

**RIPPER OIL AND GAS INC.**

**STATEMENT OF RESERVES DATA AND  
OTHER OIL AND GAS INFORMATION**

**EFFECTIVE MARCH 31, 2004**

**PREPARED ON JULY 7, 2004**

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## ABBREVIATIONS AND CONVERSIONS

In this document, Ripper Oil and Gas Inc. is referred to as Ripper or the Corporation and the abbreviations set forth below have the following meanings:

### Oil, Natural Gas Liquids and Natural Gas

Bbl	barrel
Mcf	thousand cubic feet
Bbls	barrels
Mmcf	million cubic feet
Mbbl	thousand barrels
Mcf/d	thousand cubic feet per day
Mbbl	million barrels
Mmcf/d	million cubic feet per day
Mstb	1,000 stock tank barrels
MMBTU	million British Thermal Units
Bbls/d	barrels per day
Bcf	billion cubic feet
BOPD	barrels of oil per day
GJ	gigajoule
NGLs	natural gas liquids
STB	stock tank barrels

### Other

AECO	EnCana Corp.'s natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil.
ARTC	Alberta Royalty Tax Credit
BOE	barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 1 BOE for 6 Mcf is based on an energy equivalency method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
BOE/d	barrel of oil equivalent per day
m <sup>3</sup>	cubic metres
MBOE	1,000 barrels of oil equivalent
\$000 or \$M	thousand of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
NI 51-101	National Instrument 51-101 – Standards for Disclosure for Oil and Gas Activities of the Canadian Securities Administrators

References to oil, gas, natural gas liquids, reserves (gross, net, proved, probable, possible, developed, developed producing, developed non-producing, undeveloped), constant prices and costs, forecast prices and costs, operating costs, development costs, future net revenue and future income tax expense shall, unless expressly stated to be the contrary, have the meaning attributed to such terms as set out in NI 51-101, Companion Policy 51-101CP and all forms referenced therein.

## FORWARD LOOKING STATEMENTS

This statement of Reserves Data and Other Oil and Gas Information contains forward-looking statements. These statements relate to future events or Ripper's future performance. All statements other than statements of historical fact are forward-looking statements. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expect", "plan", "anticipate", "believe", "estimate", "predict", "potential", "continue", or the negative of these terms or other comparable terminology. These statements are only predictions. Actual events or results may differ materially. Undue reliance should not be placed on these forward-looking statements as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By its nature, forward-looking information involves numerous assumptions involving known and unknown 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.

Although Ripper believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Ripper cannot guarantee future results, levels of activity, performance, or achievements. Moreover, Ripper does not assume responsibility for the accuracy and completeness of the forward-looking statements.

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. All forward-looking statements contained in this Statement of Reserves Data and Other Oil and Gas Information are expressly qualified by this cautionary statement. Ripper is not under any duty to update any of the forward-looking statements after the date hereof to conform such statements to actual results or to changes in Ripper's expectations.

## RESERVES DATA AND FUTURE NET REVENUE

An independent engineering evaluation of Ripper's oil and gas properties was conducted effective as at March 31, 2004 by Gilbert Laustsen Jung Associates Ltd. ("GLJ") in accordance with NI 51-101. GLJ's report on this evaluation is herein called the GLJ Evaluation.

The effective date of the information contained in the GLJ Evaluation is March 31, 2004.

The preparation date of the GLJ Evaluation is June 2, 2004 and the preparation date of the information contained in this disclosure is July 7, 2004.

For the purposes of properly understanding the reserves and future net revenue data presented from GLJ's Report it is important to understand each of the following:

The tables below are a summary of the oil, NGL and natural gas reserves of the Corporation and the net present value of future net revenue attributable to such reserves as evaluated in the GLJ Evaluation based on constant and forecast price and cost assumptions. The tables summarize the data contained in the GLJ Evaluation. Due to rounding, certain columns may not add exactly.

