DEMONSTRATING VALUE

STRATEGIES IN ACTION

We are very pleased to report our progress in 2005 and have made important strides by following our strategy.

- Current production has exceeded 1,100 boe/d comprising 35% light oil and 65% natural gas.
- Increased our proved reserve base by 33% at year-end.
- Replaced production by approximately 460% on a total proved plus probable reserve basis.
- Increased our drilling inventory to over 150 drill-ready locations.

We increased our total proved plus probable reserves to 3.5 million boe from 2.6 million boe in 2004, representing an increase of approximately 35%. Subsequent to year end, our reserves increased to 4.9 million boe including recognition from wells drilled in late 2005, corresponding to an 84% increase over 2004.

We have established a $16-million capital program for 2006. We plan to drill 23 to 28 gross wells (14 to 17 net), focusing approximately 80% on development projects and 20% for exploration projects. We expect that our capital program will be primarily funded by C1's existing cash flow and bank facilities.

In conformity with Canadian Securities Administrator's National Instrument ("NI") NI 51-101 "Standards of Disclosure for Oil and Gas Activities", natural gas volumes have been converted to equivalent barrels of oil ("boe") using a conversion ratio of six thousand cubic feet ("mcf") of natural gas to one boe. This ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Readers are cautioned that boe may be misleading, particularly if used in isolation.

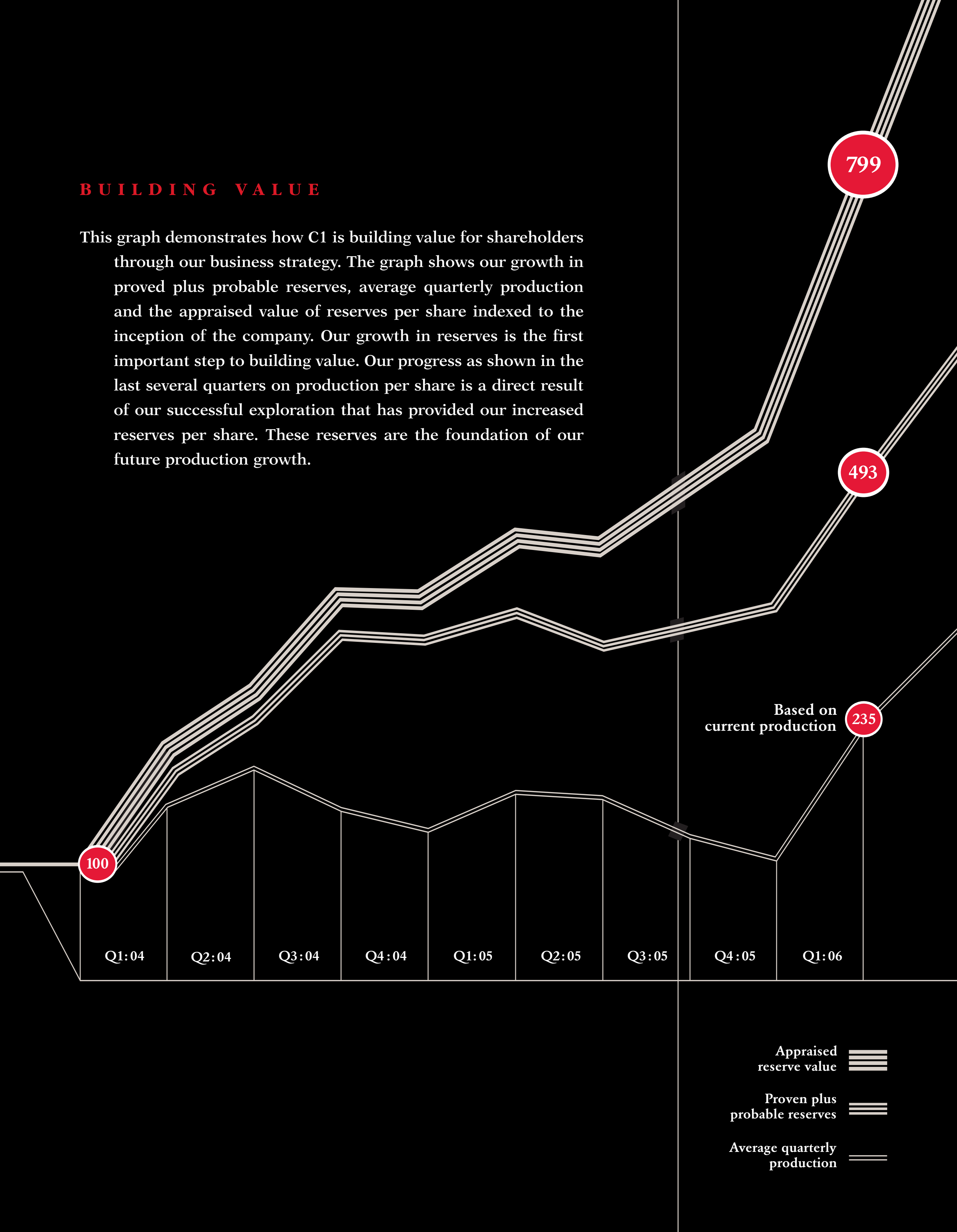
ANNUAL MEETING

Shareholders and guests are invited to attend the Annual Meeting to be held on May 11, 2006, at 3:00 p.m. in the Royal Room of the Metropolitan Conference Center, 333 – 4th Avenue S.W., Calgary, Alberta.

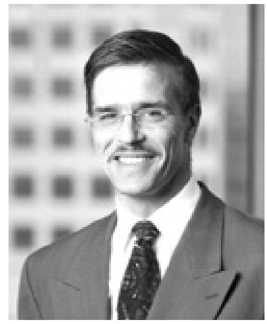
CONTENTS

BUILDING VALUE

This graph demonstrates how C1 is building value for shareholders through our business strategy. The graph shows our growth in proved plus probable reserves, average quarterly production and the appraised value of reserves per share indexed to the inception of the company. Our growth in reserves is the first important step to building value. Our progress as shown in the last several quarters on production per share is a direct result of our successful exploration that has provided our increased reserves per share. These reserves are the foundation of our future production growth.



MESSAGE FROM THE PRESIDENT



Hugh Pattillo

President and Chief Executive Officer

2005 was a year marked by significant accomplishments and challenges for C1. Our Company emerged from 2005 with the key achievement of having increased both our proved and proved plus probable reserves. Our growth in reserves is the first of what we believe will be significant steps in 2006 to building our production and cash flow.

In terms of challenges, C1 faced considerable third-party service and regulatory delays resulting from the increased activity in the industry. This contributed to slower than anticipated production growth. As a result, the adjusted production targets we set in 2005 were not realized in the year. We met those adjusted targets in the first quarter of 2006 and our business plan remains on course.

Throughout 2005 we conducted a diversified exploration drilling program in selected areas of Western Canada. We drilled 22 gross wells encompassing prospects from deep gas targets in the Alberta foothills to our first successes in a coal bed methane (CBM) project at our Hobbema property.

2005 ACCOMPLISHMENTS Our production increases were delayed in 2005 due to weather, regulatory delays and access to services which were experienced through all of our industry. Now, in March 2006 our production exceeds 1,100 barrels of oil equivalent per day (boe/d); and our behind pipe volumes exceed 500 boe/d. Our current production increases have been achieved through the drill bit and reflect a 47% increase over our 2004 exit production rate.

In the first quarter of 2005 we drilled a 100% interest well in Blueberry that provided a significant portion of our first quarter 2005 production additions. The well had very rapid decline in the second quarter which had a profound effect on our production at the time. The decline was due to mechanical problems and not a reservoir issue as was initially thought. The well has been brought back on production in early 2006 and we have substantially restored the value that was regarded as lost.

Our proved plus probable reserves increased by 35% to 3.5 million boe from year end 2004. Since year end these reserves have been increased again to 4.9 million boe, an increase of 40%. Our proved reserves increased as well, by 33% from 2004 to 2.2 million boe and subsequent to year-end by a further 51% to 3.3 million boe.

The reserve growth since we commenced operations in December 2003 has been substantial, on a per share basis it has increased by approximately 400% and on an absolute basis almost 900% from 504 thousand boe to 4,985 thousand boe today. The full value of this increase has not yet been realized through to production but it provides a low risk basis for the company to grow its production via independently recognized reserves.

During the year we drilled 22 gross wells (14.8 net to C1) at an 86% success rate (80% net). Of those successes only 2 wells contributed to our production base at year end; three wells began production in the first quarter of 2006; and the remainder is expected to begin production through 2006 and early 2007.

A key element of this drilling program in 2005 is that it provided the first results from two new focus areas, Blueberry and Hobbema. The beginning of our Blueberry project goes back to the acquisition of Extreme Energy in 2004. We have maximized our land position from that acquisition and added substantially to our landholdings. Our new production and reserve additions accomplished from our 2005 drilling program came from those newly acquired lands.

An important portion of those Blueberry lands were acquired in mid-2005 after the drilling of our second well. We had a 50% operated working interest in that well which was standing and untested at the end of Q1 2005 due to access to services. No reserves or production was attributed to this well that time. Through Q2 and early Q3 we successfully acquired our partner's 50% interest in the well and their interests in 4 additional sections of lands. In early 2006, we completed and commenced production from the well at a rate of 2.35 mmcf/d (390 boe/d) at a 100 % interest. We completed the acquisition of the well and the lands for $400,000. Where our partner saw very little value we have since proven reserve and production value at very strong metrics to our growth.

SIGNIFICANT GROWTH

- Increased our total proved plus probable reserves by 84% over 2004 subsequent to the year end 2005
- Current production reflects a 47% increase over our 2004 exit production rate
- Over 136,000 net acres of undeveloped land
- Exclusive agreement to explore an additional 168,000 net acres of undeveloped land
- Over 150 drill-ready locations
- Drilled 22 gross wells (14.8 net to C1) at an 86% success rate
- Established a new low-risk CBM resource at Hobbema where we have over 74 drill-ready locations

At Hobbema we have now drilled 5 gross (2.5 net) potential coal bed methane ("CBM") gas wells in the Horseshoe Canyon Coals. Hobbema is a rapidly expanding area of successful CBM activity by industry. We have an average 50% non-operated working interest in over 15 sections of land and an additional 4 sections which we own and operate at 100% working interest in the midst of this activity. The operator of the larger block of our lands has CBM experience and capital efficiency which we expect to benefit from as we begin to develop this resource. We currently have 70 boe/d (net) behind-pipe production from conventional gas zones in these 5 wells which begins to establish our production capability in this area. We currently recognize 74 drilling locations on this property for CBM potential. These locations will have multi-zone gas potential for conventional gas targets as well.

From these and other projects our drilling inventory is now over 150 gross locations. These locations are dominantly year round accessible providing an excellent risk mix of low, medium and high risk exploration and low risk development locations to confirm and expand our production and reserves. The increased percentage of development locations provides an expanded low risk platform to augment our other production sources and significantly reduce the risks associated with production growth in the near and longer terms.

With a larger opportunity base comes a greater ability to deploy our capital to projects that are more capitally efficient and meet our requirements. This means we can defer opportunities that are currently inefficient, such as Chipmunk due to non-operated infrastructure problems, until such time as the problems have been resolved and our efficiency requirements can be met. This will provide both the operating metrics and on-time reliability of new production in areas like Blueberry that were a problem in areas like Chipmunk in the past.

We are proud of what we've accomplished in the face of significant challenges in 2005. We again achieved significant growth in the key aspects of our business.

FUNDAMENTAL STRENGTHS OF C1 C1 has over 136,000 net acres of undeveloped land, 168,000 net acres of agreement lands and a inventory of over 150 drill-ready locations. Our drill bit growth strategy, which uses a balanced mix of low, medium and high-risk projects, is allowing us to translate our success in reserves growth into significant production growth.

We continue to hold to our core business plan of growing our company through exploration. That strategy utilizes the drill bit as its primary tool so that through exploration drilling we will progress to lower risk development of our new pools. While acquisition is not our focus we have now shown twice that selectively we executed acquisitions that provide attractive growth results to the company.

We expect to see the significant benefit of that strategy in 2006 as we commence operations of a inventory of low risk development and tie-in projects. These we believe will provide a more predictable base for production growth which is the product of our successful exploration drilling in 2005.

2006 OUTLOOK 2006 offers the strongest base for growth in C1's history. We have a $16 million capital program in place which is expected to be funded from existing cash flow and bank facilities. Our capital plan includes drilling 23 to 28 wells (14 to 17 net to C1) which begins the development of our new discoveries and continues the exploration of our other lands. With our capital program expected to be funded from our own resources we intend to protect our shareholders from diluting the value of our company. Through this time of regaining our momentum from a challenging 2005 we must maintain the strength of our balance sheet and wait until our share price reflects this regained momentum before considering potential equity offerings.

