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CONNACHER OIL AND GAS LIMITED

ANNUAL REPORT 2005

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CORPORATE PROFILE

Connacher Oil and Gas Limited is a Calgary-based Canadian oil and natural gas exploration, development and production company. Its principal asset is a 100 percent interest in 110 sections (70,400 acres) of oil sands leases at its Great Divide oil sands project near Fort McMurray, Alberta. It also maintains conventional production at Battrum, Tompkins and Steelman, Saskatchewan. Connacher presently owns 33 percent of and manages Petrolifera Petroleum Limited, which has interests in Argentina and Peru. In early 2006, Connacher acquired Luke Energy Ltd., adding natural gas reserves and associated production and cash flow. The Company has also announced plans to acquire and operate an 8,300 bbl/d refinery located in Great Falls, Montana.

In pursuing its objective of maximizing shareholder value, where possible Connacher secures large, operated interests. Over time, a balanced portfolio of oil and natural gas interests is being pursued. An opportunistic approach, supported by timely decisions, reflects management's experience and aggressive strategy towards realizing growth objectives. Connacher pursues its objectives utilizing a conservative financial structure which reflects its asset base.

TABLE OF CONTENTS

Certain information contained in this Annual Report including introductory messages, Letter to Shareholders, Review of Operations and Management's Discussion and Analysis include forward-looking information which is subject to risks, uncertainties and assumptions that are described herein. See page 30, Management's Discussion and Analysis for a discussion of these risks, uncertainties and assumptions.

Annual and Special Meeting
Thursday, May 11, 2006 - 3:00 pm MST
Eau Claire Room
The Westin
320 - 4 Avenue SW
Calgary, AB

CONNACHER OIL AND GAS IS ALWAYS COMMITTED TO CREATING SHAREHOLDER VALUE ABOVE ALL ELSE. USING AN INNOVATIVE AND COMMITTED APPROACH, IN 2005 WE SUCCESSFULLY SEIZED COMPANY-MAKER OPPORTUNITIES. WE ARE LOOKING TOWARDS OUR FUTURE WITH CONFIDENCE.

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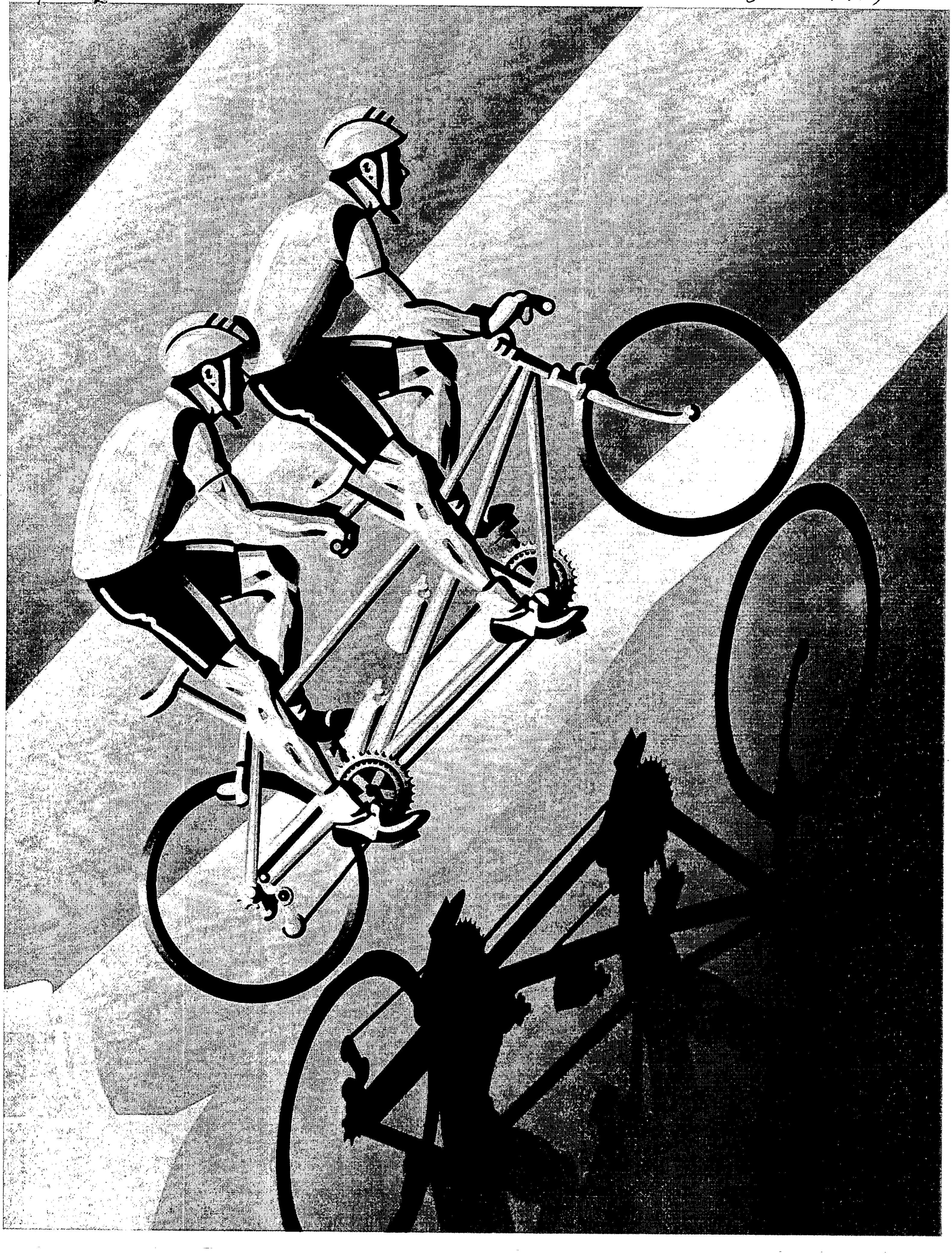

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LIBERATING VALUE AND CREATING GROWTH

One way to liberate value and create growth is to actually create a focused affiliate. This is what we did - and with great success. Petrolifera Petroleum Ltd. began trading publicly on the Toronto Stock Exchange in November 2005. Connacher currently owns 33% and is the largest shareholder of this dynamic company which explores and produces for oil and gas in South America. With some impressive oil discoveries right out of the gate and significant land holdings in Argentina and Peru, Petrolifera is another way Connacher has created value for its shareholders.

CONNACHER OIL AND GAS LIMITED

petrolifera PETROLEUM LIMITED

PROTECTING OUR ASSETS

We worked hard this year to build a strong asset base for you, our shareholders. In late 2005, we announced our intent to acquire Luke Energy Ltd., a natural gas-focused junior producer. The transaction offsets our exposure to the price of natural gas, which is a significant input for development of our oil sands assets at Great Divide. The transaction was approved by Luke shareholders on March 15, 2006 and closed on March 16, 2006.

We have also agreed to purchase refining assets in Montana which will give us greater protection against volatile and widening price differentials for heavy oil.

We reduced financial risk by raising significant amounts of new equity capital at improving prices.

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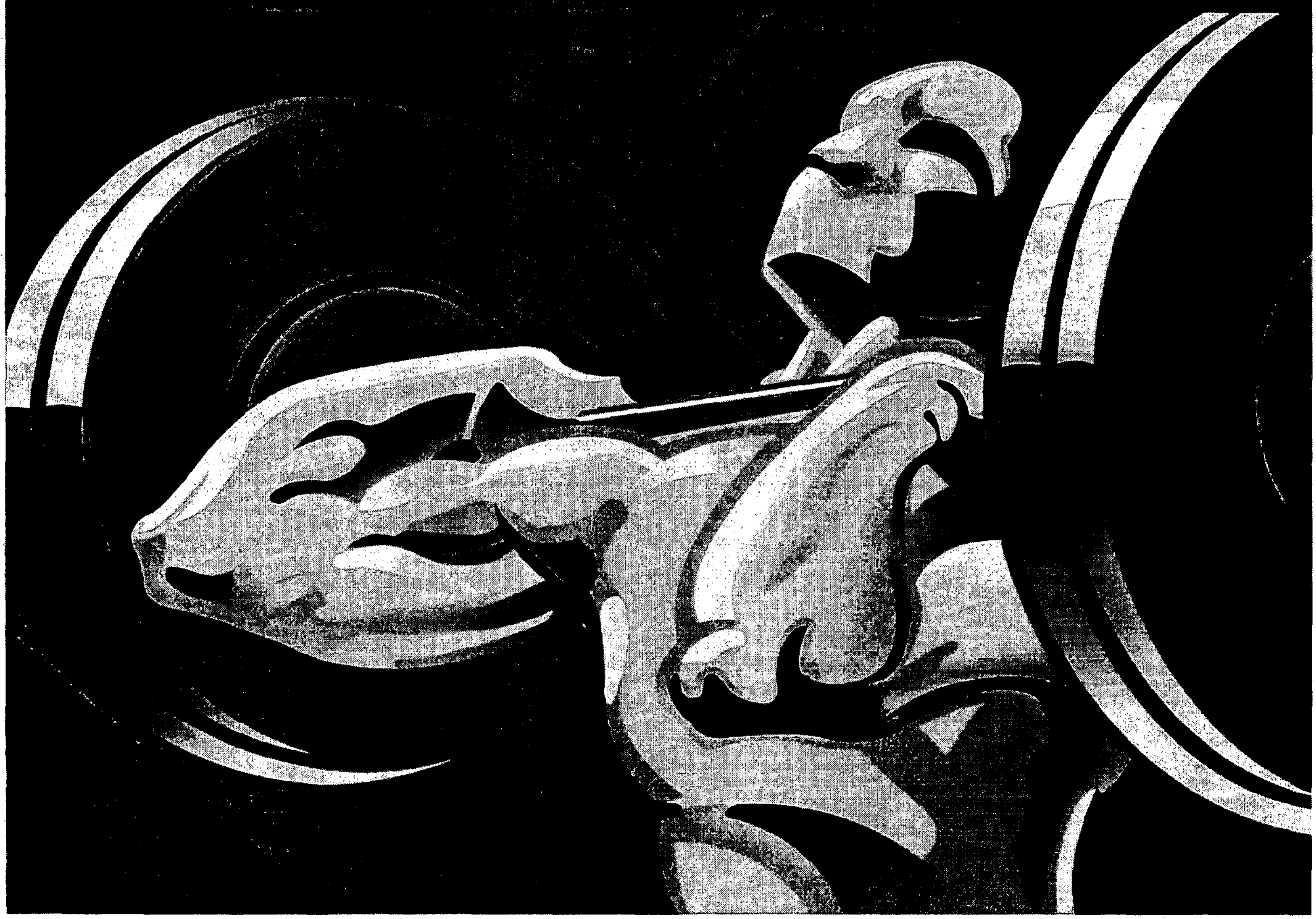
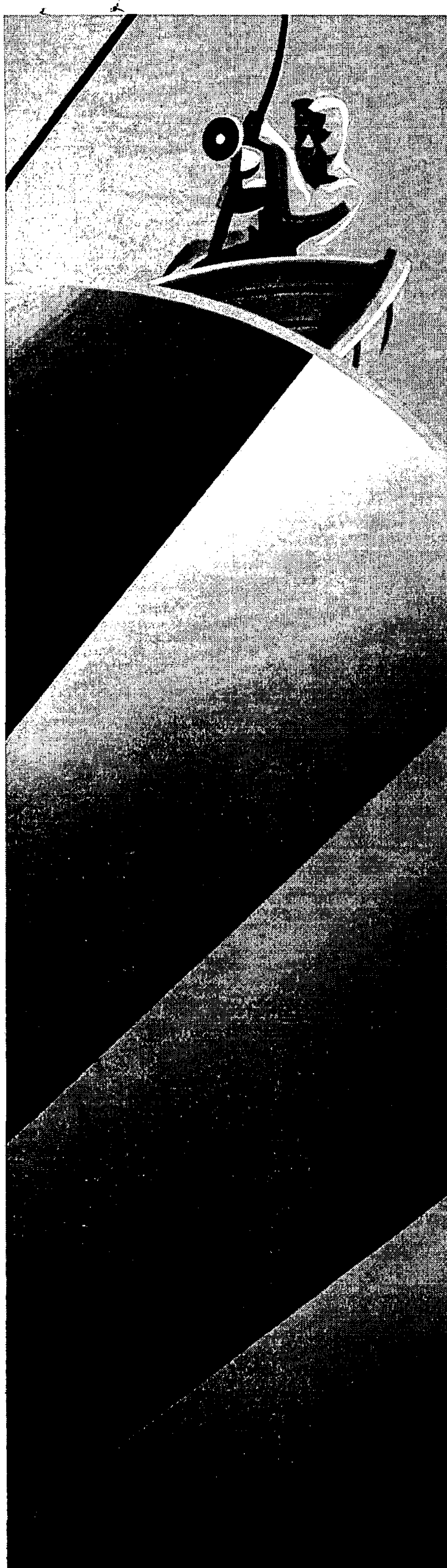
BUILDING ON OUR STRENGTHS

Many factors contributed to Connacher's 598 percent share price increase in 2005. We had success exploring in regions where most juniors don't. We mitigated risks through strategic deal-making. We built a strong balance sheet. We successfully added to our team of dedicated and forward-thinking employees. Connacher is getting stronger every day.