**The net present value of future net revenue attributable to the Corporation's reserves is based on GLJ's April 1, 2004 price forecast and is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs.**

**It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Corporation's reserves estimated by GLJ represent the fair market value of those reserves.**

**Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of the Corporation's oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.**

The GLJ Evaluation is based on certain factual data supplied by the Corporation and GLJ's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to Ripper's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by Ripper to GLJ and accepted without any further investigation. GLJ accepted this data as presented and neither title searches nor field inspections were conducted.

BOE's may be misleading, particularly if used in isolation. In accordance with NI 51-101, a BOE conversion ratio for natural gas of 6 Mcf: 1 bbl has been used which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value of equivalency at the wellhead.

Estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

**Summary of Oil and Gas Reserves  
as at March 31, 2004**

**Constant Prices and Costs**

The following tables set forth a summary of Ripper's oil and gas reserves and net present values of future net revenue based on constant prices and costs. The prices used by GLJ for this purpose are WTI at \$US 35.76, light sweet crude at Edmonton at \$48.50, AECO-C spot price of \$6.36 and a \$US/\$Cdn exchange rate of 0.7631.

	Light/Medium Oil		NGLs		Natural Gas	
	Gross <sup>(1)</sup> (mstb)	Net <sup>(2)</sup> (mstb)	Gross <sup>(1)</sup> (mstb)	Net <sup>(2)</sup> (mstb)	Gross <sup>(1)</sup> (mmcf)	Net <sup>(2)</sup> (mmcf)
Proved Producing	215.9	191.1	33.4	25.8	2,796	2,141
Proved Developed Non-Producing	-	-	0.2	0.1	246	213
Proved Undeveloped	28.2	26.8	-	-	588	543
Total Proved	244.1	217.9	33.6	25.9	3,630	2,898
Probable	41.2	37.2	6.3	4.9	1,070	902
Proved and Probable	285.4	255.1	40.0	30.8	4,699	3,800

Notes:

1. Gross Reserves means Ripper's interest (operating and non-operating) before deduction of royalties and income taxes.
2. Net Reserves means Ripper's interest (operating and non-operating) after deduction of royalties but before deduction of income taxes.

**Summary of Net Present Value of Future Net Revenue  
as at March 31, 2004  
Constant Pricing and Costs  
(in Cdn\$ thousands)**

	Before Tax					After Tax				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Proved Producing	18,294	14,019	11,526	9,892	8,732	14,012	10,824	8,958	7,730	6,858
Proved Developed Non-Producing	891	693	559	465	395					
Proved Undeveloped	2,649	1,806	1,309	989	769					
Total Proved	21,834	16,518	13,394	11,345	9,896	16,272	12,387	10,096	8,590	7,523
Probable	5,452	3,097	2,013	1,422	1,062	3,498	1,970	1,263	876	640
Proved and Probable	27,287	19,615	15,407	12,767	10,958	19,770	14,357	11,359	9,466	8,163

**Total Future Net Revenue as at March 31, 2004**

(Undiscounted)

**Constant Price and Costs  
(In Cdn\$ thousands)**

	Proved	Proved Plus Probable
Revenue	34,082	42,619
Royalties	5,395	6,574
Operating Costs	5,381	6,770
Abandonment Costs	589	621
Development Costs	883	1,368
Net Revenue Before Income Tax	21,834	27,287
Income Tax Expense	5,562	7,516
Future Net Revenue After Income Tax	16,272	19,770

**Net Present Value of Future Net Revenue  
By Production Group as at March 31, 2004**

(Discounted at 10%)

**Constant Price and Costs  
(In Cdn\$ thousands)  
(Before Income Taxes)**

RESERVE CATEGORY	Light/Medium Oil	Natural Gas and NGL's	Other Revenue	Total
Proved	3,456	9,532	406	13,394
Probable	340	1,614	59	2,013
Proved Plus Probable	3,796	11,146	465	15,407

