

Q2

PROGRESS ENERGY LTD.



Progress

2003 QUARTERLY REPORT TO THE SHAREHOLDERS

FOR THE SIX MONTHS ENDED JUNE 30, 2003

PROGRESS REPORTS Q2 RESULTS – DRILLING INVENTORY CONTINUES TO GROW – SHALLOW GAS PROGRAM COMMENCED

HIGHLIGHTS	Three Months Ended		Six Months Ended		
	2003	June 30 2002	2003	June 30 2002	
Financial	<i>(\$ thousands, except per share amounts)</i>				
Gross revenue	22,818	7,905	50,733	14,004	
Cash flow from operations	12,505	4,064	28,585	7,413	
Basic per share	0.40	0.17	0.92	0.32	
Diluted per share	0.37	0.16	0.86	0.30	
Net earnings	6,894	357	13,416	517	
Basic per share	0.22	0.02	0.43	0.02	
Diluted per share	0.21	0.01	0.40	0.02	
Capital expenditures	15,192	4,848	40,669	9,835	
Campion acquisition	-	20,518	-	20,518	
Net debt	57,748	36,980	57,748	36,980	
Operations	Production				
	Crude oil (bbls/d)	2,260	1,591	2,178	1,630
	Natural gas liquids (bbls/d)	284	79	297	60
	Natural gas (mcf/d)	26,873	11,300	26,851	9,700
	Total production (boe/d @ 6:1)	7,022	3,553	6,950	3,307
	Average sales price (after hedging)				
	Crude oil (\$/bbl)	33.90	29.01	37.95	26.83
	Natural gas liquids (\$/bbl)	27.85	31.30	33.66	29.09
	Natural gas (\$/mcf)	6.19	3.38	6.99	3.29
	Netback per boe (6:1) (\$)				
	Petroleum and natural gas sales	35.71	24.45	40.33	23.40
	Royalties	8.15	3.11	9.23	3.36
	Operating expenses	5.46	4.85	5.44	4.62
	Operating netback	22.10	16.49	25.66	15.42

ACCOMPLISHMENTS

- Six successful wells (100percent working interest) drilled late in second quarter.
- Active third quarter drilling confirmed approximately 20 wells planned.
- The number of drill ready opportunities has continued to expand. Drilling inventories exceed one year of activity at the current pace.
- The Company undertook its first shallow gas project at Unity in west central Saskatchewan with sales expected by early-September.
- Undeveloped land inclusive of option lands grew to over 400,000 acres by the end of the quarter.

Progress is listed on the Toronto Stock Exchange, symbol PEX

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SHAREHOLDER UPDATE

EXPLORATION

Traditionally, exploration field activities in western Canada in the second quarter slow in response with the onset of spring weather. This year, an unusually protracted spring resulted in wet field conditions and together with lengthy road bans prevented drilling equipment from operating until very late in the quarter. As a result Progress drilled seven wells and has just commenced completion activities by the end of the quarter. These activities were fully engaged by the start of the third quarter and are planned to continue as such to the end of the year. Of the seven wells drilled in the second quarter, four are potential gas wells, two are cased as oil wells and one was dry and subsequently abandoned resulting in an 86 percent success rate. Of particular note in the second quarter was a Fort St. John Triassic depth exploration test that encountered oil and gas in four separate zones. The Company will have this discovery on production in the third quarter along with the balance of the successful second quarter tests.

Second Quarter Drilling Results

	Gross Wells					Net Wells				
	Gas	Oil	Service	Dry	Total	Gas	Oil	Service	Dry	Total
British Columbia	2	-	-	-	2	2.0	-	-	-	2.0
Alberta	3	-	-	1	4	3.0	-	-	1.0	4.0
Saskatchewan	1	-	-	-	1	1.0	-	-	-	1.0
Total	6	-	-	1	7	6.0	-	-	1.0	7.0

In the second quarter, the exploration group was busy on the crown land front purchasing a dominant contiguous land position in a shallow gas play conceived and tested by the Company in the last quarter of 2002 and into the first quarter of 2003. The Unity Upper Cretaceous shallow gas play is located in west central Saskatchewan covering over forty sections of Company controlled land. Drilling commenced late in the second quarter with one well drilled and the balance of the program, seven wells, drilled in early July. Well completion, tie-in, facilities and sales line construction should all be completed by late August with first gas flowing by early September. It is anticipated that this first phase of the Unity development will deliver between 1,500 to 2,000 mcf per day. A second development phase of 8 to 12 wells will be considered for the fourth quarter. In addition, the Company has acquired a position in a second shallow gas concept elsewhere in Saskatchewan that will be tested in the third quarter of this year.