Our successes in late 2005 and early 2006 have provided the means to regain our momentum in 2006. Growth through exploration in a small company is very dependent on individual wells, both good and bad such as our experience at Blueberry in 2005. With more producing wells in better operating areas and with a level of established production performance from many of our wells, these ups and downs should become less dramatic. With an increased inventory of development drilling in these same areas, our ability to grow our production should be much stronger.

We believe the challenges we faced in 2005 relating to regulatory and third-party service delays will continue in 2006. The industry is already experiencing a continuing shortage of equipment and manpower coupled with escalating costs. We are prepared to meet these challenges by maintaining our high percentage of operatorship to control the timing of our capital expenditures and maintaining high quality facilities to mitigate operating expense increases.

Our increased inventory of behind pipe production and wells awaiting testing and tie-in should provide us better predictability in timing our production additions. At year end we had an inventory of 14 wells (10.2 net) that need to have final completion, testing and tie-in work done prior to production. This reduces the risk profile of our production growth in 2006 as a large portion will come from wells that have already been drilled and have indicative testing completed. An added benefit is that we will not be as dependent on securing drilling rigs and associated services, particularly in the first half of the year, in order increase production.

I would like to thank the staff and Board of Directors of C1 for the work, foresight and dedication through 2005. The diligence and technical excellence of our staff has resulted in a near nine-fold growth in reserves in our first two full years of operations. I believe that those reserves will translate into significant production gains in 2006.

On behalf of the Board, the management of C1 would like to thank our shareholders for their support. It was instrumental in allowing us to realize the progress we made in 2005. We believe the coming year begins with the assets and growth potential that is among the strongest in our peer group. We look forward to your continued support while we work to reward your confidence with strong return.

On behalf of the Board of Directors

Hugh Pattillo
President and Chief Executive Officer

March 10, 2006

CORPORATE VISION AND STRATEGY

C1 is a Calgary-based junior exploration and production company. Our objective is to create shareholder value through exploration, development, strategic acquisitions and production of oil and gas primarily in the province of Alberta. Our vision is to build a high-quality asset and production base that will generate sustainable cash flow and a profitable return to our shareholders.

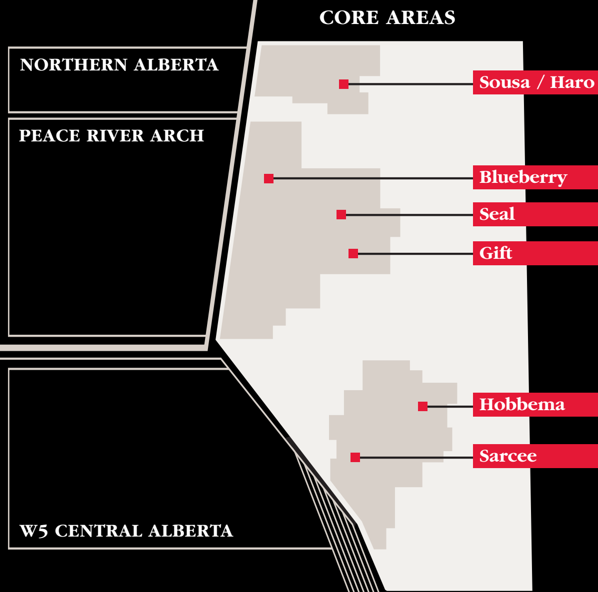
Our strategy for building a high-quality asset base concentrates on finding and developing oil and natural gas through the exploration of a diversified, mixed risk drilling portfolio while maximizing production and recoveries from our existing assets.

Our operational objectives in implementing our strategy include:

- Drill primarily internally generated exploration and development prospects.
- Target areas and projects that offer meaningful reserve and production additions.
- Focus exploration efforts on multi-zone areas in order to maximize opportunities for drilling success and gain exposure to higher risk, high-impact targets.
- Explore and develop light oil and natural gas projects in Western Canada Sedimentary Basin.
- Operate and maintain a majority working interest in our core areas to establish operating efficiencies in the field and control the timing of project development and capital expenditures.
- Conduct field operations in an environmentally prudent manner.
- Rigorously pursue opportunities to enhance production and recoveries from our existing pools.
- Gain control of facilities and infrastructure where possible to reduce operating costs and maximize our production.
- Expand the production and prospect base through strategic acquisitions, land sales and farm-ins.

PROPERTY OVERVIEW

Our exploration and development program is focused primarily in the Peace River Arch and the W5 exploration areas of Alberta. Our asset base consists of over 136,000 net acres of undeveloped lands in proven producing fairways. We have agreements on exclusive access to an additional 168,000 net acres of undeveloped lands for a total inventory of over 300,000 net acres.



We have identified over 150 drilling locations on our land base, which, through our significant reserve growth, is expected to provide the basis for our production growth in 2006 and beyond. Our mixed risk portfolio is unique for a junior exploration company and in 2006 will be focused on the development of our existing discoveries. The resulting production and cash flow growth will provide the means to continue to build and expand our land and opportunity base.

- Currently own or have exclusive access to over 300,000 net acres of undeveloped land
- Over 150 drill-ready locations focused on liquids rich natural gas and light oil
- High netback products
- Multi-zone targets to a depth not greater than 2200 meters

PEACE RIVER ARCH

- Average 82% working interest; 55% operations control
- Key assets: Gift, Seal, Blueberry
- Prospect mix – 42% oil vs. 58% gas
- 45 drilling opportunities
- 3.7 million boe of proved plus probable reserves*
- 65% of capital budget allocated 2006

W5/CENTRAL ALBERTA

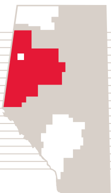
- Average 57% working interest; 45% operations control
- Key assets: Hobbema, Sarcee
- Prospect mix – 100% gas
- 79 drilling opportunities
- 1.0 million boe of proved plus probable reserves
- 35% capital budget allocated 2006

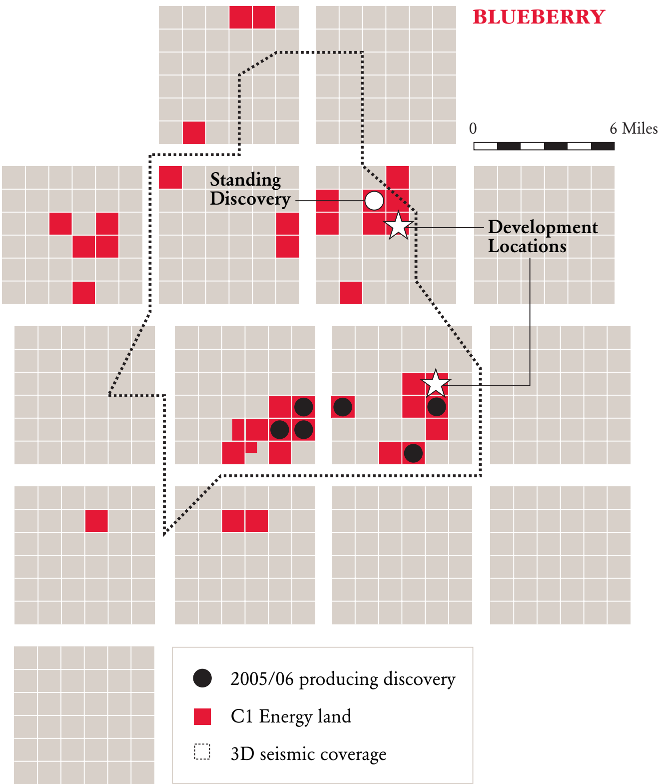
NORTHERN ALBERTA

- Average 67% working interest, 93% operations control
- Key areas: Haro
- Prospect mix – 100% gas
- 32 drilling opportunities
- 0.2 million boe of proved plus probable reserves*

* Based on February 28, 2006 reserve update

DELIVERING VALUE





THE BLUEBERRY AREA IS LOCATED APPROXIMATELY 500 KILOMETERS NORTHWEST OF EDMONTON

BLUEBERRY HIGHLIGHTS

- An average 60% working interest in over 30 sections of land
- Over 3.4 mmcf/d of sweet gas and 60 bbls/d of light oil and associated liquids of production
- Proven plus probable reserve base of over 2.0 million boe.
- Drilled five exploration wells with an 80% success rate in 2005
- Maintain an inventory of over 15 drill-ready locations
- 1,100 boe/d production in the first quarter of 2006
- An additional 500 boe/d of behind-pipe production to be brought on stream through 2006
- Expanded from land holdings in one township in 2004 to holdings in eight surrounding townships today
- 150 square miles of 3D seismic coverage provides continuing prospect generation

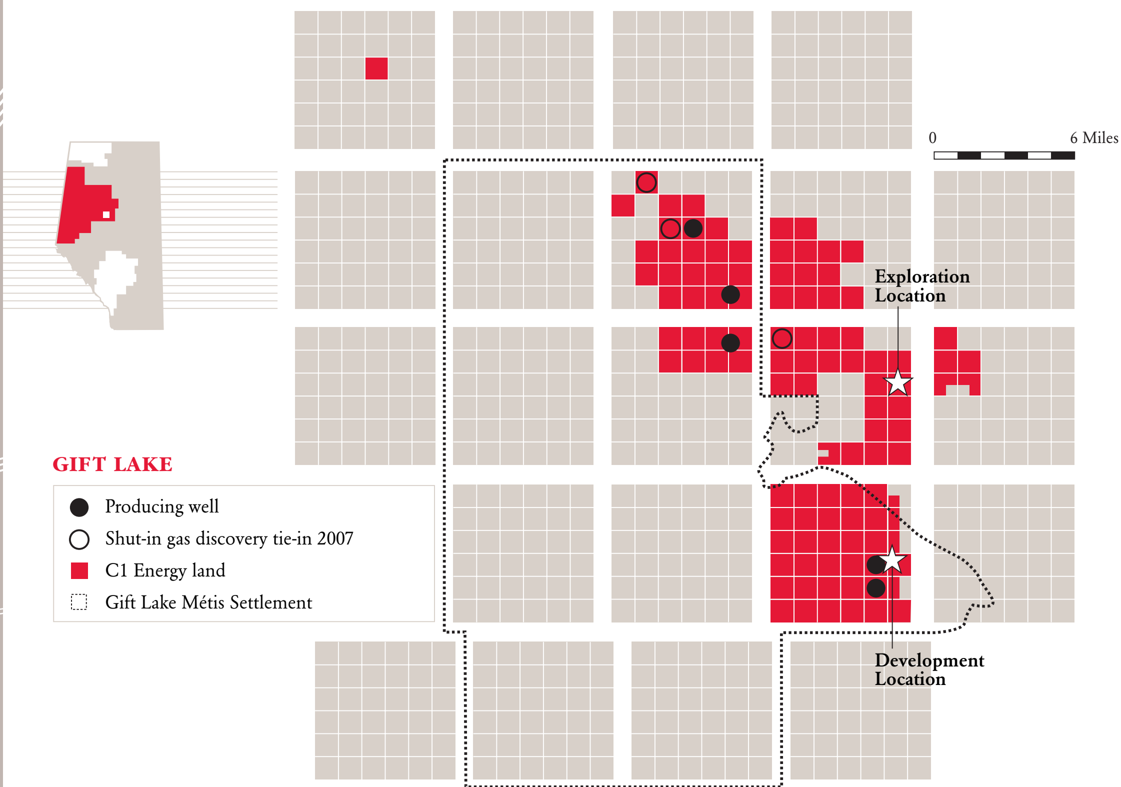
Over the past 12 months, it has grown to be our most valued exploration area. We have significantly expanded our production and reserve base in this area and have added additional lands and drilling opportunities.

C1's involvement in the area began in 2004 through a farm-in and joint venture relationship. At that time we had no land and no production, reserves or drill-ready locations. Today we have an average 60% working interest in over 30 sections of land. We are producing over 3.4 mmcf/d of sweet gas and 60 bbls/d of light oil and associated liquids and have a proven plus probable reserve base of 2.0 million boe. In 2005 we drilled five exploration wells and maintained an inventory of over 15 drill-ready locations.

Our growth in this area provides a good example of our drill-bit oriented, mixed-risk portfolio business strategy.

We first identified Blueberry as a prospective core area because it was characterized by multi-zone gas prospects with year-round access. It also had the benefit of extensive 3D seismic coverage over an area with abundant available or expiring lands coupled with an under-utilized infrastructure system. The 3D seismic definition of the prospective targets and their multi-zone potential provided a medium-risk set of exploration opportunities. New proprietary 3D was shot in the third quarter of 2005, which further expanded and improved our drilling inventory.