GOING AFTER THE BIG ONE

2005 saw impressive share price gains and success on top of success. But we're not satisfied. We think big at Connacher with our focus on the oil sands. Our Great Divide project already has recognized recoverable reserves of over 100 million barrels and is targeted to produce 10,000 barrels per day for up to 25 years. This is just Pod One, and our work indicates there could be further development potential.

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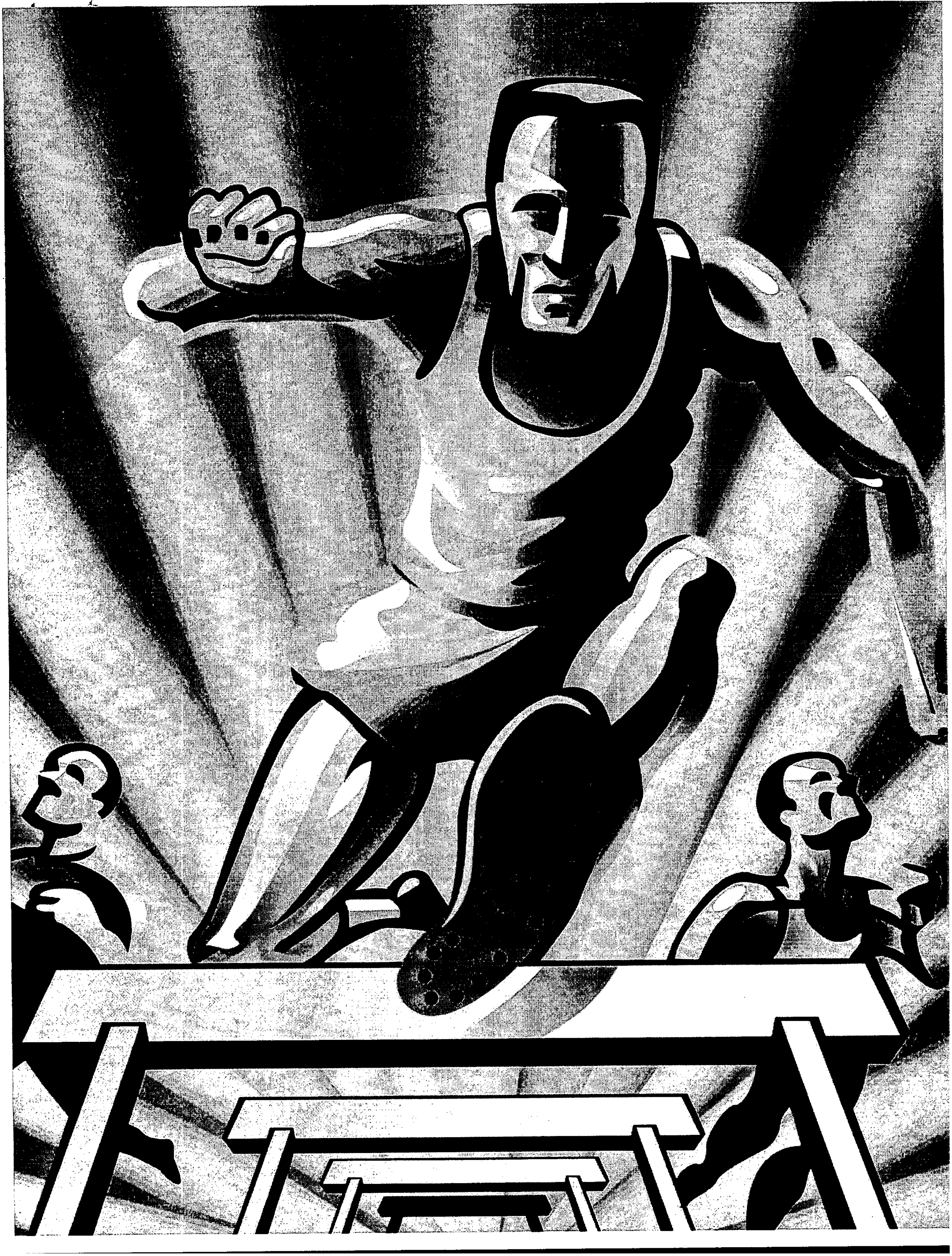
THE YEAR BEHIND US, THE YEAR AHEAD

In 2005 we took big steps in order to move ahead of the pack and increase shareholder value. We identified some great prospects in Great Divide, secured balanced assets with the Luke acquisition and gained diversity and mitigated risks with the prospective purchase of refining assets in Montana. We now have the prospect of stronger cash flow from diverse sources, while operating with a strong balance sheet. 2006 could see Connacher moving further forward.



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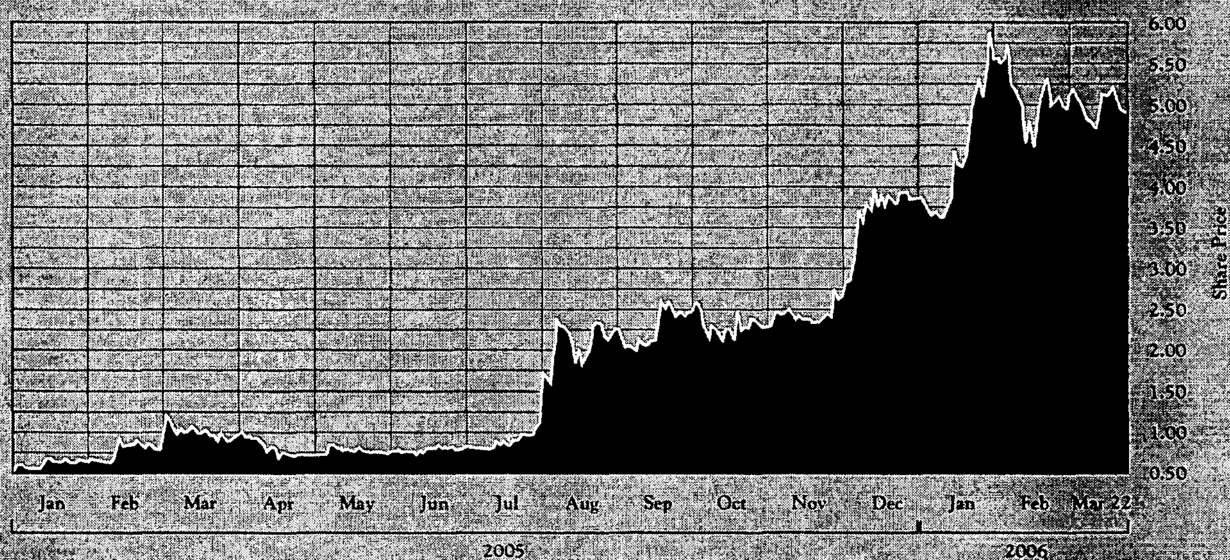
FINANCIAL AND OPERATING HIGHLIGHTS

2005 FINANCIAL AND OPERATING HIGHLIGHTS

- Increased proved and probable reserves by 2,600 percent to 72.1 million boe; 3P reserves reached 112 million boe.
- Submitted application for 10,000 bbl/d Great Divide Project.
- Raised $90 million of new equity at improving prices.
- Benefited immensely from skyrocketing value of Petrolifera holdings due to new Argentinean discoveries.
- Finished year with debt-free balance sheet and year-end working capital of $75 million.
- Recognized as the top performing TSX-listed oil and gas company for the year.

SUBSEQUENT EVENTS

- Acquired Luke Energy Ltd. through a Plan of Arrangement in March 2006.
- Raised $100 million of new equity.
- Reached agreement to acquire refining assets in Montana.
- Surpassed $1 billion for fully-diluted market capitalization(excluding approximately $400 million capitalization of Petrolifera).



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	2005	2004	% Change
FINANCIAL ($000s except per share amounts)			
Total revenue [1]	**12,378**	11,216	10
Cash flow from operations before working capital changes [2]	**4,358**	2,409	81
Per basic and diluted share [2]	**0.04**	0.05	(20)
Net earnings (loss)	**991**	(2,976)	-
Per share, basic and diluted	**0.01**	(0.06)	-
Capital expenditures	**16,807**	17,629	(5)
Proceeds of disposition	**-**	17,604	-
Working capital	**75,427**	3,549	2,025
Cash on hand	**75,511**	3,914	1,829
Shareholders' equity	**129,108**	40,375	220
Total assets	**134,813**	46,090	192
Common shares outstanding (000's)			
Weighted average			
Basic	**106,114**	50,908	108
Diluted	**111,846**	53,329	110
End of Period			
Issued	**139,940**	89,627	56
Fully diluted	**150,027**	98,916	52
OPERATING			
Daily production / sales volumes			
Crude oil - bbl/d	**729**	785	(7)
Natural gas - mcf/d	**827**	1,620	(49)
Barrels of oil equivalent - boe/d [3]	**867**	1,055	(18)
Selling prices	**36.91**	28.95	27
Operating cost	**7.73**	9.75	(21)
Operating netback - $/boe[3][4]	**23.23**	13.75	69
Reserves (mboe) [3][5]			
Proved	**1,501**	1,521	(1)
Probable	**70,598**	1,295	5,352
Possible	**39,788**	52,783	(24)
Total	**111,889**	55,602	101

(1) In the third quarter of 2005 the company discontinued consolidating the financial and operating results of Petrolifera Petroleum Limited. Comparative figures have not been restated, except for 2004 reserves. See Note 5 below.

(2) Cash flow from operations before working capital changes, cash flow per share and netbacks do not have standardized meanings prescribed by Canadian generally accepted accounting principles ("GAAP") and therefore may not be comparable to similar measures used by other companies. Cash flow from operations before working capital changes includes all cash flow from operating activities and is calculated before changes in non-cash working capital. The most comparable measure calculated in accordance with GAAP would be net earnings. Cash flow from operations before working capital changes is reconciled with net earnings on the Consolidated Statement of Cash Flows and in the accompanying Management Discussion & Analysis. Management uses these non-GAAP measurements for its own performance measures and to provide its shareholders and investors with a measurement of the company's efficiency and its ability to fund a portion of its future growth expenditures.

(3) All references to barrels of oil equivalent (boe) are calculated on the basis of 6 mcf : 1 bbl. Boes may be misleading, particularly if used in isolation. This conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(4) Operating netback is a non-GAAP measure used by management as a measure of operating efficiency and profitability. It is calculated as petroleum and natural gas revenue less royalties and operating costs.

(5) 2004 reserves restated to reflect deconsolidation of Petrolifera.

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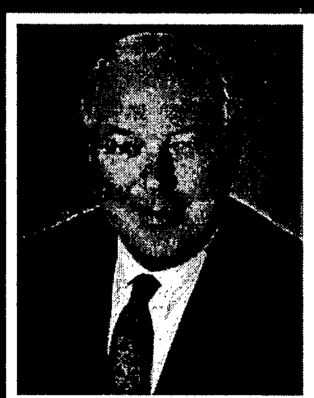
LETTER TO SHAREHOLDERS



R.A. Gusella

President and
Chief Executive Officer

CONNACHER HAD AN EXTREMELY BUSY AND SUCCESSFUL YEAR DOMINATED BY PERFORMANCE, PROGRESS AND MARKET RECOGNITION OF OUR ACCOMPLISHMENTS. THROUGHOUT THIS ANNUAL REPORT YOU WILL SEE VARIOUS METAPHORS FOR SUCCESS. THIS REFLECTS CONNACHER'S ACHIEVEMENTS ON A NUMBER OF FRONTS IN 2005.

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During the year, we strengthened our balance sheet. We advanced our Great Divide oil sands project. We liberated the value of our international assets through the creation of Petrolifera Petroleum Limited, while retaining a significant equity interest.

Two bought deal equity financings during 2005 and another one in early 2006, at sequentially higher issue prices, positioned us to seize opportunities and mitigate financial risk. A total of $190 million was raised. By March 2006 Connacher's fully-diluted market capitalization had risen to over $1 billion, while Petrolifera's was approaching $400 million. This compares to only $15 million some eighteen months ago.

At our Great Divide oil sands project, significant reserve volumes were booked upon receipt of a report by an independent engineering consultant. These were recognized as we had prepared and then submitted an application to Alberta's Energy and Utility Board ("EUB") and other related agencies to develop Pod One at Great Divide. This declaration and our application brought capital market attention into focus and translated into share price appreciation. In fact, Connacher's common shares outperformed all other oil and gas equities on the Toronto Stock Exchange for 2005. Trading liquidity remained excellent, allowing larger institutional investors to easily modify their positions. At the same time, individual investors continued their active trading of our common shares. We appreciate the support of all shareholders, which now number close to 40,000.