2003 Year to Date Drilling Results

	Gross Wells					Net Wells				
	Gas	Oil	Service	Dry	Total	Gas	Oil	Service	Dry	Total
British Columbia	7	4	1	1	13	4.9	3.3	0.7	0.7	9.6
Alberta	6	3	-	4	13	6.0	2.7	-	3.1	11.8
Saskatchewan	3	-	-	2	5	3.0	-	-	2.0	5.0
Total	16	7	1	7	31	13.9	6.0	0.7	5.8	26.4

For the balance of the year drilling and seismic activities will be predominantly focused on the major core areas of Fort St. John, the shallow British Columbia foothills and the new shallow gas programs.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis as provided by the management of Progress Energy Ltd. ("Progress" or the "Company") should be read in conjunction with the unaudited consolidated interim financial statements for the three and six months ended June 30, 2003 and 2002 and the audited consolidated financial statements for the year ended December 31, 2002.

For the purposes of calculating unit costs, natural gas has been converted to a barrel equivalent ("BOE") using six thousand cubic feet equal to one barrel unless otherwise stated. This conversion conforms with the Canadian Securities Regulators proposed National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities. Boe's are a very approximate comparative measure that, in some cases, could mislead particularly if used in isolation.

Management's Discussion and Analysis contains the term cash flow from operations, which should not be considered an alternative to, or more meaningful than cash flow from operating activities as determined in accordance with Canadian generally accepted accounting principals ("GAAP") as an indicator of the Company's performance. Progress' determination of cash flow from operations may not be comparable to that reported by other companies. The reconciliation between net earnings and cash flow from operations can be found in the consolidated statements of cash flows in the unaudited interim financial statements. The Company also presents cash flow from operations per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of earnings per share.

PRODUCTION

For the three months ended June 30, 2003, Progress increased production 98 percent to 7,022 boe per day compared to 3,553 boe per day for the same period in 2002. For the six months ended June 30, 2003 production increased 110 percent to 6,950 boe per day compared to 3,307 boe per day for the same period in 2002.

	Three Months Ended June 30		Six Months Ended June 30	
	2003	2002	2003	2002
Daily Production				
Crude oil (<i>bbls/d</i>)	2,260	1,591	2,178	1,630
Natural gas liquids (<i>bbls/d</i>)	284	79	297	60
Natural gas (<i>mcf/d</i>)	26,873	11,300	26,851	9,700
Total (<i>boe/d</i>)	7,022	3,553	6,950	3,307

Crude oil production for the three months ended June 30, 2003 increased 42 percent to 2,260 bbls per day from 1,591 bbls per day for the same period in 2002. For the six months ended June 30, 2003 crude oil production increased 34 percent to 2,178 barrels per day compared to 1,630 in the same period in 2002.

Natural gas liquids production for the three months ended June 30, 2003 increased 259 percent to 284 bbls per day from 79 bbls per day for the same period in 2002. For the six months ended June 30, 2003 oil and liquids production increased 395 percent to 297 barrels per day compared to 60 in the same period in 2002.

Natural gas production increased 138 percent to 26,873 mcf per day during the three months ended June 30, 2003 compared to 11,300 mcf per day for the same period in 2002. For the six months ended June 30, 2003 natural gas production increased 177 percent to 26,851 mcf per day compared to 9,700 mcf per day in the same period in 2002. This increase in natural gas production is due largely to the Campion

acquisition in June 2002, the acquisition of the Fort St. John assets in September 2002 and successful drilling results.

Production during the quarter was impacted by a number of factors including plant turnarounds to two gas processing facilities in British Columbia and wet weather and normal spring breakup conditions which delayed completion and tie in work of first quarter drilling successes. As was disclosed in the Company's first quarter report, natural gas production during the second quarter was impacted by annual planned turnarounds at the Duke MacMahon processing plant that partially curtailed production during the month of May. This turnaround impacted the Company's natural gas production at Fort St. John and its Town/Begg properties in the shallow foothills. The turnaround lasted 18 days and ongoing line pressure problems post start up further impacted production. The Duke Fort Nelson planned turnaround commenced June 23 and continued until July 14 and curtailed production during this period. This turnaround impacted the Company's natural gas production at Milo. The plant turnarounds impacted the quarter's natural gas production by approximately 200 boe per day. At the end of the first quarter the Company had approximately 900 boe per day of behind pipe production awaiting completion or tie-in. Due to wet weather during the second quarter and late road ban removals in British Columbia completion of these projects have been delayed. Of these projects, two in British Columbia were completed in late June and on production in early July contributing approximately 300 bbls per day of crude oil production. The balance of the completion and tie-ins will be completed by late August.

COMMODITY MARKETS

During the second quarter, crude oil prices subsided somewhat from the first quarter highs of WTI US\$33.86 to average US\$28.90 per barrel. While the WTI futures curve remains steeply backwardated, the front month is trading in the US\$29.00 to US\$30.00 per barrel range with the outer months falling within OPEC's desired basket price range well into 2004. North American crude oil inventories continue to be well below historic levels and have failed to build substantially since the end of the Iraq war. Supply interruptions from both OPEC and non-OPEC nations have resulted in supply being below targeted levels. It seems unlikely that inventories will reach normal levels before the end of the year thereby supporting WTI prices.

