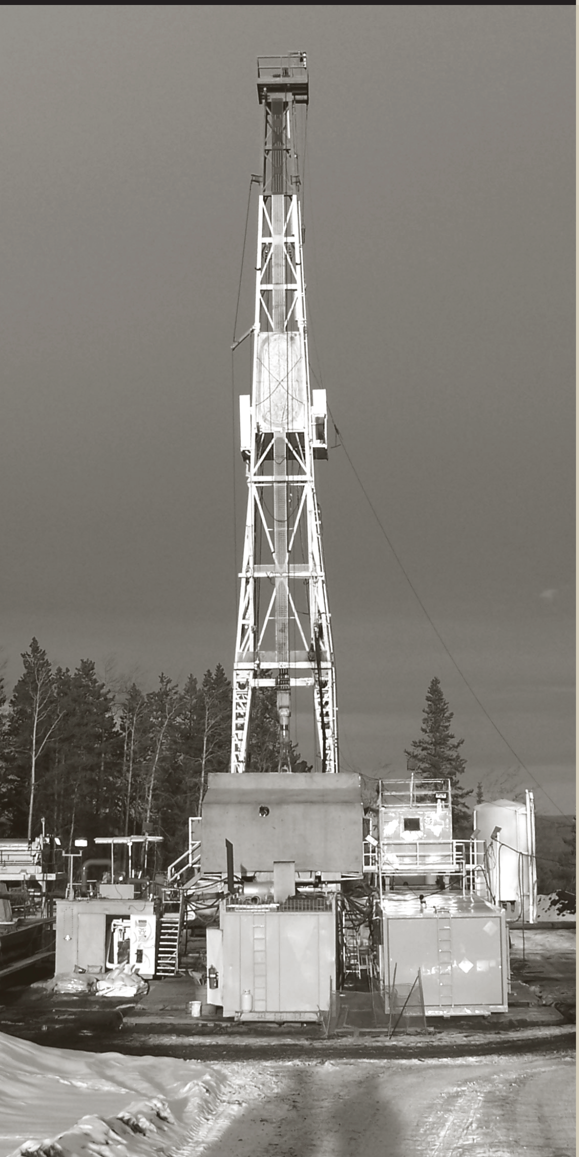
2005 1st Quarter Report

DYNAMIC OIL & GAS, INC.



Dynamic Oil & Gas, Inc. is a Canadian-based energy company engaged in the production and exploration of western Canada's natural gas and oil reserves. We own working interests in producing and early-stage exploration properties located in various areas of southwestern and northeastern British Columbia, central Alberta and southwestern Saskatchewan.

Dynamic's common shares trade on The Toronto Stock Exchange under the symbol "DOL" and on the NASDAQ under the symbol "DYOLF".

Abbreviations

bbl or bbls	barrel or barrels
mcf	thousand cubic feet
bbl/d	barrels per day
mcf/d	thousand cubic feet per day
mbbl	thousand barrels
mmcf	million cubic feet
bcf	billion cubic feet
boe	barrels of oil equivalent (6 mcf = 1 bbl)
mmcf/d	million cubic feet per day
boe/d	barrels of oil equivalent per day
NGL's	natural gas liquids
mboe	thousand barrels of oil equivalent

MANAGEMENT'S DISCUSSION & ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following should be read in conjunction with our Financial Statements and the Notes thereto included in this Interim Report. The Financial Statements have been prepared in accordance with Canadian generally accepted accounting principles (GAAP).

Unless otherwise noted, tabular amounts are in thousands of Canadian dollars, and sales volumes, production volumes and reserves are before royalties. We have presented our working interest before royalties, as we measure our performance on this basis, which is consistent with other Canadian oil and gas companies.

Throughout this discussion and analysis, we analyze expense factors on a unit cost of production basis. It is industry practice among our peer-group to monitor trends in expenses against daily average production volumes and the common unit of production used is the barrel of oil equivalent ("boe"). Gross revenue tends to be a less reliable trending tool due to the variability caused by volatility in commodity prices.

For ease of reading, we refer throughout this discussion and analysis to the periods reported as follows:

Periods Reported

January 1, 2005 – March 31, 2005, referred to as	2005-Q1
January 1, 2004 – March 31, 2004, referred to as	2004-Q1

EXECUTIVE OVERVIEW

Key Measures for the Comparative Periods Presented

($ 000's unless otherwise stated)	*2005-Q1*	*2004-Q1*
Gross revenues	9,715	10,975
Cash flow from operations [1]	5,106	5,749
Cash flow from operations per share *($/share)*	0.21	0.26
Net earnings (loss)	797	(788)
Net earnings (loss) per share *($/share)*	0.03	(0.04)
Daily average production *(boe/d)*	2,911	3,387
Total production *(mboe)*	262	308
Capital expenditures	6,959	12,496
Net debt [2]	26,896	26,161
Net debt to cash flow annualized [3]	1.3:1	1.1:1

(1) Cash flow from operations is a non-GAAP measure and therefore may or may not be comparable to similar measures presented by other companies. We consider it a key measure as it demonstrates our ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt.

($ 000's)	*2005-Q1*	*2004-Q1*
Cash provided by (used in) operating activities (GAAP)	4,029	(384)
Changes in non-cash working capital affecting operating activities (GAAP)	1,076	6,133
Cash flow from operations (non-GAAP)	5,106	5,749

(2) Net debt is working capital. We have no long term debt.

(3) Net debt divided by cash flow from operations annualized. Annualized numbers are presented by multiplying the three-month numbers by four. This method, however, does not reflect actual results for the applicable extrapolated periods and as such may differ from the extrapolations generated by this calculation.