The creation of Petrolifera has proven to be a successful value creating initiative. In addition to acquiring substantial high potential licenses covering over five million acres onshore Peru, late in 2005 Petrolifera embarked on a multi-well drilling program on its Puesto Morales/Rinconada Concession in the Neuquén Basin onshore Argentina. This resulted in several significant new discoveries of light gravity oil from flowing oil wells, which sparked a strong stock market reaction. Connacher's equity stake in Petrolifera remains unencumbered and is valued well in excess of $150 million, compared to a cash cost of $2 million. This value liberating exercise also rewarded Connacher shareholders by contributing to our share price appreciation. Further accretion is anticipated with excellent long run potential recognized. Current plans are to retain this attractive investment for the longer term, due to its recognized growth potential. This investment could afford Connacher a degree of financial freedom and flexibility as a prospective source of funds should market conditions change.

In early 2006 Connacher acquired Luke Energy Ltd. ("Luke") for its natural gas reserves at a cost exceeding $200 million. Also, an agreement was reached to purchase a small but profitable 8,300 barrel per day refinery, together with product inventory, located in Great Falls, Montana for approximately $60 million. These strategic purchases should strengthen our current cash flow while mitigating risks associated with anticipated oil sands production.

INDUSTRY DEVELOPMENTS – HIGHER PRICES A DOMINANT THEME

Most of the changes which characterized the energy sector in 2005 revolved around the surge in commodity prices during the year. The market for crude oil saw record high prices, contango in the futures market and a considerable risk premium which persisted in the context of volatile geopolitical conditions, largely related to the war in Iraq. Strong demand growth and the forecast of continued growth from China, India and other developing nations also contributed to the quantum jump in crude oil prices. These strong prices brought into focus the relentless issue of reserve replacement and the continuing debate about the reliability of supply from the Middle East and other established petroleum-producing regions.

These rising oil prices and the need for dependable long-term supplies coalesced during 2005 and brought Canada's oil sands deposits into focus. The unofficial oil sands "press index" reached an all-time high, with financial papers reporting almost relentlessly on the projects under development, the potential importance to North American certainty of supply of the oil sands and on visits by dignitaries representing large consuming nations. Interest about securing participation in our project was also expressed to Connacher by Asian, North American and European companies. There were numerous capital raising initiatives by large and small companies alike. Transportation alternatives, upgraders and land sales with rising per acre bonuses and significant new capital flows into the sector were also topics of extensive discussion.

Simultaneously, despite significantly higher oil prices, differentials for heavier crude oil such as that produced in the oil sands widened and became more volatile, as refiners had not yet invested in downstream facilities to handle the reality of more heavy oil entering the market. Of course, higher differentials also gave refiners an opportunity to improve margins and should eventually result in further investment in more sophisticated capacity, capable of improving yields from this feedstock. As crude prices rose, so inexorably did natural gas prices, fuelled partially by supply disruptions due to the impact of hurricanes in the Gulf Coast of the United States. This becomes a cost concern for steam-assisted gravity drainage ("SAGD") operations in the oil sands until alternate fuel sources, including direct burning of bitumen, are commercialized.

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CONNACHER'S RESPONSE WAS TIMELY AND FOCUSED

Against this backdrop, Connacher focused on its Great Divide assets. The company drilled numerous additional core holes and conducted a complementary 3D seismic program. The presence of a commercially exploitable accumulation was subsequently confirmed at Pod One on Connacher's 110-section land base in the Divide region southwest of Fort McMurray, Alberta. This well-situated accumulation, located in close proximity to existing highway, pipeline and power infrastructure, was assigned 180 million barrels of oil-in-place reserves by a qualified independent consultant. Additional resources were also recognized. More importantly, probable and possible recoverable reserves exceeding 100 million barrels were assigned. While reserves will remain in these categories until we secure EUB approval and place the accumulation on stream at a targeted rate of 10,000 bbl/d, these are significant volumes with considerable value for Connacher's shareholders.

Based on the drilling results and supported by third party confirmation of reserve estimates, in August 2005 we submitted an application to Alberta's EUB and associated environmental and regulatory agencies for approval to proceed with commercial exploitation of this significant asset. It is no coincidence that capital market attention in Connacher accelerated from the date we disclosed these reserve estimates. This also occurred on the same day a major international oil company announced a bid, at a considerable premium to market, to acquire another Canadian company possessing certain assets similar in nature and size to Connacher's.

Our focus also allowed us to start the process of raising the capital needed to bring our Great Divide oil sands projects on stream. We had three successful bought deal equity financings, two during 2005 and one subsequent to year-end, raising $190 million of gross proceeds to provide funds for acquisitions such as Luke and for new initiatives on our extensive oil sands holdings, including drilling of SAGD wells and construction of facilities to enable commercial production once regulatory approvals are received. While we received numerous approaches during the year from international state oil companies and other commercial enterprises seeking participation in our assets, we concluded that our shareholders' interests were better served by accessing funds in capital markets and retaining our 100 percent interest in Great Divide. This ensured our ability to maintain control of the project while capitalizing on our managerial expertise, the quality of our assets and the buoyant environment in this space, positioning Connacher to deliver maximum prospective value to its shareholders.

We are fortunate that our reserve base at Great Divide possesses excellent reservoir characteristics. Even though indentified individual accumulations cover relatively small areas, they are rich enough and of such high quality that they afford the prospect of attractive economic returns. They are not entirely without risk, however, even though SAGD technology is being applied on a commercial basis. Our focus, however, is on the efficiency of small-scale operations. Recognized risk factors must be managed and mitigated despite our emphasis on modularity and our ability to build our facilities at lower cost off-site and transport them to the proposed plant location, due to strong infrastructure support and access to experienced and qualified personnel.

MANAGING RISK

In addition to managing balance sheet or financial risk by expanding our equity account, in late 2005 we announced plans to acquire Luke, a natural gas producer with an operating strategy similar to ours. The purchase will allow us to deal with the energy input costs associated with steam generation and the SAGD process. The Luke acquisition, which was consummated in mid-March 2006, provided Connacher with immediate additional cash flow; a hedge against natural gas price increases; if necessary, access to physical natural gas molecules; and a more diversified asset base in Alberta. The $200 million-plus transaction ended up being largely financed with equity and cash balances. Connacher retains significant cash balances and had over $50 million of unused available credit facilities subsequent to the transaction.

As previously noted, crude oil price differentials for heavier oil have widened and become more volatile in the context of rising crude oil prices. As these circumstances evolved, Connacher decided to mitigate this risk by acquiring a small, well-run oil refinery in Montana. This refinery was being supplied from southern Alberta medium gravity crude oil pools and Connacher expects it could send certain and prospectively all of its Pod One Great Divide volumes to this refinery once it commences production, hopefully by early 2007.

The purchase of these assets is scheduled to close on March 31, 2006. This should permit Connacher a window of opportunity to gain experience in the operation of the refinery until our Great Divide crude comes onstream. We will benefit from the continued employment and availability of the existing experienced and qualified personnel who remained with the acquired assets. We believe this risk-mitigating transaction could enable Connacher to achieve attractive and stable rates of return from an integrated operation on a sustainable basis, even in periods of wide differentials. This should accordingly reduce shareholders' risk. The refinery is well-situated, prospectively could be expanded and inserts Connacher into

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the United States business scene for heavy oil and refined product marketing. We believe this will serve us well in the future as we believe most oil sands production will eventually be destined for these markets.

POSITIONING FOR THE FUTURE

Connacher utilizes a simple and effective business model, employing an experienced and capable core staff, supplemented by access to contracted technical expertise in select areas associated with the oil sands and heavy oil. During the year we strengthened our in-house technical expertise and also hired key personnel with considerable and recent experience in the modular construction of oil sands facilities. We also added support personnel in the financial, operations and engineering areas.

When regulatory approval is secured for our Great Divide project, we could have about 200 people working for us at peak construction times and then about 20 people to operate our facilities once production is underway. We look forward to working with our new staff, including those joining us from Luke and scheduled to join us at the Montana refinery. We also anticipate fostering and maintaining excellent relations with our indigenous people, with contractors, and with all our shareholders at our Great Divide project in the wilderness of northern Alberta.

During 2005 we strengthened and expanded our compact and competent Board of Directors. Mr. D. Hugh Bessell joined the Board and was appointed Chairman of the Audit Committee. Hugh rose to be Deputy Chairman of a national accounting firm in his business career and brings sound judgment and requisite financial expertise, as mandated by the prevailing governance initiatives of regulators and stock exchanges. Following his recent retirement as President of McDaniel and Associates Consultant Ltd., a preeminent oil and gas reserve evaluation firm based in Calgary, Mr. W. C. (Mike) Seth also joined the Board. He has assumed Chairmanship of our Reserves Committee, allowing us to capitalize on his expertise in this area. Connacher's Board also created a Health, Safety and Environment Committee in recognition of the growing importance of these issues in our business. During the year, Mr. Gary Freeman resigned for reasons related to his personal relocation and we thank him for his contributions during his tenure as a director. In early 2006 Mr. Stephen A. Marston was appointed Vice President, Exploration and we welcome him to our team.

Connacher's success reflects the dedication of a small number of competent, hard-working people who make the company and its initiatives work. Their efforts are supported by our experienced and engaged Board of Directors, which provides guidance and a policy framework within which management can focus on value-adding transactions and accomplishments to the benefit of our shareholders. Our approach is to recognize opportunities, secure them and then convert them into production, cash flow and shareholder value, including recognition in public capital markets. Based on what transpired in 2005, this approach seemed to work well and no material change to this approach or style is anticipated in 2006. We must, however, make adjustments to our much expanded revenue base and record capital outlays planned for the year with the appropriate discipline and controls in place.

OUTLOOK FOR 2006

During 2006 Connacher will focus on integrating our acquisitions and the people we need to bring these assets and companies into our sphere in the most productive manner. We will continue to monitor new opportunities. We intend to work to ensure capital markets are aware of our assets and their underlying value. We will monitor and enact procedures to ensure assets are optimized in the interests of our shareholders. We will strive to maintain a strong balance sheet with limited short-term indebtedness, relying primarily on longer-term project financing consistent with the long reserve life of our oil sands properties, thus using appropriately structured leverage to the benefit of our shareholders.

Our appreciation is extended to employees, contractors, shareholders and investors. Although we cannot guarantee results, we remain optimistic that drilling on our Great Divide block could result in additional exploitable accumulations for sustained growth and further value enhancement. We believe our shareholding in Petrolifera has the potential of additional appreciation. We are encouraged that we could be able to enhance the value of Luke properties and their associated productive capacity. With a 2006 capital budget approaching $500 million, we expect to have a busy and productive year with limited, if any, additional equity required to sustain our growth.

We look forward to reporting to you on our progress in 2006. It should be another productive and successful year. As portrayed on the cover of this report, we expect to be "on board" when the claxton rings!

Respectfully submitted on behalf of the Board of Directors,

Signed,

"R.A. Gusella"

Richard A. Gusella
President and Chief Executive Officer

March 23, 2006

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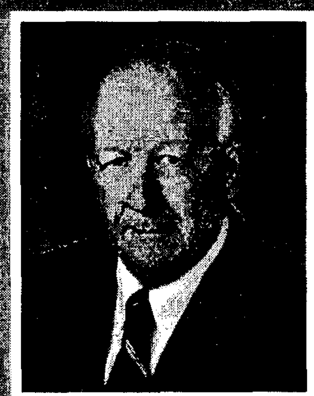
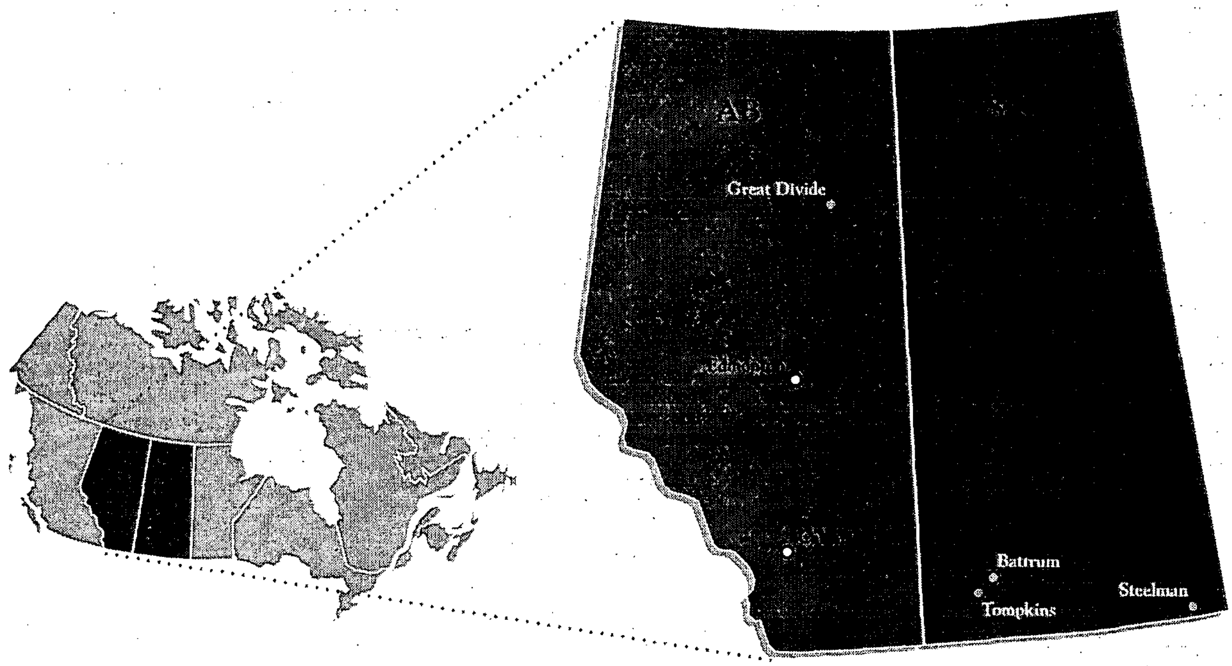
REVIEW OF OPERATIONS