**Summary of Oil and Gas Reserves  
as at March 31, 2004**

**Forecast Prices and Costs**

The following table sets forth a summary of Ripper's oil and gas reserves and net present values of future net revenue as at March 31, 2004 using GLJ's April 1, 2004 forecast prices and costs which are set forth below:

	Light/Medium Oil		NGLs		Natural Gas	
	Gross <sup>(1)</sup> (mstb)	Net <sup>(2)</sup> (mstb)	Gross <sup>(1)</sup> (mstb)	Net <sup>(2)</sup> (mstb)	Gross <sup>(1)</sup> (mmcf)	Net <sup>(2)</sup> (mmcf)
Proved Producing	209.7	185.8	33.4	25.8	2,796	2,141
Proved Developed Non-Producing	-	-	0.2	0.1	246	211
Proved Undeveloped	28.3	27.1	-	-	588	543
<b>Total Proved</b>	<b>238.1</b>	<b>212.9</b>	<b>33.6</b>	<b>26.0</b>	<b>3,630</b>	<b>2,896</b>
Probable	40.7	36.9	6.3	4.8	1,068	901
<b>Proved and Probable</b>	<b>278.8</b>	<b>249.8</b>	<b>39.9</b>	<b>30.8</b>	<b>4,699</b>	<b>3,797</b>

Notes:

1. Gross Reserves means Ripper's interest (operating and non-operating) before deduction of royalties and income taxes.
2. Net Reserves means Ripper's interest (operating and non-operating) after deduction of royalties but before deduction of income taxes.

**Summary of Net Present Value of Future Net Revenue  
as at March 31, 2004**

**Forecast Prices and Costs  
(in Cdn\$ thousands)**

	Before Tax Discounted at					After Tax Discounted at				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Proved Producing	13,436	10,530	8,833	7,714	6,914	10,873	8,575	7,222	6,327	5,686
Proved Developed Non-Producing	671	539	446	378	328	-	-	-	-	-
Proved Undeveloped	1,681	1,135	804	587	437	-	-	-	-	-
<b>Total Proved</b>	<b>15,788</b>	<b>12,204</b>	<b>10,082</b>	<b>8,679</b>	<b>7,679</b>	<b>12,359</b>	<b>9,600</b>	<b>7,958</b>	<b>6,869</b>	<b>6,091</b>
Probable	4,091	2,266	1,436	990	721	2,608	1,430	888	595	418
<b>Proved and Probable</b>	<b>19,879</b>	<b>14,470</b>	<b>11,518</b>	<b>9,669</b>	<b>8,400</b>	<b>14,967</b>	<b>11,030</b>	<b>8,846</b>	<b>7,464</b>	<b>6,509</b>

**Total Future Net Revenue as at March 31, 2004**

**(Undiscounted)**

**Forecast Prices and Costs  
(In Cdn\$ thousands)**

	Proved	Proved Plus Probable
Revenue	27,755	35,161
Royalties	4,479	5,498
Operating Costs	5,886	7,629
Abandonment Costs	709	770
Development Costs	892	1,384
<b>Net Revenue Before Income Tax</b>	<b>15,788</b>	<b>19,879</b>
Income Tax Expense	3,429	4,912
<b>Future Net Revenue After Income Tax</b>	<b>12,359</b>	<b>14,967</b>

**Net Present Value of Future Net Revenue  
By Production Group as at March 31, 2004**

(Discounted at 10%)

**Forecast Prices and Costs  
(In Cdn\$ thousands)  
(Before Income Taxes)**

RESERVE CATEGORY	Light/Medium Oil	Natural Gas and NGL's	Other Revenue	Total
	Proved	2,323	7,410	349
Probable	221	1,167	48	1,436
Proved Plus Probable	2,544	8,577	397	11,518

**Constant Prices and Costs**

The following table sets forth the constant commodity prices used by GLJ for the purposes of the constant price cases contained in the GLJ Evaluation.

