year	Oil: WTI@ CUSHING $US/bbl	Oil: EDMONTON REF PRICE $CDN/bbl	Oil: HARDISTY 25° API $CDN/bbl	Natural Gas: TCGSL $CDN/mmbtu	Natural Gas: ALBERTA 1 YEAR FIRM $CDN/mmbtu	Natural Gas: SPOT $CDN/mmbtu
3 MOS/2002	28.50	43.51	33.51	4.50	4.85	4.85
2003	25.00	37.42	30.42	4.44	4.74	4.74
2004	22.00	32.78	26.78	4.52	4.72	4.72
2005	22.44	33.44	27.32	4.60	4.70	4.70
2006	22.89	34.11	27.87	4.76	4.76	4.76
2007	23.35	34.79	28.42	4.81	4.81	4.81
2008	23.81	35.49	28.99	4.87	4.87	4.87
2009	24.29	36.20	29.57	4.93	4.93	4.93
2010	24.78	36.92	30.16	4.98	4.98	4.98
2011	25.27	37.66	30.77	5.04	5.04	5.04
2012	25.78	38.41	31.38	5.09	5.09	5.09
2013	26.29	39.18	32.01	5.15	5.15	5.15
2014	26.82	39.96	32.65	5.20	5.20	5.20
2015	27.35	40.76	33.30	5.25	5.25	5.25
2016	27.90	41.58	33.97	5.36	5.36	5.36

Thereafter all prices escalated at 2%.

(8) Product prices used in the constant price and cost evaluations are $43.51/bbl (Edmonton light sweet) per stock tank barrel for oil and $5.02/mcf (AECO) per mcf for gas. The constant price and cost assumptions assume the continuance of current laws, regulations and operating costs in effect on the effective date of the Paddock Report. Product prices have not been escalated. In addition, operating and capital costs have not been increased on an inflationary basis.
(9) The Paddock Report estimates total capital investment net to Real necessary to achieve the estimated future net cash flow, to be 16,992 (6,919 in 2002 and 9,773 in 2003) based on escalated price and cost assumptions and 16,500 (6,919 in 2002 and 9,581 in 2003) based on constant price and cost assumptions.
(10) Effective January 1, 1995, the ARTC program refunds a portion of eligible crown royalties and varies from a maximum rate of refund of 75% of $2 million when the oil reference price is below $100 per m3, to a minimum of 25% of $2 million when the oil price is above $210 per m3. The ARTC program was assumed to continue indefinitely.

The values for ARTC included in the escalated price and cost assumption tables are as follows:

	Escalating $ Economics Present Value Cash Flow			
Reserve Category	**0% (M$)**	**10% (M$)**	**15% (M$)**	**20% (M$)**
Proved Producing	2,880	1,941	1,690	1,504
Proved Non-Producing	1,179	668	530	431
Total Proved Developed	4,059	2,609	2,220	1,935
Proved Undeveloped	718	227	149	105
Total Proved	4,777	2,836	2,369	2,040
Probable Additional Unrisked	2,092	670	442	306
Proved + Probable Unrisked	6,869	3,506	2,811	2,346
50% Reduction For Risk	(1,046)	(335)	(221)	(153)
Proved + Risked Probable	5,823	3,171	2,590	2,193

The values for ARTC included in the constant price and cost assumption tables are as follows:

	Constant $ Economics Present Value Cash Flow			
Reserve Category	**0% (M$)**	**10% (M$)**	**15% (M$)**	**20% (M$)**
Proved Producing	3,093	2,100	1,826	1,622
Proved Non-Producing	1,014	552	429	341
Total Proved Developed	4,107	2,652	2,255	1,963
Proved Undeveloped	689	236	159	114
Total Proved	4,796	2,888	2,414	2,077
Probable Additional Unrisked	1,851	612	401	276
Proved + Probable Unrisked	6,647	3,500	2,815	2,353
50% Reduction For Risk	(925)	(306)	(200)	(138)
Proved + Risked Probable	5,722	3,194	2,615	2,215