Storage continues to be the lead story in North American natural gas markets. The United States year over year storage deficit is 502 Bcf which after five recent weeks of historically high injections, storage levels remains 146 Bcf below the seven year average. This steady demand for storage injection gas helped keep Alberta natural gas prices at \$6.50 per GJ on average for the second quarter. As we move forward lower than expected supply from U.S. and Canadian production sources are starting to raise concerns as demand remains fairly robust even with fuel switching occurring and an economic downturn underway. Although somewhat lower than the first half of the years price, the AECO forward price remains strong and is averaging around \$5.50 per GJ for the remainder of 2003.

COMMODITY PRICING

For the three and six months ended June 30, 2003, Progress realized the following commodity prices compared to the same period in 2002.

Progress Average Realized Prices	Three Months Ended June 30		Six Months Ended June 30	
	2003	2002	2003	2002
Crude oil (before hedging) (\$/bbl)	34.60	34.11	39.97	29.96
Hedging settlements (\$/bbl)	-	(5.10)	(3.00)	(2.98)
Amortization of hedge premiums (\$/bbl)	(0.70)	-	0.03	(0.15)
Change in fair value of financial instrument (\$/bbl)	-	-	0.95	-
Crude oil (after hedging) (\$/bbl)	33.90	29.01	37.95	26.83

Natural gas (before hedging) (\$/mcf)	6.15	3.33	6.92	3.26
Hedging settlements (\$/mcf)	0.05	-	0.07	-
Amortization of hedge premiums (\$/mcf)	(0.09)	-	(0.09)	-
Amortization of commodity sales contract (\$/mcf)	0.08	0.05	0.09	0.03
Natural gas (after hedging) (\$/mcf)	6.19	3.38	6.99	3.29
<hr/>				
Natural gas liquids (\$/bbl)	27.85	31.30	33.66	29.09

The commodity prices recorded above for the three months ended June 30, 2003 were reduced for the effects of commodity price hedging charges of \$0.3 million (\$0.7 million in 2002) and increased due to the amortization of a commodity sales contract of \$0.2 million (\$0.1 million in 2002). For the six months ended June 30, 2003, commodity price hedging charges were \$0.9 million (\$0.9 million in 2002) and the amortization of a commodity sales contract was \$0.4 million (\$0.1 million in 2002).

For detailed disclosure of Progress' hedging transactions refer to Note 6, Financial Instruments in the Consolidated Financial Statements.

REVENUES

For the three months ended June 30, 2003, revenues increased 189 percent to \$22.8 million from \$7.9 million for the same period in 2002 due largely to higher production volumes. During the six months ended June 30, 2003, revenues increased 262 percent to \$50.7 million from \$14.0 million for the same period in 2002. This increase resulted from the higher production and commodity prices received during the period. During the three months ended June 30, 2003 crude oil prices increased 17 percent to \$33.90 per bbl (after the effects of hedging charges) from \$29.01 per bbl compared to the same period in 2002, natural gas liquids prices decreased 11 percent to \$27.85 per bbl from \$31.30 per bbl compared to the same period in 2002, while natural gas prices increased 83 percent to \$6.19 per mcf from \$3.38 per mcf. For the six months ended June 30, 2003 crude oil prices decreased 41 percent to \$37.95 per bbl (after the effects of hedging charges) from \$26.83 per bbl compared to the same period in 2002, natural gas liquids prices increased 16 percent to \$33.66 per bbl (after the effects of hedging charges) from \$29.09 per bbl compared to the same period in 2002, while natural gas prices increased 112 percent to \$6.99 per mcf from \$3.29 per mcf.

ROYALTIES

For the three months ended June 30, 2003, royalties increased 420 percent to \$5.2 million from \$1.0 million for the same period in 2002. For the six months ended June 30, 2003, royalties increased 480 percent to \$11.6 million from \$2.0 million for the same period in 2002. The increase is due to higher commodity prices and a \$0.5 million crown reimbursement recorded in 2002. The Company's average royalty rate for the three months ended June 30, 2003 was 22.8 percent (after removing the effects of hedging charges) compared to 17.4 percent in 2002 (after removing the effects of hedging charges and the crown reimbursement) and for the six months ended June 30, 2003 was 22.7 percent compared to 16.8 percent in 2002.

OPERATING EXPENSES

Operating expenses increased 119 percent to \$3.5 million during the three months ended June 30, 2003 compared to \$1.6 million during the same period in 2002. For the six months ended June 30, 2003 operating expenses increased 143 percent to \$6.8 million compared to \$2.8 million during the same period in 2002. On a boe basis, the second quarter operating costs increased 13 percent to \$5.46 per boe from \$4.85 per boe for the same period in 2002, while year to date operating expenses increased 18 percent to \$5.44 per boe from \$4.62 per boe. Operating costs per boe during the quarter were adversely impacted by production downtime in British Columbia. The Company is currently forecasting operating costs between \$5.25 and \$5.50 per boe for the year. The Company is focused on reducing operating costs going forward.