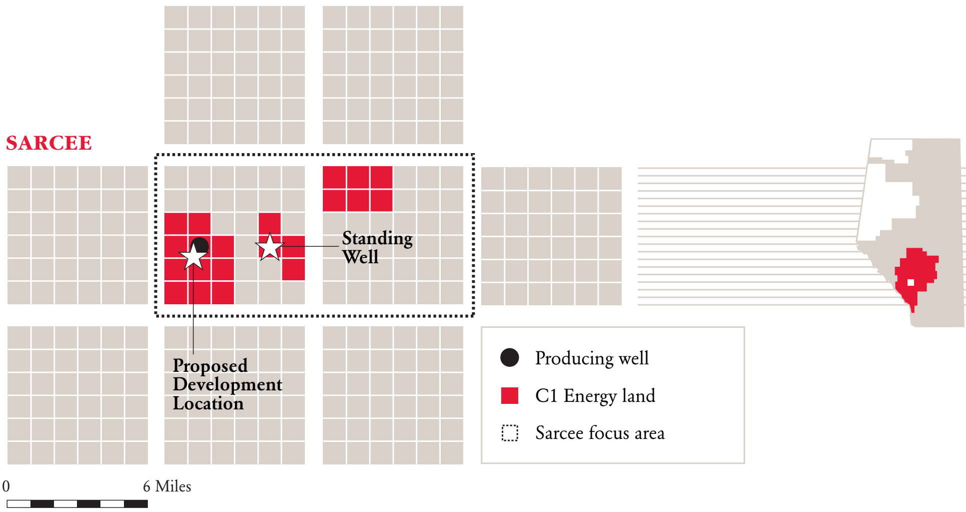
After almost 18 months of acquiring various lands through crown sales, joint ventures, farm-ins, and acquisitions, we began drilling in the first quarter of 2005. During the year we drilled five wells with an 80% success rate in a purely exploration play. The exploration successes have now produced a solid inventory of development locations. Our risk strategy, geological, geophysical and deal-making capabilities contributed to the success of this project. The resultant growth for our shareholders has been substantial.



GIFT LAKE HIGHLIGHTS

- 75% working interest; 100% operations control
- Light oil exploration – Gift Lake
- Dry gas exploration – Chipmunk
- 7 wells drilled in 2005; 57% success rate
- 21 drill-ready locations
- 72,386 acres undeveloped land
- Exclusive access to an additional 168,000 gross acres (8 townships)
- 3D-defined locations; 12% of lands currently evaluated by 3D

The four discoveries in 2005 have provided the main basis for attaining current production of 1,100 boe/d. The discoveries have provided an inventory of over eight to 10 development locations that supplement our drilling inventory of 15 exploratory locations. As well, our Blueberry area has expanded from land holdings in one township in 2004 to holdings in eight surrounding townships today.



SARCEE HIGHLIGHTS

- 50 to 100% working interest – gas and liquids; 87.5% operations control
- 12-13 Sarcee discovery – standing
- Whiskey Creek development – 40-70 bcf of original gas in place
- Access to infrastructure

OPERATIONS REVIEW

PRODUCTION

During 2005, C1's production increased from 501 boe/d in 2004 to 627 boe/d in 2005, an increase of 25%. We increased production with new production from the 2-18-82-07W6 well in the Blueberry area late in the first quarter, however production from that well declined quickly due to what we subsequently found to be mechanical issues. The well was recompleted late in the fourth quarter and production was re-established at 800 mcf/d in 2006. Another well in Blueberry at 11-3-82-07W6 that was drilled and tested during 2005, was not tied-in until the first quarter of 2006. After the initial drilling, in which we had a 50% working interest, we acquired the balance of interests in the wellbore and other lands in the area from a joint venture partner and now have 100% ownership. The well was stimulated and production tested last autumn when weather conditions and equipment availability allowed; but regulatory delays prevented us from completing the tie-in prior to year end. The well commenced production in February 2006 at an initial rate of 2.0 mmcf/d. Other wells drilled and cased late in the fourth quarter in Blueberry were not tested or tied-in until 2006.

We faced significant production challenges in some of our other areas in 2005. Third-party compression and processing facilities had poor on-time reliability, which affected Chipmunk gas production. We have decided not to invest significant additional capital into the area until upgrades that are planned for the plant are finished. We were affected, along with the rest of the industry, by a very wet summer and by equipment and personnel shortages from very high industry activity levels.

Production from the Seal field was restricted for the first half of 2005 until the battery was re-built. The old battery was unable to process all of the emulsion that was being produced by our existing wells and was creating measurement issues, as well. Now that the battery has been re-built, we are in a position to begin a significant exploration and development program in the area in 2006 and will have capacity to handle any increased production.

A development well drilled on the western edge of the Gift Lake "G" Pool encountered a tight reservoir and remains standing. Although production from the "G" Pool responded well to the waterflood and has been stable, we did not see the production increase we initially expected. We are planning to initiate a horizontal re-entry of a standing well into the western side of the "G" Pool as part of our 2006 program. This should increase production and ultimate recoveries from the "G" Pool.

	2005				2004			
	Oil (bbl/d)	**Gas (mcf/d)**	**NGLs (bbl/d)**	**Total (boe/d)**	Oil (bbl/d)	Gas (mcf/d)	NGLs (bbl/d)	Total (boe/d)
Blueberry	**7**	**688**	**5**	**127**	–	–	–	–
Gift/Chipmunk	**161**	**753**	**–**	**287**	156	832	–	295
Seal	**88**	**6**	**–**	**89**	104	141	–	127
Sousa	**28**	**10**	**–**	**30**	69	10	–	71
Sarcee	**–**	**222**	**15**	**52**	–	–	–	–
Other	**2**	**223**	**3**	**42**	2	34	–	8
Total	**286**	**1,902**	**23**	**627**	331	1,017	–	501

DRILLING ACTIVITY

	Exploration		Development		Total	
	Gross	Net	Gross	Net	**Gross**	**Net**
Year ended December 31, 2005						
Oil	**2**	**1.5**	**–**	**–**	**2**	**1.5**
Gas	**11**	**6.8**	**6**	**3.5**	**17**	**10.3**
D&A	**1**	**1.0**	**2**	**2.0**	**3**	**3.0**
Total	**14**	**9.3**	**8**	**5.5**	**22**	**14.8**
Year ended December 31, 2004						
Oil	2	1.2	–	–	2	1.2
Gas	2	1.5	–	–	2	1.5
D&A	1	1.0	–	–	1	1.0
Total	5	3.7	–	–	5	3.7

During 2005, C1 drilled a total of 22 wells (14.8 net) resulting in 17 gas wells (10.3 net), 2 oil wells (1.5 net) and 3 dry holes (3.0 net) for a success rate of 86% (80% net). Similar to 2004, a significant portion of the Company's drilling activity was higher risk exploration drilling targeting new pools. For the first time, we were able to complement the drilling activity with development projects, with 36% of the wells drilled in the year being development wells. The comparison of drilling activity to 2004 demonstrates the beginning of a transition in our capital program that is expected to continue into 2006. We anticipate the predictability of results to improve in 2006 as the overall risk profile of the drilling program reduces. For the year 2005, the success rate on exploration wells was 93% (89% net) and on development wells was 75% (64% net).

RESERVES

The following tables summarize certain information with regard to C1's oil and gas reserves as evaluated by Sproule Associates Limited as at December 31, 2005. Additional information required under NI 51-101 will be included in the Annual Information Form to be filed for fiscal 2005. Estimated values disclosed in this Annual Report do not represent fair market value. In addition, the estimates of reserves and future net revenues for individual properties contained in this Annual Report may not reflect the same confidence level as estimates of reserves and future net revenue for all properties due to the aspects of aggregation.

	Crude Oil		Natural Gas[1]		Natural Gas Liquids		Barrels of Oil Equivalent	
Reserve category	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)	Gross (mbbl)	Net (mbbl)	Gross (mboe)	Net (mboe)
Proved								
Developed producing	511.5	410.0	3,207	2,339	123.3	73.8	1,169.3	873.6
Developed non-producing	9.8	9.0	–	–	–	–	9.8	9.0
Undeveloped	72.0	66.1	4,545	3,184	139.7	81.9	969.3	678.7
Total proved	593.3	485.1	7,752	5,523	263.0	155.8	2,148.4	1,561.3
Probable	536.1	431.4	4,398	3,329	50.1	30.4	1,319.1	1,016.7
Total proved plus probable	**1,129.4**	**916.5**	**12,150**	**8,852**	**313.1**	**186.1**	**3,467.5**	**2,578.0**

(1) Includes solution gas plus non-associated and associated gas

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE [1]

As of December 31, 2005 ($000s)	Forecast Prices and Costs			
	Before Income Taxes Discounted at (%/Year)			
Reserve category	0%	5%	10%	15%
Proved				
Developed producing	29,111	24,164	20,992	18,749
Developed non-producing	307	293	281	269
Undeveloped	19,419	14,569	11,539	9,487
Total proved	48,837	39,027	32,812	28,505
Probable	28,807	19,120	14,057	10,954
Total proved plus probable	**77,644**	**58,146**	**46,869**	**39,458**

(1) Net present value of future net revenue include all resource income includes sale of oil, gas, by-product reserves; processing third party reserves; and other income

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS

As of December 31, 2005

	Forecast Prices and Costs							
	WTI Oil Cushing Oklahoma ($US/bbl)	Edmonton Oil Par Price 40° API ($Cdn/bbl)	Cromer Oil Medium 29.3° API ($Cdn/bbl)	Natural Gas[1] AECO Gas Prices ($Cdn/mmbtu)	Pentanes Plus FOB Field Gate ($Cdn/bbl)	Butanes FOB Field Gate ($Cdn/bbl)	Inflation Rate[2] (%/Year)	Exchange Rate[3] ($US/$Cdn)
Historical								
2002	26.09	40.12	35.46	4.04	40.80	25.39	2.7	0.637
2003	31.14	43.23	37.53	6.66	44.16	34.55	2.5	0.716
2004	41.42	52.91	45.72	6.87	53.91	41.37	1.3	0.826
2005	**56.45**	**69.28**	**57.38**	**8.58**	**69.13**	**45.20**	**1.6**	**0.850**
Forecast								
2006	60.81	70.07	59.62	11.58	71.77	47.01	2.5	0.850
2007	61.61	70.99	60.39	10.84	72.71	47.62	2.5	0.850
2008	54.60	62.73	53.48	8.95	64.25	42.08	2.5	0.850
2009	50.19	57.53	49.18	7.87	58.92	38.59	1.5	0.850
2010	47.76	54.65	46.75	7.57	55.97	36.66	1.5	0.850
Thereafter	Various Escalation Rates							

(1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.

(2) Inflation rates for forecasting prices and costs.

(3) Exchange rates used to generate the benchmark reference prices in this table.

Notes: Product sale prices will reflect these reference prices with further adjustments for quality and transportation to point of sale.

RESERVES LIFE INDEX [1]

	Total Proved	Proved Plus Probable
Total gross reserves (mboe)	2,148.4	3,467.5
Fourth quarter production (boe/d)	487	487
Annual 2005 production (boe/d)	627	627
RLI based on annualized fourth quarter production (years)	12.1	19.5
RLI based on annual 2005 production (years)	9.4	15.2

(1) Calculated by taking total reserves divided by annualized production

NET ASSET VALUE

The net asset value for the Company at December 31, is determined as follows:

($000s except per share amounts)	2005 Forecast Prices and Costs on Reserves	2005 Constant Prices and Costs on Reserves	2004 Forecast Prices and Costs on Reserves	2004 Constant Prices and Costs on Reserves
Present value of proved plus probable reserves (discounted at 10% before tax) (1)	**$ 46,869**	**$ 59,119**	$ 26,544	$ 31,711
Undeveloped land (2)	**13,359**	**13,359**	9,623	9,623
Lands subject to exclusive access by C1 (3)	**7,560**	**7,560**	4,450	4,450
Working capital (deficiency)	**(4,619)**	**(4,619)**	4,468	4,468
Proceeds from exercise of stock options	**2,772**	**2,772**	2,064	2,064
Net asset value	**$ 65,941**	**$ 78,191**	$ 47,149	$ 52,316
Diluted common shares outstanding (4)	**35,013**	**35,013**	29,014	29,014
Net asset value per share	**$ 1.88**	**$ 2.23**	$ 1.63	$ 1.80

(1) Value obtained from independent engineering evaluation

(2) Value from independent third party evaluation dated November 10, 2005 plus incremental value of $2.1 million on lands in Hobbema based on December land sale

(3) Lands on the Gift Lake Métis Settlement covered by the area of mutual interest ("AMI") valued at $45/acre * 168,000 net acres (2004 – Land on the Gift Lake Métis Settlement covered by the AMI plus lands under Haro Joint venture valued at $25/acre x 178,000 net acres) as determined by management

(4) Includes 33,036,726 C1 common shares plus 1,335,410 options, and 640,744 shares on conversion of performance shares based on an average trading price of $2.58 per share (2004 – 27,609,408 common shares, 625,000 options, 371,117 warrants and 409,000 shares on conversion of performance shares based on an average trading price of $1.94 per share).