Reconciliation of Changes in Reserves

The following table summarizes the changes in reserves during the past year[(1)(2)]:

	Total Proved Reserves (Gross)				Total Proved + Probable (Gross)			
	Oil MSTB	**NGL MSTB**	**Sales Gas MMCF**	**6:1 MBOE**	**Oil MSTB**	**NGL MSTB**	**Sales Gas MMCF**	**6:1 MBOE**
January 1, 2002	6,370	285	30,830	11,793	7,460	388	38,044	14,189
Production	871	28	2,530	1,321	871	28	2,530	1,321
Drilling	1,463	136	9,193	3,131	1,833	229	11,313	3,947
Acquisitions	--	4	1,387	235	--	5	1,510	256
Divestitures	321	--	--	321	351	--	--	351
Adjustments	(427)	71	(1,576)	(619)	(702)	75	(2,792)	(1,092)
September 30, 2002	6,214	468	37,304	12,899	7,369	669	45,545	15,628

Notes:
(1) **Probable reserves have been risked at 50%.**
(2) Based on the Escalating $ Economics Case.

Reserve Life Index

The following table summarizes by the reserve life index for the total proved and proved plus probable reserves by product and on a barrel of oil equivalent basis [(1)].

RLI – Years	Crude Oil and NGL's	Natural Gas	BOE
Total Proved	7.4	14.7	10
Total Proved + Probable[(2)]	8.9	18.0	12

Notes:
(1) Based on September 30, 2002 reserves divided by the average production for the 9 months ended September 30, 2002.
(2) **Probable reserves have been risked at 50%.**

Undeveloped Lands

The following table sets out Real's undeveloped land holdings[(1)] in Alberta, Saskatchewan and Manitoba as at September 30, 2002.

	Acres	
Working Interest Area	**Gross[(2)]**	**Net[(3)]**
Alberta	259,677	164,958
Manitoba	4,867	4,867
Saskatchewan	24,490	11,154
Total undeveloped land holdings	289,034	180,979

Notes:
(1) "Undeveloped land holdings" refers to those lands in which Real has an interest and which have not been assigned reserves.
(2) "Gross Acres" refers to the number of acres in which Real has an interest.
(3) "Net Acres" refers to the aggregate of the numbers obtained by multiplying each gross acre by Real's percentage interest therein.

Production

The following table shows the average daily net production of Real before deduction of royalties payable to others for the periods indicated:

	Nine Months Ended September 30, 2002	2001	2000	1999	1998	1997
Crude Oil and NGLs (bbl/d)	3,293	2,603	2,160	1,665	1,608	357
Natural Gas (mcf/d)	9,267	10,025	4,658	344	396	665
Total Production (boe/d)	4,837	4,274	2,937	1,722	1,674	468

Producing Wells

The following table shows the number of producing and shut-in oil and gas wells in which the Corporation had an interest as at September 30, 2002.

	Oil Wells				Gas Wells			
	Producing		Shut-In		Producing		Shut-In	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	325	128	56	26	210	154	52	30
Saskatchewan	48	23	5	5	--	--	--	--
TOTAL	373	151	61	31	210	154	52	30

Oil, NGL and Natural Gas Production

	Year 2002			
	1st Quarter	2nd Quarter	3rd Quarter	9 Mos. Ended
Average Daily Production Volumes				
Oil (bbls)	3,016	3,365	3,190	3,191
NGL (bbls)	117	95	94	102
Natural Gas (mcf)	10,133	9,101	8,585	9,267
Netbacks ($/boe)				
Sales Revenue	27.08	30.33	30.49	29.32
Net Royalties	(5.88)	(4.93)	(6.27)	(5.68)
Production Expenses	(5.44)	(5.71)	(5.69)	(5.62)
Field Netback	15.76	19.69	18.53	18.02
Administrative, Interest & Taxes	(2.41)	(2.81)	(2.97)	(2.73)
Cash Flow Netback	13.35	16.88	15.56	15.29