WTI Crude Oil (\$US/bbl)	Edmonton Light Crude Oil (\$CDN/bbl)	Bow River Crude Oil Stream at Hardisty (\$CDN/bbl)	Natural Gas at AECO (\$CDN/mmbtu)	Natural Gas Liquids			Currency Exchange Rate \$US/\$CDN	Inflation Rate
				Edm Propane	Edm Butane	Edm C <sup>5+</sup>		
35.76	48.50	38.75	6.36	37.50	40.50	49.00	0.7631	0.0%

The following table sets forth the actual average commodity prices received for 2003 and the forecast prices used by GLJ for the purposes of the GLJ Evaluation.

Historical and Forecast Prices									
Year	WTI Crude Oil (\$US/bbl)	Edmonton Light Crude Oil (\$CDN/bbl)	Bow River Crude Oil Stream at Hardisty (\$CDN/bbl)	Natural Gas at AECO (\$CDN/mmbtu)	Natural Gas Liquids			Currency Exchange Rate \$US/\$CDN	Inflation Rate
					Edm Propane	Edm Butane	Edm C <sup>5+</sup>		
2003									
Actual	31.07	43.66	32.11	6.66	32.14	34.36	44.23	0.721	2.8%

**GLJ April 1, 2004 Price Forecast**

2004	34.25	44.75	35.00	6.65	33.75	36.75	45.25	0.750	1.5%
2005	29.00	37.75	30.25	5.55	25.75	28.75	38.25	0.750	1.5%
2006	27.00	35.25	28.75	5.20	23.25	25.25	35.75	0.750	1.5%
2007	25.00	32.50	26.00	5.00	20.50	22.50	33.00	0.750	1.5%
2008	25.00	32.50	26.00	5.00	20.50	22.50	33.00	0.750	1.5%
2009	25.00	32.50	26.00	5.00	20.50	22.50	33.00	0.750	1.5%
2010	25.50	33.00	26.50	5.10	21.00	23.00	33.50	0.750	1.5%
2011	25.75	33.50	27.00	5.20	21.50	23.50	34.00	0.750	1.5%
2012	26.25	34.00	27.50	5.25	21.75	24.00	34.50	0.750	1.5%
2013	26.50	34.50	28.00	5.35	22.00	24.50	35.00	0.750	1.5%
2014	27.00	35.00	28.50	5.45	22.50	24.75	35.50	0.750	1.5%
thereafter	Escalate at 1.5% per year								

**Reconciliation of Changes in Net Reserves  
Using Forecast Prices and Costs**

The following table sets forth a reconciliation of Ripper's total net proved, probable and proved plus probable reserves as at March 31, 2004 against such reserves as at March 31, 2003 based on forecast price and cost assumptions.

	Light and Medium Oil			NGLs			Natural Gas		
	Net Proved (m bbl)	Net Probable (m bbl)	Net Proved Plus Probable (m bbl)	Net Proved (m bbl)	Net Probable (m bbl)	Net Proved Plus Probable (m bbl)	Net Proved (mmcf)	Net Probable (mmcf)	Net Proved Plus Probable (mmcf)
March 31, 2003	222	28	250	20	2	22	1,112	189	1,301
Extensions	1	-	1	-	-	-	654	403	1,058
Improved Recovery	-	-	-	-	-	-	25	12	36
Technical Revisions	-9	8	-1	9	4	13	1,407	302	1,709
Discoveries	40	6	46	1	-	1	184	28	212
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-21	-5	-26	-2	-1	-2	-160	-31	-191
Economic Factors	-	-1	-1	-	-	-	-1	-2	-2
Production	-21	-	-21	-2	-	-2	-324	-	-324
March 31, 2004	213	37	250	26	5	31	2,896	901	3,797

The reserve estimates for the opening balance were prepared using National Policy 2-B reserves definitions. For purpose of the comparison reflected in this table the probable reserves for the opening balance estimated under National Policy 2-B have been risked at 50%.