Note: Net asset value excludes an estimated $10.7 million of seismic value in 2005 (2004 – $7.5 million)

Subsequent to the end of the year, C1 retained Sproule to provide an updated reserve report to February 28, 2006 pertaining to changes to existing wells and to include wells that were drilled and cased prior to year end but were not completed and production tested until early in 2006 and as a result were largely excluded from our 2005 Sproule report. Based on the results of this February 28, 2006 update, the net present value of proved plus probable reserves (discounted at 10% before tax) increased by $24.4 million for the forecast price case and by $29.1 million on the constant price case. We estimate that we incurred $1.7 million of additional capital on completion and testing activities related to these additions in the first quarter of 2006.

UNDEVELOPED LAND

All of C1's undeveloped land was evaluated by an independent third party as of December 31, 2004. In 2005, C1's undeveloped land inventory rose 11% to 136,000 net acres, an increase of approximately 14,000 acres from last year. All of C1's undeveloped acreage is located in Alberta. This does not include an additional 168,000 net acres of land on the Gift Lake Métis Settlement to which C1 has exclusive surface access under an agreement with the Gift Lake Métis Settlement and Gift Lake General Council.

UNDEVELOPED LAND HOLDINGS BY REGION

December 31, 2005	Gross Acres	Net Acres	Average Working Interest
Peace River Arch	114,370	95,568	84
W5M	23,754	15,634	66
Northern	34,240	24,779	72
Other	642	473	74
Total	**173,006**	**136,454**	**79**

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion is management's assessment of the operating and financial results of C1 Energy Ltd. ("C1" or the "Company") as well as its future opportunities and risks, and should be read in conjunction with the audited financial statements and related notes of the Company for the years ended December 31, 2005 and 2004. The financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The commentary is as of March 10, 2006. The reader should be aware that historical results are not necessarily indicative of future performance.

In conformity with Canadian Securities Administrator's National Instrument ("NI") NI 51-101 "Standards of Disclosure for Oil and Gas Activities", natural gas volumes have been converted to equivalent barrels of oil ("boe") using a conversion ratio of six thousand cubic feet ("mcf") of natural gas to one boe. This ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Readers are cautioned that boe may be misleading, particularly if used in isolation.

FORWARD LOOKING STATEMENTS

This disclosure contains forward looking statements that involve substantial known and unknown risks and uncertainties, certain of which are beyond C1's control, including: the impact of general economic conditions in Canada and the United States, industry conditions, changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced, increased competition, the lack of availability of qualified personnel or management, fluctuations in foreign exchange or interest rates, stock market volatility and market valuations of companies with respect to announced transactions and the final valuations thereof, and obtaining required approvals of regulatory authorities. C1's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward looking statements and, accordingly, no assurances can be given that any of the events anticipated by the forward looking statements will transpire or occur.

NON-GAAP MEASUREMENTS

The MD&A contains the term "cash flow from operations" ("cash flow"), which should not be considered an alternative to, or more meaningful than, "cash flow from operating activities" as determined in accordance with Canadian GAAP as an indicator of the Company's financial performance. C1's 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 statements of cash flows in the financial statements. The Company evaluates its performance based on net income and cash flow from operations. The Company considers cash flow from operations to be a key measure as it demonstrates the Company's ability to generate the cash necessary to repay debt and to fund future growth through capital investment. Cash flow from operations per share is calculated using the diluted weighted average number of shares for the period.

RESULTS OF OPERATIONS

OIL AND GAS SALES

($000's)	2005	2004
Crude oil sales	**7,393**	6,278
Natural gas sales	**5,933**	2,440
Total petroleum and natural gas sales	**13,326**	8,718

Oil and gas revenue increased 53% to $13.3 million in 2005 from $8.7 million in 2004. The increase is attributed to a 25% increase in average daily production combined with a 22% increase in average commodity prices received. The Company increased average daily production through a combination of exploration and acquisition activities.

AVERAGE SELLING PRICES

	2005	2004
Crude oil ($/bbl)	**65.42**	51.78
Natural gas ($/mcf)	**8.52**	6.55
Total average realized price ($/boe)	**58.19**	47.51

Crude Oil Pricing

C1 received an average price of $65.42/bbl for its crude oil for the year compared to $51.78 in 2004, an increase of 26%. West Texas Intermediate ("WTI") prices have remained strong throughout 2005, averaging US $56.69/bbl compared to US $41.39 last year. Prices have been influenced by continued growth in oil demand, particularly from China and India and bolstered by low levels of spare production capacity worldwide. This was demonstrated convincingly in the third quarter by the price spikes that occurred when supplies were disrupted in the wake of hurricanes that shut down production in the US Gulf Coast. We anticipate that the price of light crude oil will remain strong in 2006 as no new refining capacity will come on stream for several years.

Natural Gas Pricing

C1 received an average price of $8.52/mcf for its natural gas production for the year compared to $6.55/mcf in 2004. C1 is currently marketing 100% of its gas to a third party based on the daily index price at AECO. Natural gas prices at AECO have averaged over $8.70/mcf in 2005 due to strong draws from storage in North America and the strength of crude oil prices..

ROYALTIES

Royalties, net of ARTC for the year, were $2.4 million ($10.36/boe) compared to $2.0 million ($11.08/boe) in 2004. Royalty per boe decreased from last year due to an increase in production from wells eligible for ARTC combined with lower per-well production rates. For the year, crown royalties before ARTC averaged 14.9% and freehold and other royalties averaged 5.4% of total revenue compared to 21.0% and 4.9%, respectively, in 2004 due to changes in the production mix in 2005.

OPERATING EXPENSES

Operating expenses for 2005 were $3.0 million ($12.97/boe) compared to $1.7 million ($9.22/boe) last year. Costs per boe of production increased in 2005 mainly due to lower average daily production at certain properties combined with higher costs for services.

TRANSPORTATION COSTS

Transportation costs for the year were $0.3 million ($1.20/boe) compared to $0.2 million ($1.10/boe). The transportation cost increase correlates with the production increases for both crude oil and natural gas.

GENERAL AND ADMINISTRATIVE EXPENSES

	2005		2004	
($000's except per unit amounts)	**$**	**$/boe**	$	$/boe
Gross G&A	**2,941**	**12.84**	1,577	8.59
Capitalized overhead	**(1,109)**	**(4.84)**	(506)	(2.76)
Overhead recoveries	**(448)**	**(1.96)**	(239)	(1.30)
	1,384	**6.04**	832	4.54

General and administrative expenses ("G&A") were $1.4 million ($6.04/boe) in 2005 compared to $0.8 million ($4.54/boe) last year. We terminated the services agreement with NAV Energy Trust and hired additional staff and moved into our own office space in the last quarter of 2004. We also incurred increased support services in 2005 to assist in assimilating the operations from the Extreme acquisition which closed in December 2004. G&A costs were net of $1.1 million of capitalized overhead costs (2004 – $0.5 million). As our behind-pipe production comes on stream in 2006, costs per boe are expected to decline and we are well positioned to continue growth without significant staff additions.

STOCK-BASED COMPENSATION

Stock-based compensation for the year was $0.7 million ($2.96/boe), similar to last years costs of $0.7 million ($3.73/boe). Stock-based compensation represents a non-cash charge resulting from applying the fair value method on performance shares and stock options issued. Under this method, compensation expense related to these programs is recorded in the statement of operations over their respective vesting periods.

DEPLETION, DEPRECIATION AND ACCRETION

Depletion, depreciation, and accretion ("DD&A") amounted to $4.0 million ($17.61/boe) for the year compared to $4.5 million ($24.69/boe) for 2004. The DD&A rate decreased compared to prior year primarily from reserve additions late last year in Gift Lake combined with reserve additions in 2005. Due to significant reserve additions early in 2006 from wells drilled late in 2005, our reserve life index has increased which will translate to lower DD&A rates in the future.

CEILING TEST

C1 applies a ceiling test periodically on the carrying costs of petroleum and natural gas properties. The net amount at which petroleum and natural gas properties are carried is limited to the fair value of those properties based on the net present value of the future net revenues. Commodity prices used to determine the future cash flows of C1 were taken from pricing forecasts published by C1's independent engineers. The ceiling test in 2005 was calculated using the following prices:

	Light, Sweet Crude Oil at Edmonton ($Cdn/bbl)	AECO-C Spot ($Cdn/mcf)	Exchange Rate $US/$Cdn
2006	70.07	11.58	0.85
2007	70.99	10.84	0. 85
2008	62.73	8.95	0. 85
2009	57.53	7.87	0. 85
2010	54.65	7.57	0. 85
2011 onwards	1.5% escalation thereafter		Constant at 0.85

There was no impairment to the carrying costs of our petroleum and natural gas properties in 2005 or 2004.

CAPITAL AND INCOME TAXES

There were $0.6 million (2004 – $4.2 million) of future tax benefits recorded during the year as a result of recognizing the value of future tax benefits not previously recorded due to uncertainty of utilization. The future tax asset of $1,983,000 at December 31, 2004 has changed into a liability position of $1,621,000 at the end of 2005. The liability is primarily a result of the renunciation of $12.0 million of resource expenditures to flow through shareholders in 2005.

At the end of 2005, C1 had approximately $51.3 million of tax pools available for deduction against future taxable income compared to $38.8 million in 2004. The tax pools available were as follows:

($000s)	**2005**	2004
Canadian oil gas property expense	**$ 12,891**	$ 12,672
Canadian development expense	**8,699**	9,163
Canadian exploration expense	**15,444**	8,863
Foreign exploration and development expense	**205**	228
Undepreciated capital cost	**8,065**	5,529
Non-capital losses carried forward	**4,246**	624
Share issue costs	**1,761**	1,714
Total tax pools	**$ 51,311**	$ 38,793

NETBACK, CASH FLOW AND NET INCOME

	2005		2004	
Production				
Natural gas (mcf/d)		**1,902**		1,017
Oil and liquids (bbls/d)		**286**		332
Boe/d (6:1)		**627**		501
Financial ($000's except per unit amounts)	**$**	**$/boe**	$	$/boe
Oil and gas production	**13,326**	**58.19**	8,718	47.51
Royalties (net of ARTC)	**(2,374)**	**(10.36)**	(2,033)	(11.08)
Operating expenses	**(2,970)**	**(12.97)**	(1,693)	(9.22)
Transportation	**(274)**	**(1.20)**	(201)	(1.10)
Operating netback	**7,708**	**33.66**	4,791	26.11
General and administrative	**(1,384)**	**(6.04)**	(832)	(4.54)
Current tax	**(22)**	**(0.10)**	–	–
Cash flow from operations	**6,302**	**27.52**	3,959	21.57
Depletion and depreciation	**(4,033)**	**(17.61)**	(4,531)	(24.69)
Stock-based compensation	**(678)**	**(2.96)**	(685)	(3.73)
Future tax recovery	**600**	**2.62**	4,248	23.15
Net income	**2,191**	**9.57**	2,991	16.30

CAPITAL EXPENDITURES

Capital expenditures for the year ended December 31, 2005 were $28.3 million (2004 – $26.1 million).

Total capital expenditures were up $2.2 million or 8% but the mix of the expenditures was significantly different in 2005. We expanded our drilling program during 2005 and drilled a total of 22 wells (14.8 net) compared to last year when we drilled five wells (3.7 net). We had an overall success rate of 86% (80% net) in 2005 compared to an 80% (73% net) success rate in 2004. We also increased spending on seismic programs and facilities construction compared to last year.