Peter D. Sametz
Executive Vice President and
Chief Operating Officer



Timothy J. O'Rourke
Vice President,
Oil Sands Operations

CONNACHER'S PRINCIPAL ASSET IS ITS 100 PERCENT OWNERSHIP AND OPERATORSHIP OF 110 SECTIONS OF OIL SANDS RIGHTS AT ITS GREAT DIVIDE PROJECT IN NORTHEASTERN ALBERTA. DURING 2005 THE COMPANY CONDUCTED AN EXTENSIVE CORE HOLE PROGRAM TO DELINEATE AN ACCUMULATION, NOW IDENTIFIED AS POD ONE, WITH A VIEW TO DETERMINING IF IT CONTAINED SUFFICIENT RESERVES TO SUPPORT COMMERCIAL EXPLOITATION AND AN APPLICATION TO REGULATORS TO PROCEED WITH PLANT CONSTRUCTION AND THE COMMENCEMENT OF PRODUCTION. THIS DRILLING PROGRAM WAS SUPPLEMENTED BY A TIGHTLY-GRIDDED 3D SEISMIC PROGRAM TO ASSIST IN POOL DELINEATION. ADDITIONALLY, SEVERAL CORE HOLES WERE DRILLED ON WHAT IS IDENTIFIED AS POD THREE SITUATED SOUTHWEST OF POD ONE. OUR PROGRAM YIELDED POSITIVE RESULTS.



As a consequence of its evaluation program over Pod One, an Application and Project Development Plan was prepared and submitted to the EUB and Alberta Environment ("Environment") in August 2005. The application was for approval of the Great Divide Project, which contemplates a 10,000 bbl/d SAGD project to recover bitumen from the McMurray Formation in the Athabasca Oil Sands Deposit. Connacher anticipates a regulatory ruling, which would lead to an immediate startup of construction, drilling of SAGD horizontal well pairs and other developments to place Pod One on stream in early 2007.

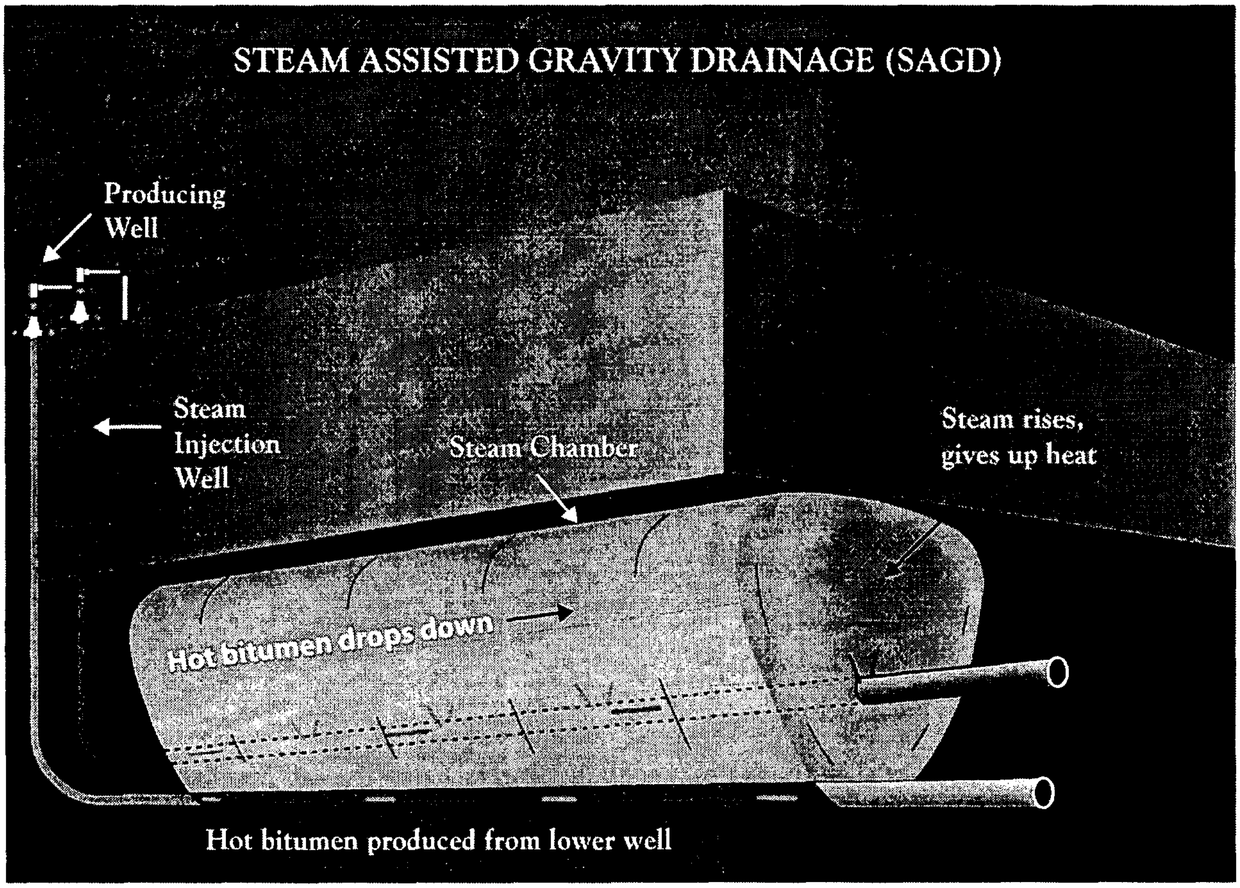
Coincident with the preparation of the application, Connacher also received an initial report by an independent engineering company, GLJ Petroleum Consultants of Calgary, Alberta ("GLJ"), which provided an independent appraisal of the reserves and resources associated with Connacher's Great Divide holdings. This report was primarily done for disclosure, banking and capital market purposes and was prepared in compliance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). It served to validate the company's assessment that it had identified a significant, valuable and prospectively commercial accumulation.

As a consequence of the EUB application, much of the balance of 2005 was devoted to preparations for the receipt of regulatory approval. This entailed preliminary engineering and design work, detailing equipment, preparing cost estimates and consultation with interested parties, including the government, indigenous and aboriginal peoples and other stakeholders whose activities could be directly or indirectly affected by the Great Divide Project.

Efforts were also directed towards examining the risks associated with an oil sands project, including energy costs and the widening and increasingly volatile differentials associated with heavy oil in a rising price market. As a consequence, the prospective Montana Refining purchase, which is to be completed on March 31, 2006, was assessed from an operational perspective throughout the past year. The Operations group also was engaged with Corporate in the assessment of the assets of Luke, especially with regard to their attractive Marten Creek natural gas reserves and production, of consequence to a prospective consumer of energy to make steam for a SAGD operation.

Finally, during 2005 Connacher also drilled a number of wells, largely of a developmental nature, at its Battrum crude oil property in southwest Saskatchewan. Production from this region provided the company with a stable and growing source of cash flow to fund its activities until new sources of revenue provide a broader base to fund capital activities.

During 2005 approximately one-half of the company's expenditures of $16.8 million were focused on Great Divide. Principal activities were the drilling of 19 core holes and a 3D seismic program. Conventional drilling expenditures and well workover costs totaled $5 million or 30 percent of the total 2005 budget.



All operations in 2005 were affected by the significant increase in crude oil prices. Subsequently natural gas prices in North America also rose in the aftermath of several hurricanes in the Gulf Coast region of the United States of America. This significant increase in energy prices brought with it increased interest in the sector and, in particular, increased investor and industry interest in the oil sands. Higher prices also resulted in a higher cost of doing business. The demand for services rose dramatically as industry participants attempted to accelerate investment in established and new projects throughout North America and the world.

The demand for new opportunities escalated dramatically against this backdrop. This was especially true for the oil sands. An increase in geopolitical risks during 2005 also contributed to a resurgence in interest in both mining and SAGD projects. Among reasons for this was the long-life nature of associated reserves, the relative political stability of Alberta and Canada as a host venue for these resources and growing concern over the industry's ability to replace conventional production with new discoveries during a period of rapid demand growth in the world, especially in less-developed countries. With its established position, Connacher was increasingly perceived to be well-situated as valuations appreciated in tandem with rising commodity prices.

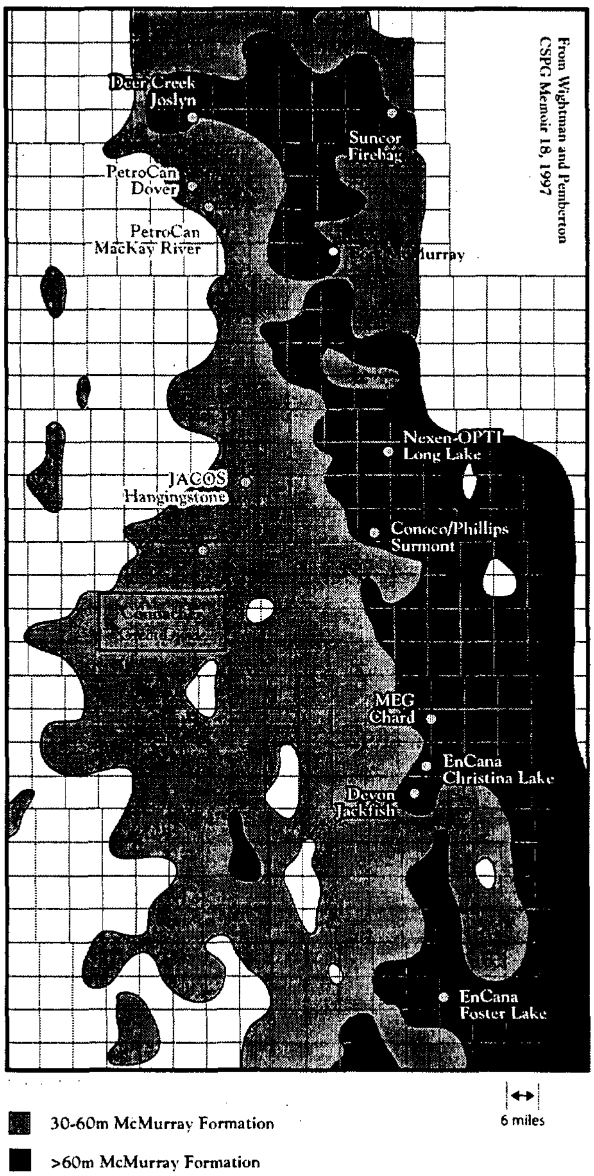
GREAT DIVIDE

Connacher holds a 100 percent interest in 110 sections (70,400 acres) of oil sands leases in the Great Divide region of northeastern Alberta, situated along Highway 63 approximately 50 miles southwest of Fort McMurray. The leases were acquired at Crown Sales, primarily in early 2004, before the renewed explosion of interest in the oil sands referred to earlier in this report.

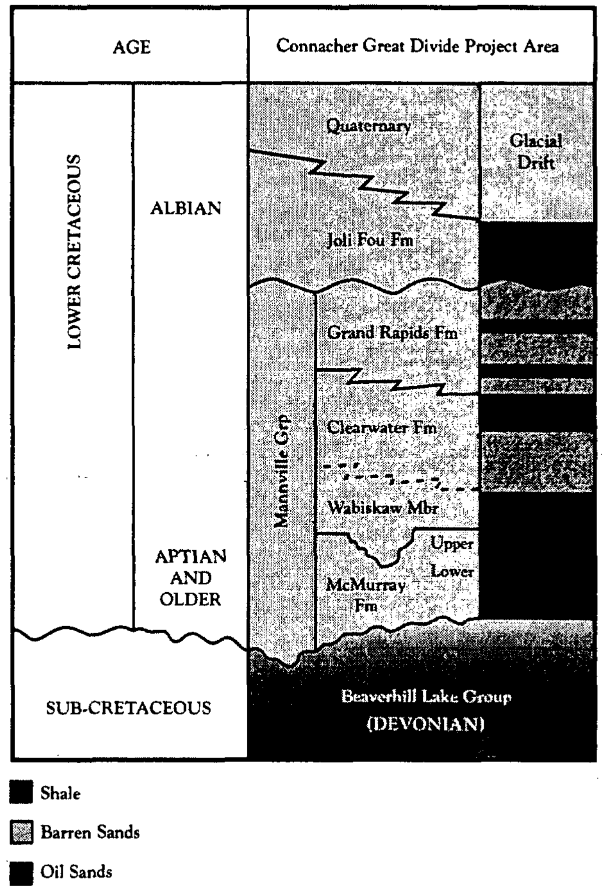
The company had leads with respect to prospective accumulations or channels, derived from a review of conventional well results which had been obtained by others during drilling for natural gas in the region. Many of these wells were drilled through the prospective bitumen zones to basement for geological control. This review led Connacher to believe these leads might be indicative of larger channels with sufficient reserves and resources to support commercial exploitation, using SAGD technology.