2005-Q1 vs 2004-Q1

Gross revenues remained relatively strong at $9.7 million during 2005-Q1. Comparatively, gross revenues in 2004-Q1 were 12% higher at $11.0 million. Our weighted average prices realized for all commodities in 2005-Q1 improved our comparative gross revenues by $1.3 million, while production decreases in natural gas and light/medium crude oil had a weakening effect on gross revenues of $4.3 million. However, production increases in natural gas liquids and heavy crude oil helped to strengthen 2005-Q1 gross revenues by $1.7 million.

Our total production in 2005-Q1 was 262 mboe compared to 308 mboe in 2004-Q1 and daily average production was 2,911 boe/d, compared to 3,387 boe/d. At St. Albert and some of our other Alberta fields, we experienced predictable rates of natural decline in natural gas, natural gas liquds and light/medium crude oil. This accounted for a daily average production decrease of 886 boe/d. At Cypress/Chowade, two wells that produced natural gas at higher daily rates last year performed at lower levels than expected in 2005-Q1, accounting for a further decrease of 280 boe/d.

Of significance to our 2005-Q1 daily average production results, was the commencement of heavy crude oil production from our new Mantario East pool. The pool, first discovered in late Fiscal 2004, accounted for an increase in our daily average production rate of 690 boe/d.

Cash flow from operations was $5.1 million compared to $5.7 million. The $0.6 million variance was the net result of decreases in gross revenues and cash expenses relating to operating activities. As discussed above, gross revenues decreased by $1.3, while operating cash expenses decreased by $0.7 million.

Net earnings was $0.8 million compared to a net loss of $0.8 million, an increase of $1.6 million. This increase in net earnings was due to the same factors discussed above that decreased cash flow from operations by $0.6 million, accompanied by a net decrease of $1.7 million in non-cash expenses and expenses relating to investing activities, and a gain of $0.5 million relating to the sale of certain oil and gas assets. Most of the net decrease in non-cash expenses was due to a decrease in exploration expenses.

Capital Investment Program by Classification for the Comparative Periods Presented [1]

($000's)	*2005-Q1*	*2004-Q1*
Land acquisitions	126	2,308
Drilling, completions and equipping:		
Exploration [2]	1,616	3,938
Development	4,601	336
Facilities and pipelining	438	3,276
Seismic	77	2,623
Other	101	15
Total	6,959	12,496

(1) During Fiscal 2004, we changed our method of reporting capital transactions. We now gather capital transactions under the title, "Capital Investment Program" instead of the former title, "Capital Expenditures". The difference in methods is that Capital Investment Program includes exploration expenses relating to seismic and unsuccessful drilling efforts, whereas Capital Expenditures did not. Seismic and unsuccessful drilling costs comprise the majority of our Exploration expense as reported in our Statements of Operations and Deficit. Capital expenditures are reported on our Balance Sheets. When combined, annual expenditures for capital, and annual expenses for seismic and unsuccessful drilling represent the sum total of our Capital Investment Program. All comparative amounts have been restated accordingly.

(2) We follow the successful efforts method of accounting, whereby costs of drilling an unsuccessful well are recorded as exploration expense when it

becomes known the well did not result in a discovery of proved reserves or where one year has elapsed since the completion of drilling and near-term efforts to establish proved reserves are not foreseeable, intended, or in our control.

During 2005-Q1, our total capital investment was $7.0 million, over 89% of which was for drilling, completion and equipping work. Most of our investment was spent on drilling activities related to five wells that commenced drilling at Mantario East in 2005-Q1 and two wells that commenced drilling at Cypress/Chowade in 2004.

PROPERTIES AND CAPITAL INVESTMENT

2005-Q1

Capital Investment Program by Property and Classification

($ 000's)

	Land	*Drilling, Completions & Equipping*	*Facilities & Pipelining*	*Seismic*	*Other*	*Total*
Alberta						
St. Albert	-	154	202	-	5	361
Peavey/Morinville	-	299	-	-	(4)	295
Halkirk and Alexander	72	261	-	-	-	333
Total Alberta	72	714	202	-	1	989
British Columbia						
Cypress/Chowade	48	3,061	68	25	-	3,202
Orion	-	294	6	6	1	307
Total British Columbia	48	3,355	74	31	1	3,509
S.W. Saskatchewan						
Mantario East	6	2,039	162	29	-	2,236
Flaxcombe	-	-	-	17	-	17
Sangren	-	109	-	-	-	109
Total S.W. Saskatchewan	6	2,148	162	46	-	2,362
Other	-	-	-	-	99	99
Total	126	6,217	438	77	101	6,959

Land

We made an investment of $0.1 million in land during 2005-Q1. In total, we acquired working interests in Alberta (1,457 net acres), British Columbia (705 net acres), and Saskatchewan (844 net acres).

Drilling, Completions, Equipping, Facilities and Pipelining

During 2005-Q1, expenditures totaled $6.2 million, of which $0.7 million was in Alberta, $3.4 million was in British Columbia and $2.1 million was in Saskatchewan, incurred mainly as follows:

Alberta
St. Albert – In the quarter we spent $0.4 million mainly on the completion of one light/medium crude oil well and on pipeline and compression facilities.

Peavey/Morinville – We spent $0.3 million on the completion of two natural gas wells. Both wells came into production in this quarter.

British Columbia
Cypress/Chowade – We recorded $3.2 million of expenditures during the quarter. Approximately $1.2 million was for a re-entry of a natural gas well, $0.8 million was for the completion of a natural gas well and $0.7 million was spent on field compression facilities.

Orion – We spent $0.3 million most of which related to costs of drilling a well in late 2004 that targeted natural gas in the Bluesky, Banff and Jean Marie formations.

S.W. Saskatchewan
Mantario East, Flaxcombe & Sangren - During the quarter, we invested $2.4 million at Mantario East, Sangren and Flaxcombe. In total, we drilled five wells targeting heavy crude oil all of which drilled at a 75% working interest. Of the five wells, one is currently producing and three others are standing heavy crude oil wells. One well was unsuccessful.

