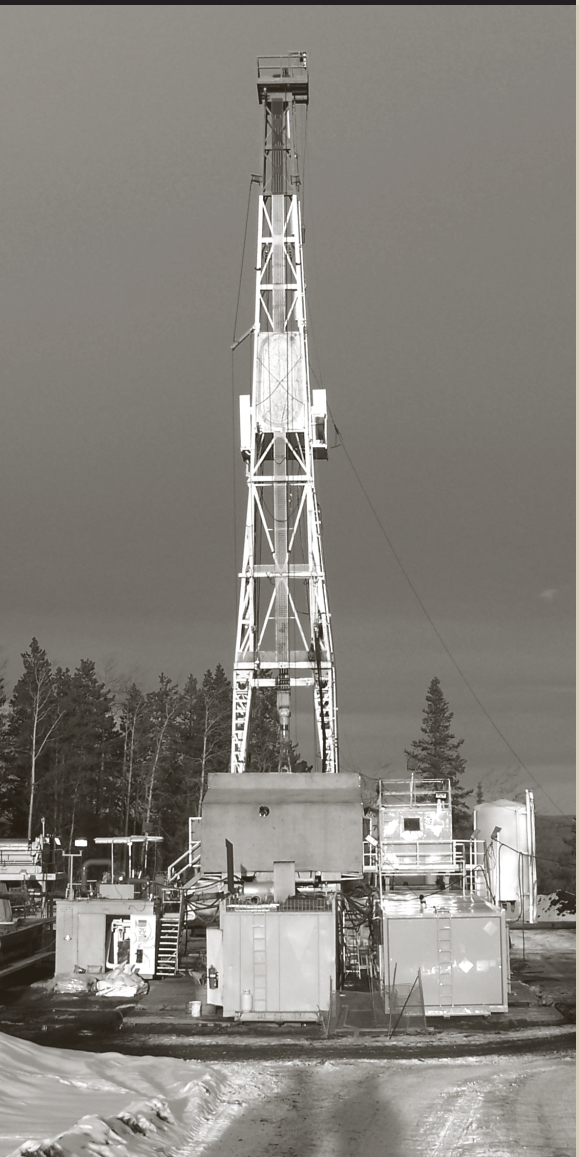
2005 2nd Quarter Report

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, as this 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 volatility in commodity prices.

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

Periods Reported

	2005	*2004*
April 1 to June 30, referred to as	2005-Q2	2004-Q2
January 1 to June 30, referred to as	2005-Half	2004-Half
January 1 – March 31, referred to as	2005-Q1	2004-Q1
January 1 – December 31, referred to as	Fiscal 2005	Fiscal 2004

EXECUTIVE OVERVIEW

Key Measures for the Comparative Periods Presented

($000's unless otherwise stated)	*2005-Q2*	*2004-Q2*	*2005-Half*	*2004-Half*
Gross revenues	8,971	10,320	18,687	21,295
Cash flow from operating activities [1]	3,755	4,649	7,784	4,264
Net (loss) earnings	(982)	413	(185)	(375)
Net (loss) earnings per share *($/share)*	(0.04)	0.02	(0.01)	(0.02)
Daily average production *(boe/d)*	2,607	2,996	2,758	3,191
Total production *(mboe)*	237	273	499	581
Capital investment (includes exploration expenses)	559	5,321	7,518	17,844
Net debt [2]	21,417	14,899	21,417	14,899

[1] Commencing in 2005-Q2, our prior disclosure of the non-GAAP measure, "cash flow from operations", has been discontinued. "Cash flow from operating activities" is a GAAP measure.

[2] Net debt is working capital. We have no long term debt.

2005-Q2 vs 2004-Q2

Gross revenues decreased by $1.3 million or 13%, to $9.0 million during 2005-Q2. Comparatively, gross revenues in 2004-Q2 were 13% higher at $10.3 million. Our weighted average prices realized for all commodities in 2005-Q2 improved our comparative gross revenues by $1.6 million, while production decreases in natural gas, natural gas liquids and light/medium crude oil had a weakening effect on gross revenues of $5.1 million. However, production increases in heavy crude oil helped to strengthen 2005-Q2 gross revenues by $2.2 million.

Our total production in 2005-Q2 was 237 mboe compared to 273 mboe in 2004-Q2 and daily average production was 2,607 boe/d, compared to 2,996 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 662 boe/d. At Cypress/Chowade, two wells that produced natural gas at higher daily rates in 2004-Q2 performed at lower levels in 2005-Q2, accounting for a further decrease of 548 boe/d.

Of comparative significance to daily average production results, was the commencement in late Fiscal 2004 of heavy crude oil production from our new Mantario East pool. This accounted for an increase in our daily average production rate of 821 boe/d.

At the close of 2005-Q2, four new wells commenced production – two natural gas wells at Cypress/Chowade and two heavy crude oil wells at Mantario East.

Net (loss) earnings decreased between periods by $1.4 million (a loss of $1.0 million from net earnings of $0.4 million), most of which was due to the decrease in revenues discussed above. The remainder of the decrease was due to various increases and decreases in expenses and other income items. The most significant item was an increase in exploration expenses of $1.3 million due mainly to the expensing of costs related to the drilling in 2004 of two exploratory natural gas wells at Cypress/Chowade.