	Year 2001					Year 2000				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year Ended	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Year Ended
Average Daily Production Volumes										
Oil (bbls)	2,016	2,498	2,702	2,701	2,482	1,983	2,295	2,002	2,014	2,073
NGL (bbls)	101	118	121	141	121	53	90	91	113	87
Natural Gas (mcf)	8,708	9,612	10,432	11,315	10,025	2,128	3,327	4,554	8,580	4,658
Netbacks ($/boe)										
Sales Revenue	43.55	35.64	30.72	25.21	33.04	32.34	34.63	37.14	41.21	36.78
Net Royalties	(9.82)	(6.39)	(5.11)	(5.00)	(6.36)	(5.25)	(6.07)	(7.20)	(9.23)	(7.14)
Production Expenses	(6.13)	(5.45)	(5.96)	(5.74)	(5.81)	(5.55)	(4.86)	(4.85)	(5.69)	(5.25)
Field Netback	27.60	23.80	19.65	14.47	20.87	21.54	23.70	25.09	26.29	24.39
Administrative, Interest & Taxes	(3.63)	(2.94)	(3.07)	(3.14)	(3.18)	(2.42)	(3.01)	(3.86)	(3.50)	(3.25)
Cash Flow Netback	23.97	20.86	16.58	11.33	17.69	19.12	20.69	21.23	22.79	21.14

Drilling Activity

Real drilled, or participated in drilling, exploratory and development wells in Alberta and Saskatchewan as shown in the following table, for the periods indicated. The wells listed as "Oil" or "Gas" comprise all wells capable of production, whether producing or capped, in which Real has an interest.

	Nine Months Ended September 30, 2002		Years Ended December 31			
			2001		2000	
	Gross	Net	Gross	Net	Gross	Net
Oil	37	30.2	33	20.7	11	9.0
Gas	7	5.9	35	23.9	22	15.5
Service	--	--	--	--	--	--
Dry	20	14.9	18	8.6	12	7.6
Total	64	51.0	86	53.2	45	32.1

Capital Expenditures

Real had the following capital expenditures for the periods indicated:

($000's)	Nine Months Ended September 30, 2002	Year Ended December 31 2001	2000	1999	1998	1997
Corporate Acquisitions	--	2,888	26,390	--	990	18,816
Property Acquisitions	1,701	4,323	5,795	1,412	4,741	32
Land	2,936	3,170	2,653	1,016	2,555	763
Seismic	1,687	1,093	1,176	835	1,015	651
Drilling and Exploration	15,827	19,558	14,894	6,807	6,937	2,120
Capitalized G&A Costs	674	790	845	532	576	280
Well Equipment & Facilities	5,605	7,768	3,693	1,439	2,665	820
Office Equipment	47	66	66	19	96	60
	28,477	39,656	55,512	12,060	19,575	23,542

Capital Expenditures by Quarter
2002 Three Months Ended

($000's)	March 31	June 30	September 30
Corporate Acquisitions	--	--	--
Property Acquisitions (net of dispositions)	163	(45)	1,583
Land	1,330	806	800
Seismic	388	680	619
Drilling and Exploration	4,736	4,531	6,560
Capitalized G&A Costs	220	208	246
Well Equipment & Facilities	2,834	658	2,113
Office Equipment	37	5	5
	9,708	6,843	11,926

Capital Expenditures by Quarter
2001 Three Months Ended

($000's)	March 31	June 30	September 30	December 31
Corporate Acquisitions	2,888	--	--	--
Property Acquisitions	375	2,460	--	1,488
Land	1,236	749	767	418
Seismic	212	217	423	241
Drilling and Exploration	5,810	7,403	4,579	1,766
Capitalized G&A Costs	179	203	198	210
Well Equipment & Facilities	1,228	2,725	2,506	1,309
Office Equipment	13	11	33	9
	11,941	13,768	8,506	5,441

Capital Expenditures by Quarter
2000 Three Months Ended

($000's)	March 31	June 30	September 30	December 31
Corporate Acquisitions	4,000	--	22,390	--
Property Acquisitions	1,959	3,749	87	--
Land	146	1,577	469	461
Seismic	408	141	185	442
Drilling and Exploration	3,830	863	3,452	6,749
Capitalized G&A Costs	134	155	297	259
Well Equipment & Facilities	1,067	388	639	1,599
Office Equipment	14	11	8	33
	11,558	6,884	27,527	9,543