FINANCIAL RESULTS

Cash Flow from Operations, Revenue and Net Earnings

2005-Q1 vs 2004-Q1

Cash flow from operations was $5.1 million versus $5.7 million, a decrease between periods of $0.6 million or 11%. This decrease was due to net variances in revenue and operating cash expenses as discussed below.

Revenue from the sale of all commodities decreased cash flow from operations by $1.3 million or 12% ($9.7 million versus $11.0 million) due mainly to lower volume sales in natural gas and light/medium crude oil, higher volume sales in natural gas liquids and heavy crude oil, and higher realized commodity prices. A breakdown of the volume/price-based variances by commodity is shown in the table below.

Revenue Variances by Commodity between the Comparative Periods Presented

($ 000's)	*2005-Q1 vs 2004-Q1* Volume-based	Price-based	Total
Natural gas	(2,817)	615	(2,202)
Natural gas liquids	201	174	375
Light/medium crude oil	(1,472)	525	(947)
Heavy crude oil [1]	1,514	-	1,514
Total	(2,574)	1,314	(1,260)

(1) The reporting period, 2004-Q1, preceded the commencement of production from our new-pool heavy crude oil discovery in late Fiscal 2004 at Mantario East.

Cash expenses related to operating activities decreased between periods by $0.7 million. This was the net result of certain decreases and increases. The decreases to operating cash expenses were in royalties ($0.8 million). The increases to operating cash expenses were in production costs, net interest, and general and administrative costs ($0.1 million, in aggregate).

Net earnings increased between periods by $1.6 million (net earnings of $0.8 million from a loss of $0.8 million), due to the same factors discussed above that decreased our cash flow from operations by $0.6 million, accompanied by a net decrease of $1.7 million in non-cash expenses and expenses relating to investing activities, and a gain of $0.5 million relating to the sale of certain oil and gas assets. The net decrease in expenses of $1.7 million was accounted for by a decrease in exploration expenses ($3.4 million) and increases in future income taxes ($1.0 million), amortization and depletion expense ($0.6 million) and various other expenses ($0.1 million).

Daily Average Production Rates and Total Production

Daily Average Production Rates by Commodity and Field, and Total Production for the Comparative Periods Presented

(Units as stated)	*2005-Q1*	*2004-Q1*
Daily average production rates		
Natural gas		
St. Albert	6,701	9,594
Halkirk	702	1,110
Peavey/Morinville	506	516
Other Alberta	535	726
Cypress/Chowade, British Columbia	952	2,634
Total natural gas *(mcf/d)*	9,396	14,580
Total natural gas *(boe/d)*	1,566	2,430
Natural gas liquids		
St. Albert	513	679
Other Alberta	4	5
Total natural gas liquids *(bbl/d)*	517	684
Light/medium crude oil		
St. Albert	137	272
Other, Saskatchewan	1	1
Total light/medium crude oil *(bbl/d)*	138	273
Heavy crude oil		
Mantario East	690	-
Total heavy crude oil *(bbl/d)*	690	-
Total daily average production *(boe/d)*	2,911	3,387
Total production all products *(mboe)*	262	308

2005-Q1 vs 2004-Q1

Total production of all products was 262 mboe versus 308 mboe and our total daily average production was 2,911 boe/d versus 3,387 boe/d. This represented a net decrease in daily average production of 476 boe/d or 14%. Of this net decrease, natural gas, natural gas liquids, and light/medium crude oil production all decreased, while heavy crude oil production increased.

Our daily average production of natural gas from our Alberta properties decreased by 3,502 mcf/d (585 boe/d) due mainly to naturally declining reservoir pressures, a factor that also explains a decrease of 167 boe/d in the production of natural gas liquids. At Cypress/Chowade in British Columbia, our daily average natural gas production decreased by 1,682 mcf/d (280 boe/d) due primarily to higher-than-expected decline rates from two wells.

Whlie our daily average production of light/medium crude oil decreased by 135 boe/d due to declining production from one St. Albert well, heavy crude oil increased by 690 boe/d due to our new-pool discovery in late Fiscal 2004.

Weighted Average Commodity Prices

Our weighted average natural gas prices are a reflection of the posted New York Mercantile Exchange (NYMEX) price at the Henry Hub in Louisiana, adjusted for exchange rates, prices of competing fuels and transportation ("differentials") back to various trading points that apply to us in Alberta and British Columbia. The natural gas price indices that affect us are the AECO-C Spot in Alberta and the B.C. Westcoast Station 2 in British Columbia.

Our weighted average light/medium crude oil prices are based on prices for West Texas Intermediate (WTI) at Cushing, Oklahoma, adjusted for differentials back to Edmonton, Alberta. The Edmonton index par price is for a 40° to 45° crude having less than 1/2% sulphur content. The actual wellhead price for our light/medium crude varies with the quality of the oil and the cost of transportation to Edmonton.

We estimate our natural gas liquids to be 45% natural gas-based and 55% crude oil-based. Therefore, our weighted average price for liquids generally follows the above-mentioned respective indices.

Our weighted average heavy crude oil prices are based on the index, Hardisty Heavy 12° API, for heavy crude oil in the proximity of southern Saskatchewan. Production from our new Mantario East field is, for the most part, approximately 13.4° API.

Sproule Associates Limited, an engineering firm in Calgary, Alberta independently evaluates our reserves each year. They maintain a website showing historical and forecasted prices, which help to provide trends of the above-described indices affecting our weighted average prices. The website address is: www.sproule.com/prices/defaultprices.htm.

Management regularly employs price-trending information for its internal cash flow forecasting purposes from the websites of two firms that regularly market hydrocarbon commodities. They are www.progas.com and www.nexenmarketing.com.