GENERAL AND ADMINISTRATIVE EXPENSES

During the second quarter of 2003, net general and administrative expenses were \$0.7 million, which is comparable to the same period in 2002. For the six months ended June 30, 2003, net general and administrative expenses increased to \$1.5 million from \$1.0 million. The increase resulted mainly from the increase in full-time and contract staff required as a result of the increased size of the Company's operations. On a boe basis, the second quarter net general and administrative expenses decreased 50 percent to \$1.06 per boe from \$2.12 per boe, while year to date net general and administrative expenses decreased 26 percent to \$1.22 per boe from \$1.65 per boe.

INTEREST

Financing charges for the three months ended June 30, 2003 increased to \$0.6 million compared to \$0.4 million during the same period in 2002. For the six months ended June 30, 2003 financing charges increased to \$1.0 million compared to \$0.5 million during the same period in 2002. This increase is a result of higher average debt during the period compared to 2002 somewhat offset by lower average interest rates.

INCOME AND CAPITAL TAXES

During the second quarter of 2003, capital taxes were \$0.2 million which is comparable to the same period in 2002 and for the six months ended June 30, 2003 increased to \$0.4 million from \$0.3 million in 2002. This increase in capital taxes is due to the increase in size of the Company.

The provision for future income taxes for the three months ended June 30, 2003 resulted in a recovery of \$0.1 million compared to a charge of \$0.4 million in same period in 2002. For the six months ended June 30, 2003 the provision for future taxes was a charge \$4.5 million compared to \$0.6 million in 2002. Included in the 2003 amounts is a benefit of \$3.3 million related to substantively enacted changes to the federal income tax rate and deductions for resource income. The changes will reduce the rate on resource income by seven percent, provide for the deduction of crown royalties and eliminate the resource allowance and will be phased in over a five year period. In addition, a benefit of \$0.2 million was recorded related to a 0.5 percent reduction to the Alberta income tax rate. The effective tax rate (excluding capital taxes) for the three months ended June 30, 2003 was (11) percent and 21 percent for the six months ended June 30, 2003, this compares to 41 percent and 44 percent during the corresponding periods in 2002.

Based on the Company's forecast for 2003, Progress does not anticipate that it will pay any current income taxes during the year.

DEPLETION AND DEPRECIATION

For the three months ended June 30, 2003 depletion and depreciation, which includes the provision for site restoration and abandonment increased 74 percent to \$5.9 million from \$3.4 million for the same period in 2002. For the six months ended June 30, 2003, depletion and depreciation increased 83 percent to \$11.5 million from \$6.3 million for the same period in 2002. The increase for both the three and six month periods is largely due to increased production. On a boe basis, depletion and depreciation for the three months ended June 30, 2003 decreased to \$9.24 from \$10.49 in 2002 and to \$9.12 from \$10.55 for the six months ended June 30, 2003. The decrease in boe depletion charges is a result of lower cost of reserve additions during the latter part of 2002 and during the first half of 2003.

NET EARNINGS AND CASH FLOW FROM OPERATIONS

	Three Months Ended		Six Months Ended	
	2003	June 30 2002	2003	June 30 2002
Net Earnings	6,894	357	13,416	517
Basic per share	0.22	0.02	0.43	0.02
Diluted per share	0.21	0.01	0.40	0.02
Cash flow from operations	12,505	4,064	28,585	7,413
Basic per share	0.40	0.17	0.92	0.32
Diluted per share	0.37	0.16	0.86	0.30

CAPITAL EXPENDITURES

During the six months ended June 30, 2003 the Company spent approximately \$40.7 million in capital expenditures.

(\$ Thousands)	Three Months Ended		Six Months Ended	
	2003	June 30 2002	2003	June 30 2002
Land acquisitions and retention	3,884	1,218	6,878	1,642
Geological and geophysical	864	287	4,042	762
Drilling and completions	6,586	2,018	19,339	4,389
Equipping and facilities	2,869	935	8,215	2,441
Net property acquisitions (dispositions)	926	65	2,016	139
Other	63	325	179	462
Total capital expenditures (before Campion)	15,192	4,848	40,669	9,835

The British Columbia government recently announced incentive programs to promote all season oil and gas activities in the province. Of particular importance to Progress is the summer drilling incentive which is effective for wells drilled between July 1 and November 30 of each year from July 2003 until November 2005. The incentive amount is the lesser of \$100,000 or 10 percent of the drilling and completion costs of each well.

LIQUIDITY AND CAPITAL RESOURCES

At June 30, 2003 the Company had outstanding on its credit facility approximately \$52.6 million, a working capital deficiency of \$5.1 million, totaling \$57.7 million of total net debt. The Company had a credit facility of \$75 million at June 30, 2003. Subsequent to the end of the quarter the Company has added a second bank to its lending group.

	June 30, 2003	December 31, 2002
Net debt (\$ Thousands)		
Working capital deficiency	5,142	3,933
Bank debt	52,606	43,386
	57,748	47,319

The Company's investing activities which consisted primarily of expenditures on the capital program for 2003 has been funded primarily with cash flow and additional net debt. The issuance of equity during the period was from the exercise of employee stock options.