PROPERTIES AND CAPITAL INVESTMENT

Capital Investment Program by Classification for the Comparative Periods Presented

($000's)	*2005-Q2*	*2004-Q2*	*2005-Half*	*2004-Half*
Land acquisitions	39	46	165	2,353
Drilling, completions and equipping: [1]				
Exploration	(246)	2,002	419	5,918
Development	1	1,029	5,553	1,806
Facilities and pipelining	684	1,771	1,122	4,655
Seismic	(56)	417	21	3,041
Other	137	56	238	71
Total	559	5,321	7,518	17,844

[1] 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.

2005-Q2

During 2005-Q2, we recorded a net of $0.5 million toward our capital investment program.

Capital Investment Program by Property and Classification

($000's)	*Land*	*Drilling, Completions & Equipping*	*Facilities & Pipelining*	*Seismic*	*Other*	*Total*
Alberta						
St. Albert	–	58	196	-	(5)	249
Wimborne	–	26	–	–	–	26
Halkirk	–	169	–	–	–	169
Peavey/Morinville	-	–	(7)	(46)	(1)	(54)
Other	7	13	-	-	-	20
Total Alberta	7	266	189	(46)	(6)	410
British Columbia						
Cypress/Chowade	(2)	(645)	(241)	67	-	(821)
Orion	-	19	25	(207)	(1)	(164)
Total British Columbia	(2)	(626)	(216)	(140)	(1)	(985)
S.W. Saskatchewan						
Mantario East	34	112	711	140	10	1,007
Sandgren	-	3	-	-	-	3
Total S.W. Saskatchewan	34	115	711	140	10	1,010
Other	-	-	-	-	124	124
Total	39	(245)	684	(46)	127	559

The most significant items included in our 2005-Q2 capital investment program were:

- $0.4 million incurred at St. Albert and Halkirk in Alberta. Work at St. Albert included gas plant reconfiguration and water disposal facilities, while at Halkirk we drilled one successful natural gas well not yet in production as at June 30, 2005;
- $(0.8) million arising mostly from adjustments to partner billings related to Cypress/Chowade;
- $(0.2) million mainly related to the sale of seismic data at Orion; and
- $1.0 million incurred on completions operations of two previously cased and standing heavy crude oil wells, and on construction of battery and pipeline facilities in the Mantario East field.

Subsequent Events

Subsequent to the period ended June 30, 2005, the Company concluded that previously capitalized costs associated with the drilling of three exploration wells should be recorded as exploration expense. In aggregate, the wells have an estimated net carrying value of $6,343,126. Also subsequent to June 30, 2005, the Company recorded a gain on sale of $600,000 in respect of one of the three wellbores above that was sold to a third party. The Company retained full hydrocarbon interests associated with the lands on which the sold wellbore was located. Two of the wells were located in northeast British Columbia and the other well was located in southwest Saskatchewan.

On July 21, 2005, we announced that we had entered into agreements whereby Sequoia Oil & Gas Trust ("Sequoia") of Calgary, Alberta will acquire all of our Alberta oil and natural gas assets, and whereby we will reorganize all of our British Columbia and Saskatchewan oil and natural gas assets into a new exploration company (the "Transaction"). The Transaction will be completed by way of a Plan of Arrangement (the "Plan").

Accordingly, we will establish Shellbridge Oil & Gas, Inc., as a new exploration-focused, Canadian publicly-traded subsidiary, ("Shellbridge") and will transfer into it, effective May 1, 2005, all of the benefits and obligations of our producing assets and undeveloped lands located in the provinces of British Columbia and Saskatchewan. We will retain all of our Alberta properties. Sequoia will purchase all of our outstanding shares of common stock for a cash payment to our shareholders of $72.9 million less approximately $28.9 million in certain benefits, liabilities and obligations that are being assumed by Sequoia. As a result, each of our shareholders of record at closing, will receive $1.71 in cash and one share of Shellbridge for each share held of Dynamic's common stock. Shellbridge will be governed by five of our current Board of Directors, and managed by current management.

The Plan has the unanimous support of both our board and Sequoia's board of directors. The Plan includes a break fee of $2.16 million payable by either party if the Transaction is not completed under certain circumstances.

Consummation of the Plan is subject to certain closing conditions including, without limitation, shareholder approval, judicial determination of fairness, regulatory approval and the conditional listing of Shellbridge shares for trading on the Toronto Stock Exchange (TSX) or the TSX Venture Exchange. Further details of the Plan are provided on our website at www.dynamicoil.com.

An Information Circular detailing the Plan is anticipated to be mailed to our shareholders in late August 2005. Shareholders will be asked to approve the Plan at a special meeting expected to be held in late September 2005, with closing to follow shortly thereafter.

2005-Half vs 2004-Half

Gross revenues decreased by $2.6 million or 12%, to $18.7 million during 2005-Half. Comparatively, gross revenues in 2004-Half were 12% higher at $21.3 million. Our weighted average prices realized for all commodities in 2005-Half improved our comparative gross revenues by $2.8 million, while production decreases in natural gas, natural gas liquids and light/medium crude oil had a weakening effect on gross revenues by $9.1 million. However, production increases in heavy crude oil helped to strengthen 2005-Half gross revenues by $3.7 million.