Weighted Average Commodity Prices for the Comparative Periods Presented

(Units as stated)	*2005-Q1*	*2004-Q1*
Natural gas *($/mcf)*	7.05	6.56
Natural gas liquids *($/bbl)*	31.35	26.99
Light/medium crude oil *($/bbl)*	58.31	44.30
Heavy crude oil *($/bbl)*	24.36	-

2005-Q1 vs 2004-Q1

Our weighted average prices of natural gas, natural gas liquids and light/medium crude oil increased by 7%, 16% and 32%, respectively. We did not report a weighted average price for heavy crude oil in 2004-Q1 due to our not having realized any sales during that period.

Hedging

We have no hedge positions. However, because of our product mix of natural gas, natural gas liquids and crude oil, the potential price-volatility risk that single-product pricing could have on our net earnings is reduced. Further, we vary our natural gas sales mix between AECO-spot prices and aggregator-based prices (which are, in turn, based on a blend of AECO-spot, long term and NYMEX contracts).

Since 1997, we committed to sell our future natural gas production from St. Albert through Progas under a life-of-reserves agreement. As other fields have come on stream, we have elected to sell the uncommitted natural gas into the AECO daily spot market. Management believes that this current allocation of our gas production into the two markets provides an optimum balance portfolio.

Royalties, Mineral Taxes and Royalty Credits

Royalties, Mineral Taxes, Royalty Credits and Unit Total Royalties for the Comparative Periods Presented

($ 000's unless otherwise stated)	*2005-Q1*	*2004-Q1*
Crown	528	634
Freehold and overriding	1,417	1,403
Freehold mineral taxes	(86)	436
Provincial royalty credits	(189)	(55)
Total royalties [1]	1,670	2,418
Unit total royalties per boe *($)*	6.37	7.84

(1) Total royalties includes mineral taxes and provincial royalty credits.

2005-Q1 vs 2004-Q1

Total royalties were $1.7 million versus $2.4 million. Unit royalties expense decreased by a net of $1.47 or 19%, to $6.37 per boe. The majority of the net decrease in unit royalties expense was for accrued mineral tax recoveries related to the past three years.

Production Costs

Production Costs and Unit Production Costs for the Comparative Periods Presented

($ 000's unless otherwise stated)	*2005-Q1*	*2004-Q1*
Production costs	1,870	1,813
Unit production costs per boe *($)*	7.14	5.88

2005-Q1 vs 2004-Q1

Total production costs remained relatively unchanged at $1.9 million versus $1.8 million. On a unit basis, however, production costs increased by a net of $1.26 or 21%, to $7.14 per boe. This increase was mainly due to the continued incurrence of fixed costs versus declining production from our St Albert field.

Amortization and Depletion Expense (A&D)

A&D Expense and Unit A&D Expense for the Comparative Periods Presented

($ 000's unless otherwise stated)	*2005-Q1*	*2004-Q1*
Total A&D	3,675	3,040
Unit A&D expense per boe *($)*	14.03	9.87

2005-Q1 vs 2004-Q1

Our total A&D expense was $3.7 million versus $3.0 million. Unit A&D expense increased by a net of $4.16 or 42%, to $14.03 per boe. Over 31% of this increase was due to amortization of new petroleum and natural gas rights that were acquired since 2004-Q1. The balance of the increase was predominantly due to the introduction of new depletion in 2005-Q1 related to our Mantario East properties.

Exploration Expenses

Exploration Expenses and Unit Exploration Expenses for the Comparative Periods Presented

($ 000's unless otherwise stated)	*2005-Q1*	*2004-Q1*
Drilling (1)	665	1,464
Seismic data activity	77	2,623
Other	103	128
Total exploration expenses	845	4,215
Unit exploration expenses per boe *($)*	3.22	13.68

(1) We follow the successful efforts method of accounting, whereby costs of drilling an unsuccessful well are expensed immediately if it is known the well did not result in the discovery of proved reserves. If the economic importance was not immediately known after drilling, the expensing of our drilling costs may be temporarily deferred. We expense such deferred costs after one year if near-term efforts to establish proved reserves are not foreseeable, intended, or in our control. Collectively, we report these costs are "Drilling" in the above table.

2005-Q1 vs 2004-Q1

Total exploration expenses were $0.8 million versus $4.2 million. Unit exploration expenses decreased by $10.46 or 76%, to $3.22 per boe. Seventy-nine percent of this decrease was due to the difference in our seismic data activity (in 2004-Q1, we spent $2.6 million on a 44 square-kilometer 3D proprietary seismic program at Orion). The remainder of the decrease was mostly due to lower expenses relating to unsuccessful drilling attempts. While two unsuccessful drilling attempts were recognized in 2005-Q1, one of the wells commenced drilling in 2004. The costs recognized in 2005-Q1 related to development wells at Mantario East that were less costly to drill than the costs in 2004-Q1 that related to two exploratory wells at Cypress/Chowade.

Interest Expense - Net

Net Interest Expense and Unit Net Interest Expense for the Comparative Periods Presented

($ 000's unless otherwise stated)	*2005-Q1*	*2004-Q1*
Net interest expense	208	179
Unit net interest expense per boe *($)*	0.79	0.58

2005-Q1 vs 2004-Q1

Net interest expense remained relatively unchanged at $0.2 million between periods. The average daily balance of our bank operating facility increased by $3.2 million or 21%, to $18.8 million and the closing balance was $19.2 million. The effective interest rates applicable to our borrowings in 2005-Q1 and 2004-Q1 were 4.6% and 4.5%, respectively.