In the late winter of 2004, Connacher was able to drill a sufficient number of core holes to become enthusiastic about the potential of its properties. This led to the decision to drill additional core holes in late 2004 and early 2005 on or around Pod One and to supplement this activity with a densely-gridded 3D seismic program over the bulk of the geologically-mapped accumulation to confirm the size and nature of the channel. This program was carried out in the first four months of 2005. It generated very favourable and confirmatory results, leading the company to conclude that this accumulation contained the reservoir characteristics and the size to

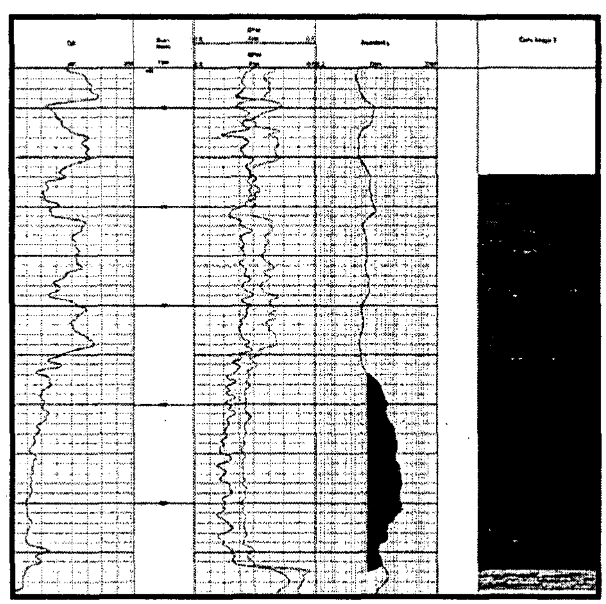
Oil Sands Region, Northeast Alberta



Great Divide Stratigraphic Column



Great Divide Reservoir Log



Great Divide 3D Seismic

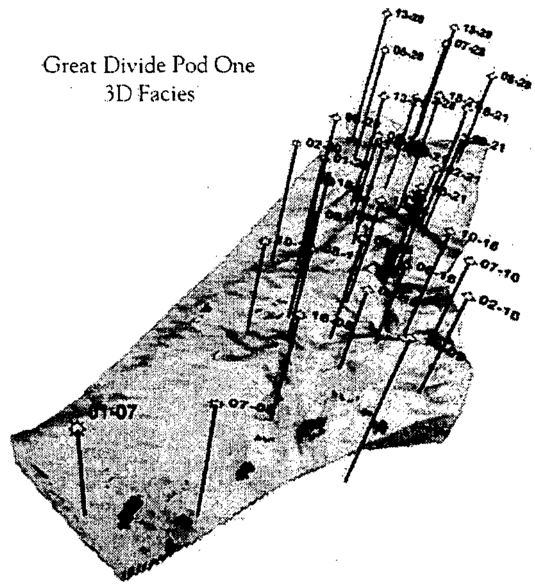
prospectively support a commercial SAGD project of 10,000 bbl/d.

Subsequently, detailed reservoir simulation and geostatistical modeling reinforced the assessment that Connacher's Pod One was comprised of high quality sandstones with excellent evident porosities and permeabilities, both horizontal and vertical, as well as high measurable oil saturation (alternatively expressed as high levels of bitumen content by weight, in mining terms). These characteristics would also normally suggest that a low steam/oil ratio ("SOR") might be achievable due to the excellent reservoir characteristics. This becomes important in determining ongoing operating costs when natural gas is being utilized to generate steam.

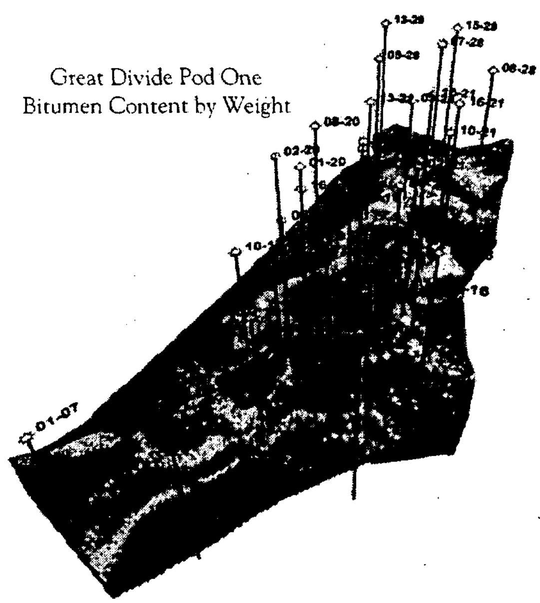
Accordingly, Connacher proceeded with the preparation of its application to the EUB and Environment seeking approval of its Great Divide Project. It was submitted in August 2005 and since that time there has been a steady dialogue between Connacher and the regulators as well as with stakeholders, including aboriginal people and affected business interests in the area. Also, considerable time, effort and capital were dedicated to early engineering and design and analysis of pricing and procurement to attempt to secure a clear understanding of the costs and timetable to startup, once regulatory approval was in hand.

The company also secured an independent assessment ("GLJ Report") of its Great Divide reserves and resources from GLJ Petroleum Consultants, independent evaluators of Calgary, Alberta. GLJ are recognized to be among the preeminent evaluators of oil and gas properties in Canada, including oil sands. Their evaluation is summarized later in this section of the annual report and underscored the prospective importance and value of Great Divide to Connacher. This became evident in capital markets,

Great Divide Pod One
3D Facies



Great Divide Pod One
Bitumen Content by Weight



especially as the results of the GLJ Report were coincidentally released on the same day it was announced that a major international company was making a bid for another public oil sands company at a considerable premium to its trading price prior to the offer (and this offer was increased at a later date). This company was in the midst of developing a 12,000 bbl/d project similar to Connacher's and also possessed other mineable assets, but its takeover propelled Connacher into the forefront as there are limited investment alternatives among oil sands participants.

The timing of the GLJ Report and the offer for the other public company coincided with the rapid surge in energy prices and in a worldwide renewal of interest in the oil sands and oil sands projects. As a consequence, Connacher has had numerous inquiries from interested third parties from all parts of the world to determine whether we were interested in partnering or joint venturing with another larger company. After due assessment of our technical and our financial capacity, we concluded our shareholders' interests were better served by "going it alone". We are fortunate to have secured or identified the type of financing that could be available to enable us to bring onstream a project such as Great Divide, so our focus going forward will be redirected to execution.

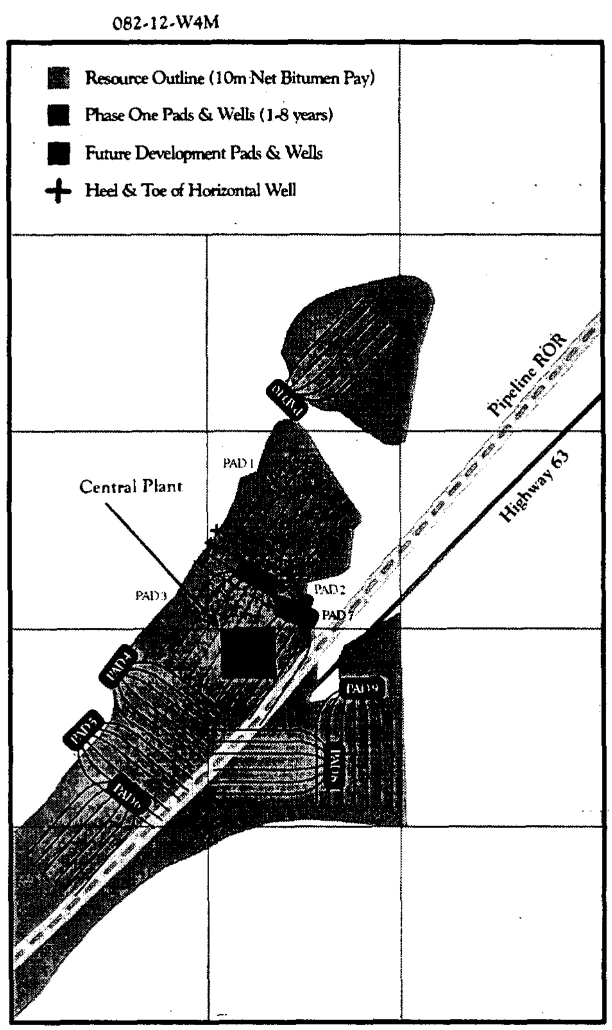
We expect to continue emphasizing a modular approach to our proposed plant construction and operation. In this manner we can capitalize on our technical expertise, adapting heavy oil technology and approaches to the oil sands. We are in effect mining our deposit, which is situated at about 450 to 470 meters subsurface, with horizontal wells and steam as the agent to liberate the bitumen. We intend to continue emphasizing efficiencies of small scale operations in order to control costs in the context of severe inflationary and scheduling pressures in this space.

We recently reorganized our engineering procurement alliances and were able to contract a smaller engineering firm with recent hands on experience in building a plant similar to that we proposed. Certain water treatment and other technological advances were introduced after this change, which required some revision to our application and may have delayed approval procedures in a minor fashion. Offsetting this, we were also able to attract key personnel who had recently worked on similar plants and processes for another oil sands company with SAGD operations to join our project and we feel this will assist us in capital cost savings and increased construction efficiency once we receive the green light to proceed. Our current assessment is that at least 300 days from approval are needed to complete the construction and commission the plant.

As reported last year, we envisage a 10,000 bbl/d operation for approximately 25 years, based on current reserve estimates. This would require approximately 10 well pads to initiate and then maintain this level of production, with our plant operating at near capacity for the duration. Approximately 200 personnel would be required during construction and 30 personnel in total to operate the facility on a 24/7 basis. Unlike conventional accumulations, where drilling continues to establish aerial extent and reserve size, Connacher has upfront knowledge of its projects' reserve base and planned productivity. Our goal is to exploit the accumulation to plant size and standards.

This annuity-like character of oil sands production is part of its appeal to investors. Also, the nature of the production profile and reserve base ultimately lead to a more predictable cash flow profile to assist in determining

Great Divide Pod One Development Scheme

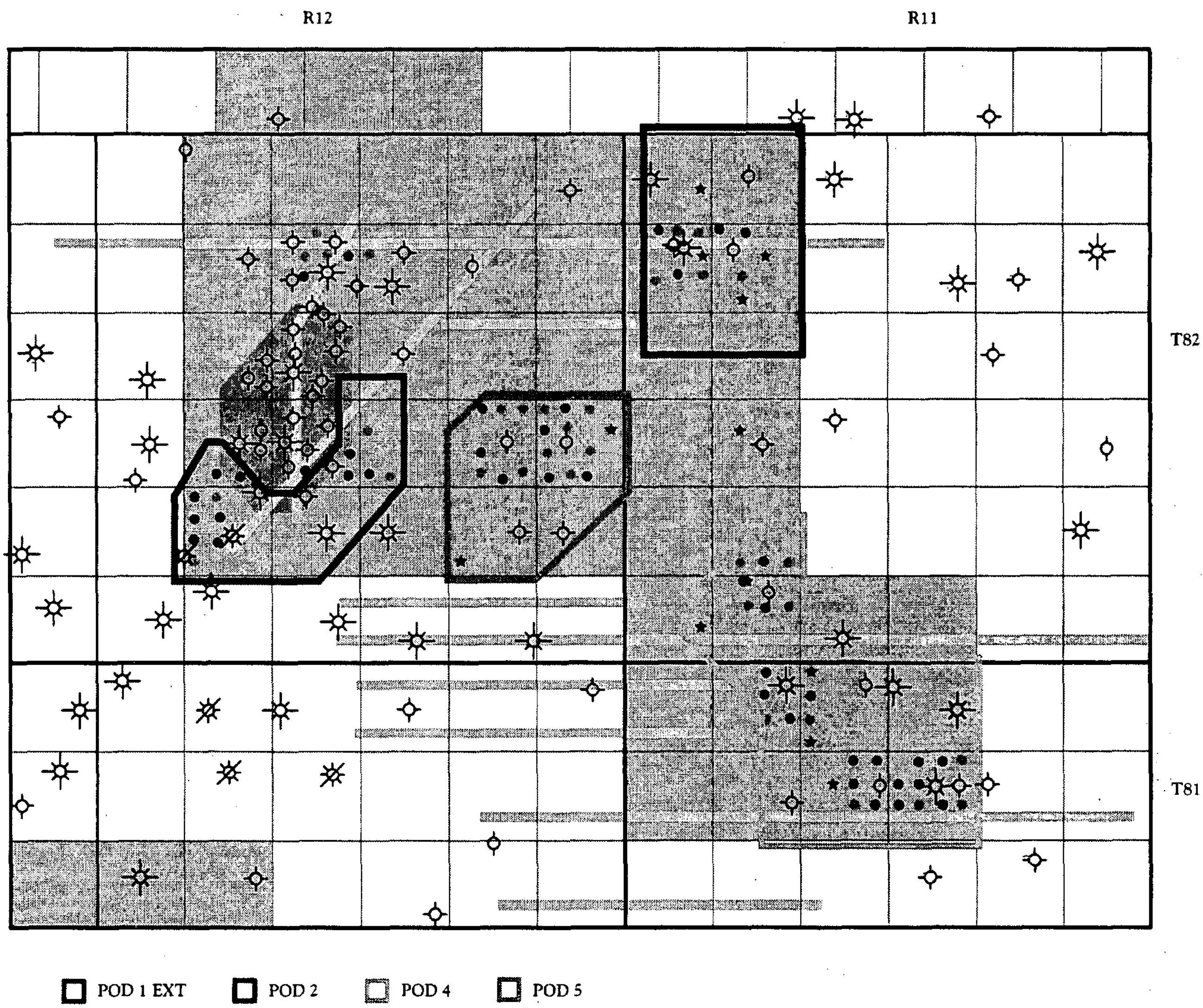


optimum financing alternatives, especially in looking ahead to developing other accumulations on the company's properties over time.