Our total production in 2005-Half was 499 mboe compared to 581 mboe in 2004-Half and daily average production was 2,758 boe/d, compared to 3,191 boe/d. As discussed above, predictable rates of natural decline in Alberta production accounted for a decrease in daily average production of 775 boe/d, and lower-than-expected performance in two British Columbia natural gas wells accounted for a further decrease of 414 boe/d. Daily average production increased in Saskatchewan by 756 boe/d due to a new-pool heavy crude oil discovery in late Fiscal 2004.

Our net loss decreased between periods by $0.2 million (a loss of $0.2 million from a loss of $0.4 million). This was due to the decrease in revenues discussed above, accompanied by a net decrease in expenses and other income items. The most significant item was a decrease in exploration expenses, mainly due to a comparative decrease in the costs of gathering seismic data at Orion during 2004-Half.

During 2005-Half, capital investment expenditures totaled $7.5 million, of which $1.4 million was in Alberta, $2.5 million in British Columbia, $3.4 million in Saskatchewan, and $0.2 million allocated to other. Most significant among these expenditures were: the completion of one light/medium crude oil well at St. Alberta and two natural gas wells at Peavey/Morinville; the re-entry of one natural gas well and the completion of another at Cypress/Chowade; the drilling of five wells targeting heavy crude oil wells, two of which were completed at Mantario East; and the construction of field production facilities at both Cypress/Chowade and Mantario East.

FINANCIAL RESULTS

Revenues, Expenses and Net (Loss) Earnings

2005-Q2 vs 2004-Q2

Revenues from the sale of all commodities decreased by $1.3 million or 13% ($9.0 million versus $10.3 million) due mainly to higher realized commodity prices and lower volume sales in all commodities except heavy crude oil. 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-Q2 vs 2004-Q2*			*2005-Half vs 2004-Half*		
	Volume-based	*Price-based*	*Total*	*Volume-based*	*Price-based*	*Total*
Natural gas	(4,336)	925	(3,411)	(7,052)	1,439	(5,613)
Natural gas liquids	(293)	359	66	(72)	513	441
Light/medium crude oil	(505)	272	(233)	(1,988)	809	(1,179)
Heavy crude oil [1]	2,229	-	2,229	3,742	-	3,742
Total	(2,905)	1,556	(1,349)	(5,570)	2,761	(2,609)

[1] The reporting period, 2004-Q2, preceded the commencement of production from our new-pool heavy crude oil discovery in late Fiscal 2004 at Mantario East.

Net (loss) earnings decreased between periods by $1.4 million (a loss of $1.0 million from net earnings of $0.4 million), due to the same factors discussed above that decreased revenues by $1.3 million, accompanied by a net increase of $0.1 million in the various expenses and other income items discussed below.

Cash expenses related to operating activities decreased between periods by a total of $0.2 million. This was the net result of certain increases and decreases. The increases were in production costs and interest expense ($0.2 million, in aggregate). The decreases were in royalties and general and administrative costs ($0.4 million, in aggregate).

Non-cash expenses related to operating activities decreased between periods by a total of $1.0 million, primarily due to a decrease in future income taxes.

Expenses (cash and non-cash) related to investing activities increased between periods by a total of $1.3 million. This was the net result of an increase in exploration expenses of $1.5 million and a gain on the sale of certain natural gas interests of $0.2 million.

2005-Half vs 2004-Half

Revenues from the sale of all commodities decreased by $2.6 million or 13% ($18.7 million versus $21.3 million) due mainly to higher realized commodity prices and lower volume sales in all commodities except heavy crude oil. A breakdown of the volume/price-based variances by commodity is shown in the table above.

Our loss decreased between periods by $0.2 million (a loss of $0.2 million from a loss of $0.4 million), due to the same factors discussed above that decreased revenues by $2.6 million, accompanied by a net decrease of $2.4 million in the various classifications of expenses and other income items discussed below.

Cash expenses related to operating activities decreased between periods by a total of $0.8 million. This was the net result of increases in production costs, interest expense and current income taxes ($0.3 million, in aggregate) and decreases in royalties and general and administrative costs ($1.1 million, in aggregate).

Non-cash expenses related to operating activities increased between periods by a total of $0.6 million, due mainly to amortization and depletion expense.

Expenses (cash and non-cash) related to investing activities expenses decreased between periods by a total of $2.6 million. This was the net result of a decrease in exploration expenses of $1.9 million and a gain on the sale of certain natural gas interests of $0.7 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-Q2*	*2004-Q2*	*2005-Half*	*2004-Half*
Daily average production rates				
Natural gas				
St. Albert	5,814	7,677	6,258	8,636
Halkirk	552	1,091	624	1,101
Peavey/Morinville	336	505	420	510
Other Alberta	270	692	402	708
Cypress/Chowade, British Columbia	630	3,916	792	3,276
Total natural gas *(mcf/d)*	7,602	13,881	8,496	14,231
Total natural gas *(boe/d)*	1,267	2,314	1,416	2,372
Natural gas liquids *(bbl/d)*				
St. Albert	427	508	470	594
Other Alberta	2	4	3	4
Total natural gas liquids *(bbl/d)*	429	512	473	598
Light/medium crude oil				
St. Albert	89	169	112	220
Other, Saskatchewan	1	1	1	1
Total crude oil *(bbl/d)*	90	170	113	221
Heavy crude oil				
Mantario East	821	-	756	-
Total heavy crude oil *(bbl/d)*	821	-	756	-
Total daily average production *(boe/d)*	2,607	2,996	2,758	3,191
Total production all products *(mboe)*	237	273	499	581