Sensitivity Analysis for Cash Flow and Earnings
September 30, 2002

	Change	Approximate Change in Cash Flow from Operations		Approximate Change in Net Earnings	
		$000s	Per Share	$000s	Per Share
Price of Crude Oil ($/barrel)	US$1.00	1,122	$0.06	640	$0.03
Price of Natural Gas ($/mcf)	$0.10	201	$0.01	115	$0.01
Exchange Rate: Cdn$:U.S.$	$0.01	382	$0.02	218	$0.01
Interest Rate	1%	255	$0.01	145	$0.01

Sensitivity Analysis for Cash Flow and Earnings
December 31, 2001

	Change	Approximate Change in Cash Flow from Operations		Approximate Change in Net Earnings	
		$000s	Per Share	$000s	Per Share
Price of Crude Oil ($/barrel)	US$1.00	1,110	$0.06	635	$0.03
Price of Natural Gas ($/mcf)	$0.10	277	$0.01	165	$0.01
Exchange Rate: Cdn$:U.S.$	$0.01	380	$0.02	216	$0.01
Interest Rate	1%	306	$0.02	175	$0.01

Industry Conditions

Real's financial performance largely depends on its production volumes, the price it receives for its crude oil, liquids and natural gas and the Corporation's ability to find and produce oil and gas efficiently. Real's ability to explore for, produce and purchase oil and gas assets determines its production capacity. Buyers for oil and liquids are limited in Canada and, therefore, marketing options are restricted. Although sales can be affected by pipeline capacity, North American markets for light and medium oil exceed production capacity and therefore markets are virtually assured.

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. Outlined below are some of the more significant aspects of the relevant legislation and regulations. It is not expected that any of such controls and regulations will affect the operations of the Corporation in a manner materially different than they will affect other oil and gas companies of similar size.

Pricing and Marketing – Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Such price depends in part on oil quality, prices of competing oils, distance to market and the value of refined products. Oil exporters are also entitled to enter into export contracts and export oil provided that, for contracts which do not exceed one year in the case of light crude oil and two years in the case of heavy crude oil, an export order must be obtained from the National Energy Board (the "**NEB**") prior to the export. Any export pursuant to a contract of longer duration must be made pursuant to an NEB export licence and Governor in Council approval.

Pricing and Marketing – Natural Gas

In Canada, the price of natural gas sold in intra-provincial and inter-provincial trade is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the government of Canada. The price received by the Corporation depends, in part, on the prices of competing natural gas and other substitute fuels, access to downstream transportation, distance to markets, length of the contract term, weather conditions, the supply/demand balance and other contractual terms. Exporters are free to negotiate prices with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the Government of Canada. The Government of Alberta also holds residual authority to regulate the volume of natural gas which may be removed from the province for consumption elsewhere. As in the case with oil, natural gas exports for a term of less than two years must be made pursuant to an NEB order and in the case of exports for a longer duration, pursuant to an NEB licence and Governor in Council approval.

The governments of Alberta and Saskatchewan also regulate the volume of natural gas which may be removed from each such province for consumption elsewhere.

North American Free Trade Agreement

On January 1, 1994 the North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective. 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 the restrictions are otherwise justified under certain provisions of the General Agreement on Tariffs and Trade (the "**GATT**") and then only if any export restrictions do not: (i) reduce the proportion of the energy resource exported relative to the total supply of energy resource (based upon the proportions prevailing in the most recent 36 months); (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.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to avoid discriminatory actions and to minimize disruption of contractual arrangements.

Provincial Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time the governments of Canada, Alberta and Saskatchewan have established incentive programs which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas production and enhanced production projects.

Oil royalty rates vary from province to province. In Alberta, oil royalty rates vary between 10% and 35% for oil and 10% and 30% for new oil. New oil is applicable to oil pools discovered after March 31, 1974 and prior to October 1, 1992. The Alberta Government introduced the Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 30, 1992.