There continue to be risks with bitumen production from the oil sands. However, Connacher's Pod One has excellent reservoir characteristics. The company is also fortunate to be in close proximity to infrastructure, including highways, pipelines and electrical transmission lines. This will contribute to the efficiency and timeliness of Connacher's Great Divide project. Nevertheless, there are pipeline and transportation issues to be resolved in the next several months. Also, gas costs have been volatile and high, as have crude oil price differentials for heavy oil. These risk factors have been addressed, in part, through the Luke acquisition and the planned Montana Refining transaction mentioned earlier.

As a consequence, Connacher has prospectively emerged as the first junior integrated oil sands company. We will have a growing and expanded cash flow base from which to finance our capital program at Great Divide. We believe these risk mitigating transactions will serve to assuage the cyclical nature of our industry at a time of large capital outlays. This will be complemented by a well-structured debt financing which is suited to the long-life nature of our assets, which when combined with our strong equity base, serves to reduce the residual financial risk of this type of project for a smaller company. Finally, the focus on a discrete and manageable scale of plant in the

Great Divide Winter Drilling and 3D Seismic Program



10,000 bbl/d range is reinforced by our experience with projects of this scale in the conventional arena. Connacher plans to keep its options open and available to new concepts and technological advances for our next pods, should they be confirmed with this winter's drilling and seismic.

As inferred above, we are in the midst of an effort to complete up to 50 core holes on what we have now labeled Pods Two, Four and Five on our main lease block at Great Divide. This drilling campaign moved slowly but is accelerating with additional rig availability as this report is being written. The proposed core hole program will again be supplemented by 3D seismic over the regions comprising these Pods. It certainly proved to be a useful tool with Pod One, where additional extension drilling is also being undertaken. Our goal is simply to have a new pod or pods identified by the end of the winter program so we can apply as soon as possible for separate new developments similar to our Great Divide Project.

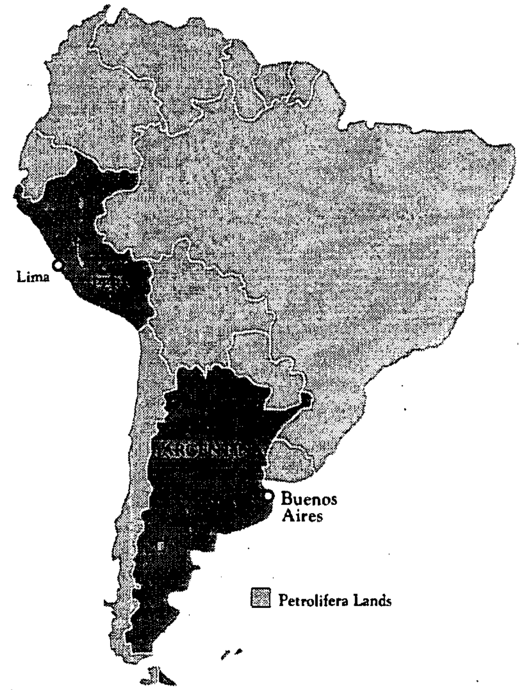
CONVENTIONAL DRILLING ACTIVITY

During 2005 Connacher drilled seven gross (6.75 net) conventional wells at Battrum, Saskatchewan. The wells were designed to maintain productivity from this region as it provides about 700 bbl/d of production of medium gravity crude oil. This gives the company cash flow to fund its ongoing operations and pay its overhead until new major projects like Great Divide are on stream. Battrum is a mature waterflood property and requires consistent and effective engineering to maintain production. Efforts were made during the year to expand and diversify the company's operating base in this region, but the competitive nature of the business, higher purchase prices than we were prepared to pay and competition from royalty trusts precluded a successful transaction. At the same time, prices paid underline the value of the asset we control and operate.

SOUTH AMERICA

During 2005 the business affairs of Petrolifera Petroleum Limited ("Petrolifera") was managed by Connacher along with Gary Wine, Petrolifera's President. We had consolidated the assets and results of Petrolifera until mid-summer 2005, when Petrolifera's board of directors was reconstituted. Thereafter, these results were deconsolidated and we now report our stake in Petrolifera on an equity accounting basis.

Connacher created Petrolifera to liberate the value of its South American assets in Argentina. Since its formation, Petrolifera was also able to secure two significant exploration licenses covering over five million acres in the Maranon and Ucayali Basins onshore Peru. This acquisition complemented Petrolifera's ownership of near-term opportunities, as identified and enhanced by a 3D seismic program, over the Puesto Morales/Rinconada concession in the Neuquén Basin onshore Argentina.



In November 2005, Petrolifera completed its $21 million initial public offering, with proceeds of this financing to accelerate its proposed development plans in Argentina and Peru. In late 2005, Petrolifera commenced a multi-well drilling program on Puesto Morales and has announced a number of very prolific and significant discoveries on the block with tested capacity from the initial six wells exceeding 15,000 bbl/d form the Jurassic Quintuco, Sierras Blancas and Punta Rosada Formations. Petrolifera plans to drill up to 24 additional wells and install permanent facilities on its acreage in 2006, with a proposed initial capital budget of approximately $32 million. It is anticipated this program can be financed from projected cash flow, cash balances and attendant growing production, without needing to raise additional permanent or debt capital.

Connacher's equity stake in Petrolifera has appreciated handsomely during the past several months and we remain a committed long-term shareholder.

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NEW VENTURES

Luke Energy Ltd.

In late 2005 the opportunity to acquire Luke was brought to our attention. We quickly recognized the appeal of this, as Luke was largely a natural gas producer with good growth potential. It operated most of its properties with largely 100 percent working interests, its properties were physically proximate to Great Divide, such that we could access the produced natural gas molecules if required for fuel at Great Divide. The transaction as a whole provided Connacher with a physical hedge against natural gas price escalation and volatility, not only for Pod One, but also for future developments.

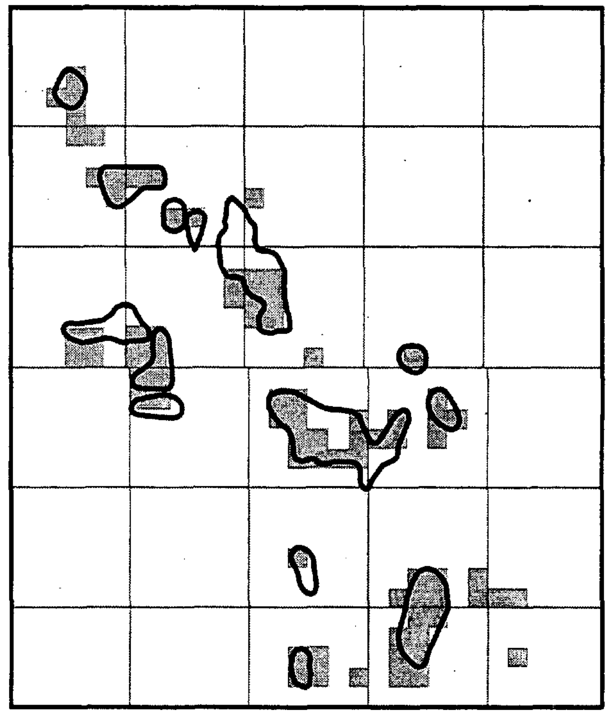
A Plan of Arrangement was negotiated involving the payment of $2.31 per Luke common share, the assumption of an agreed level of indebtedness and the issuance of 0.75 of one Connacher common share for each Luke common share outstanding. The transaction was viewed favorably by capital markets and closed with almost unanimous support from Luke shareholders on March 16, 2006.

Luke presently produces approximately 2,800 boe/d of crude oil and primarily (about 90 percent) natural gas, largely from the Marten creek area of central northern Alberta. Like Great Divide, this is also a winter drilling region and the company holds extensive undeveloped acreage in the midst of ample available Crown lands.

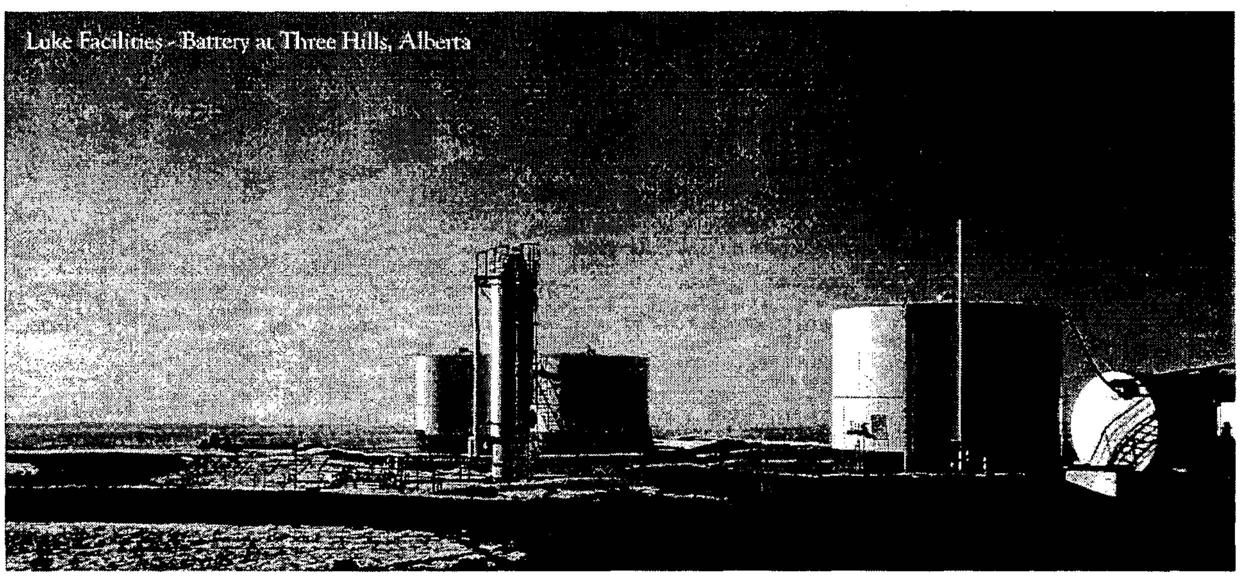
Luke also holds attractive oil properties with deeper gas potential at Three Hills, Alberta.

The Luke transaction provides Connacher with significant immediate additional cash flow and a broader asset base to mitigate operational and financial risk.

Luke's Marten Creek Properties



Several experienced and qualified personnel elected to become Connacher employees. We welcome our new employees and in particular we welcome former Luke shareholders as new Connacher shareholders. We hope they will maintain their shareholdings and thereby continue to participate in our broadened corporate asset base and prospective growth.



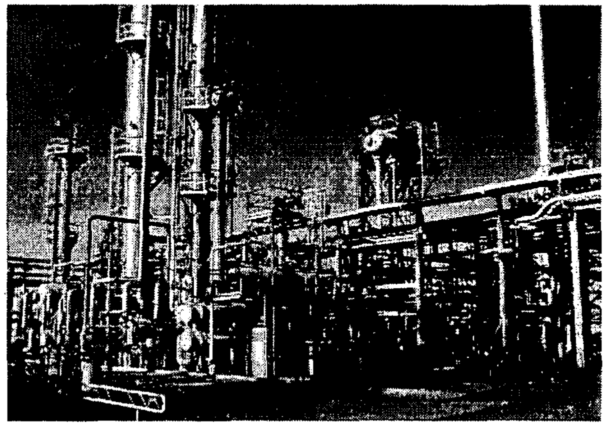
Luke Facilities - Battery at Three Hills, Alberta

Montana Refining Company, Inc.