2005-Q2 vs 2004-Q2

Total production of all products was 237 mboe versus 273 mboe and our total daily average production was 2,607 boe/d versus 2,996 boe/d. This represented a net decrease in daily average production of 389 boe/d or 13%. Of this net decrease, natural gas, natural gas liquids, and light/medium crude oil production decreased, while heavy crude oil production increased.

Our daily average production of natural gas from our Alberta properties decreased by 2,994 mcf/d (499 boe/d) due mainly to naturally declining reservoir pressures, a factor that also explains a decrease of 83 boe/d in the production of natural gas liquids. At Cypress/Chowade in British Columbia, our daily average natural gas production decreased by 3,288 mcf/d (548 boe/d) due primarily to higher-than-expected decline rates from two wells.

While our daily average production of light/medium crude oil decreased by 80 boe/d due to declining production from one St. Albert well, heavy crude oil increased by 827 boe/d due to our new-pool discovery in late Fiscal 2004.

2005-Half vs 2004-Half

Total production of all products was 499 mboe versus 581 mboe and our total daily average production was 2,758 boe/d versus 3,191 boe/d. This represented a net decrease in daily average production of 433 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.

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-Q2*	*2004-Q2*	*2005-Half*	*2004-Half*
Natural gas *($/mcf)*	7.68	6.90	7.32	6.73
Natural gas liquids *($/bbl)*	35.77	28.25	33.36	27.54
Light/medium crude oil *($/bbl)*	66.62	49.57	61.70	46.39
Heavy crude oil *($/bbl)*	29.84	–	27.35	–

2005-Q2 vs 2004-Q2

Our weighted average prices of natural gas, natural gas liquids and light/medium crude oil increased by 11%, 27% and 34%, respectively. We did not report a weighted average price for heavy crude oil in 2004-Q2 due to our not having realized any sales during that period.

2005-Half vs 2004-Half

Our weighted average prices of natural gas, natural gas liquids and light/medium crude oil increased by 9%, 21% and 33%, respectively. We did not report a weighted average price for heavy crude oil in 2004-Half 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

($000's unless otherwise stated)	*2005-Q2*	*2004-Q2*	*2005-Half*	*2004-Half*
Crown	680	791	1,268	1,425
Freehold and overriding	1,221	1,342	2,577	2,744
Freehold mineral taxes	161	213	75	650
Provincial royalty credits	(29)	(25)	(218)	(80)
Total royalties	2,033	2,321	3,702	4,739
Unit total royalties per boe *($)*	8.57	8.51	7.42	8.16

2005-Q2 vs 2004-Q2
Total royalties were $2.0 million versus $2.3 million. Unit royalties expense increased by a net of $0.06 or 1%, trending with production volume decreases.

2005-Half vs 2004-Half
Total royalties were $3.7 million versus $4.7 million. Unit royalties expense decreased by a net of $0.74 or 9%, to $7.42 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

($000's unless otherwise stated)	*2005-Q2*	*2004-Q2*	*2005-Half*	*2004-Half*
Production costs	2,204	2,162	4,075	3,975
Unit production costs per boe *($)*	9.29	7.93	8.16	6.84

2005-Q2 vs 2004-Q2
Total production costs remained relatively unchanged at $2.2 million. On a unit basis, however, production costs increased by a net of $1.36 or 17%, to $9.29 per boe. This increase was mainly due to the continued incurrence of fixed costs versus declining production from our St. Albert field and higher operating costs from our new Saskatchewan field.

2005-Half vs 2004-Half
Total production costs remained relatively unchanged at $4.1 million versus $4.0 million. On a unit basis, however, production costs increased by a net of $1.26 or 20%, to $8.16 per boe due mainly to the same reasons above.

Amortization and Depletion Expense (A&D)

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

($000's unless otherwise stated)	*2005-Q2*	*2004-Q2*	*2005-Half*	*2004-Half*
Total A&D	2,735	2,812	6,410	5,852
Unit A&D expense per boe *($)*	11.53	10.31	12.84	10.08

2005-Q2 vs 2004-Q2
Our total A&D expense was $2.7 million versus $2.8 million. Unit A&D expense increased by a net of $1.22 or 12%, to $11.53 per boe. Over 64% of this increase was due to the introduction since 2004-Q2 of amortization of newly-acquired petroleum and natural gas rights and increased depreciation of our capital assets. The balance of the increase was predominantly due to the introduction since 2004-Q2 of new depletion related to our Mantario East properties.

2005-Half vs 2004-Half
Our total A&D expense was $6.4 million versus $5.9 million. Unit A&D expense increased by a net of $2.76 or 27%, to $12.84 per boe. Over 41% of this increase was due to the introduction since 2004-Q2 of amortization of newly-acquired petroleum and natural gas rights and increased depreciation of our capital assets. The balance of the increase was predominantly due to the introduction since 2004-Q2 of new depletion expense related to our Mantario East properties.