Effective January 1, 1994, the calculation and payment of natural gas royalties became subject to a simplified process. The royalty reserved to the Crown, subject to various incentives, is between 15% and 30%, in the case of new gas, and between 15% and 35%, in the case of old gas, depending upon a prescribed or corporate average reference price. Natural gas produced from qualifying exploratory natural gas wells spudded or deepened after July 31, 1985 and before June 1, 1988 continues to be eligible for a royalty exemption for a period of 12 months, or such later time that the value of the exempted royalty quantity equals a prescribed maximum amount. Natural gas produced from qualifying intervals in eligible natural gas wells spudded or deepened to a depth below 2,500 metres is also subject to a royalty exemption, the amount of which depends on the depth of the well.

In Alberta, a producer of oil or natural gas is entitled to a credit against the royalties payable to the Crown by virtue of the ARTC program. The ARTC rate is based on a price-sensitive formula and varies between 75% for prices at or below the royalty tax credit reference price of $100 per cubic metre decreasing to 25% for prices above the royalty tax credit reference price of $210 per cubic metre. The ARTC rate will be applied to a maximum annual amount of

$2,000,000 of Alberta Crown royalties payable for each producer or associated group of producers. Crown royalties on production from producing properties acquired from corporations claiming maximum entitlements to ARTC will generally not be eligible for ARTC. The rate is established quarterly based on the average "par price", as determined by the Alberta Department of Energy for the previous quarterly period. On December 22, 1997, the Alberta Government announced that it would conduct a review of the ARTC program with the objective of setting out better targeted objectives for a smaller program and to deal with administrative difficulties. On August 30, 1999, the Alberta Government announced that it would not be reducing the size of the program, but that it would introduce new rules to reduce the number of persons who qualify for the program. The new rules will preclude companies that pay less than $10,000 in royalties per year and non-corporate entities from qualifying from the program.

Effective January 1, 1994, the Government of Saskatchewan revised its fiscal regime for the oil and gas industry. Some royalties on wells existing as of that date will remain unchanged and therefore subject to various periods of royalty/tax reduction. While a number of incentives were eliminated or reduced (such as incentives for vertical infill wells and lower cost horizontal wells), new incentive programs were initiated to encourage greater exploration and development activity in the province.

The new fiscal regime in Saskatchewan provides an incentive to encourage the drilling of new vertical oil wells through a revised royalty/tax structure for new vertical oil wells and incremental production from new or expanded water flood projects, but not horizontal wells. The "Third Tier" Crown royalty rate and freehold production tax structure, which does not apply to horizontal wells, is price sensitive and varies between heavy and non-heavy oil (from a minimum of 10% for heavy oil at a base price to a maximum of 35% for non-heavy oil at a price above the base price). Previous time-based royalty/tax holidays applicable to new vertically drilled oil wells have been replaced with volume-based royalty/tax reduction incentives in which a maximum royalty of 5% (before application of the 1% Saskatchewan Resource Credit) will apply to various volumes depending on the depth and nature of the well (up to 25,000 cubic metres of oil in the case of deep exploratory wells). The maximum royalty applicable to the first 12,000 cubic metres of oil has been increased from 5% to 10% for production from certain re-entry horizontal wells. In addition, royalty/tax holidays for deep horizontal oil wells have been replaced with a 25,000 cubic metres volume incentive (5% maximum royalty). Oil production from qualifying reactivated oil wells are subject to a maximum new royalty rate of 5% (before the application of the 1% Saskatchewan Resource Credit) for the first five years following re-activation in the case of wells reactivated after 1993 and shut-in or suspended prior to January 1, 1993. With respect to qualifying exploratory natural gas wells, the first 25 million cubic metres of natural gas produced will be subject to an incentive maximum royalty rate of 5% (0% freehold production tax).

On October 7, 2002, the Premier of Saskatchewan announced a number of major changes affecting the Crown Royalty and Freehold Production tax structures and the Corporation Capital Tax Surcharge applicable to production from new oil and gas exploration and development activity in the province.