**Reconciliation of Changes  
in Net Present Values of Future Net Revenue  
Discounted at 10%**

**Total Proved Reserves  
Constant Prices and Costs**

Period and Factor	After Tax 2004 (M\$)	Before Tax 2004 (M\$)
Estimated Net Present Value as at March 31, 2003	5,912	8,167
Oil and Gas Sales During the Period Net of Production Costs and Royalties <sup>(1)</sup>	(2,690)	(2,690)
Changes due to Prices and Royalties Related to Forecast Production <sup>(2)</sup>	66	66
Development Costs During the Period <sup>(3)(9)</sup>	7,650	7,650
Changes in Forecast Development Costs <sup>(4)</sup>	(7,631)	(7,631)
Changes Resulting from Extensions and Improved Recovery <sup>(5)</sup>	2,169	2,169
Changes Resulting from Discoveries <sup>(5)</sup>	1,274	1,274
Changes Resulting from Acquisitions of Reserves <sup>(5)</sup>	-	-
Changes Resulting from Dispositions of Reserves <sup>(5)</sup>	(895)	(895)
Accretion of Discount <sup>(6)</sup>	817	817
Net Change in Income Taxes <sup>(7)</sup>	(1,043)	-
Changes Resulting from Technical Reserves Revisions	4,612	4,612
All Other Changes <sup>(8)</sup>	(145)	(145)
Estimated Net Present Value as at March 31, 2004	10,096	13,394

(1) Company actual before income taxes, excluding G&A.

(2) The impact of changes in prices and other economic factors on future net reserves.

(3) Actual capital expenditures relating to the exploration, development and production of oil and gas reserves.

(4) The change in forecast development costs.

(5) End of period net present value of the related reserves.

(6) Estimated as 10% of the beginning of period net present value.

(7) The difference between forecast income taxes at beginning of period and the actual taxes for the period plus forecast income taxes at the end of period.

(8) Includes changes due to revised production profiles, development timing, operating costs, royalty rates, actual price received versus forecast, etc.

(9) For unproved property acquisition costs included see page 12.

## Undeveloped Reserves

### Proved Undeveloped Reserves

Most of Ripper's proved undeveloped reserves estimated in the GLJ Evaluation are based on gas wells not yet production tested and pipeline connected and infill drilling locations at the Corporation's Russelton, Shackleton and Greater Shackleton, Saskatchewan properties. Ripper intends to develop the majority of the proved undeveloped reserves within the next two years of the effective date.

### Probable Undeveloped Reserves

The majority of Ripper's probable undeveloped reserves estimated in the GLJ Evaluation are also based in the areas and for the reasons noted in proved undeveloped reserves, however this category also includes other scattered infill drilling locations. Ripper intends to develop the majority of the probable undeveloped reserves within the next two years of the effective date.

### Significant Factors or Uncertainties

National Instrument 51-101 requires that this disclosure discuss the significant factors or uncertainties that affect the reserves data presented herein.

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting on oil and gas prices and costs change. The reserve estimates contained herein are based on GLJ's production forecasts, prices and economic conditions at the time of preparation of the GLJ Evaluation.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required over time due to changes in well performance, prices, economic conditions and governmental restrictions. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact on these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

### Future Development Costs

The following table sets out the development costs in the estimation of future net revenues attributable to proved reserves (using both constant prices and costs and forecast prices and costs) and proved plus probable reserves (using forecast prices and costs only).

YEAR	Constant Prices and Costs	Forecast Prices and Costs	
	Proved Reserves Cdn\$ thousands	Proved Reserves Cdn\$ thousands	Proved Plus Probable Reserves Cdn\$ thousands
2004	235	235	279
2005	648	657	1,104
2006	-	-	-
2007	-	-	-
2008	-	-	-
Remaining Years	-	-	-
Total Undiscounted	883	892	1,384
Total Discounted 10%	801	810	1,250

Ripper expects to be able to fund the development costs required in the future from internally generated funds and bank lines. Ripper does not expect any significant costs to be associated with such funding sources.