Exploration Expenses

Exploration Expenses and Unit Exploration Expenses for the Comparative Periods Presented

($000's unless otherwise stated)	*2005-Q2*	*2004-Q2*	*2005-Half*	*2004-Half*
Drilling [1]	2,365	381	3,030	1,845
Seismic data activity	(46)	417	31	3,041
Other	103	137	221	265
Total exploration expenses	2,437	935	3,282	5,151
Unit exploration expenses per boe *($)*	10.27	3.43	6.57	8.87

[1] Exploration drilling costs are capitalized pending evaluation as to whether sufficient quantities of reserves have been found to justify commercial production. If commercial quantities of reserves are not found, costs of exploration drilling are expensed. All exploratory wells are evaluated for commercial viability within twelve months of completion. Exploration wells that discover potentially-commercial quantities of reserves in areas requiring major expenditures before the commencement of production and where commercial viability requires the drilling of additional exploratory wells, remain capitalized as long as the drilling of the additional exploratory wells is underway or firmly planned.

2005-Q2 vs 2004-Q2
Total exploration expenses were $2.4 million versus $0.9 million. Unit exploration expenses increased by $6.84 or 199%, to $10.27 per boe. The increase was mostly due to higher expenses related to unsuccessful drilling attempts. Costs of two unsuccessful drilling attempts were expensed in 2005-Q2. There were no unsuccessful drilling attempts recognized in 2004-Q2. The expense recognized in 2005-Q2 related to two exploratory wells drilled in 2004 at Cypress/Chowade.

2005-Half vs 2004-Half
Total exploration expenses were $3.3 million versus $5.2 million. Unit exploration expenses decreased by net of $2.30 or 26%, to $6.57 per boe. Seismic data activity decreased by $5.18 per boe and costs associated and unsuccessful drilling attempts increased by $2.90 per boe. The balance of the decrease related to other exploratory costs. The decrease in seismic data activity related to our share of costs spent in 2004-Half on a 44 square-kilometer, 3D proprietary seismic program at Orion. Four unsuccessful drilling attempts were recognized in 2005-Half - two exploratory wells drilled in 2004 at Cypress/Chowade and two development wells at Mantario East. In 2004-Half we expensed costs that related to two other exploratory wells at Cypress/Chowade

General and Administrative Expenses (G&A)

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

($000's unless otherwise stated)	*2005-Q2*	*2004-Q2*	*2005-Half*	*2004-Half*
Cash G&A	741	883	1,602	1,700
Non-cash G&A (stock-based compensation)	148	228	200	268
Total G&A	889	1,111	1,802	1,968
Per boe *($)*	3.75	4.08	3.61	3.39

2005-Q2 vs 2004-Q2
Total G&A expenses, which decreased by 20% to $0.9 million, contain both cash and non-cash items (stock-based compensation being non-cash). Unit G&A costs decreased by $0.33 or 8%, to $3.75 per boe. The majority of this decrease was due to lower professional fees related to engineering and legal, and lower non-cash stock-based compensation.

2005-Half vs 2004-Half
Total G&A expenses were $1.8 milllion versus $2.0 million. Unit G&A expenses increased by $0.22 or 6% to $3.61. This change in unit G&A was mainly caused by a lower production denominator and greater overhead credits earned as operator of properties.

Interest Expense - Net

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

($000's unless otherwise stated)	*2005-Q2*	*2004-Q2*	*2005-Half*	*2004-Half*
Net interest expense	242	128	450	307
Unit net interest expense per boe *($)*	1.02	0.47	0.90	0.53

2005-Q2 vs 2004-Q2
Net interest expense increased by $0.1 million to $0.2 million. The average daily balance of our bank operating facility increased by $8.8 million or 72%, to $20.0 million and the closing balance was $19.8 million. The effective interest rates applicable to our borrowings in 2005-Q2 and 2004-Q2 were 4.6% and 4.2%, respectively.

2005-Half vs 2004-Half
Net interest expense increased by $0.1 million to $0.5 million. The effective interest rates applicable to our borrowings in 2005-Half and 2004-Half were 4.5% and 4.2%, respectively.

Gain on Sale of Oil and Gas Assets

2005-Q2 vs 2004-Q2
During 2005-Q2, we recorded the sale of a gas well that had been shut in since 2004-Q1 as a result of acid-gas contamination by a third party. The sale included the well bore and its associated reserves, hydrocarbon rights and production facilities. Proceeds on the sale were $2.4 million, resulting in a gain of $0.2 million. There were no gains recorded in 2004-Q2.

2005-Half vs 2004-Half
In addition to the gain of $0.2 million discussed above, we recorded a gain on the 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 (Recoveries) Expenses for the Comparative Periods Presented

($000's)	*2005-Q2*	*2004-Q2*	*2005-Half*	*2004-Half*
Income tax (recoveries) expenses				
Current	7	(52)	7	(52)
Future	(477)	464	(282)	(322)
Total	(470)	412	(275)	(374)

2005-Q2 vs 2004-Q2 and 2005-Half vs 2004-Half

Total income taxes of $0.5 million were recovered in 2005-Q2 compared to $0.4 million expensed in 2004-Q2. In 2005-Half income taxes of $0.3 million were recovered compared to $0.4 million recovered in 2004-Half.