1. Reduction in the Corporation Capital Tax Surcharge from 3.6% to 2.%.

    (a) all oil and gas that is produced from oil and gas wells with a finished drilling date on or after October 1, 2002; and

    (b) incremental oil related to new or expanded enhanced oil recovery ("**EOR**") projects or waterflood projects having a commencement date on or after October 1, 2002.

Environmental Regulation

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions and regulation on the storage and transportation of various substances produced or utilized in association with certain oil and gas industry operations and can affect the location and operation of wells and facilities and the extent to which exploration and development is permitted. In addition, legislation requires that well and facilities sites be abandoned and reclaimed to the satisfaction of provincial authorities. As well, applicable environmental laws may impose remediation obligations with respect to property designated as a contaminated site upon certain responsible persons, which include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any past or present owner, tenant or other person in possession of the site. Compliance with such legislation can require significant expenditures and a breach of such legislation may result in the suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, the imposition of fines and penalties or the issuance of clean-up orders. Applicable environmental laws in Alberta are consolidated in the *Environmental Protection and Enhancement Act*. Under this Act, environmental standards and compliance for releases, clean-up and reporting are stricter and more onerous than the previous legislation. Also, the range of enforcement actions available and the severity of penalties have been significantly increased. These changes will have an incremental effect on the cost of conducting operations in Alberta.

Real is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased, although not material, expenditures of both a capital and expense nature as a result of increasingly stringent laws relating to the protection of the environment.

Human Resources

At September 30, 2002, the Corporation had 38 employees.

SELECTED FINANCIAL INFORMATION

The selected annual financial information set forth below has been derived from and should be read in conjunction with the financial statements of the Corporation and related notes contained in the Corporation's 2001 Annual Report.

	Nine Months Ended	Year Ended December 31		
	September 30, 2002	2001	2000	1999
Revenue	38,717,000	51,527,000	39,526,000	15,816,000
Royalties – net [1]	7,506,000	9,927,000	7,675,000	2,069,000
Operating Expenses	7,416,000	9,061,000	5,640,000	3,635,000
General and Administrative Expenses	2,088,000	2,663,000	1,833,000	1,403,000
Cash Flow from Operations [2]	20,193,000	27,586,000	22,720,000	8,061,000
- per Common Share (basic)	$1.02	1.48	1.35	0.54
- per Common Share (diluted)	$1.01	1.45	1.25	0.51
Net Earnings	3,756,000	7,607,000	8,582,000	4,569,000
- per Common Share (basic)	$0.19	0.41	0.51	0.30
- per Common Share (diluted)	$0.19	0.40	0.48	0.29
Total Assets	135,038,000	121,038,000	99,833,000	35,115,000
Long Term Debt	41,329,000	30,037,000	22,725,000	3,789,000
Shareholders' Equity	55,684,000	53,787,000	42,120,000	23,118,000

Notes:
(1) Royalties - net is calculated as royalties paid less ARTC.
(2) Funds provided from operations is calculated as net earnings adjusted for non-cash items included in net earnings.

The following table sets forth selected quarterly financial information for the three quarters in 2002, year ended December 31, 2001 and for the four quarters in 2000.

	Quarter Ending		
	September 20,2002	June 30, 2002	March 31, 2002
Revenue	13,230	13,734	11,753
Cash Flow from Operations	6,752	7,645	5,796
Cash Flow per Share (diluted)	$0.34	$0.38	$0.29
Net Earnings	1,261	1,622	873
Net Earnings per Share (diluted)	$0.06	$0.08	$0.05
Net Earnings per Share (basic)	$0.06	$0.08	$0.05