# OTHER OIL AND GAS INFORMATION

## Crude Oil and Natural Gas Wells

The following table summarizes Ripper's interest, as at March 31, 2004, in producing and non-producing crude oil and natural gas wells.

Location	Light/Medium Oil				Gas			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross <sup>(1)</sup>	Net <sup>(2)</sup>	Gross <sup>(1)</sup>	Net <sup>(2)</sup>	Gross <sup>(1)</sup>	Net <sup>(2)</sup>	Gross <sup>(1)</sup>	Net <sup>(2)</sup>
Alberta	29	8.29	2	0.41	21	3.60	10	2.69
Saskatchewan	-	-	-	-	14	3.50	41	11.25
Total	29	8.29	2	0.41	35	7.10	51	13.94

Notes:

- (1) "Gross Wells" are all wells in which Ripper has an interest.
- (2) "Net Wells" are the aggregate percentage of Ripper's interest in Gross Wells.
- (3) Ripper has various gross overriding royalties on 50 gross oil and gas wells and 5 units.

## Oil and Gas Properties

The following is a summary of Ripper's major producing and exploration properties as at the most recently completed financial year. All properties are onshore.

### Halkirk, Alberta

Ripper's Halkirk property is located in Central Alberta in Townships 37-39, Ranges 15-22 W4M, approximately 75 miles east of the city of Red Deer, Alberta. The Corporation's net production for March, the last month of our fiscal year, was 140 boepd. Ripper has an average working interest of 26.2% in eighteen gross oil and gas wells and a gross overriding royalty in nine gross wells. Ripper has a various working interest in 29 gross sections of developed and undeveloped land.

### Provost, Alberta

The Provost Cummings "Y" Unit No. 1 is located in Township 37, Range 4 W4M, approximately 170 miles northeast of Calgary, Alberta. Ripper holds a 16.543% working interest in the unit (25 gross wells) and various interests in four non-unit wells. Ripper's average production for the year was 32 boepd.

Subsequent to year end the unit operator has proposed a major capital expenditure to reduce operating costs, increase recoverable reserves and increase production.

### Spirit River, Alberta

The Spirit River property is located in Northwestern Alberta approximately 30 miles north of the city of Grand Prairie. The Corporation participated for 50% of the cost in an exploratory discovery well last summer. Good Production Practice has been approved by regulatory authorities and the well is now pipelined for gas conservation. Independent engineers have anticipated the well will average 77 bopd net to Ripper for the rest of the year.

### Shackleton, Saskatchewan

The Shackleton area is located in Townships 20-23, Ranges 15-23 W3M. Ripper has a 25% working interest in 112 sections of land in the Shackleton area of Southwest Saskatchewan, located 80 miles northwest of Swift Current, Saskatchewan. The mineral rights were acquired from a private oil and gas company for cash and drilling commitments. As of April 30, 2004, Ripper had participated for a 25% cost and working interest in 42 Milk River test wells. An additional six wells were drilled at no cost to Ripper. By year end only one well had been tied-in. Lack of completing equipment and an early spring break-up has delayed further tie-ins. Subsequent to year end the Corporation has tied in 18 gas wells.

### Twining, Alberta

The Twining property is located in Townships 31-32, Range 24 W4M, approximately 54 miles northeast of Calgary, Alberta. Ripper holds working interests in four wells; three 100% operated oil and gas wells and one 25% non-operated gas well. All four wells produce from the Lower Manville "A" and Rundle "A" Pool. Average production for the year was 51 boepd.

## Properties With No Attributed Reserves

As at March 31, 2004, Ripper held 85,070 gross acres of undeveloped land and 21,230 net acres of undeveloped land. Of this 156 gross acres, 78 net acres are due to expire prior to the end of the Corporation's next fiscal year.

### Forward Contracts and Financial Instruments

Ripper has no forward contracts or financial instruments.