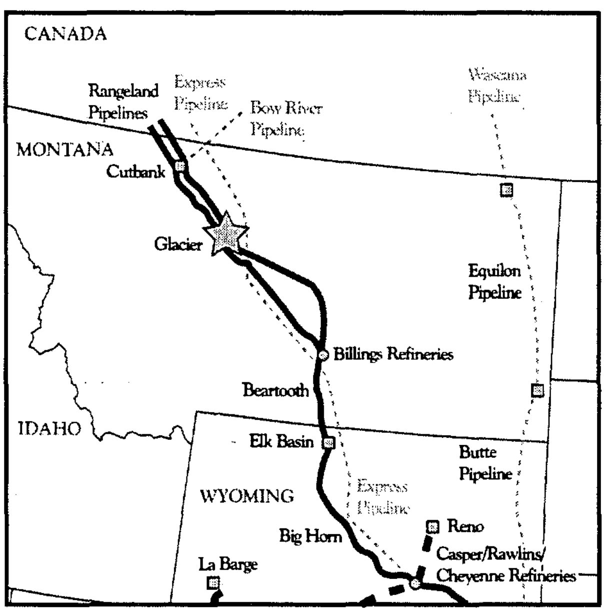
As a prospective producer of significant volumes of bitumen using SAGD technology, Connacher has been mindful of market pressures on natural gas prices and of the increasing volatility and widening of price differentials for heavier oil as crude oil prices rose inexorably during the past two years.

As a small company, we could not afford the risk of getting our Great Divide project on stream and then facing rising fuel costs, higher diluent charges or shortages of this product to blend with our bitumen in order to meet pipeline specifications. Furthermore, as a SAGD operation requires continuous steam input, we also had to be able to sustain ourselves during periods of high, wide or volatile differentials for heavier crude, if they resulted in low, even negative cash flow or net operating income for extended periods of time.

To mitigate these risks, acknowledging the difficulty of successful financial hedging opportunities, Connacher spent much of 2005 assessing an opportunity to acquire a small but profitable and accessible refinery in Great Falls, Montana, which was owned by a large US refiner known to be interested in disposing of this asset. Subsequent to year end we arrived at an agreement to acquire the refining assets and related inventory of product and material for US$55 million subject to typical closing adjustments for such a transaction. The purchase price was comprised of US$51 million of cash and one million Connacher common shares from treasury. The purchase is scheduled to close on March 31, 2006 and immediately after closing a scheduled turnaround will be initiated, after which normal operations will resume.



MRC Refinery, Montana



Pipeline Access from Alberta through Montana

Connacher is fortunate in that most of the highly-qualified and committed personnel associated with this 8,300 bbl/d refinery will stay with the operation. This will assist us in a smooth transition of ownership and will enable us to familiarize ourselves with the operation before our Great Divide bitumen becomes available, when it could serve as feedstock in future years. The refinery is a very sophisticated plant which is capable of producing everything from gasoline and jet fuel to asphalt. We see significant synergies and effective risk mitigation from being able to operate our oil sands and refining operation on an integrated basis in future years. We also believe this involvement will serve Connacher well as it expands its production base at Great Divide, as critical strategic alliances may have been established through our downstream engagement.

We will retain the Montana Refining Company brand name and its recognition as part of the transaction. We will initially finance with a bridge loan from BNP Paribas, and the plan of repayment with a term debt facility for the refinery and oil sands venture scheduled to be undertaken and completed during the second quarter, if market conditions remain favourable.

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Oil and Gas Reserves - Great Divide and Conventional

GLJ Report on Great Divide, Alberta

The following is a summary of the bitumen reserves and resources and the value of future net revenue to the company for these properties as at December 31, 2005 as evaluated by GLJ in the report dated March 16, 2006 (the "GLJ Report"). The GLJ Report was prepared using assumptions and methodology guidelines outlined in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and in accordance with National Instrument 51-101 ("NI 51-101"). The pricing used in the forecast price evaluations is set forth in the notes to the tables. The results contained in the GLJ Report recognize Connacher submitted applications to develop Pod One at Great Divide with the relevant Alberta regulators. These applications were submitted on August 15, 2005. Necessary regulatory approvals are anticipated by the company in 2006. Production start-up is forecast by GLJ to occur in 2007 and a peak rate of 10,500 barrels of oil per day is forecast to be achieved by 2009. The GLJ Report did not take into account or consider any core holes drilled after December 31, 2005. Accordingly, the results of Connacher's 2006 program will be assessed at a later date.

Reserves were only assigned to Pod One, in the proved and probable ("2P") and proved, probable and possible ("3P") categories, although no proved reserves were assigned pending start-up of production. The study assumed 45 steam-assisted gravity drainage ("SAGD") well pairs for the 2P case and 74 well pairs for the 3P case, with cumulative steam-oil ratios ("SOR") of 2.6 in both cases, but declining to 2.3 during peak production periods. The cutoffs used by GLJ for probable reserves were 15 metres of net pay for 2P reserves and 10 metres of net pay for 3P reserves.

All evaluations of future revenue are after the deduction of royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenues contained in the following tables do not necessarily represent the fair market value of the company's reserves. There is no assurance that the forecast and constant price and cost assumptions contained in the GLJ Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the GLJ Report. The recovery and reserves estimates of the company's properties described herein are estimates only. The actual reserves on the company's properties may be greater or less than those calculated.

Reserves and Net Present Value of Future Net Revenue
Based on Forecast Prices and Costs(6)(7)

	Bitumen		Before Deducting Income Taxes Discounted At		
	Gross(1) (mbbl)	Net(1) (mbbl)	0% (MM$)	5% (MM$)	10% (MM$)
Total Proved(2)	-	-	-	-	-
Probable Undeveloped(3)(5)	69,604	60,983	704	346	168
Total Probable(3)	69,604	60,983	704	346	168
Total Proved Plus Probable(2)(3)	69,604	60,983	704	346	168
Total Possible(4)	38,723	33,259	625	179	60
Total Proved Plus Probable Plus Possible(2)(3)(4)	108,327	94,242	6,329	525	228

(1) "Gross Reserves" are the company's working interest (operating or non-operating) share before deducting royalties and without including any royalty interests of the company. "Net Reserves" are the company's working interest (operating or non-operating) share after deduction of royalty obligations, plus the company's royalty interests in reserves.

(2) "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is 90% likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(3) "Probable" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

(4) "Possible" reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

(5) "Undeveloped" reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

(6) The pricing assumptions at the wellhead for bitumen used in the GLJ Report with respect to values of future net revenue (forecast) are set forth below. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

(7) Includes estimated capital costs, in the 2P case over the 25 year forecast life of the project (10.9 years half-life) of $300 million and, in the 3P case over the 36 year forecast life of the project (16.2 years half-life) of $458 million.

Forecast	Heavy Oil Bitumen Wellhead Current ($Cdn/bbl)
2007	25.62
2008	25.75
2009	25.37
2010	26.25
2011	27.50
2012	27.50
2013	28.12
2014	28.75
2015	US 29.62
2016	30.12
Thereafter	+2.5%

The GLJ Report also provided calculations of Contingent Resources comprised of "Low Estimate Resources (>15 metre Pay) - higher certainty" together with "Best Estimate Resources (>15 metre Pay) - likely certainty" and "High Estimate Resources (>10 metre Pay) - lower certainty". Low Estimate recoverable resources are comprised of mapped original oil-in-place assigned to Pod One (>15 metre Pay) with a lower recovery factor than are applied to the estimate of 2P reserves. Best Estimate Resources are comprised of 2P remaining recoverable reserves together with an estimate of recoverable resources attributable to four other pods on Connacher's lands. High Estimate Resources (lower certainty) include 3P recoverable reserves at Pod One together with recoverable resources at the other four pods on Connacher's acreage, but with a larger aerial extent and a higher recovery factor than attributable under the Best Estimate Category.

Only Pod One had sufficient well and seismic control to warrant the assignment of reserves. The other four pods had insufficient drilling density, seismic mapping or project definition at December 31, 2005 to be categorized as reserves at this time. Additional drilling and seismic activity could result in upgrading these to reserve status over time. In the interim, a range of contingent resources was assigned to reflect uncertainties. The GLJ Report also recognized High Estimate (low certainty) prospective resources attributable to two undiscovered pods with attributable resources of 160.6 million barrels of original oil-in-place and 91.6 million barrels of initial and remaining recoverable resources, utilizing average parameters from five identifiable pods, including Pod One. No calculation was done of the present value of the future cash flow from remaining recoverable or prospective resources other than the reserves attributable to Pod One as detailed herein.

Low Estimate Resources (>15 Metre Pay, Higher Certainty)

	Original Oil-in-Place (mmstb)	Recoverable Resources (mmstb)
POD 1	128.9	46.4
POD 2, POD 2 South	-	-
POD 3, POD 4	-	-
TOTAL	128.9	46.4

Best Estimate Resources (>15 Metre Pay, Likely Certainty)

	Original Oil-in-Place (mmstb)	Recoverable Resources (mmstb)
POD 1	128.9	69.6 (2P reserves)
POD 2, POD 2 South	53.8	21.8
POD 3, POD 4	79.5	36.1
TOTAL	262.2	127.5

High Estimate Resources (>10 Metre Pay, Lower Certainty)

	Original Oil-in-Place (mmstb)	Recoverable Resources (mmstb)
POD 1	178.6	108.3 (3P reserves)
POD 2, POD 2 South	82.3	45.0
POD 3, POD 4	116.8	66.0
TOTAL	377.7	219.3

D&M Report on Canadian Conventional Canadian Reserves

The following is a summary of the crude oil and natural gas reserves and the value of future net revenue of the company's conventional Canadian reserves as at December 31, 2005 as evaluated by D&M in a report dated March 8, 2006 (the "D&M Report"). The D&M

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Report was prepared using assumptions and methodology guidelines outlined in the COGE Handbook and in accordance with NI 51-101. The pricing used in the forecast price evaluation is set forth in the notes to the tables below.

All evaluations of future revenue are after the deduction of royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenues contained in the following tables do not necessarily represent the fair market value of the company's reserves. There is no assurance that the forecast price and cost assumptions contained in the D&M Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the D&M Report. The recovery and reserves estimates of the company's properties described herein are estimates only. The actual reserves on the company's properties may be greater or less than those calculated.

Connacher owns a 33 percent equity stake in Petrolifera Petroleum Limited. See the company's Annual Information Form ("AIF) as posted on SEDAR (www.sedar.com). Also, these reserves do not include those of Luke Energy Ltd. which was acquired on March 16, 2006, subsequent to the 2005 year-end. Connacher plans to update its corporate reserves at the end of the first quarter 2006.

Reserves Data - Forecast Prices And Costs

Crude Oil and Natural Gas Reserves Based on Forecast Prices and Costs(9)

	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
	Gross(1) (mbbl)	Net(1) (mbbl)	Gross(1) (mmcf)	Net(1) (mmcf)	Gross(1) (mbbl)	Net(1) (mbbl)
Proved Developed Producing(2)(5)	1,220	973	123	112	2.2	4.6
Proved Developed Non-Producing(2)(6)	1	1	161	124	-	-
Proved Undeveloped(2)(7)	232	185	-	-	-	-
Total Proved	1,452	1,161	284	236	2.1	1.6
Total Probable(3)	936	744	348	282	0.6	0.4
Total Proved Plus Probable(2)(3)	2,387	1,905	632	518	2.7	3.0
Total Possible(4)	1,044	922	125	114	0.1	0.1
Total Proved Plus Probable Plus Possible(2)(3)(4)	3,431	2,826	757	632	2.9	2.1

Net Present Value of Future Net Revenue Based on Forecast Prices and Costs(8)(11)

	Before Deducting Income Taxes Discounted At		
	0% (M$)	5% (M$)	10% (M$)
Proved Developed Producing(2)(5)	26,416	22,273	19,261
Proved Developed Non-Producing(2)(6)	806	754	707
Proved Undeveloped(2)(7)	4,544	3,599	2,858
Total Proved(2)	31,766	26,626	22,826
Total Probable(3)	22,909	16,552	12,424
Total Proved Plus Probable(2)(3)	54,675	43,178	35,250
Total Possible(4)	24,779	16,929	11,710
Total Proved Plus Probable Plus Possible(2)(3)(4)	79,454	60,107	96,960

(1) "Gross Reserves" are the company's working interest (operating or non-operating) share before deducting royalties and without including any royalty interests of the company. "Net Reserves" are the company's working interest (operating or non-operating) share after deduction of royalty obligations, plus the company's royalty interests in reserves.

(2) "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is 90% likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(3) "Probable" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

(4) "Possible" reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

(5) "Developed Producing" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(6) "Developed Non-Producing" reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(7) "Undeveloped" reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

(8) The pricing assumptions used in the D&M Report with respect to values of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below. D&M is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

(9) Values include processing and other income.