	Quarter Ending			
	December 31, 2001	**September 30, 2001**	**June 30, 2001**	**March 31, 2001**
Revenue	10,963	12,896	13,681	13,987
Cash Flow from Operations	4,877	6,957	8,055	7,697
Cash Flow per Share (diluted)	$0.25	$0.37	$0.42	$0.41
Net Earnings	205	1,944	3,142	2,316
Net Earnings per Share (diluted)	$0.01	$0.10	$0.17	$0.12
Net Earnings per Share (basic)	$0.01	$0.10	$0.17	$0.13
	December 31, 2000	**September 30, 2000**	**June 30, 2000**	**March 31, 2000**
Revenue	13,483	9,763	9,247	7,033
Cash Flow from Operations	7,456	5,580	5,525	4,159
Cash Flow per Share (diluted)	$0.37	$0.31	$0.32	$0.24
Net Earnings	2,455	2,213	2,286	1,629
Net Earnings per Share (diluted)	$0.12	$0.12	$0.13	$0.10
Net Earnings per Share (basic)	$0.14	$0.13	$0.14	$0.10

For further details, please refer to the audited financial statements of the Corporation for the year ended December 21, 2001 and for the nine months ended September 30, 2002, which are incorporated herein by reference and form a part of this Annual Information Form.

Dividend Policy

The Corporation has not paid dividends on the Common Shares and intends to reinvest any earnings to fund the development and growth of its business and does not expect to pay any dividends in the foreseeable future. Any future payment of dividends will depend upon the financial condition, capital requirements and earnings of the Corporation, as well as other factors the board of directors may deem relevant.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The Corporation's Management's Discussion and Analysis relating to the Corporation's financial statements for the period from January 1, 2001 to December 31, 2001, which is contained on pages 18 through 24 of the Corporation's Annual Report, is incorporated herein by reference and forms an integral part of this Annual Information Form.

MARKET FOR SECURITIES

As at November 15, 2002, 19,612,176 Common Shares were issued and outstanding. The outstanding Common Shares of the Corporation are listed and posted for trading on The Toronto Stock Exchange under the symbol "RER".

DIRECTORS AND OFFICERS

The Board of Directors of the Corporation is comprised of six members. Each director is appointed to serve until the next annual meeting of the shareholders of the Corporation. The name, position with the Corporation, municipality of residence and principal occupation of each director and officer of the Corporation are set out below.

Name and Municipality of Residence (5)(9)	Office	Principal Occupation for the 5 Previous Years
Lowell E. Jackson(2)(3) Calgary, Alberta	Director, President and Chief Executive Officer	President and Chief Executive Officer of Real Mr. Jackson was appointed President and CEO of Real on November 15, 1997 and was appointed to the Board of Directors of Real in January, 1998. Prior to that time he was employed by Grad & Walker Energy Corporation from March, 1991 to July, 1997 holding various responsibilities including Senior Vice President and Chief Operating Officer.