The above amounts were consistent with our pre-tax earnings. Our income tax recovery in 2004-Half reflects declining future income tax rates, and the deductibility/non-deductibility of resource allowances and crown payments respectively.

Our effective tax rate for 2005-Half was 59.8%.

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 June 30, 2005, we incurred approximately 87% of the qualifying expenditures.

Summary of Quarterly Results

Summary of Results for Eight Most Recently Completed Quarters

	2005 Q2	*2005 Q1*	*2004 Q4*	*2004 Q3*	*2004 Q2*	*2004 Q1*	*2003 Q4*	*2003 Q3*
Revenue	8,971	9,715	9,822	9,689	10,320	10,975	9,636	11,980
Net (loss) earnings	(1,397)	797	(11,528)	(378)	413	(788)	(781)	965
Net (loss) earnings per share								
basic	(0.06)	0.03	(0.49)	(0.01)	0.02	(0.04)	(0.04)	0.04
diluted	(0.06)	0.03	(0.49)	(0.01)	0.02	(0.03)	(0.04)	0.04

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 Q2	*2005 Q1*	*2004 Q4*	*2004 Q3*	*2004 Q2*	*2004 Q1*	*2003 Q4*	*2003 Q3*
Total production *(mboe)*	237	262	256	265	273	308	305	353
Daily average production rates:								
Natural gas *(mcf/d)*	7,602	9,396	11,073	13,404	13,881	14,580	14,010	14,292
Natural gas liquids *(bbl/d)*	429	517	554	538	512	684	724	707
Light/medium crude oil *(bbl/d)*	90	137	145	111	170	273	253	742
Heavy crude oil *(bbl/d)*	821	690	242	–	–	–	–	–
Weighted average commodity prices:								
Natural gas *($/mcf)*	7.68	7.05	6.70	6.51	6.90	6.56	5.73	5.80
Natural gas liquids *($/boe)*	35.77	31.35	33.25	32.85	28.25	26.99	25.58	26.17
Light/medium crude oil *($/boe)*	66.62	58.31	57.14	55.02	49.57	44.30	36.94	40.53
Heavy crude oil *($/boe)*	29.84	24.36	21.07	–	–	–	–	–
A&D expense	2,734	3,675	14,863	3,467	2,812	3,040	4,550	3,396
Exploration expenses [1]	2,437	845	7,850	1,400	935	4,215	1,552	565

(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.

2005-Q2 – Details are included in earlier sections of this Management's Discussion and Analysis.

2005-Q1 – Revenue of $9.7 million reflected slightly higher production but lower revenues due to a change in sales mix. Production of lower-priced heavy crude oil from Mantario East increased, countering natural production declines from Alberta properties. Net earnings were $0.8 million after accounting for decreased exploration expenses and the return of A&D expense to more historical levels. Exploration expenses recognized related to two development wells at Mantario East that were less costly to drill. Income tax increased in 2005-Q1 over 2004-Q4 due to the recovery in 2004-Q4 of $6.9 million associated with the $11.5 million loss.

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.

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-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-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.

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.

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.

OUTLOOK FOR 2005

On July 21, 2005, subsequent to the close of 2005-Q2, we announced a material change to corporate affairs that is expected to significantly alter our business plans for the remainder of Fiscal 2005. Details of the announcement are provided under the heading, "Subsequent Events", in the Executive Overview and in the notes to our financial statements. Further details of the announcement are provided on our website at www.dynamicoil.com.

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

Our capital resources at the end of 2005-Q2 consisted of cash flow from operations and available lines of bank credit.

For the remainder of Fiscal 2005, our sources and uses of cash are expected to reflect the effect of the anticipated material transaction discussed above under Outlook For 2005.

Financing activities – As at June 30, 2005, our revolving, demand bank loan facility was $25.0 million, of which $19.8 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 operating activities, the amount of our capital investment program, the timing of incurred field activities, and external sources of financing.

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.

Unaudited Financial Statements

Notice to Reader

The accompanying financial statements of Dynamic Oil & Gas, Inc., comprised of the Balance Sheets as at June 30, 2005 and December 31, 2004, and the Interim Statements of Earnings and Cash Flows for the three and six-month periods ended June 30, 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)

	June 30 2005 $	*December 31 2004 $*
ASSETS		
Current		
Accounts receivable	9,103,989	7,565,975
Income taxes receivable	617,839	541,487
Prepaid expenses	456,179	361,277
Deferred costs *[note 4]*	370,089	-
Total current assets	10,548,096	8,468,739
Natural gas and oil interests	52,553,857	56,726,494
Capital assets	403,971	414,913
Future income tax asset	-	2,082,092
	63,505,924	67,692,238
LIABILITIES & SHAREHOLDERS' EQUITY		
Current Liabilities		
Bank indebtedness	1,660,309	1,083,000
Operating loan	19,800,000	15,550,000
Accounts payable and accrued liabilities	10,505,025	17,348,723
Total current liabilities	31,965,334	33,981,723
Asset retirement obligations	2,734,604	2,555,756
Future income tax liability	1,595,630	-
Total liabilities	36,295,568	36,537,479
Share capital *[note 2]*	35,892,565	39,852,368
Contributed surplus *[note 3]*	958,049	757,689
Deficit	(9,640,258)	(9,455,298)
Total shareholders' equity	27,210,356	31,154,759
	63,505,924	67,692,238