($000s)	2005	2004
Drilling and completions	**$ 17,571**	$ 8,292
Land	**1,835**	1,310
Equipment and facilities	**4,151**	3,021
Geological and geophysical	**3,063**	1,366
Asset retirement obligations	**524**	(57)
Capitalized general and administrative expenses	**1,109**	506
Property acquisitions	**–**	605
Corporate acquisition	**–**	10,879
Other	**32**	171
Total capital expenditures	**$ 28,285**	$ 26,093

CAPITAL PROGRAM EFFICIENCY

	Proved	Proved plus Probable
Capital expenditures ($ thousands)	28,285	28,285
Change in future development cost ($ thousands)	3,222	1,864
Total costs	31,507	30,149
Reserves additions including revisions (mboe)	769	1,068
Finding and development costs ($/boe)		
Based on capital spent	36.78	26.48
Based on capital spent and changes in future capital	40.97	28.23
Recycle ratios (3)		
Based on capital	0.75	1.04
Based on capital spent and changes in future capital	0.67	0.97

Notes:

(1) Calculated as outlined in NI 51-101, including the change in future development capital from the prior year end reserve report.

(2) C1 Energy gross working interest proved plus probable extensions and discovered reserves, before deductions for royalties, net of revision.

(3) Year ended December 31, 2005 cash flow from operations per boe of $27.52 divided by total finding and development costs per boe based on 2005 capital.

The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

Subsequent to year end, C1 obtained an engineering update on wells that were drilled and cased prior to December 31, but had not yet been production tested. Based on that February 28, 2006 update, total proved reserve additions increased by 1,106 Mboe and proved plus probable reserve additions increased by 1,335 Mboe. Capital expenditures incurred to test the wells cost approximately $1.7 million and future capital increased by $2.4 million for proved reserves and $2.7 million for proved plus probable reserves.

LIQUIDITY AND CAPITAL RESOURCES

FINANCING RESOURCES

The 2005 capital program was funded as follows:

($000s)	
Cash flow from operations	**$ 6,302**
Changes in working capital	**1,371**
Cash/bank debt utilized	**7,566**
Asset dispositions	**48**
Increase in asset retirement obligations	**524**
Equity issued (net of issuance costs)	**12,474**
Total capital expenditures	**$ 28,285**

FUNDING OF CAPITAL PROGRAM

The 2006 capital program is currently budgeted at $16.0 million. C1 expects the capital expenditures to be funded by cash flow from operations and bank debt.

BANK FACILITIES

C1 has $15.0 million of credit facilities available with a Canadian chartered bank. The facilities are composed of a $11.0 million revolving demand loan plus a $4.0 million non-revolving acquisition/development demand loan. The interest rate on outstanding debt is set at the bank's prime lending rate plus 0.25% and 0.50%, respectively. The facilities are secured by a floating charge over all of C1's assets. We had $1.7 million of bank debt outstanding at December 31, 2005 compared to nil in 2004. The facility is under review for April 2006 with the intention of incorporating new reserve additions identified in the year end engineering evaluation plus activities undertaken in the first quarter of 2006. The current loan facility is anticipated to be increased after review of the facility.

The 2006 capital program of $16.0 million will be primarily funded by cash flow with working capital/bank debt utilized for the remainder.

SHARE CAPITAL

At December 31, 2005, C1 had 33,036,726 shares issued and outstanding with a weighted average number of shares outstanding of 30,514,138 (diluted – 31,568,920). Common shares outstanding at December 31, 2004 were 27,609,408 with a weighted average number of 20,475,249 (diluted – 28,067,617). As at March 10, 2005, we had 33,036,726 shares issued and outstanding. We also had 1,335,410 options outstanding which, upon vesting, are exercisable into 1,335,410 common shares and 1,178,000 performance shares which are convertible into 327,572 common shares.

During June 2005, we completed an equity offering whereby we issued 4,255,320 common shares and 833,334 flow through common shares at a price of $2.35 and $3.00 per share respectively for gross proceeds of $12.5 million. The entire flow through commitment of $2.5 million was spent in 2005.

CONTRACTUAL OBLIGATIONS

($000s)	**Total**	2006	2007	2008	Thereafter
Office lease obligations	**1,639**	395	341	295	608

SELECTED ANNUAL AND QUARTERLY INFORMATION

	2005				
Financial ($000s)	1Q	2Q	3Q	4Q	Year
Gross revenues before royalties	**3,176**	**3,699**	**3,286**	**3,165**	**13,326**
Cash flow from operations	**1,316**	**1,864**	**1,790**	**1,332**	**6,302**
Per share – basic ($)	**0.05**	**0.06**	**0.06**	**0.04**	**0.21**
Per share – diluted ($)	**0.05**	**0.06**	**0.06**	**0.03**	**0.20**
Net income (loss)	**(88)**	**331**	**446**	**1,502**	**2,191**
Per share – basic ($)	**0.00**	**0.01**	**0.01**	**0.05**	**0.07**
Per share – diluted ($)	**0.00**	**0.01**	**0.01**	**0.05**	**0.07**
Total assets	**54,600**	**61,868**	**67,302**	**71,039**	**71,039**
Capital expenditures	**11,812**	**5,060**	**6,655**	**4,758**	**28,285**
Operational					
Production					
Oil and NGLs (bbls/d)	**392**	**295**	**276**	**277**	**310**
Natural gas (mcf/d)	**1,758**	**2,852**	**1,769**	**1,261**	**1,906**
Boe/d (6:1)	**685**	**770**	**570**	**487**	**627**
Average selling price					
Crude oil and NGLs ($/bbl)	**61.01**	**59.18**	**72.35**	**69.85**	**65.42**
Natural gas ($/mcf)	**6.47**	**8.13**	**8.65**	**11.94**	**8.52**
Operating netback ($/boe)	**29.10**	**31.57**	**37.95**	**38.17**	**33.66**
Cash flow netback	**21.36**	**26.60**	**34.11**	**29.71**	**27.52**

	2004				
Financial ($000s)	1Q	2Q	3Q	4Q	Year
Gross revenues before royalties	1,572	2,721	2,124	2,301	8,718
Cash flow from operations	798	1,133	904	1,124	3,959
Per share – basic and diluted ($)	0.04	0.06	0.04	0.05	0.19
Net income (loss)	2,565	(601)	(612)	1,639	2,991
Per share – basic ($)	0.14	(0.03)	(0.04)	0.07	0.15
Total assets	31,538	35,717	33,699	52,685	52,685
Capital expenditures	8,828	1,549	2,083	13,633	26,093
Operational					
Production					
Oil and NGLs (bbls/d)	281	431	313	306	332
Natural gas (mcf/d)	739	1,104	946	1,292	1,017
Boe/d (6:1)	404	615	470	516	501
Average selling price					
Crude oil and NGLs ($/bbl)	44.51	51.35	54.00	56.52	51.78
Natural gas ($/mcf)	6.28	7.03	6.56	6.30	6.55
Operating netback ($/boe)	25.76	24.26	27.47	27.34	26.11
Cash flow netback	21.71	20.23	20.91	23.67	21.57

FOURTH QUARTER REVIEW

	Three Months Ended December 31, 2005		Three Months Ended December 31, 2004	
Production				
Natural gas (mcf/d)		**1,261**		1,292
Oil and liquids (bbls/d)		**277**		306
Boe/d (6:1)		**487**		516
Financial ($000's except per unit amounts)	**$**	**$/boe**	$	$/boe
Oil and gas production	**3,165**	**70.62**	2,301	48.47
Royalties (net of ARTC)	**(532)**	**(11.87)**	(490)	(10.32)
Operating expenses	**(858)**	**(19.15)**	(525)	(11.06)
Transportation	**(64)**	**(1.43)**	12	0.25
Operating netback	**1,711**	**38.17**	1,298	27.34
General and administrative	**(372)**	**(8.30)**	(214)	(4.51)
Current tax	**(7)**	**(0.16)**	40	0.84
Cash flow from operations	**1,332**	**29.71**	1,124	23.67
Depletion and depreciation	**(1,031)**	**(23.00)**	(652)	(13.73)
Stock-based compensation	**(180)**	**(4.03)**	(194)	(4.09)
Future tax recovery	**1,381**	**30.81**	1,361	28.67
Net income	**1,502**	**33.49**	1,639	34.52

Petroleum and natural gas sales were $3.1 million in the quarter compared to $2.3 million last year. The fourth quarter of 2005 was marked by higher commodity prices but lower production volumes due to temporary facilities problems that arose primarily at Blueberry and Chipmunk.

The average natural gas price in the fourth quarter this year was $11.94/mcf which was 90% higher than the same period last year when we received $6.30/mcf. The average crude oil and NGL price of $69.85/bbl for the fourth quarter was 25% higher than the same period last year when we received an average price of $55.96/bbl.

Royalties were $0.5 million during the fourth quarter of 2005 compared to $0.5 million last year. Royalties were $11.87/boe compared to $10.32/boe for the same period last year primarily due to a royalty holiday received on a well in the Seal area last year. Lease operating expenses for the quarter were $0.9 million ($19.15/boe) compared to $0.5 million ($11.06/boe) for the same period last year. This resulted primarily from higher industry operating costs compared to the previous period. Also, a relatively high fixed cost component plus an increase in repair and maintenance costs in Chipmunk combined to increase per unit costs when production was shut-in during the fourth quarter this year.

General and administrative costs of $0.4 million ($8.30/boe) for the fourth quarter were higher than the same period a year ago due to lower production during the quarter. As well, our salary costs did not begin to rise until November of last year when the majority of our technical team became full-time C1 employees. Current and capital taxes were $0.16/boe in the fourth quarter compared to a recovery last year.

Higher commodity prices offset increases in operating costs resulting in a cash flow netback of $29.71/boe for the fourth quarter, higher than the same period last year when we had a cash flow netback of $23.67/boe. Stock based compensation of $180,000 for the quarter was slightly lower than $194,000 incurred last year. Depletion and depreciation was $1.0 million ($23.00/boe) during the quarter compared to $652,000 ($13.73/boe) during the fourth quarter last year. This was primarily the result of reserves from wells drilled late in the fourth quarter not being recognized until early 2006. There was a $1.4 million tax recovery during the quarter, similar to the same period last year. The recovery of income taxes relates primarily to the recognition of the value of future tax benefits not previously recorded due to uncertainty of utilization. Net income was $1.5 million for the quarter ($0.05 per share) compared to net income of $1.6 million ($0.07 per share) over the same period last year.

CRITICAL ACCOUNTING POLICIES

The preparation of the consolidated financial statements in accordance with Canadian GAAP requires management to make judgments and estimates that affect the financial results of the Company. The critical estimates are discussed below.

FULL COST ACCOUNTING

C1 follows the full cost method of accounting for petroleum and natural gas operations as outlined in Canadian Institute of Chartered Accountants ("CICA") accounting guideline "Oil and Gas Accounting – Full Cost" (AcG-16). Under this accounting method, all costs related to the exploration and development of petroleum and natural gas reserves are capitalized. Capitalized costs, as well as the estimated future expenditures to develop proved reserves, are depleted using the unit of production method based on estimated proved petroleum and natural gas reserves. The carrying value of petroleum and natural gas properties is limited to their fair value. The fair value is equal to estimated future cash flows from proved and probable reserves using future price forecasts and costs discounted at a risk-free rate.

PETROLEUM AND NATURAL GAS RESERVES

All of C1's petroleum and natural gas reserves are evaluated and reported on by independent petroleum engineering consultants. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. The Company expects that its estimates of reserves will change to reflect updated information. Reserve estimates are critical to the following accounting estimates:

- Calculation of unit of production depletion and future site restoration rates. Proved reserve estimates are used to determine the DD&A rate applied to each unit of production.
- Ceiling test calculation, measurement of impairment of oil and gas assets. The fair value of future cash flows is estimated from proved and probable reserves using future price forecasts.

The above accounting estimates are critical to the determination of net earnings. These estimates, including the calculation of proved reserves, are affected by the following events:

- Changes to commodity prices;
- Production performance of wells;
- Changes to reservoir performance/pressures;
- New geological and geophysical data;
- Competitor production practices;
- Changes to government regulations.

Reserve estimates can be revised upward or downward based on the results of future drilling, testing or production levels.

UNPROVED PROPERTIES

Certain costs related to unproved properties may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted. The costs related to unproved properties are also excluded from the book value subject to the ceiling test measurement.

ASSET RETIREMENT OBLIGATIONS

The Company is required to provide for future removal and site restoration costs. The Company must estimate these costs in accordance with existing laws, contracts or other policies. These estimated costs are charged to the property and equipment and the appropriate liability account over the expected service life of the asset. The estimate of future removal and site restoration costs involves a number of estimates related to timing of abandonment, determination of economic life of the asset, costs associated with abandonment and site restoration, review of potential abandonment methods and salvage/usage of tangible equipment.