### Abandonment and Reclamation Costs

Ripper uses its internal historical costs to estimate its abandonment and reclamation costs when available. The costs are estimated on an area by area basis. The industry's historical costs are used when available. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements.

Ripper has 29.74 net wells for which it expects to incur abandonment and reclamation costs. The total of such costs, at forecast prices net of estimated salvage value, is \$709 thousand (undiscounted) and \$270 thousand (discounted at 10%) in respect of proved reserves. 100% of such amounts were deducted as abandonment and reclamation costs in estimating future net revenue of the Corporation in respect of proved reserves disclosed above. Ripper expects to pay \$60 thousand during the next three years.

### Tax Horizon

Ripper estimates that based on current expenditure plans no income taxes will be payable on the Corporation's income for the fiscal year ended March 31, 2005. It is likely that the Corporation will not become taxable so long as Ripper continues to grow and expend capital beyond its internally generated cash flow.

### Acquisition, Exploration and Development Costs Incurred

The following table sets out Ripper's property acquisition, exploration and development costs for the fiscal year ended March 31, 2004.

	Property Acquisition Costs		Exploration Costs (in Cdn\$ thousands)	Development Costs (in Cdn\$ thousands)
	Proved (in Cdn\$ thousands)	Unproved (in Cdn\$ thousands)		
Alberta	-	16	607	579
Saskatchewan	-	3,875	671	2,013
Total	-	3,891	1,278	2,592

### Exploration and Development Drilling Activity

The following table set out the number of exploration and development wells in which Ripper has an interest, on a gross and net basis.

	Year Ended March 31, 2004			
	Exploratory		Development	
	Gross <sup>(1)</sup>	Net <sup>(2)</sup>	Gross <sup>(1)</sup>	Net <sup>(2)</sup>
Crude Oil	1	.5	1	.066
Natural Gas	21	6.25	27	6.6775
Dry/Abandoned	3	2.25	1	.50
Total	25	9	29	7.2435

Notes:

- (1) "Gross Wells" are wells in which Ripper has an Interest.
- (2) "Net Wells" are the aggregate percentage of Ripper's Interest in Gross Wells.

### Future Anticipated Exploration and Development Activities

Ripper Oil and Gas Inc. ("Ripper") has a 25% net working interest in a large inventory of undeveloped lands in the Shackleton area of Southwest Saskatchewan. More exploratory and development drilling will take place in the next fiscal year. Infrastructure is presently being built to tie-in 20-30 gas wells.

Our acreage in Central Alberta (Halkirk, Twining, Mikwan and Chigwell) is situated in an area presently being exploited for coal bed methane. We see potential for coal bed methane development on the Corporation's lands. Three sections on which the Corporation has a gross overriding royalty have 4-8 wells per section being drilled for coal bed methane.

At Spirit River further evaluation of Ripper's undeveloped land is planned contingent on the production performance of our discovery well. We anticipate additional development drilling later next year. Ripper's net interest in any future drilling would be 25-30%.

At Provost Ripper has a 16.534% working interest in the Provost Cummings "Y" Unit No. 1. The unit operator is proposing to eliminate single well batteries and tie-in each well to a central unit owned treating facility with pipeline connection to gas and oil sales lines, add injection capability and drill up to 10 infill wells. These capital expenditures will reduce operating expenses, increase recoverable reserves and substantially increase in net production.

### Production Estimates

The following tables set out Ripper's estimated production of oil, natural gas and NGLs for fiscal year ended March 31, 2005 as set out in the GLJ Evaluation.