(\$ thousands)	Three Months Ended		Six Months Ended	
	2003	June 30 2002	2003	June 30 2002
Investment Program Funding				
Cash flow from operations	12,505	4,064	28,585	7,413
Changes in non-cash working capital	(9,516)	(10,154)	(1,364)	(6,804)
Bank debt	10,947	11,627	9,220	9,384
Issue of shares (net of share issue costs)	1,259	42	1,319	573
Cash position, beginning of period	-	-	2,946	-
	15,195	5,579	40,706	10,566

OUTLOOK

The success of Progress's drilling program to date has contributed to the significant increase in future prospect inventory as well as providing the basis of production growth for the balance of 2003.

Looking forward, effective allocation of capital will continue to be the primary goal of the Company. This year exploration and development drilling has attracted the majority of capital spending due to the depth of internally generated prospect inventory on lands acquired during 2002. Large acquisitions during 2003 seem unlikely due to differing views on value between earnings focused buyers and potential sellers.

Within the balance of this year's drilling program the Company has allocated increasing effort and capital towards the Fort St. John, British Columbia area, exploring for and exploiting multi well pools. This project area has provided solid results to date and is less competitive than the areas of Alberta that the Company is active in.

The second half of 2003 will be important for Progress as the Company moves to a larger investment in long life natural gas. The base assets owned when Progress was recapitalized in late 2001 are being harvested with approximately 80 percent of cash flow allocated to the creation of the central Alberta and Fort St. John project areas. The Company is now leveraging increased cash flow and its momentum to pursue long life gas in the shallow foothills of British Columbia and Unity in western Saskatchewan. These programs will continue through 2004 and will provide balance to Progress's portfolio of projects

The remainder of 2003 will see 34 to 39 wells drilled with 15 in British Columbia, 15 to 20 at Unity and four in Alberta. Construction projects which were delayed during the second quarter due to extreme wet weather are now underway and firm plans for the first quarter of 2004 are nearing completion with well licensing and rig scheduling in full swing.

On behalf of the Board of Directors,

(Signed) "David D. Johnson"

David D. Johnson
 President & Chief Executive Officer
 July 31, 2003

Forward Looking Statements – Certain information regarding Progress Energy Ltd. set forth in this document, including management's assessment of Progress Energy Ltd.'s future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. These forward-looking statements are subject to numerous risks and uncertainties, certain of which are beyond Progress Energy Ltd.'s control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, current fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Progress Energy Ltd.'s actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that Progress Energy Ltd. will derive therefrom.

PROGRESS ENERGY LTD
CONSOLIDATED BALANCE SHEETS

<i>(\$ Thousands)</i>	June 30, 2003	December 31, 2002
	(Unaudited)	(Audited)
ASSETS		
Current		
Cash and short-term investments	-	2,946
Accounts receivable	16,446	13,519
Prepaid expenses and deposits	3,105	2,833
	19,551	19,298
Property, plant and equipment	188,694	158,665
Goodwill	9,000	9,000
	217,245	186,963
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	24,693	23,231
Bank debt <i>(Note 2)</i>	52,606	43,386
Commodity sales contracts <i>(Note 6)</i>	3,260	3,694
Site restoration and abandonment	3,374	2,574
Future income taxes <i>(Note 4)</i>	29,024	24,525
	112,957	97,410
SHAREHOLDERS' EQUITY		
Share capital <i>(Note 3)</i>	76,072	74,753
Retained earnings	28,216	14,800
	104,288	89,553
	217,245	186,963

See accompanying notes to the consolidated financial statements

PROGRESS ENERGY LTD.
CONSOLIDATED STATEMENTS OF EARNINGS AND RETAINED EARNINGS
(Unaudited)

	Three Months Ended		Six Months Ended	
	June 30		June 30	
<i>(\$ Thousands, except per share amounts)</i>	2003	2002	2003	2002
REVENUES				
Petroleum and natural gas	22,818	7,905	50,733	14,004
Royalties (net of Alberta Royalty Tax Credit)	(5,208)	(1,006)	(11,616)	(2,012)
	17,610	6,899	39,117	11,992
EXPENSES				
Operating	3,488	1,568	6,843	2,762
General and administrative	675	686	1,536	988
Financing charges	553	367	971	503
Depletion and depreciation	5,904	3,390	11,477	6,312
	10,620	6,011	20,827	10,565
Earnings before taxes	6,990	888	18,290	1,427
TAXES				
Capital taxes	186	163	375	275
Future income taxes (recovery) <i>(Note 4)</i>	(90)	368	4,499	635
	96	531	4,874	910
NET EARNINGS	6,894	357	13,416	517
Retained earnings, beginning of period	21,322	11,516	14,800	11,356
Retained earnings, end of period	28,216	11,873	28,216	11,873
NET EARNINGS PER SHARE <i>(Note 3)</i>				
Basic	0.22	0.02	0.43	0.02
Diluted	0.21	0.01	0.40	0.02