INCOME TAX ACCOUNTING

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment subsequent to the financial statement reporting period. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

GOODWILL

The process of accounting for the purchase of a company, results in recognizing the fair value of the acquired company's assets on the balance sheet of the acquiring company. Any excess of the purchase price over fair value is recorded as goodwill. Since goodwill results from the culmination of a process that is inherently imprecise, the determination of goodwill is also imprecise. In accordance with the issuance of CICA section 3062, "Goodwill and Other Intangible Assets", goodwill is not amortized but assessed periodically for impairment. The process of assessing goodwill for impairment necessarily requires the Company to determine the fair value of its assets and liabilities. Such a process involves considerable judgment.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the Company is accumulated and communicated to the Company's management as appropriate to allow timely decisions regarding required disclosure. The Company's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by the annual filings, that the Company's disclosure controls and procedures are effective to provide reasonable assurance that material information related to the Company is made known to them by others within the entity. It should be noted that while the Company's Chief Executive Officer and Chief Financial Officer believe that the Company's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures or internal controls over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

RISK AND UNCERTAINTY

As an exploration and production company in the oil and gas industry, C1 is exposed to a number of business risks, which are beyond the control of management. These risks can be categorized as operational, financial and regulatory.

Operational risks include exploring for and developing oil and natural gas reserves on an economic basis, drilling risks, reservoir performance, access to contract services, availability of skilled labor and weather conditions affecting the timing of capital program completion. C1 maintains an insurance policy consistent with industry standards to protect against well blowouts and other drilling problems, destruction and damage to tangible assets, pollution and third-party liability coverage. In addition, we employ highly qualified staff and experienced contract services and provide a compensation environment that rewards above average performance, develops long-term relationships and provides measurement objectives consistent with shareholder value enhancement. Managing reservoir risk for a company our size is difficult due to the high asset concentration that currently exists with our assets. C1 is focused on diversification of our assets to provide a geologically diverse prospect inventory while protecting access to pipeline and facilities.

Financial risks include fluctuations in commodity price, interest rates and the Canadian/US dollar exchange rate. C1 does not have any hedge instruments in place to cover any of these named risks. As the production base begins to diversify, we will develop a hedging/risk management policy that will define strict controls to managing financial market exposure. Our approach to managing these risks is to maintain a healthy balance sheet with prudent levels of debt measured by debt to cash flow and debt coverage ratios. This allows for strong financial capacity to maintain exploration and development activities in any downturn in commodity prices. An additional financial risk is credit risk for failure of performance by counter-parties. This risk is controlled by an evaluation of the credit risk before contract initiation and ensuring product sales and delivery contracts are made with well-known and financially strong crude oil and natural gas marketers.

The oil and gas industry is a heavily regulated industry with respect to environmental and safety practices. However, production and drilling practices of competitors may challenge the regulations creating production disruptions for the Company. With respect to environmental and safety issues, we maintain an environmental and safety policy with a well-defined reporting process to the Board of Directors. Other regulatory risks include changes to royalty and tax legislation over which the Company has no control.

Additional information relating to the Company including our annual information form can be found on SEDAR at www.sedar.com.

MANAGEMENT'S REPORT

To the Shareholders of C1 Energy Ltd.:

The preparation and presentation of the Company's financial statements is the responsibility of management. The financial statements have been prepared in accordance with generally accepted accounting principles (GAAP) and include management's best estimates and judgments, where required. The financial information contained elsewhere in this annual report is consistent with the financial statements.

Management is responsible for installing and maintaining a system of internal controls to provide reasonable assurance that assets are safeguarded and that reliable financial information is produced for preparation of the financial statements.

The Audit Committee is appointed by the Board and its members are outside unrelated directors. The Committee meets periodically with management, as well as the external auditors, to discuss internal controls over the financial reporting process, auditing matters and financial reporting issues; to satisfy itself that each party is properly discharging its responsibilities; and, to review the annual report, the financial statements and the external auditors' report. The Committee reports its findings to the Board for consideration when approving the financial statements for issuance to the shareholders. The Committee also considers, for review by the Board and approval by the shareholders, the engagement or re-appointment of the external auditors.

Deloitte & Touche LLP, the independent auditors, are appointed by the shareholders to express an opinion as to whether the financial statements present fairly the company's financial position, results of operations and cash flows in accordance with GAAP. The external auditors have full and unrestricted access to the Audit Committee to discuss their audit and related findings.

Hugh Pattillo
President and Chief Executive Officer

Gary Lobb, CA
Vice President and Chief Financial Officer

Calgary, Alberta
March 10, 2006

AUDITORS' REPORT

To the Shareholders of C1 Energy Ltd.:

We have audited the balance sheets of C1 Energy Ltd. as at December 31, 2005 and 2004 and the statements of operations and retained earnings (deficit) and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants

Calgary, Alberta
March 10, 2006

BALANCE SHEETS

As at December 31 (dollars in thousands)	2005	2004
Assets		
Current assets		
Cash and cash equivalents	**$ 864**	$ 6,930
Accounts receivable	**4,975**	3,754
Prepaid expenses	**220**	80
	6,059	10,764
Property and equipment (note 3)	**58,448**	34,158
Goodwill (note 2)	**6,532**	5,780
Future income tax (note 8)	**–**	1,983
	$ 71,039	$ 52,685
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 9,028**	$ 6,296
Bank loan (note 4)	**1,650**	–
	10,678	6,296
Asset retirement obligations (note 7)	**996**	536
Future income tax (note 8)	**1,621**	–
	13,295	6,832
Commitments (Note 11)		
Shareholders' equity		
Share capital (note 5)	**51,190**	42,072
Warrants (notes 2 and 5)	**–**	91
Contributed surplus (note 5)	**1,372**	699
Retained earnings	**5,182**	2,991
	57,744	45,853
	$ 71,039	$ 52,685

See accompanying notes to the financial statements.

Approved by the Board,

Raymond Chan
Director

Hugh Pattillo
Director

STATEMENTS OF OPERATIONS AND RETAINED EARNINGS

For the years ended December 31, 2005 and 2004
(dollars in thousands except per share amounts)

	2005	2004
Revenue		
Petroleum and natural gas sales	**$ 13,326**	$ 8,718
Royalties, net of Alberta Royalty Tax Credit	**(2,374)**	(2,033)
	10,952	6,685
Expenses		
Operating	**2,970**	1,693
Transportation	**274**	201
General and administrative	**1,384**	832
Stock-based compensation (note 5)	**678**	685
Depletion, depreciation and accretion (note 3)	**4,033**	4,531
	9,339	7,942
Income (loss) before income taxes	**1,613**	(1,257)
Income tax		
Current and capital	**22**	–
Future recovery (note 8)	**(600)**	(4,248)
	(578)	(4,248)
Net income	**2,191**	2,991
Retained earnings (deficit), beginning of year	**2,991**	(3,060)
Elimination of accumulated deficit (note 5)	**–**	3,060
Retained earnings, end of year	**$ 5,182**	$ 2,991
Net income per common share (note 6)		
– Basic	**$ 0.07**	$ 0.15
– Diluted	**$ 0.07**	$ 0.14

See accompanying notes to the financial statements.

STATEMENTS OF CASH FLOWS

For the years ended December 31, 2005 and 2004 (dollars in thousands)	2005	2004
Cash provided by (used in)		
Operating activities		
Net income	**$ 2,191**	$ 2,991
Add (deduct):		
Future income tax recovery	**(600)**	(4,248)
Depletion, depreciation and accretion	**4,033**	4,531
Stock-based compensation	**678**	685
Funds from operations	**6,302**	3,959
Asset retirement expenditures (note 7)	**(150)**	–
Net change in non-cash working capital (note 10)	**(443)**	910
	5,709	4,869
Investing activities		
Property and equipment expenditures	**(27,761)**	(15,272)
Cash costs of Extreme acquisition (note 2)	**–**	(1,272)
Disposal of property and equipment	**48**	–
Net change in non-cash working capital (note 10)	**1,814**	(716)
	(25,899)	(17,260)
Financing activities		
Issuance of common shares	**13,358**	10,000
Share issue costs	**(884)**	(639)
Increase in bank indebtedness	**1,650**	–
	14,124	9,361
Net decrease in cash and cash equivalents	**(6,066)**	(3,030)
Cash and cash equivalents, beginning of year	**6,930**	9,960
Cash and cash equivalents, end of year	**$ 864**	$ 6,930

See accompanying notes to the financial statements.

NOTES TO THE FINANCIAL STATEMENTS

For the years ended December 31, 2005 and 2004
(all tabular dollars in thousands except per unit amounts)

1. SIGNIFICANT ACCOUNTING POLICIES

BUSINESS AND BASIS OF PRESENTATION

C1 Energy Ltd. ("C1" or the "Company") is a Calgary-based oil and natural gas exploration and production company whose key business activities are focused in Alberta. The Company was incorporated on September 25, 2003 and commenced operations on December 29, 2003. C1 is a public company and commenced trading on the Toronto Stock Exchange on January 6, 2004 under the symbol "CTT".

These financial statements are prepared in accordance with accounting principles generally accepted in Canada. Management has made the necessary estimates and assumptions regarding certain types of assets, liabilities, revenues and expenses in the preparation of the financial statements. Actual results could differ from those estimates. Significant accounting policies are summarized as follows:

a) Cash and cash equivalents

Cash and cash equivalents consists of cash in the bank, less outstanding cheques, and deposits with a maturity of less than three months at the time of purchase.

b) Petroleum and natural gas properties

i) Full cost accounting

The Company uses the full cost method of oil and gas accounting whereby all costs relating to the exploration for and development of petroleum and natural gas reserves are capitalized. Such costs include land acquisition, drilling of productive and non-productive wells, geological and geophysical, production facilities, carrying costs directly related to unproved properties and corporate expenses directly related to acquisition, exploration and development activities. Gains or losses on sales of properties are recognized only when crediting the proceeds to costs would result in a change of 20% or more in the depletion rate.

ii) Depletion and depreciation

Depletion of exploration and development costs and depreciation of production equipment is provided using the unit-of-production method based upon estimated gross proved petroleum and natural gas reserves. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of six thousand cubic feet of gas equating to one barrel of oil equivalent (boe). The costs of significant undeveloped properties are excluded from costs subject to depletion. Unproved properties are evaluated for impairment on an annual basis.

iii) Ceiling test

The net amount at which petroleum and natural gas properties are carried is limited to the fair value of those properties based on the net present value of the estimated future net revenues (the "ceiling test"). This is a two-stage process which is to be performed at least annually. The first stage is a recognition test which compares the undiscounted future cash flow from proved reserves plus the cost less impairment of unproved properties to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. An impairment loss exists when the carrying amount of the petroleum and natural gas assets exceeds such undiscounted cash flows. The amount of impairment, if any, to be recorded is measured as the amount by which the carrying amount of assets capitalized exceeds the sum of: (i) the expected net present value of future net revenues from proved and probable reserves discounted at a risk free interest rate and (ii) the costs (less any impairment) of unproved properties that have been subject to a separate test for impairment. Commodity prices used to determine future net revenues are based on the best information available to the Company and are consistent with quoted benchmark prices in the futures market (adjusted for quality differences). If the net carrying costs exceed the fair value, the impairment is recorded as additional depletion and depreciation.

c) Goodwill

Goodwill is recorded at cost (less impairment, if any) and is not amortized. The Company must record goodwill relating to a corporate acquisition when the total purchase price exceeds the fair value for accounting purposes of the net identifiable assets and liabilities of the acquired company.