General and Administrative Expenses (G&A)

G&A Expenses and Unit G&A Expenses for the Comparative Periods Presented

($ 000's unless otherwise stated)	*2005-Q1*	*2004-Q1*
Cash G&A	861	817
Non-cash G&A (stock-based compensation)	52	40
Total G&A	913	857
Per boe *($)*	3.48	2.78

2005-Q1 vs 2004-Q1

Total G&A expenses, which increased by 7% to $0.9 million, contain both cash and non-cash items (stock-based compensation being non-cash). While our total G&A did not change significantly between periods, our total unit G&A costs increased by $0.70 or 25%, to $3.48 per boe. This change in unit G&A was mainly caused by a lower production denominator and fewer overhead credits earned as the operator of properties.

Gain on Sale of Oil and Gas Assets

The gain on sale of oil and gas assets of $0.5 million related to the sale of two sections of mineral rights at Wimborne that were fully amortized with no remaining net book value. The proceeds from the sale were comprised of two sections of mineral rights at Halkirk valued at $0.1 million and $0.4 million in cash.

Income Tax Expense

We use the liability method of tax allocation in accounting for income taxes. Future tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities, and measured using the substantially-enacted rates and laws that will be in effect when the differences are expected to reverse.

Current and Future Income Tax Expenses (Recoveries) for the Comparative Periods Presented

($ 000's)	*2005-Q1*	*2004-Q1*
Income tax expense (recovery)		
Future	195	(785)
Total	195	(785)

2005-Q1 vs 2004-Q1

Total income taxes in 2005-Q1 were an expense of $0.2 million compared to a recovery of $0.8 million in 2004-Q1.

The above amounts were consistent with our pre-tax earnings and the recovery in 2004-Q1 further reflected declining future income tax rates and the deductibility/non-deductibility of resource allowances and crown payments.

On April 30, 2004, we issued 2,000,000 flow-through shares at $5.60 per share through private placement for total gross proceeds of $11,200,000. The gross proceeds will be used to incur qualifying Canadian Exploration Expense ("CEE") as defined in the Income Tax Act (Canada).

On February 28, 2005, the Company officially renounced $11,200,000 of taxable benefits relating to qualifying expenses in favour of shareholders that participated in the flow-through private placement. As at March 31, 2005, we incurred approximately 85% of the qualifying expenditures.

Summary of Quarterly Results

Summary of Results for Eight Most Recently Completed Quarters

	2005 Q1	2004 Q4	2004 Q3	2004 Q2	2004 Q1	2003 Q4	2003 Q3	2003 Q2
Revenue	9,715	9,822	9,689	10,320	10,975	9,636	11,980	10,924
Net earnings (loss)	797	(11,528)	(378)	413	(788)	(781)	965	1,472
Net earnings (loss) per share								
basic	0.03	(0.49)	(0.01)	0.02	(0.04)	(0.04)	0.04	0.07
diluted	0.03	(0.49)	(0.01)	0.02	(0.03)	(0.04)	0.04	0.07

Changes in revenues between quarters are affected by three identifiable trend factors. They are: changes in total and daily production volumes of commodities; changes in prices of commodities; and changes in daily production volume-mix between commodities. Changes in net earnings and net earnings per share between quarters are mainly affected by three identifiable trend factors. They are the same changes affecting revenues as discussed above, plus changes in amortization and depletion (A&D) expense and changes in exploration expenses.

The table below shows identifiable trend factors that affect changes in revenues, net earnings and net earnings per share of the eight most recent quarters.

Identifiable Trend Factors of Eight Most Recently Completed Quarters

	2005 Q1	2004 Q4	2004 Q3	2004 Q2	2004 Q1	2003 Q4	2003 Q3	2003 Q2
Total production *(mboe)*	262	256	265	273	308	305	353	292
Daily average production rates:								
Natural gas *(mcf/d)*	9,396	11,073	13,404	13,881	14,580	14,010	14,292	11,615
Natural gas liquids *(bbl/d)*	517	554	538	512	684	724	707	576
Light/medium crude oil *(bbl/d)*	137	145	111	170	273	253	742	695
Heavy crude oil *(bbl/d)*	690	242						
Weighted average commodity prices:								
Natural gas *($/mcf)*	7.05	6.70	6.51	6.90	6.56	5.73	5.80	6.87
Natural gas liquids *($/boe)*	31.35	33.25	32.85	28.25	26.99	25.58	26.17	26.02
Light/medium crude oil *($/boe)*	58.31	57.14	55.02	49.57	44.30	36.94	40.53	40.70
Heavy crude oil *($/boe)*	24.36	21.07						
A&D expense	3,675	14,863	3,467	2,812	3,040	4,550	3,396	1,890
Exploration expenses [1]	845	7,850	1,400	935	4,215	1,552	565	848

(1) We follow the successful efforts method of accounting, whereby costs of drilling an unsuccessful well ("dry hole") are expensed when it becomes known the well did not result in a discovery of proved reserves.

2003-Q2 – Revenue of $10.9 million was the result of slightly weaker commodity prices and lower production. Lower production was mainly the result of an annual two-week plant turnaround at St. Albert. Net earnings were $1.5 million after accounting for relatively lower A&D expense of $1.9 million, primarily due to lower production. Exploration expenses of $0.8 million included the cost of one dry hole at Wimborne.

2003-Q3 – Revenue of $12.0 million was our second-highest on record. This was the net result of record-high production against comparatively weaker commodity prices. Net earnings were $1.0 million after accounting for $3.4 million in A&D expense, which was due to higher production volumes combined with a significant increase in our depletable asset base. Our depletable assets increased due to the repurchase of gross overriding interests that previously burdened our total current and future production by 3%. Exploration expenses were $0.6 million, most of which related to one dry hole at Halkirk.

2003-Q4 – Revenue of $9.6 million reflected a significant decrease in crude oil prices and production volumes. Crude oil decreased at St. Albert mainly due to declining productivity in two wells. Net earnings were a loss of $0.8 million. A&D expense of $4.6 million reflected a lower producing reserve base due to year-end independent reserve estimations. Exploration expenses were $1.6 million, most of which was for our share of 3D, seismic data-gathering costs at Cypress/Chowade.