See accompanying notes to the consolidated financial statements

PROGRESS ENERGY LTD.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended		Six Months Ended	
	June 30		June 30	
<i>(\$ Thousands, except per share amounts)</i>	2003	2002	2003	2002
Cash provided by (used in)				
Operations				
Net earnings	6,894	357	13,416	517
Depletion and depreciation	5,904	3,390	11,477	6,312
Amortization of commodity sales contract	(203)	(51)	(434)	(51)
Change in fair value of financial instrument	-	-	(373)	-
Future income taxes	(90)	368	4,499	635
Cash flow from operations	12,505	4,064	28,585	7,413
Changes in non-cash working capital <i>(Note 5)</i>	(591)	(680)	14	(1,800)
	11,914	3,384	28,599	5,613
Financing				
Increase in bank debt	10,947	11,627	9,220	9,384
Issue of shares	1,259	197	1,319	738
Share issue costs	-	(155)	-	(165)
	12,206	11,669	10,539	9,957
Investing				
Corporate acquisition	-	(599)	-	(599)
Capital asset additions	(15,192)	(4,848)	(40,669)	(9,835)
Site restoration and abandonment expenditures	(3)	(132)	(37)	(132)
Change in non-cash working capital <i>(Note 5)</i>	(8,925)	(9,474)	(1,378)	(5,004)
	(24,120)	(15,053)	(42,084)	(15,570)
Increase (decrease) in cash	-	-	(2,946)	-
Cash, beginning of period	-	-	2,946	-
Cash, end of period	-	-	-	-

See accompanying notes to the consolidated financial statements

PROGRESS ENERGY LTD.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. ACCOUNTING POLICIES

The interim consolidated financial statements of Progress Energy Ltd. (the “Company”) have been prepared following the same accounting policies and methods of computation as the consolidated financial statements of the Company for the year ended December 31, 2002. The disclosures provided below are incremental to those included with the annual consolidated financial statements and certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. These interim consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto in the Company’s annual report for the year ended December 31, 2002.

Progress Energy Ltd. is involved in the exploration, development and production of petroleum and natural gas in British Columbia, Alberta, Saskatchewan and Manitoba. The consolidated financial statements include the accounts of the Company, its wholly owned subsidiaries and partnership. The consolidated financial statements are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles.

2. BANK DEBT

<i>(\$ thousands)</i>	June 30, 2003	December 31, 2002
Direct advances	4,757	-
Banker’s acceptances	47,849	43,386
Total bank debt	52,606	43,386

The Company has a revolving term credit facility available up to \$75 million with a Canadian bank. The facility is available on a revolving basis for a period of 364 days until May 31, 2004. On May 31, 2004, at the Company’s discretion, the facility is available on a non-revolving basis for a one year term until May 31, 2005, at which time the facility would be due and payable. Alternatively the facility may be extended for a further 364 day period at the request of the Company and subject to approval by the bank. The credit facility is secured by a \$150 million fixed and floating charge debenture on the assets of the Company. The \$75 million borrowing base is subject to a semi-annual and annual review by the bank.

3. SHARE CAPITAL

<i>(\$ thousands – except share amounts)</i>	Six Months Ended June 30			
	2003		2002	
	Number	Amount	Number	Amount
Common Shares				
Balance at beginning of period	30,911,781	74,477	22,087,398	29,332
Issued on exercise of stock options	408,562	1,319	592,500	738
Shares issued on the acquisition of Campion Resources Ltd.	-	-	3,634,770	19,919
Share issue expense		-		(94)
Balance at June 30	31,320,343	75,796	26,314,668	49,895

Warrants				
Balance at June 30	1,253,498	276	1,253,498	276
Total share capital		76,072		50,171

As at July 30, 2003 the issued and outstanding common shares of the Company were 31,322,510, options outstanding were 2,677,521 and warrants outstanding of 1,253,498.

Earnings per share

The following table summarizes the common shares used in calculating net earnings per common share.

Weighted Average Common Shares	Three Months Ended June 30		Six Months Ended June 30	
	2003	2002	2003	2002
Basic	31,104,380	23,728,124	31,013,915	23,092,231
Diluted	33,400,838	25,289,785	33,274,760	24,607,544

The reconciling items between the basic and diluted average common shares are outstanding stock options and warrants.

Stock options

The following table sets forth a reconciliation of the stock option plan activity through to June 30, 2003.

<i>(\$ except share amounts)</i>	Number of options	Weighted average exercise price
Balance, December 31, 2002	2,818,750	4.21
Granted	269,500	8.51
Exercised	(408,562)	3.23
Balance, June 30, 2003	2,679,688	4.79

The Company accounts for its stock based compensation plan using the intrinsic-value method. Under this method, no costs are recognized in the financial statements for share options granted to employees or directors when the options are issued at market value. Canadian generally accepted accounting principles require disclosure of the impact on net earnings had the fair value method been used for stock options issued on or after January 1, 2002. If the fair value method had been used, the Company's net earnings and net earnings per share for the three and six months ended June 30, 2003 and 2002 would approximate the following pro forma amounts:

	Three Months Ended June 30		Six Months Ended June 30	
	2003	2002	2003	2002
Net Earnings:				
As reported	6,894	357	13,416	517
Pro forma	6,373	283	12,895	435
Net Earnings per Share:				
Basic				
As reported	0.22	0.02	0.43	0.02
Pro forma	0.20	0.01	0.42	0.02