The goodwill balance is assessed for impairment annually at year-end or as events occur that could result in an impairment. Impairment is recognized based on the fair value of the reporting entity (the Company) compared to the book value of the reporting entity. If the fair value of the Company is less than the book value, impairment is measured by allocating the fair value of the Company to the identifiable assets and liabilities as if the Company had been acquired in a business combination for a purchase price equal to its fair value. The excess of the fair value of the Company over the amounts assigned to the identifiable assets and liabilities is the fair value of the goodwill. Any excess of the book value of goodwill over this implied fair value of goodwill is the impairment amount. Impairment is charged to earnings in the period in which it occurs.

d) Asset retirement obligations

The Company recognizes the fair value of the asset retirement obligations related to its property and equipment using expected cash flows discounted at a credit-adjusted risk-free rate, for future asset retirement costs in the period in which they are incurred. Upon initial recognition of a liability for future asset retirement costs, the carrying value of the petroleum and natural gas properties is increased by the amount of the liability. These costs are included in the carrying value subject to depletion and depreciation and the ceiling test. The liability accretes until the expected settlement date. Subsequent changes to the fair value of the liability arising from revisions to the timing or amount of the original estimate of undiscounted cash flows are recognized as an increase or a decrease in the carrying amount of the obligation and are capitalized as part of the carrying value of the petroleum and natural gas properties.

e) Foreign currency

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at year-end exchange rates. Non-monetary items are translated at the average exchange rate during the month they are recognized. Exchange gains or losses are included in income in the period incurred.

f) Measurement uncertainty

The amounts recorded for depletion, depreciation and accretion are based on estimates of reserves and future costs as well as estimates of reserves in the case of depletion and depreciation. By their nature, these estimates and those related to the assessment of estimated future cash flows used to assess impairment, are subject to measurement uncertainty and the impact on the financial statements of future periods could be material.

g) Joint interests

A portion of the Company's exploration, development and production activities are conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

h) Revenue recognition

Revenue associated with sales of crude oil, natural gas, and natural gas liquids is recognized when title passes to the purchaser, normally at the pipeline delivery point for natural gas and at the wellhead for crude oil.

i) Flow-through shares

The Company has financed a portion of its exploration and development activities through the issue of flow-through shares. Under the terms of the flow-through share agreements, the tax attributes of the related expenditures are renounced to the subscribers. Share capital is reduced and future income tax liability is increased by the estimated cost of the renounced tax deductions at the time the expenditures are renounced.

j) Hedging

The Company may periodically utilize certain financial instruments to reduce exposures related to petroleum and natural gas prices and foreign exchange fluctuations on a portion of its crude oil and natural gas production in accordance with Company policy. Under hedge accounting, gains and losses on these contracts, all of which must constitute effective hedges, are recognized in revenue concurrently with the hedged transaction. If hedge requirements are not met, the financial instruments are recorded at fair value; any gains or losses are included in income in the period.

k) Future income taxes

The Company follows the liability method of accounting for income taxes. Under this method 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 substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse.

l) Stock-based compensation

The Company has stock-based compensation plans, which are described in note 5. Compensation expense is recognized for these plans when stock options or performance shares are issued to employees. Any consideration paid by employees upon exercise of stock options is credited to share capital. Compensation costs are recognized in the statement of operations and included in contributed surplus.

m) Per share amounts

Net income per share is calculated using the weighted average number of shares outstanding during the period. Diluted net income per share is calculated using the treasury stock method to determine the dilutive effect of stock options and other dilutive elements. The treasury method assumes that the proceeds received from the exercise of "in the money" stock options are used to re-purchase and cancel common shares at the average trading price for the period.

2. CORPORATE ACQUISITION

On December 16, 2004, C1 acquired Extreme Energy Corporation ("Extreme") and Extreme shareholders received 0.22 of a common share of C1 ("C1 Common Share") for each common share of Extreme (5,854,992 C1 common shares valued at an ascribed value of $1.80 per common share). The total cost to C1 to acquire the Extreme shares was $10,878,719 including transaction costs of $248,633 and 371,116 warrants at an ascribed value of $91,100. This transaction has been accounted for using the purchase method with the results of Extreme being included in the statement of operations of C1 from December 17, 2004.

The following table summarizes the allocation of the purchase price to the estimated fair value of the assets acquired and liabilities assumed as at the closing date.

Bank indebtedness	**$ (1,023)**
Accounts receivable	**1,641**
Prepaid expenses and deposits	**38**
Petroleum and natural gas properties	**7,347**
Goodwill	**5,780**
Accounts payable and accrued liabilities	**(2,970)**
Future income tax asset	**273**
Asset retirement obligations	**(207)**
	$ 10,879

In accordance with the terms of Extreme's various flow-through share offerings, and pursuant to certain provisions of the Income Tax Act (Canada), the Company renounced in 2005, for income tax purposes, exploration expenditures in the aggregate of $2,000,000 related to Extreme flow-through shares issued in 2004. The effect of this renunciation was to increase the future income tax liability and increase goodwill by approximately $752,000 in 2005.

3. PROPERTY AND EQUIPMENT

	2005	2004
Petroleum and natural gas properties and equipment	**$ 70,153**	$ 41,917
Accumulated depletion and depreciation	**(11,705)**	(7,759)
Net book value	**$ 58,448**	$ 34,158

At December 31, 2005, $20.6 million (2004 – $16.7 million) of costs relating to unproved properties and seismic were excluded from costs subject to depletion.

During 2005, $1,109,000 (2004 – $506,000) of general and administrative expenses relating to exploration and development activities were capitalized.

The ceiling test in 2005 was calculated using the following prices:

	Light, Sweet Crude Oil at Edmonton ($Cdn/bbl)	AECO-C Spot ($Cdn/mcf)	Exchange Rate $US/$Cdn
2006	70.07	11.58	0.85
2007	70.99	10.84	0. 85
2008	62.73	8.95	0. 85
2009	57.53	7.87	0. 85
2010	54.65	7.57	0. 85
2011 onwards	1.5% escalation thereafter		Constant at 0.85

There was no impairment to the carrying costs of our petroleum and natural gas properties in 2005 or 2004.

4. BANK LOAN

On December 31, 2005, the Company had $15,000,000 of credit facilities available with a Canadian chartered bank. The facilities are composed of an $11,000,000 revolving demand loan facility plus a $4,000,000 non-revolving acquisition / development demand loan. The interest rate on outstanding debt is set at the bank's prime lending rate plus 0.25% and 0.50% respectively. The facilities are secured by a floating charge over all of C1's assets. $1,650,000 was outstanding under the revolving facility at December 31, 2005 (2004 – $nil).

5. SHARE CAPITAL

a) Authorized

The Company is authorized to issue an unlimited number of common shares and 1,442,000 performance shares ("Performance Shares").

b) Issued and outstanding

Common shares	Number of shares	Amount
Balance at December 31, 2003	17,754,416	$ 27,755
Flow-through shares issued (i)	4,000,000	10,000
Tax effect of renunciation of resource expenditures on flow-through shares (ii)	–	(2,886)
Issued on Extreme acquisition (note 2)	5,854,992	10,637
Share issue costs, net of future tax benefit of $251,452 (i)	–	(387)
Reduction in stated capital (iii)	–	(3,060)
Balance at December 31, 2004	27,609,408	42,059
Issued on conversion of Performance Shares	5,482	–
Issued on exercise of stock options	22,000	55
Issuance of common shares (iv)	4,255,320	10,000
Issuance of flow-through shares (iv)	833,334	2,500
Compensation expense related to options exercised and Performance Shares converted	–	22
Issuance of common shares on exercise of warrants	311,182	804
Ascribed value of warrants exercised	–	74
Tax effect of renunciation of resource expenditures on flow-through shares (v)	–	(3,762)
Share issue costs, net of future tax benefit of $309,380 (iv)	–	(574)
Balance at December 31, 2005	**33,036,726**	**$ 51,178**

i) On May 18, 2004 C1 completed a private placement equity financing to issue 4,000,000 common shares on a flow-through basis at a price of $2.50 per share for total proceeds of $10,000,000 prior to share issuance costs of $0.4 million (net of future tax benefit of $0.3 million). The tax effect of the renouncement was recorded in 2005, when the related expenditures were renounced.

ii) In accordance with the terms of the Company's various flow-through share offerings, and pursuant to certain provisions of the Income Tax Act (Canada), in 2004 the Company renounced, for income tax purposes, exploration expenditures related to the purchases of its flow-through shares issued in 2003 in the aggregate of $7,290,000.

iii) Pursuant to a vote by the shareholders at the annual and special meeting on May 18, 2004, C1's accumulated deficit at December 31, 2003 was eliminated by a reduction in stated capital.

iv) On June 18, 2005 C1 completed a private placement equity financing to issue 4,255,320 common shares plus 833,334 common shares on a flow-through basis at a price of $2.35 and $3.00 per share respectively for total proceeds of $12,500,000 prior to share issuance costs of $884,000. The tax effect of the renouncement will be recorded in 2006 when the related expenditures are renounced.

v) In accordance with the terms of C1's various flow-through share offerings, and pursuant to certain provisions of the Income Tax Act (Canada), the Company renounced, for income tax purposes, exploration expenditures related to the purchases of its flow-through shares issued in 2004 in the aggregate of $10,000,000.

Performance Shares	Number of shares	Amount
Balance at December 31, 2003 and 2004 (i)	1,344,000	$ 13
Conversion into common shares	(25,335)	–
Redemption upon termination of services agreement (ii)	(140,665)	(1)
Balance at December 31, 2005	**1,178,000**	**$ 12**

i) On December 23, 2003, C1 issued a total of 1,344,000 Performance Shares at an issue price of $0.01 per share. Each Performance Share is convertible into the percentage of a C1 common share equal to the closing trading price of the C1 common shares on the Toronto Stock Exchange (the "Closing Price") less $1.35, if positive, divided by the Closing Price. Each Performance Share is convertible, at the option of the holder, into C1 common shares as to 1/3 on each of the day following the first, second and third anniversaries from the date of issuance. If the C1 Closing Price less $1.35 is not positive on any conversion date, C1 has the right, subject to applicable laws, to redeem the Performance Shares that would have otherwise been converted at the redemption price of $0.01 per share. The fair value of each Performance Share was determined, at date of issuance, using the Black-Scholes model with the variables described in note 5(c).

ii) The Company terminated a services agreement with Navigo Energy Inc. ("Navigo") whereby certain administrative services were performed for C1 by Navigo. As a result, certain performance shares that were issued to Navigo employees did not vest and were redeemed by C1 as the individuals were no longer service providers to C1.

Warrants	Number of warrants	Amount
Balance at January 1, 2004	–	$ –
Issued on Extreme acquisition (i)	371,116	91
Balance at December 31, 2004	371,116	91
Exercised (i)	(311,182)	(74)
Expired (i)	(59,934)	(17)
Balance at December 31, 2005	**–**	**$ –**

i) On the acquisition of Extreme, C1 issued 371,116 share purchase warrants to Extreme warrant holders with an ascribed price of $91,100 on the same pro rata terms as the Extreme common shareholders. The fair value of each warrant was determined, at the date of issuance, using the Black-Scholes model. The fair value of the warrants issued was estimated to be $0.24 per share using a risk free interest rate of 4.0%, volatility of 50%, and an average expected life of 0.6 years. This amount is amortized over the life of the warrant and is included in stock-based compensation expense. In July 2005, a total of 311,182 warrants that were due to expire on July 27, 2005 were exercised for proceeds of $804,251. The balance of the warrants expired on August 31, 2005.

Contributed surplus	Amount
Balance at December 31, 2003	$ 14
Stock based compensation	685
Balance at December 31, 2004	699
Stock based compensation	678
Exercise of options and conversion of Performance Shares	(22)
Expiry of warrants	17
Balance at December 31, 2003 and 2004	**$ 1,372**

c) Stock-based compensation

The fair value of each Performance Share was determined, at the date of issuance, using the Black-Scholes model. The fair value of the Performance Shares issued was estimated to be $0.78 per share using a risk free interest rate of 3.5%, volatility of 43%, and an expected life of three years. This amount is amortized over the life of the Performance Share and is included in stock-based compensation expense (2005 – $184,000, 2004 – $609,000).

The Company has a stock option plan (the “Plan”) under which options to purchase common shares of the Company have been issued to employees, officers and directors. Under the Plan, all options awarded have a maximum term of five years, and vest over three years on the basis of one-third per year commencing with the first anniversary of the grant. The Plan, including the number of shares issuable upon the conversion of our Performance Shares, has a maximum number of shares reserved equal to 10% of the outstanding common shares. Total activity related to the Plan was as follows:

Stock options	Number of Options	Weighted Average Price
Balance at December 31, 2003	–	–
Granted	625,000	1.83
Balance at December 31, 2004	625,000	1.83
Granted	732,410	2.29
Exercised	(22,000)	2.50
Balance at December 31, 2005	**1,335,410**	**2.08**

Additional details on the Company's stock options outstanding at December 31, 2005 are as follows:

Exercise Price ($/share)	Number of Options	Contractual Life (years)	Options Exercisable
1.75	325,000	3.88 years	108,333
1.91	175,000	3.46 years	58,333
1.95	125,000	3.50 years	41,667
2.10	75,000	4.11 years	–
2.31	635,410	4.25 years	–
2.08	1,335,410	3.98 years	208,333

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model. This value is amortized over the life of the options and is included in stock-based compensation expense (2005 – $494,000, 2004 – $76,000). The weighted average fair value and assumptions are as follows:

Stock options	**2005**	2004
Weighted average fair value of options granted	**$ 0.85**	$ 0.72
Risk free interest rate	**4.0%**	4.0%
Expected lives (years)	**3.0**	3.0
Expected volatility	**50.0%**	47.0%

6. NET INCOME PER SHARE

C1 uses the treasury stock method to determine dilution resulting from the issuance of stock options, warrants and other dilutive instruments. The number of shares used to calculate the diluted net income per share for the year ended December 31, 2005 included the weighted average number of C1 common shares outstanding of 30,514,138 plus 1,054,782 shares related to the dilutive effect of the conversion of Performance Shares and stock options (2004 – 20,475,249 plus 856,778 shares, respectively). In calculating the weighted-average number of diluted C1 common shares outstanding for the year ended December 31, 2004, 371,116 share purchase warrants were excluded because their exercise price was greater than the average common share market price during the period the warrants were outstanding.