### Future Production Estimates

#### Constant Prices and Costs

	Estimated Production for Year Ended March 31, 2005											
	Light/Medium Oil (mdbl)				Natural Gas (mmcf)				NGLs (mdbl)			
	Proved		Proved and Probable		Proved		Proved and Probable		Proved		Proved and Probable	
	Gross <sup>(1)</sup>	Net <sup>(2)</sup>	Gross <sup>(1)</sup>	Net <sup>(2)</sup>	Gross <sup>(1)</sup>	Net <sup>(2)</sup>	Gross <sup>(1)</sup>	Net <sup>(2)</sup>	Gross <sup>(1)</sup>	Net <sup>(2)</sup>	Gross <sup>(1)</sup>	Net <sup>(2)</sup>
Halkirk	2	2	2	2	280	219	285	223	1	1	1	1
Spirit River	13	10	13	11	89	46	90	46	-	-	-	-
Other Properties	18	17	18	18	171	154	177	159	4	3	4	3
Total	33	29	33	31	540	419	552	428	5	4	5	4

Notes:

- (1) Gross Reserves means Ripper's working interest (operating and non-operating) before deduction of royalties and income taxes.
- (2) Net Reserves means Ripper's interest (operating and non-operating) after deduction of royalties, but before deduction of income taxes.

#### Forecast Prices and Costs

	Estimated Production for Year Ended March 31, 2005											
	Light/Medium Oil (mdbl)				Natural Gas (mmcf)				NGLs (mdbl)			
	Proved		Proved and Probable		Proved		Proved and Probable		Proved		Proved and Probable	
	Gross <sup>(1)</sup>	Net <sup>(2)</sup>	Gross <sup>(1)</sup>	Net <sup>(2)</sup>	Gross <sup>(1)</sup>	Net <sup>(2)</sup>	Gross <sup>(1)</sup>	Net <sup>(2)</sup>	Gross <sup>(1)</sup>	Net <sup>(2)</sup>	Gross <sup>(1)</sup>	Net <sup>(2)</sup>
Halkirk	2	2	2	2	280	219	285	223	1	1	1	1
Spirit River	13	11	13	11	91	46	91	47	-	-	-	-
Other Properties	18	17	18	18	175	157	181	162	4	3	4	3
Total	33	30	33	31	546	422	557	432	5	4	5	4

Notes:

- (3) Gross Reserves means Ripper's working interest (operating and non-operating) before deduction of royalties and income taxes.
- (4) Net Reserves means Ripper's interest (operating and non-operating) after deduction of royalties, but before deduction of income taxes.

### Production History

The following table sets out on a quarterly basis for the year ended March 31, 2004, Ripper's average daily production volume, prior to royalties, and the prices received, royalties paid, production costs incurred and netbacks on a per unit of volume basis for each product type. All of the Corporation's production is in Canada.

	Average Daily Production Information Three Months Ended				12 Months Ended
	June 30, 2003	Sept. 30, 2003	Dec. 31, 2003	March 31, 2004	March 31, 2004
Average Daily Production					
Oil & NGLs (boe/day)	83	76	92	77	85
Natural Gas (mcf/day)	698	1,290	1,397	1,702	1,274
Total (boe/day)	200	291	324	361	297
Average Net Price					
Oil & NGLs (\$/bbl)	35.90	35.71	42.89	34.38	36.71
Natural Gas (\$/mcf)	7.21	6.20	5.89	6.60	6.38
Royalties (\$/BOE)	6.59	6.68	6.18	7.26	6.66
Operating Expenses (\$/BOE)	6.38	7.29	5.40	6.80	6.42
Netback (\$/BOE)	27.13	22.87	24.21	27.34	25.00

**Production Volume by Field**

The following table discloses for each important field and in total, Ripper's working interest production volumes for the financial year ended March 31, 2004 for each production type.

	<b>Oil (bbls)</b>	<b>NGLs (bbls)</b>	<b>Natural Gas (mmcf)</b>	<b>Percent of Total</b>
Alberta				
Halkirk	2,768	1,142	263	48
Provost	11,553	-	-	12
Spirit River	3,448	-	16	6
Twining	4,531	1,888	74	19
Other	2,541	1,317	70	15
<b>Total</b>	<b>24,841</b>	<b>4,347</b>	<b>423</b>	<b>100</b>