2004-Q1 – Revenue of $11.0 million reflected strengthening prices in all commodities. Net earnings were a loss of $0.8 million after accounting for a significant increase in exploration expenses. Exploration expenses were $4.2 million due mainly to a 44 square-kilometer, 3D proprietary seismic program at Orion and the recognition of two unsuccessful drilling attempts at Cypress/ Chowade.

2004-Q2 – Revenue of $10.3 million reflected comparatively stronger prices and lower production in all commodities. Lower production was mainly the net result of continuing production declines and an annual two-week plant turnaround at St. Albert, and the start-up of three new natural gas wells at Cypress/Chowade. Net earnings were $0.4 million after accounting for relatively unchanged A&D burdens and $0.9 million in exploration expenses. There were no dry holes reported in the period.

2004-Q3 – Revenue of $9.7 million reflected slightly lower production. Lower production was mainly the result of natural declines in production from our Alberta properties and a temporary shutdown of our sour gas compressor at St. Albert. Net earnings were a loss of $0.4 million after accounting for $1.4 million in exploration expenses, due mainly to the recognition of one unsuccessful drilling attempt at Wimborne.

2004-Q4 – Revenue of $9.8 million reflected a net decrease in production due to lower natural gas production at Cypress/Chowade and the introduction of heavy crude oil production at Mantario East. Net earnings were a loss of $11.5 million after accounting for significant charges to A&D expense ($14.9 million) and exploration expenses ($7.9 million). A&D expense reflected a significant decrease in our December 31, 2004 independent estimate of proved producing reserves at Cypress/Chowade. Exploration expense reflected costs associated with unsuccessful efforts to discover proved reserves in 12 wells that were drilled or worked on during the quarter. The well-locations and their number-count were as follows: Orion - four, Cypress/Chowade - one, Wimborne - two, Halkirk - one, St.Albert - one, Mantario East - two, and Flaxcombe - one.

2005-Q1 – Details are included in earlier sections of this Management's Discussion and Analysis.

OUTLOOK FOR 2005

Our daily production average rate and exit rate targets remain unchanged from those of our Fiscal 2004 year-end at 3,300 and 3,400 boe/d, respectively. The composition of these target rates is approximately 49% natural gas, 15% natural gas liquids, 6% medium/light crude oil and 30% heavy crude oil. As a percentage of our total production in Fiscal 2004 and 2005-Q1, heavy crude oil comprised 2% and 24%, respectively.

Most refineries are equipped to handle only light/medium crude. Heavy crude oil sells at lower prices relative to the lighter crude stocks, and due to its higher flow resistance transportation costs are greater. Therefore, heavy crude oil net-backs are lower than those of light/medium crude oil.

The achievement of our daily production rate targets is dependent upon our Fiscal 2005 drilling program. The program allows for the drilling of 19 development wells, 18 of which have been considered in our production targets. The one development well that is not considered in our targets is a prospective natural gas well at Orion. The others are as follows: two potential natural gas infill wells at Halkirk; one light/medium crude oil well at St. Albert; and fifteen heavy crude oil infill wells at Mantario East.

During 2005-Q1, we drilled five development wells targeting heavy crude oil at Mantario East. Of these, one was unsuccessful, two were placed into production and two others were completed as cased and standing wells. We expect the cased and standing wells will be equipped and tied into production facilities in the near-term.

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

Our capital resources at the end of 2005-Q1 consisted of cash flow from operations, available lines of bank credit and net cash proceeds provided from the issuance of equity by way of a private placement.

Based on our forecast of strong commodity prices, supported by our bank loan facility, we expect to meet our 2005 cash requirements. Consistent with our stated strategy for growth through full-cycle exploration and development, we may seek, from time-to-time, as warranted, term debt to finance long-life facilities, equity when deemed appropriate, and adjustments to our capital investment budget according to cash availability.

Financing activities – As at March 31, 2005, our revolving, demand bank loan facility was $25.0 million, of which $19.2 million was outstanding. Interest on this facility is at prime plus 3/8%, plus a standby fee on unused credit of 1/8%.

Working capital – Changes in our working capital and net debt levels are primarily dependent upon our cash flow from operations, the amount of our capital expenditures and exploration expenses, the timing of incurred field activities, and external sources of financing.

Our March 31, 2005 net debt level reflects an annualized net debt-to-cash-flow ratio of 1.3:1 (March 31, 2004 – 1.1:1).

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this Interim Report constitute "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. Additionally, forward-looking statements may be made orally or in press releases, conferences, reports, on our worldwide website or otherwise, in the future, by or on behalf of us. Such statements are generally identifiable by the terminology used such as "plans", "expects, "estimates", "budgets", "intends", anticipates", "believes", "projects", "indicates", "targets", "objective", "could", "may" or other similar words.

The forward-looking statements are subject to known and unknown risks and uncertainties and other factors that may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others: market prices for natural gas, natural gas liquids and crude oil products; the ability to produce and transport natural gas, natural gas liquids and crude oil; the results of exploration and development drilling and related activities; economic conditions in the countries and provinces in which we carry on business, especially economic slowdown; actions by governmental authorities including increases in taxes, changes in environmental and other regulations, and renegotiations of contracts; political uncertainty, including actions by insurgent groups or other conflict and the negotiation and closing of material contracts. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors; our course of action would depend upon our assessment of the future considering all information then available. In that regard, any statements as to future natural gas, natural gas liquids or crude oil production levels; capital expenditures; the allocation of capital expenditures to exploration and development activities; sources of funding for our capital program; drilling of new wells; demand for natural gas, natural gas liquids and crude oil products; expenditures and allowances relating to environmental matters; dates by which certain areas will be developed or will come on-stream; expected finding and development costs; future production rates; ultimate recoverability of reserves; dates by which transactions are expected to close; cash flows; uses of cash flows; collectibility of receivables; availability of trade credit; expected operating costs; expenditures and allowances relating to environmental matters; debt levels; and changes in any of the foregoing are forward-looking statements, and there can be no assurance that the expectations conveyed by such forward-looking statements will, in fact, be realized.

Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity, achievements or financial condition.

We wish to caution readers not to place undue reliance on any forward-looking statement and to recognize that the statements are predictions of future results, which may not occur as anticipated. Actual results could differ materially from those anticipated in the forward-looking statements and from historical results, due to the risks and uncertainties described above, as well as others not now anticipated. The foregoing statements are not exclusive and further information concerning us, including factors that potentially could materially affect our financial results, may emerge from time to time. We assume no obligation to update forward-looking statements to reflect actual results or changes in factors or assumptions affecting such forward-looking statements.

Notice to Reader

The accompanying financial statements of Dynamic Oil & Gas, Inc., comprised of the Balance Sheets as at March 31, 2005 and December 31, 2004, and the Interim Statements of Earnings and Cash Flows for the three-month periods ended March 31, 2005 and 2004 are the responsibility of the Company's management. These financial statements have not been reviewed by the independent external auditors of the Company.

BALANCE SHEETS

(unaudited)

(In Canadian dollars)

	March 31 2005 $	*December 31 2004 $*
ASSETS		
Current		
Accounts receivable	4,065,245	7,565,975
Income taxes receivable	617,839	541,487
Prepaid expenses	615,982	361,277
Total current assets	5,299,066	8,468,739
Natural gas and oil interests	59,296,741	56,726,494
Capital assets	373,472	414,913
Future income tax asset	-	2,082,092
	64,969,279	67,692,238
LIABILITIES & SHAREHOLDERS' EQUITY		
Current		
Bank indebtedness	2,174,951	1,083,000
Operating loan	19,225,000	15,550,000
Accounts payable and accrued liabilities	10,795,522	17,348,723
Total current liabilities	32,195,473	33,981,723
Asset retirement obligations	2,657,391	2,555,756
Future income tax liability	2,072,234	-
Total liabilities	36,925,098	36,537,479
Share capital	35,892,565	39,852,368
Contributed surplus [note 2]	809,810	757,689
(Deficit) retained earnings	(8,658,194)	(9,455,298)
Total shareholders' equity	28,044,181	31,154,759
	64,969,279	67,692,238

Wayne Babcock
Director

Donald Umbach
Director

STATEMENTS OF OPERATIONS AND RETAINED EARNINGS (DEFICIT)

(unaudited)

(In Canadian dollars)

Three Months Ended March 31	*2005*	*2004*
	$	*$*
REVENUE		
Natural gas, liquids and oil sales	9,715,067	10,975,078
Royalties	(1,859,585)	(2,472,905)
Production costs	(1,870,201)	(1,813,018)
	5,985,281	6,689,155
Provincial royalty credits	189,414	55,307
	6,174,695	6,744,462
EXPENSES		
General and administrative	913,042	857,317
Interest expense - net	207,886	178,803
Accretion of asset retirement obligation	42,384	25,930
	1,163,312	1,062,050
Earnings from operations before the following:	5,011,383	5,682,412
Amortization and depletion	3,675,237	3,040,423
Exploration expenses	844,519	4,215,464
Gain on sale of oil and gas assets	(500,000)	-
Earnings (loss) before taxes	991,627	(1,573,477)
Income tax expense (recovery)		
- Future	194,523	(785,129)
Net earnings (loss)	797,104	(788,348)
(Deficit) retained earnings, beginning of period	(9,455,298)	2,825,311
(Deficit) retained earnings, end of period	(8,658,194)	2,036,963
Net earnings (loss) per share		
basic	0.03	(0.04)
diluted	0.03	(0.04)

STATEMENTS OF CASH FLOWS

(unaudited)

(In Canadian dollars)

Three Months Ended March 31	*2005*	*2004*
	$	*$*
OPERATING ACTIVITIES		
Net earnings (loss)	797,104	(788,348)
Add (deduct) items not involving cash:		
Accretion of asset retirement obligation	42,384	25,930
Amortization and depletion	3,675,237	3,040,425
Stock-based compensation	52,121	40,167
Future income tax expense (recovery)	194,523	(785,129)
Gain on sale – natural gas interests	(500,000)	-
Exploration expenses	844,519	4,215,464
	5,105,888	5,748,509
Changes in non-cash working capital affecting operating activities	(1,076,438)	(6,133,247)
Cash provided by operating activities	4,029,450	(384,748)
FINANCING ACTIVITIES		
Bank indebtedness	1,091,951	(361,490)
Operating loan	3,675,000	2,300,000
Shares issued for cash	-	27,533
Cash provided by (used in) financing activities	4,766,951	1,966,043
INVESTING ACTIVITIES		
Purchase of capital assets	(24,396)	(15,099)
Natural gas and oil interests	(6,112,976)	(8,393,847)
Settlement of asset retirement	(7,419)	-
Exploration expenses	(844,519)	(4,215,464)
Proceeds on sale – natural gas interests	500,000	-
Changes in non-cash working capital affecting investing activities	(2,307,090)	11,043,115
Cash used in investing activities	(8,796,400)	(1,581,295)
Change in cash and cash equivalents	-	-
Cash and cash equivalents, beginning of period	-	-
Cash and cash equivalents, end of period	-	-
Supplemental disclosures of cash flow information		
Net cash paid during the period for:		
Interest	213,263	174,062
Income taxes	76,352	66,611

Notes to Unaudited Financial Statements

Note 1. Basis of Presentation and Summary of Significant Accounting Policies

The accompanying interim financial statements have been prepared in accordance with Canadian generally accepted accounting principles for interim financial information and accordingly do not include all disclosures required for annual financial statements.