Wayne Babcock
Director

Donald Umbach
Director

STATEMENTS OF OPERATIONS AND (DEFICIT) RETAINED EARNINGS

(unaudited)

(In Canadian dollars)

	Three Months Ended June 30 2005 $	*Three Months Ended June 30 2004 $*	*Six Months Ended June 30 2005 $*	*Six Months Ended June 30 2004 $*
REVENUES				
Natural gas, liquids and oil sales	8,971,461	10,320,100	18,686,528	21,295,178
Royalties	(2,061,153)	(2,346,072)	(3,920,738)	(4,818,977)
Provincial royalty credits	28,514	24,811	217,928	80,118
	6,938,822	7,998,839	(14,983,718)	16,556,319
EXPENSES				
Production costs	2,204,543	2,162,046	4,074,744	3,975,064
Amortization and depletion	2,734,952	2,811,594	6,410,189	5,852,019
Exploration expenses	2,437,404	935,052	3,281,923	5,150,516
General and administrative	888,499	1,111,147	1,801,541	1,968,464
Interest expense - net	242,365	127,803	450,251	306,606
Accretion of asset retirement obligations *[note 2]*	43,921	26,367	86,305	52,297
Gain on sale of oil and gas assets	(160,806)	–	(660,806)	–
	8,390,878	7,174,009	15,444,147	17,304,966
(Loss) earnings before taxes	(1,452,056)	824,830	(460,429)	(748,647)
Income tax (recovery) expense				
- Current	6,612	(51,730)	6,612	(51,730)
- Future	(476,604)	463,598	(282,081)	(321,531)
Net (loss) earnings	(982,064)	412,962	(184,960)	(375,386)
(Deficit) retained earnings beginning of period	(8,658,194)	2,036,963	(9,455,298)	2,825,311
(Deficit) retained earnings end of period	(9,640,258)	2,449,925	(9,640,258)	2,449,925
Net (loss) earnings per share				
basic	(0.04)	0.02	(0.01)	(0.02)
diluted	(0.04)	0.02	(0.01)	(0.02)

STATEMENTS OF CASH FLOWS

(unaudited)

(In Canadian dollars)

	Three Months Ended June 30 2005 $	*Three Months Ended June 30 2004 $*	*Six Months Ended June 30 2005 $*	*Six Months Ended June 30 2004 $*
OPERATING ACTIVITIES				
Net (loss) earnings	(982,064)	412,962	(184,960)	(375,386)
Add (deduct) items not involving cash:				
Amortization and depletion	2,734,952	2,811,594	6,410,189	5,852,019
Stock-based compensation	148,239	227,567	200,360	267,734
Accretion of asset retirement obligations	43,921	26,367	86,305	52,297
Future income tax (recovery) expense	(476,604)	463,598	(282,081)	(321,531)
Exploration expenses	2,437,404	935,052	3,281,923	5,150,516
Gain on sale of gas and oil interests	(160,806)	–	(660,806)	–
Changes in non-cash working capital	(9,706)	(228,143)	(1,066,732)	(6,361,400)
	(3,754,748)	4,648,997	(7,784,198)	4,264,249
FINANCING ACTIVITIES				
Bank indebtedness	(514,642)	132,436	577,309	(229,054)
Operating loan	575,000	(6,875,000)	4,250,000	(4,575,000)
Shares issued for cash	–	11,804,991	–	11,832,524
	60,358	5,062,427	4,827,309	7,028,470
INVESTING ACTIVITIES				
Capital investment and exploration expenditures	(550,865)	(5,364,038)	(7,508,360)	(17,973,349)
Purchase of capital assets	(119,344)	(56,213)	(143,740)	(71,312)
Settlement of asset retirement obligations	(1,916)	–	(9,335)	–
Proceeds on sale of gas and oil interests	2,406,250	–	2,906,250	–
Changes in non-cash working capital	5,549,232	(4,291,173)	(7,856,322)	6,751,942
	(3,815,107)	(9,711,424)	(12,611,507)	(11,292,719)
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				
Cash paid during the period for:				
Interest	244,184	133,952	457,447	310,394
Income taxes	6,612	602,805	82,964	669,416

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 and six-month periods ended June 30, 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 (Deficit) 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 Six Months Ended June 30 2005 #	*For the Six Months Ended June 30 2005 $*	*For the Year Ended December 31 2004 #*	*For the Year Ended December 31 2004 $*
Outstanding, beginning of period	24,558,978	39,852,368	22,194,778	27,747,487
Shares issued on the exercise of stock options	–	–	84,200	167,450
Shares issued on flow-through private placements	–	–	2,000,000	10,752,216
Recognition of future income taxes related to flow-through [1]	–	(3,959,803)	–	–
Shares issued on private placements	–	–	280,000	1,185,215
Outstanding, end of period	24,558,978	35,892,565	24,558,978	39,852,368

[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 June 30, 2005, the Company had incurred approximately 87% of the qualifying expenditures and committed another 13% 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.