Diluted				
As reported	0.21	0.01	0.40	0.02
Pro forma	0.19	0.01	0.39	0.02

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions and resulting values for grants as follows:

Assumptions	Three Months Ended June 30		Six Months Ended June 30	
	2003	2002	2003	2002
Risk free interest rate (%)	4.01	4.90	4.03	4.89
Expected life (years)	4.00	4.00	4.00	4.00
Expected volatility (%)	33.15	28.41	33.13	27.61
Results				
Weighted average fair value of options granted (\$)	2.81	1.57	2.74	1.61

4. TAXES

The provision for future income taxes for the three and six months ended June 30, 2003 includes a liability reduction of \$3.3 million related to substantively enacted changes to the federal income tax rate and deductions for resource income, as well as a liability reduction of \$0.2 million due to a 0.5 percent reduction to the Alberta income tax rate.

5. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

(\$ thousands)	Three Months Ended June 30		Six Months Ended June 30	
	2003	2002	2003	2002
Accounts receivable	725	300	(2,927)	(3,831)
Prepaid expenses and deposits	(609)	(119)	(272)	(179)
Accounts payable and accrued liabilities	(9,632)	(10,335)	1,835	(2,794)
Change in non-cash working capital	(9,516)	(10,154)	(1,364)	(6,804)
Relating to:				
Investing activities	(8,925)	(9,474)	(1,378)	(5,004)
Operating activities	(591)	(680)	14	(1,800)

Cash interest and taxes paid

(\$ thousands)	Three Months Ended June 30		Six Months Ended June 30	
	2003	2002	2003	2002
Cash interest paid	403	381	887	687
Cash income and other taxes paid	84	413	140	553

6. FINANCIAL INSTRUMENTS

Commodity Price Contracts

The Company has entered into several derivative financial instruments for both crude oil and natural gas for the purpose of protecting its future earnings and cash flow from operations from the volatility of crude oil and natural gas commodity prices. For the three and six months ended June 30, 2003, the Company's crude oil and natural gas price risk management program had a net cost of \$0.1 million and \$0.5 million respectively (2002 - \$0.7 million and \$0.9 million). Contracts outstanding in respect to financial instruments are as follows:

Contract	Volume	Pricing Point	Strike Price	Cost/ Premium	Term
Crude Oil					
Put option	800 bbls/d	WTI	US\$21.00	US\$1.05/bbl	Jul 01/03 – Sep 30/03
Costless collar (1)	800 bbls/d	WTI	US\$23.00– US\$27.70	n/a	Oct 01/03 – Dec 31/03
Natural Gas					
Put option	3,000 mmbtu/d	SUMAS	US\$3.30	US\$0.215/ mmbtu	Apr 01/03 – Oct 31/03
Put option	5,000 gj/d	AECO	CDN\$4.00	CDN\$0.265/gj	Apr 01/03 – Oct 31/03
Costless collar (1)	5,000 gj/d	AECO	CDN\$4.00– CDN\$6.62	n/a	Apr 01/03 – Oct 31/03
Costless collar (1)	2,000 gj/d	AECO	CDN\$5.00– CDN\$8.00	n/a	Jul 01/03 – Oct 31/03
Costless collar (1)	5,000 gj/d	AECO	CDN\$5.75– CDN\$8.00	n/a	Jun 01/03 – Oct 31/03

(1) Costless collar strike price indicates minimum floor and maximum ceiling

At June 30, 2003 the estimated fair values of the above financial instruments were as follows:

(\$ thousands)	Receivable (Payable)
Crude oil options	(102)
Natural gas options	166

The above estimated fair values as at June 30, 2003 represent the amounts the Company would receive or pay to terminate the contracts at June 30, 2003. These instruments have no carrying values recorded in the financial statements.

Commodity Sales Contract

The following physical gas sales contract was outstanding at June 30, 2003. This contract was acquired in conjunction with the acquisition of Campion Resources Ltd. on June 3, 2002, at which time the fair value of the contracts was a liability of \$4.1 million. This value was recorded as a liability on June 3, 2002, and is being amortized over the life of the contract. At June 30, 2003 the remaining liability was \$3.3 million.