7. ASSET RETIREMENT OBLIGATIONS

The following table presents the reconciliation of the beginning and ending aggregate carrying amount of the obligation associated with the retirement of oil and gas properties:

	2005	2004
Asset retirement obligations, January 1	**$ 536**	$ 368
Liabilities incurred	**350**	256
Settlement of liabilities	**(150)**	–
Disposition of liabilities	**(70)**	–
Accretion expense	**86**	18
Change in estimates	**244**	(106)
Asset retirement obligations, December 31	**$ 996**	$ 536

At December 31, 2005, the total undiscounted asset retirement obligations are estimated to be $6.0 million (2004 – $4.2 million). A 2 percent inflation rate and a 9 percent discount rate assumption have been used to estimate the obligations. Most of the obligations related to oil and natural gas wells are expected to be settled from 2015 to 2025 and those related to facilities are expected to be settled up to 2039 with all being funded from general corporate resources at the time of settlement.

8. INCOME TAXES

The components of the future income tax asset (liability) are as follows:

	2005	2004
Future income tax asset (liability)		
Property and equipment	**$ (2,991)**	$ 1,134
Asset retirement obligations	**335**	180
Attributable Canadian Royalty Income benefit (“ACRI”)	436	–
Share issue costs	**616**	620
Other	**(17)**	49
Net future income tax asset (liability), December 31	**$ (1,621)**	$ 1,983

The provision for income taxes differs from the result that would be obtained by applying the combined Canadian federal and provincial statutory income tax rates to income before income taxes. This difference results from the following:

	2005	2004
Income (loss) before taxes	**$ 1,613**	$ (1,257)
Income tax rate	**37.6%**	39.6%
Expected income tax expense (recovery)	**606**	(498)
Increase (decrease) in taxes resulting from:		
Crown royalties (net of ARTC)	**370**	467
Resource allowance	**(358)**	(340)
Stock based compensation	**255**	271
Recognition of ACRI	**(436)**	
Other	**5**	(87)
Future tax benefits recognized	**(1,042)**	(4,061)
Income tax expense (recovery)	**$ (600)**	$ (4,248)

The Company has the following estimated tax deductions available to reduce future taxable income:

	2005	2004
Canadian oil and gas property expense	**$ 12,891**	$ 12,672
Canadian development expense	**8,699**	9,163
Canadian exploration expense	**15,444**	8,863
Foreign exploration and development expense	**205**	228
Undepreciated capital cost	**8,065**	5,529
Non-capital losses carried forward	**4,246**	624
Share issue costs	**1,761**	1,714
Total available tax pools	**$ 51,311**	$ 38,793

9. FINANCIAL INSTRUMENTS

The carrying value of the Company's cash and cash equivalents, accounts receivable, accounts payable and bank loan approximates their fair value due to the short term nature of these balances and the floating rate of interest on the bank loan.

Substantially all of the Company's accounts receivable are due from customers in the oil and gas industry and are subject to the normal industry credit risks. The carrying value of accounts receivable reflects management's assessment of the associated credit risks.

The nature of the Company's operations results in exposure to fluctuations in commodity prices, exchange rates and interest rates. The Company, when appropriate, will utilize derivative contracts to manage its exposure to these risks.

10. SUPPLEMENTARY CASH FLOW INFORMATION

Changes in non-cash working capital items increased (decreased) cash and cash equivalents as follows:

	2005	2004
Accounts receivable	**$ (1,221)**	$ (3,723)
Prepaid expenses	**(140)**	119
Accounts payable and accrued liabilities	**2,732**	5,088
Non-cash working capital deficiency acquired	**–**	(1,290)
Change in non-cash working capital	**$ 1,371**	$ 194
Operating activities	**$ (443)**	$ 910
Investing activities	**1,814**	(716)
Change in non-cash working capital	**$ 1,371**	$ 194

There was $28,200 of interest paid during the year (2004 – $nil). No income or capital taxes were paid during 2005 or 2004.

11. COMMITMENTS

In October, 2004 C1 entered into a sublease agreement for office space. The sublease continues until March, 2006. C1 pays approximately $170,000 per annum for rent and estimated operating costs. The Company also pays a lease commitment on office space used by Extreme. C1 pays approximately $65,000 per annum for rent that continues until November 2007.

C1 closed a flow through share offering on June 18, 2005 and is committed to spend $2.5 million before December 31, 2006 on expenditures qualifying as Canadian exploration expenses.

The Company has guarantees and other commitments in the normal course of business which would not have a material adverse effect on the Company's liquidity, financial condition or results of operations.

12. SUBSEQUENT EVENT

In February 2006, C1 entered into a lease agreement for office space. The lease begins in April 2006 and continues for a period of five years. C1 will pay approximately $287,000 per annum for the first two years, $295,000 for the third year and $304,000 per annum for the last two years for rent and estimated operating costs.

FINANCIAL AND OPERATING HIGHLIGHTS

	Year ended December 31, 2005	Year ended December 31, 2004	Three day period ended December 31, 2003
Financial ($000s, except share information)			
Petroleum and natural gas sales	**13,326**	8,718	30
Cash flow from operations[1]	**6,302**	3,959	(9)
Per share basic	**0.21**	0.19	0.00
Per share diluted	**0.20**	0.19	0.00
Net income	**2,191**	2,991	(43)
Per share basic	**0.07**	0.15	0.00
Per share diluted	**0.07**	0.14	0.00
Capital expenditures	**28,285**	26,093	16,130
Working capital (deficiency)	**(4,619)**	4,468	8,981
Total assets	**71,039**	52,685	26,299
Shareholders' equity	**57,744**	45,853	24,722
Common shares outstanding (000s)	**33,037**	27,609	17,754
Weighted average common shares outstanding (000s)	**30,514**	20,475	17,754
Operations			
Crude oil and NGL production			
Barrels	**113,019**	121,466	567
Barrels per day	**310**	332	189
Average selling price ($/bbl)	**65.42**	51.78	43.22
Natural gas production			
Thousand cubic feet	**696,019**	372,245	1,142
Thousand cubic feet per day	**1,906**	1,017	381
Average selling price ($/mcf)	**8.52**	6.55	4.85
Oil equivalent production			
Barrels of oil equivalent	**229,022**	183,507	757
Barrels of oil equivalent per day (6:1)	**627**	501	252
Average selling price ($/boe)	**58.19**	47.51	39.67
Average operating netback ($/boe)	**33.78**	26.11	23.25
Wells drilled			
Gross	**22**	5	–
Net	**14.8**	3.7	–

(1) The Company, in part, evaluates its performance based on cash flow from operations. Cash flow from operations is a non-GAAP measure that represents cash generated from operating activities before changes in non-cash working capital items during the period. Cash flow from operations may not be comparable to similar measures used by other companies.

Please note that all natural gas values are converted to a barrel of oil equivalent (boe) on a 6:1 ratio unless otherwise stated. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

This report should be read in conjunction with previously released public documents. The comparative figures for 2003 include only three days of operations as C1 Energy Ltd. was established on December 29, 2003.

MANAGEMENT AND DIRECTORS

HUGH PATTILLO *President and Chief Executive Officer, Director*

Mr. Pattillo has over 20 years of management and technical experience in the oil and gas industry. Mr. Pattillo became President and Chief Executive Officer of C1 Energy in December 2003 after directing exploration for Navigo as its Vice President, Exploration from July 2002. Previously, Mr. Pattillo was Chief Geophysicist at Petromet Resources Ltd. and Chief Geophysicist and Northern Exploration Leader for Beau Canada Exploration Ltd. Mr. Pattillo graduated with Bachelor of Science (Honours Geophysics) from the University of Western Ontario in 1982.

GARY LOBB *Vice President of Finance and Chief Financial Officer, Director*

Mr. Lobb has over 20 years of financial experience, and became Vice President of Finance and Chief Financial Officer of C1 Energy in December 2003. Formerly Mr. Lobb was Vice President of Finance, Chief Financial Officer and Corporate Secretary of Nycan Energy Corp. from January 2002 to May 2003; and held the same role at Tetonka Drilling Inc. until the October 2000 merger of Tetonka Drilling Inc. and Bonus Well Services Corp. Prior to the merger, Mr. Lobb was the Chief Financial Officer of Tetonka Drilling Inc. since 1997. Mr. Lobb graduated with a Bachelor of Commerce degree from the University of Calgary in 1983.

RON BARMBY *Vice President and Chief Operating Officer, Director*

Mr. Barmby P.Eng, M.Eng, has more than 20 years of operations experience. He joined C1 as the Vice President of Operations in September 2004 and was promoted to Vice President and Chief Operating Officer in early 2005. Previously, Mr. Barmby was Vice President, Production and Engineering of Navigo Energy Inc. between December 2001 and June 2004 and was Vice President of Gulfstream Resources from 1995 to 2001. Mr. Barmby also worked with Amerada Hess Canada as their Drilling and Completions Manager and Production Manager.

BILL VANDERVEEN *Vice President OF Exploration, Director*

Mr. VanderVeen P.Geol., has 26 years of oil and gas exploration experience in the Western Canadian Sedimentary basin. Mr. VanderVeen joined C1 as Vice President Exploration in October 2004. Previously Mr. VanderVeen was with Navigo Energy from July 2002 and was a senior geologist at Encal from January 2001 to June 2002, and was a geological consultant for various small and medium sized exploration and development companies.

GARY CAMPBELL *Land Manager*

Mr. Campbell has 23 years of experience in the oil and gas industry. He began consulting to C1 in January 2004 and became Land Manager in June 2004. Prior to joining C1, Mr. Campbell was Team Lead - Business Development for Encana from September 2002 to December 2003. Previously he was a regional landman at Petro-Canada from January 1999 to September 2002, and Vice President of Land and Contracts at Brandon Energy from April 1996 to April 1998.

JIM DITTRICH *Chief Geophysicist*

Mr. Dittrich has 23 years of experience in the Western Canadian Sedimentary basin exploring for oil and gas. Prior to joining C1 as a Senior Geophysicist in October 2004, Mr. Dittrich was Senior Geophysicist at Navigo Energy Inc. since 2002. In the last 10 years, Mr. Dittrich was a Chief Geophysicist at Magin Energy and Senior Geophysicist at Sceptre Resources and CNRL.

STACEY RADLEY *Manager, Engineering*

Mr. Radley is a professional engineer with 11 years of experience in the oil and gas industry. Mr. Radley joined C1 in October 2004 after working with Navigo Energy as Senior Engineer since June 2002. Previously, Mr. Radley worked for Nowsco Well Service, Alberta Energy Company, and NAL Resources on drilling, completions, production, facilities and reservoir engineering.

CORPORATE INFORMATION

BOARD OF DIRECTORS

Johannes (Jim) Nieuwenburg
Independent Businessman

Raymond Chan
President and
Chief Executive Officer
Baytex Energy Trust

Ronald McIntosh
Independent Businessman

Kenneth McNeill
Independent Businessman

Christopher Nixon
Partner
Stikeman Elliott LLP

Hugh Pattillo
President and
Chief Executive Officer
C1 Energy Ltd.

Herb Pinder
President
Goal Group of Companies

OFFICERS

Hugh Pattillo
President and
Chief Executive Officer

Gary Lobb
Vice President of Finance
and Chief Financial Officer

Ron Barmby
Vice President of Operations
and Chief Operating Officer

Bill VanderVeen
Vice President of Exploration

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AUDITORS

Deloitte & Touche LLP

BANKERS

National Bank of Canada

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Associates Ltd.

TRANSFER AGENT

Computershare Investor Services Inc.

EXCHANGE LISTING

Toronto Stock Exchange
Stock Symbol: CTT

ABBREVIATIONS

bbl(s)	barrel(s)
mbbls	thousand barrels
mmbbls	million barrels
mcf	thousand cubic feet
mmcf	million cubic feet
bcf	billion cubic feet
boe	barrel of oil equivalent (6 mcf = 1 bbl)
mboe	thousand boe/d per day
mmbtu	million British thermal units
NGLs	natural gas liquids
API	Alberta Petroleum Index
AMI	Area of mutual interest
ARTC	Alberta Royalty Tax Credit
FNR	Future net revenue
GPP	Good Production Practice
NPV	Net present value
JV	Joint Venture
RLI	Reserve Life Index
WTI	West Texas Intermediate

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