($ unless otherwise stated)	*Three Months Ended June 30 2005*	*Three Months Ended June 30 2004*	*Six Months Ended June 30 2005*	*Six Months Ended June 30 2004*
Numerator:				
Net (loss) earnings per period	(982,064)	412,962	(184,960)	(375,386)
Denominator:				
Weighted average number of common shares outstanding	24,558,978	23,279,033	24,558,978	22,741,309
Effect of dilutive stock options	–	567,612	–	588,840
Basic (loss) earnings per share	(0.04)	0.02	(0.01)	(0.02)
Diluted (loss) earnings per share	(0.04)	0.02	(0.01)	(0.02)

[c] Options Outstanding

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

	For the Six Months Ended June 30, 2005		*For the Year Ended December 31, 2004*	
	Number of Shares Under Option #	*Weighted Average Exercise Price $*	*Number of Shares Under Option #*	*Weighted Average Exercise Price $*
Outstanding, beginning of period	1,768,300	2.86	1,615,834	2.61
Granted	110,000	2.48	285,000	4.03
Exercised	-	-	(84,200)	1.99
Forfeited	-	-	(48,334)	3.00
Outstanding, end of period	1,878,300	2.84	1,768,300	2.86
Options exercisable at period end	1,579,633	2.59	1,371,300	2.64

Options outstanding as at June 30, 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 six-month periods ended June 30, 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 (loss) earnings and a corresponding increase to contributed surplus of $200,360 and $267,737, respectively [for the three-month periods ended June 30, 2005 and 2004 - $148,239 and $227,567, 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 (loss) earnings and net (loss) earnings per common share had the Company applied the fair-value based method for all stock options outstanding:

	Three Months Ended June 30 2005 $	*Three Months Ended June 30 2004 $*	*Six Months Ended June 30 2005 $*	*Six Months Ended June 30 2004 $*
Net (loss) earnings:				
As reported	(982,064)	412,962	(184,960)	(375,386)
Pro forma	(1,130,303)	387,789	(385,320)	(425,732)
Basic (loss) earnings per common share:				
As reported	(0.04)	0.02	(0.01)	(0.02)
Pro forma	(0.05)	0.02	(0.02)	(0.02)
Diluted (loss) earnings per common share:				
As reported	(0.04)	0.02	(0.01)	(0.02)
Pro forma	(0.05)	0.02	(0.02)	(0.02)

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	*2005*	*2004*	*2003*
Dividend yield	0%	0%	0%
Expected volatility	47%	47%	51%
Risk-free interest rate	4.25%	4.25%	4.00%
Expected lives	3 years	3 years	3 years

Note 4. Subsequent Events

[a] Subsequent to the period ended June 30, 2005, the Company concluded that previously capitalized costs associated with the drilling of three exploration wells should be recorded as exploration expense. In aggregate, the wells have an estimated net carrying value of $6,343,126. Also subsequent to June 30, 2005, the Company recorded a gain on sale of $600,000 in respect of one of the three wellbores above that was sold to a third party. The Company retained full hydrocarbon interests associated with the lands on which the sold wellbore was located.

[b] On July 21, 2005, the Company announced that it had entered into agreements whereby Sequoia Oil & Gas Trust ("Sequoia") of Calgary, Alberta will acquire all of the Company's Alberta oil and natural gas assets, and whereby the Company will reorganize all of its British Columbia and Saskatchewan oil and natural gas assets into a new exploration company (the "Transaction"). The Transaction will be completed by way of a Plan of Arrangement (the "Plan").

Under the Plan, the Company will establish Shellbridge Oil & Gas, Inc., as a new exploration-focused, Canadian publicly-traded subsidiary, ("Shellbridge") and will transfer into Shellbridge effective May 1, 2005, all of the benefits and obligations of the Company's producing assets and undeveloped lands located in the provinces of British Columbia and Saskatchewan. The Company will retain all of its Alberta properties. Sequoia will purchase all of the outstanding shares of common stock of the Company for a cash payment to the Company's shareholders of $72.9 million less approximately $28.9 million in certain benefits, liabilities and obligations that are being assumed by Sequoia. As a result of the Plan, each of the Company's shareholders of record at closing, will receive $1.71 in cash and one share of Shellbridge for each share they hold of the Company's common stock. Shellbridge will be governed by five of the Company's current Board of Directors, and managed by the Company's current management.

The Plan has the unanimous support of the Company's board and Sequoia's board of directors. The Plan includes a break fee of $2.16 million payable by either party if the Transaction is not completed under certain circumstances. The Company has incurred costs of $370,089 related to the Transaction that have been deferred pending closing of the transaction.

Consummation of the Plan is subject to certain closing conditions including, without limitation, the Company's shareholder approval, judicial determination of fairness, regulatory approval and the conditional listing of Shellbridge shares for trading on the Toronto Stock Exchange (TSX) or the TSX Venture Exchange.

Comparative Figures

Certain of the comparative figures have been reclassified to conform with the presentation adopted in the current period.

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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Registrar and Transfer Agent

CIBC Mellon Trust Company Vancouver, British Columbia

Trading Symbols

TSX : DOL NASDAQ : DYOLF

Regulatory filings website: Canadian: www.sedar.com
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