Name and Municipality of Residence [5][9]	**Office**	**Principal Occupation for the 5 Previous Years**
Frans Burger[1][8] Calgary, Alberta	Chairman	Independent Businessman Mr. Burger has been a director of Real since 1994 and was President and Chief Executive Officer from September 24, 1994 to November 15, 1997.
Dallas L. Droppo [1] Calgary, Alberta	Director and Secretary	Partner, Blake, Cassels & Graydon LLP, Barristers and Solicitors Mr. Droppo has been a director and Corporate Secretary of Real at all material times since 1994. He is a partner in the law firm of Blake, Cassels & Graydon LLP where his practice primarily focuses on resource law, corporate finance and venture capital.
Martin G. Abbott[3] Calgary, Alberta	Director	Managing Director, TOM Capital Associates Inc. Mr. Abbott has been a director since 1994. He is a partner and managing director of TOM Capital Associates Inc., a private investment company, which was formed in 1995.
D. Nolan Blades[3][4] Calgary, Alberta	Director	President, Sunny Gables Holdings Ltd. Mr. Blades was appointed to the Board of Directors of Real in July, 2000. He has been the President of Sunny Gables Holdings Ltd. since April, 2000 and previously was the President and Chief Executive Officer of Pursuit Resources Corporation from September, 1993 to April, 2000.
Robert B. Michaleski[1] Calgary, Alberta	Director	President and Chief Executive Officer, Pembina Pipeline Corporation Mr. Michaleski was appointed to the Board of Directors of Real on June 1, 2002. He has been the President and Chief Executive Officer of Pembina Pipeline Corporation since January, 2000. Prior to this, Mr. Michaleski held the position of Vice President Finance and Chief Financial Officer of Pembina Pipeline Corporation since 1992.
Frank Muller[6] Calgary, Alberta	Vice President, Exploration	Vice President, Exploration of Real Mr. Muller joined Real in January, 1998 as a Senior Exploration Geologist, was promoted to Chief Geologist in July, 1999, and then was promoted to Vice President, Exploration on January 31, 2002. From 1996 to 1997, Mr. Muller was employed by Jordan Petroleum Ltd. as Senior Exploration Geologist.
Kenneth P. Murphy Calgary, Alberta	Executive Vice President	Executive Vice President of Real Mr. Murphy joined Real in June, 1996 as Vice President, Land and Corporate Development, and then was promoted to Executive Vice-President on September 1, 2001.
Pamela Orr [7] Calgary, Alberta	Vice President, Finance and Chief Financial Officer	Vice President, Finance and Chief Financial Officer Ms. Orr joined Real on February 21, 2002 as Vice President Finance & Chief Financial Officer in charge of all financial activities for the Corporation. Prior to joining Real, Ms. Orr was employed by PrimeWest Energy Trust as Financial Controller from March, 2001 to February, 2002. From November, 1999 to March, 2001, Ms. Orr held the position of Controller at Cypress Energy Inc. Prior to that, Ms. Orr was the Controller at Northrock Resources Ltd. from September, 1996 to September, 1999.

Notes:
(1) Members of the Audit Committee.
(2) Members of the Environmental Safety and Health Committee.
(3) Members of the Compensation Committee.

(4) Members of the Reserves Audit Committee.
(5) John M. Stewart resigned from his position of director effective February 20, 2002.
(6) Gordon Crowell retired from his office of Vice-President of Exploration effective January 7, 2002. Frank Muller was appointed to such office effective January 31, 2002.
(7) Lesley Miller resigned from her office of Vice-President of Finance and Chief Executive Officer effective January 31, 2002. Pamela Orr was appointed to such office effective February 21, 2002.
(8) Frans Burger was appointed Chairman of the Board of Directors of Real effective June 1, 2002.
(9) Sig G. Slotboom ceased to hold office of Vice-President, Production and Engineering effective August 8, 2002.

As at October 31, 2002, the directors and officers of the Corporation beneficially owned, directly or indirectly, or exercised control or direction over, in the aggregate, 1,384,923 Common Shares, representing 7.1% of the issued and outstanding Common Shares of the Corporation.

CONFLICTS OF INTEREST

As of the date of this Annual Information Form, the directors and management of Real know of no existing or potential material conflicts between Real and a director or officer of Real.

ADDITIONAL INFORMATION

The Corporation will provide to any person:

(a) when the securities of the Corporation 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:

(i) one copy of its annual information form together with one copy of any document, or the pertinent pages of any document, incorporated by reference in this annual information form;

(ii) one copy of the comparative financial statements of the Corporation for the year ended December 31, 2001, together with the accompanying report of the auditors and one copy of any subsequent interim financial statements of the Corporation;

(iii) one copy of the Corporation's Information Circular dated May 15, 2002;

(iv) one copy of any other documents that are incorporated by reference into the preliminary short form prospectus or the short form prospectus and are not required to be provided under (i) to (iii) above; or

(b) at any other time, one copy of the documents referred to in (i) to (iii) above, provided that the Corporation may require the payment of a reasonable charge if the request is made by a person who is not a Shareholder.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities, options to purchase securities and interests of insiders in material transactions, where applicable, is contained in the Corporation's information circular for its most recent annual meeting of shareholders that involved the election of directors, and additional financial information is provided in the Corporation's comparative financial statements for its most recently completed financial year.

The Corporation will provide the above documents to any person, upon request made to the corporate secretary of the Corporation at 3500, 855-2nd Street S.W., Calgary, Alberta, T2P 4J8.