Management makes estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the Financial Statements, and revenues and expenses during the reporting period. Such estimates primarily involve sales volumes, commodity prices, royalties, production costs, certain general and administrative expenses, depletion and accretion expense. Changes in facts and circumstances may result in revised estimates, and actual results may differ from these estimates. In the opinion of management, all estimates and accruals necessary for a fair presentation have been considered and included. Operating results for the three-month period ended March 31, 2005 are not necessarily indicative of the results that may be expected for the full year ending December 31, 2005.

These statements should be read in conjunction with the audited Balance Sheet as at December 31, 2004 and Statement of Operations and Retained Earnings, and Statement of Cash Flows and the notes thereto for the fiscal year ended December 31, 2004, such financial statements having been filed with the Securities Commissions. These financial statements reflect the same significant accounting policies as those described in the notes to the Company's Fiscal 2004 financial statements.

Note 2. Common Share Capital

[a] Issued and Outstanding Shares

The following table sets forth the issued and outstanding common shares.

For the Three Months Ended March 31	*2005*		*2004*	
	#	*$*	*#*	*$*
Outstanding, beginning of period	24,558,978	39,852,368	22,194,778	27,747,487
Recognition of future income taxes related to flow-through [1]	–	(3,959,803)	-	-
Shares issued on the exercise of stock options	-	-	12,533	27,533
Outstanding, end of period	24,558,978	35,892,565	22,207,311	27,775,020

(1) On April 30, 2004, the Company issued 2,000,000 flow-through shares at $5.60 per share through private placement for total proceeds of $11,200,000. Gross proceeds from the flow-through shares will be used to incur qualifying Canadian Exploration Expense ("CEE") as defined in the Income Tax Act (Canada), and the Company renounced on February 28, 2005 such CEE in favour of the original holders of the flow-through shares in an amount equal to the issue price for each flow-through share. With the renouncement, the Company recognized a future income tax liability of $3,959,803 and share capital was reduced by the same amount. As at March 31, 2005, the Company had incurred approximately 85% of the qualifying expenditures and committed another 15% that must be incurred by December 31, 2005.

[b] Earnings per Share

The following table sets forth the computation of basic and diluted earnings per share.

Three Months Ended March 31 ($ unless otherwise stated)	*2005*	*2004*
Numerator:		
Net earnings (loss) per period	797,104	(788,348)
Denominator:		
Weighted average number of common shares outstanding	24,558,978	22,203,585
Effect of dilutive stock options	425,135	665,552
Basic earnings (loss) per share	0.03	(0.04)
Diluted earnings (loss) per share	0.03	(0.04)

[c] Options Outstanding

The following table summarizes the status of the Company's stock option plan for the periods presented.

Three Months Ended March 31	*2005*	*2004*	*2005*	*2004*
	Number of Shares		*Weighted Average Option Price*	
	#	*#*	*$*	*$*
Outstanding, beginning of period	1,768,300	1,615,834	2.86	2.61
Exercised	-	12,533	-	2.20
Forfeited	-	8,667	-	2.65
Outstanding, end of period	1,768,300	1,594,634	2.86	2.61
Options exercisable at end of period	1,469,633	1,190,301	2.60	2.30

Options outstanding as at March 31, 2005 had expiry dates ranging from January 23, 2005 to April 29, 2013, with exercise prices ranging from $1.45 to $5.43 per share.

Note 3. Pro-Forma Net Earnings (Fair-Value Based Method of Accounting for Stock Options)

During the three-month periods ended March 31, 2005 and 2004, the Company used the fair-value based method to account for stock options granted to directors, employees and non-employees, resulting in a decrease to net earnings (loss) and a corresponding increase to contributed surplus of $52,121 and $40,167, respectively.

Stock options granted to directors and employees prior to January 1, 2003 were accounted for using the intrinsic-value based method. The following shows pro-forma net earnings (loss) and net earnings (loss) per common share had the Company applied the fair-value based method for all stock options outstanding:

Three Months Ended March 31	*2005*	*2004*
Net earnings (loss):		
As reported	797,104	(788,348)
Pro forma	790,337	(813,521)
Basic earnings (loss) per common share:		
As reported	0.03	(0.04)
Pro forma	0.03	(0.04)
Diluted earnings (loss) per common share:		
As reported	0.03	(0.04)
Pro forma	0.03	(0.04)

The fair values of the stock option grants were estimated based on the dates of grant using the Black-Scholes option-pricing model with the following assumptions:

For stock options granted during (1)	*2004*	*2003*
Risk-free average interest rate	4.25%	4.00%
Dividend yield	0%	0%
Estimated volatility	47%	51%
Estimated life (years)	3	3

(1) The Company did not grant any options during the three-month period ended March 31, 2005.

DYNAMIC OIL & GAS, INC.

Corporate Information

Directors

Wayne J. Babcock
David J. Jennings
Jonathan A. Rubenstein
Donald K. Umbach
John A. Greig
John Lagadin
William B. Thompson

Officers

Wayne J. Babcock, *President & Chief Executive Officer*
Donald K. Umbach, *Vice President & Chief Operating Officer*
David G. Grohs, *Vice President, Production*
Michael A. Bardell, *Chief Financial Officer & Corporate Secretary*

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Perkins Coie LLP Santa Monica, California

Auditors

Ernst & Young LLP Vancouver, British Columbia

Bankers

National Bank of Canada Calgary, Alberta

Registrar and Transfer Agent

CIBC Mellon Trust Company Vancouver, British Columbia

Trading Symbols

TSX : DOL NASDAQ : DYOLF

Regulatory filings website: Canadian: www.sedar.com
US: www.sec.gov/edgar