Volume	Pricing Point	Progress Price	Term
1,000 gj/d	AECO	\$1.91/gj in 2002 escalating at 2.5% annually	Jun 1/97 – Oct 31/08

SELECTED QUARTERLY INFORMATION

FINANCIAL HIGHLIGHTS

(\$ thousands except per share amounts)	Three Months Ended					
	2002				2003	
	March 31	June 30	Sept. 30	Dec 31	March 31	June 30
Income Statement						
Petroleum and natural gas sales	6,099	7,905	10,171	21,645	27,915	22,818
Cash flow from operations	3,349	4,064	4,609	11,999	16,080	12,505
Per share - basic	0.15	0.17	0.17	0.39	0.52	0.40
Per share - diluted	0.14	0.16	0.17	0.37	0.49	0.37
Net earnings	160	357	152	2,775	6,522	6,894
Per share - basic	0.01	0.02	0.01	0.09	0.21	0.22
Per share - diluted	0.01	0.01	0.01	0.08	0.20	0.21
Balance Sheet						
Capital Spending						
Land acquisitions and retention	424	1,218	1,201	2,628	2,994	3,884
Geological and geophysical	475	287	596	1,050	3,178	864
Drilling and completions	2,371	2,018	5,676	5,467	12,753	6,586
Equipping and facilities	1,506	935	1,803	2,072	5,346	2,869
Net property acquisitions (dispositions)	74	64	2,131	27,577	1,090	926
Acquisition of Champion Resources Ltd.	-	40,791	-	-	-	-
Corporate assets	137	325	62	112	115	63
	4,987	45,638	11,469	38,906	25,476	15,192
Total debt						
Bank debt	15,733	40,640	40,238	43,386	41,659	52,606
Working capital deficiency (surplus)	2,789	(3,660)	3,502	3,933	14,659	5,142
	18,522	36,980	43,740	47,319	56,318	57,748
Shareholders' equity	41,660	62,044	62,439	89,553	96,134	104,288

Common Share Information (thousands except where otherwise stated)

Shares outstanding at end of period						
- Common	22,585	26,315	26,430	30,912	30,937	31,320
Weighted average shares outstanding for the period						
- Basic	22,505	23,728	26,336	30,909	30,922	31,104
- Diluted	23,974	25,290	27,811	32,717	33,142	33,401
Volume traded during quarter	6,092	2,680	2,856	2,878	7,089	9,593
Common share price (\$)						
- High	6.15	6.50	6.10	8.30	9.20	11.50
- Low	3.86	5.00	4.65	5.10	7.40	7.05
- Closing	5.90	5.25	5.95	8.00	8.10	9.90

SELECTED QUARTERLY INFORMATION

OPERATIONAL HIGHLIGHTS

	Three Months Ended					
	2002				2003	
	March 31	June 30	Sept. 30	Dec 31	March 31	June 30
Production						
Natural gas (<i>mcf/d</i>)	8,083	11,300	17,488	28,205	26,830	26,873
Crude oil (<i>bbl/d</i>)	1,670	1,591	1,623	2,055	2,094	2,260
Natural gas liquids (<i>bbl/d</i>)	40	79	221	340	311	284
Total (<i>boe/d</i>) (6:1)	3,057	3,553	4,759	7,096	6,877	7,022
Total (<i>boe/d</i>) (10:1)	2,518	2,800	3,592	5,216	5,088	5,231
Pricing						
Natural gas (before hedging) (<i>\$/mcf</i>)	3.09	3.33	2.88	5.33	7.71	6.15
Hedging (<i>\$/mcf</i>)	0.06	-	0.12	(0.01)	(0.01)	(0.04)
Amortization of commodity sales contract (<i>\$/mcf</i>)	-	0.05	0.10	0.09	0.10	0.08
Natural gas (after hedging) (<i>\$/mcf</i>)	3.15	3.38	3.10	5.41	7.80	6.19
Crude oil (before hedging) (<i>\$/bbl</i>)	25.96	34.11	37.55	36.54	45.85	34.60
Hedging (<i>\$/bbl</i>)	(1.23)	(5.10)	(7.13)	(0.01)	(5.45)	(0.70)
Change in fair value of financial instrument (<i>\$/bbl</i>)	-	-	-	(1.97)	1.98	-
Crude oil (after hedging) (<i>\$/bbl</i>)	24.73	29.01	30.42	34.56	42.38	33.90
Natural gas liquids (<i>\$/bbl</i>)	24.71	31.30	31.14	33.78	38.99	27.85
Selected Highlights (<i>\$/boe</i>)						
Weighted average sales price	22.17	24.45	23.24	33.16	45.10	35.71
Royalties, net of ARTC	3.66	3.11	4.79	7.53	10.35	8.15
Production expenses	4.34	4.85	4.80	5.18	5.42	5.46
Netbacks	14.17	16.49	13.65	20.67	29.33	22.10
General and administrative	1.10	2.12	1.39	1.79	1.39	1.06
Depletion and depreciation	10.62	10.49	10.07	9.36	9.00	9.24
Net earnings	0.58	1.10	0.35	4.25	10.54	10.79
Gross Drilling Results						
Natural gas	2	2	6	6	11	6
Crude oil	-	-	1	-	6	-
Service	-	-	-	-	1	-
Dry	-	1	2	1	6	1
	2	3	9	7	24	7
Success rate (%)	100	67	78	86	75	86
Net Drilling Results						
Natural gas	0.4	2.0	4.8	5.2	8.9	6.0
Crude oil	-	-	0.4	-	5.1	-
Service	-	-	-	-	0.7	-
Dry	-	1.0	1.4	0.5	4.8	1.0
	0.4	3.0	6.6	5.7	19.5	7.0
Success Rate (%)	100	67	79	91	75	86