(10) Values include Alberta Royalty Tax Credit.

(11) Operating expenses, capital costs and abandonment costs utilized in the D&M Report were as follows:

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	Light and Medium Crude Oil	Natural Gas	Inflation Rate	Exchange Rate
	WTI Cushing Oklahoma ($US/bbl)	Alberta Spot ($Cdn/mcf)	%/year	$US/$Cdn
Forecast				
2006	58.00	10.37	2.5	0.86
2007	56.38	9.65	2.5	0.86
2008	52.53	5.53	2.5	0.86
2009	51.69	7.86	2.0	0.86
2010	52.72	7.17	2.0	0.86
2011	53.78	6.89	2.0	0.86
2012	54.85	7.01	2.0	0.86
2013	55.95	7.14	2.0	0.86
2014	57.02	7.27	2.0	0.86
2015	58.21	7.40	2.0	0.86
2016	59.38	7.53	2.0	0.86
Thereafter	2%	2%	2.0	0.86

	Forecast Prices and Costs - Canada (Undiscounted)		
	Total Proved (M$)	Proved Plus Probable (M$)	Proved Plus Probable Plus Possible (M$)
Operating Costs	17,366	28,444	38,757
Capital Costs	1,751	5,849	13,136
Abandonment	2,621	2,965	3,149

2005 Year End Reserve Reconciliation (1) (2) (3)

	Mboe (including Bitumen)			
	Prov.	Prob.	Poss.	Total
At December 31, 2004 (4)	1,521	1,295	52,783	55,602
Discoveries	-	-	-	-
Revisions of Prior Estimates	152	69,295	(13,029)	56,418
Acquisitions	100	27	34	161
Dispositions	(24)	(19)	-	(43)
Production	(251)	-	-	(251)
At December 31, 2005	1,501	70,598	39,788	111,889

(1) May not add due to rounding.

(2) Calculated based on forecast price case as at December 31, 2005.

(3) All references to barrels of oil equivalent (boe) are calculated on the basis of 6 mcf: 1bbl. 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.

(4) Restated to reflect deconsolidation of the accounts of Petrolifera Petroleum Limited during 2005.

During 2005, Connacher's total proved, probable and possible ("3P") reserves increased by 100 percent to 112 million boe, primarily reflecting the impact of additional probable reserves at Great Divide, which more than offset a reduction in the possible category for these type of reserves. This positive development reflects Connacher's identification of new reserves at Pod One through delineation drilling and 3D seismic programs during the year and the company's application to the EUB.

During 2005, the company's proved and probable ("2P") reserves increased 2,600 percent, or over 25 tonnes to 72.1 million boe, for essentially the same reasons as applicable to 3P reserves.

Connacher's 2P reserves are forecast to generate an undiscounted future revenue stream of $1.41 billion with a five percent pre-tax present worth after deduction of royalties, operating costs and future capital of $568 million and a 10 percent present worth of $263 million. Present worth values are not necessarily representative of fair market values and fluctuate depending upon various factors, including price schedules developed by independent evaluators.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Richard R. Kines

Vice President, Finance and Chief Financial Officer

The following is dated as of March 23, 2006 and should be read in conjunction with the consolidated financial statements of Connacher Oil and Gas Limited ("Connacher" or the "company") for the years ended 2005 and 2004 as contained in this annual report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and are presented in Canadian dollars. In the third quarter of 2005 the company discontinued consolidating the financial and operating results of Petrolifera Petroleum Limited as the company was no longer considered to control Petrolifera due to the election of independent directors and other factors. The investment in Petrolifera has since been accounted for following the equity basis of accounting. Comparative figures have not been restated.

This MD&A provides management's view of the financial condition of the company and the results of its operations for the reporting periods. Information contained in this report contains forward-looking information based on current expectations, estimates and projections of future production, capital expenditures and available sources of financing. It should be noted forward-looking information involves a number of risks and uncertainties and actual results may vary materially from those anticipated by the company. There can be no assurance that the plans, intentions or expectations upon which these forward-looking statements are based will occur. Forward-looking statements are subject to risks, uncertainties and assumptions, including those discussed in the company's Annual Information Form for the year ended December 31, 2005, which include, without limitation, changes in market conditions, law or governing policy, operating conditions and costs, operating performance, demand for oil and gas, price and exchange rate fluctuation, currency controls, commercial negotiations, regulatory processes and approvals and technical and economic factors. Although Connacher believes that the expectations represented in such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct.

The forward-looking statements contained herein are expressly qualified in their entirety by this cautionary statement. The forward-looking statements included in this MD&A are made as of the date of the MD&A and Connacher undertakes no obligation to publicly update such forward-looking statements to reflect new information, subsequent events or otherwise unless so required by applicable securities laws. Throughout the MD&A, per barrel of oil equivalent (boe) amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil (6:1). The conversion is based on an energy equivalency conversion method primarily applicable to the burner tip and does not represent a value equivalency at the wellhead. Boes may be misleading, particularly if used in isolation.

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FINANCIAL AND OPERATING REVIEW

PRODUCTION, PRICING AND REVENUE

	2005	2004	2003
Daily production / sales volumes			
Crude oil – bbl/d	729	785	789
Natural gas –mcf/d	827	1,620	1,190
Combined – boe/d	867	1,055	987
Product pricing ($)			
Crude oil – per bbl	42.33	31.42	30.03
Natural gas – per mcf	1.37	3.62	2.95
Boe – per boe	36.91	28.95	27.56
Revenue ($000s)			
Petroleum and natural gas	11,678	11,180	9,931
Interest and other	700	36	51
Total	12,378	11,216	9,982

In 2005, total revenue increased 10 percent to $12.4 million. Petroleum and natural gas revenues were up four percent to $11.7 million from $11.2 million for 2004. This is primarily attributable to a 35 percent increase in the selling price of the company's crude oil offset by a seven percent reduction in sales volumes. Crude oil sales volumes averaged 729 bbl/d in 2005, down from the 785 bbl/d in 2004. This decrease is principally due to offsetting the impact of deconsolidation of Petrolifera by increased production at Battrum, Saskatchewan, where the company successfully drilled new wells and worked over existing wells to minimize production declines. As a consequence of increased world oil prices this year, the company's average crude oil selling price increased to $42.33 per barrel compared to $31.42 per barrel in 2004. Crude oil sales represented 96 percent of the company's total production revenue. Natural gas sales contributed $414,000. Income, primarily earned on short-term cash deposits since closing a $75 million equity financing in early September 2005, provided $700,000.

ROYALTIES

	2005		2004	
	Total	Per boe	Total	Per boe
For the year ended December 31	$2,582,561	$8.16	$2,138,916	$5.54
percentage of petroleum and natural gas revenue	22%		19%	

Royalties represent charges against production or revenue by governments and landowners. Royalties in 2005 were $2,583,000 ($8.16 per boe, or 22 percent of petroleum and natural gas revenue) compared to $2,139,000 in 2004 ($5.54 per boe, or 19 percent of petroleum and natural gas revenue).

From year to year, royalties can change based on changes to the weighting in the product mix which is subject to different royalty rates, and rates usually escalate with increased product prices. The increase from 2004 to 2005 reflects market conditions.

OPERATING EXPENSES AND NETBACKS

Company Netbacks (1)

For the year ended December 31

	2005		2004		% Change	
	Total	Per boe	Total	Per boe	Total	Per boe
Average daily production (boe/d)		867		1,055		(18)
Petroleum and natural gas revenue	$11,677,649	$36.91	$11,179,404	$28.95	4	27
Other income	700,034	2.21	36,484	0.09	1819	2356
Total revenue	12,377,683	39.12	11,215,888	29.04	10	35
Royalties	(2,582,561)	(8.16)	(2,138,916)	(5.54)	21	47
Net revenue	9,795,122	30.96	9,076,972	23.50	8	32
Operating costs	(2,445,393)	(7.73)	(3,765,531)	(9.75)	(35)	(21)
Operating netback	$7,349,729	$23.23	$5,311,441	$13.75	38	69

(1) Calculated by dividing related revenue and costs by total boe produced, resulting in an overall combined company netback. Netbacks do not have a standardized meaning prescribed by GAAP and, therefore, may not be comparable to similar measures used by other companies. This non-GAAP measurement is a useful and widely used supplemental measure that provides management of Connacher with performance measures and that provides shareholders and investors with a measurement of Connacher's efficiency and its ability to fund future growth through capital expenditures.

For 2005 operating costs of $2,445,000 were 35 percent lower than in the prior year, and on a per unit basis, were reduced by 21 percent to $7.73 per boe. The reduction in operating costs, both absolutely and on a per unit basis, reflects the company's ability to more efficiently operate its remaining petroleum and natural gas properties, having disposed of certain higher-cost producing properties in July 2004. This was a significant accomplishment as, in general, the industry's cost structure has been rising.

As a result of higher product prices and lower operating costs, operating netbacks per boe for 2005 increased 69 percent to $23.23 per boe compared to $13.75 in 2004.

GENERAL AND ADMINISTRATIVE EXPENSES

In 2005, general and administrative ("G&A") expenses were $2.7 million compared to $2.0 million in 2004, an increase of 35 percent from 2004, reflecting inflationary effects, increased costs associated with being a public company as well as increased staffing that occurred later in 2004. G&A of $145,000 was capitalized in 2005 (2004-$70,700).

Non-cash stock-based compensation costs of $1.6 million were recorded in 2005 (2004-$181,000). These charges reflect the fair value of all stock options granted and vested in each year. Of this amount, $1.2 million was expensed (2004 - $181,000) and $409,000 was capitalized (2004 - nil).

FINANCE CHARGES AND FOREIGN EXCHANGE

Financing charges were $308,000 in 2005, a 60 percent reduction from the $770,000 reported in 2004. These charges expensed in 2005 were reduced significantly from 2004 due to debt reduction resulting from equity financings completed in late 2004 and in 2005.

When translating and consolidating Petrolifera's foreign denominated financial results prior to deconsolidation, the impact of fluctuations on the Argentinean peso relative to the Canadian dollar resulted in a foreign exchange gain of $30,000 in 2005 compared to the loss of $46,000 in 2004. The company's main exposure to foreign currency risk relates to the pricing of its crude oil sales, which are denominated in US dollars.

DEPLETION, DEPRECIATION AND ACCRETION ("DD&A")

DD&A expense is calculated using the unit-of-production method based on total estimated proved reserves. DD&A in 2005 was $5.8 million, a 16 percent decrease from last year. This equates to $18.32 per boe of production compared to $17.81 per boe last year.

Capital costs of $11.3 million (2004 – $4.4 million) related to the Great Divide oil sands project, which is in a pre-production state have been excluded from depletable costs. No proved reserves have yet been assigned to this project. Additionally, undeveloped land acquisition costs of $2.5 million (2004 – $3.4 million) were excluded from the depletion calculation, while future development costs of $1.8 million (2004 - $2.4 million) for proved undeveloped reserves were included in the depletion calculation.

Included in DD&A is a charge of $165,000 (2004 - $178,000) in respect of the company's estimated asset retirement obligations. These charges will continue to be necessary in the future to accrete the currently booked discounted liability of $3.1 million to the estimated total undiscounted liability of $5.4 million over the remaining economic life of the company's oil and gas properties.

CEILING TEST

Oil and gas companies are required to compare the recoverable value of their oil and gas assets to their recorded carrying value at the end of each reporting period. Excess carrying values over ceiling value are to be written off against earnings. No write-down was required for any reporting period in 2005 or 2004.

DILUTION GAIN

In 2004 and in 2005, the company's equity interest in Petrolifera was diluted as a result of Petrolifera issuing common shares. In November 2004, the company's equity interest was reduced from 100 percent to 61 percent; in March 2005 it was reduced to 40 percent, and in late 2005, it was further reduced to 33 percent. These reductions resulted in a dilution gain to the company of $4.5 million in 2005 and $1.4 million in 2004.

LOSS APPLICABLE TO EQUITY INTEREST IN INVESTMENTS

The loss applicable to equity interests of $27,000 in 2005 represents Connacher's equity interest share of Petrolifera's loss since commencing to account for Petrolifera on an equity basis in the third quarter of 2005.

TAXES

The income tax provision of $870,000 in 2005 includes a current tax provision of $102,000 which is principally the Large Corporations Tax in Canada and a future income tax provision of $768,000.

As a result of a recent adjustment proposed by Canada Revenue Agency to resource tax pools respecting assets acquired in 2002, the December 31, 2002 balance of property and equipment was increased by $850,000 and the future income tax asset balance was reduced by $850,000. Additional depletion of $124,000 ($72,000 net of tax) for 2002 and $92,000 ($55,000 net of tax) for 2003 was recorded as an adjustment to the opening balance of retained earnings for 2004. There was no significant impact to the Statements of Operations for 2004 and 2005.

At December 31, 2005 the company had approximately $3 million of non-capital losses which do not expire before 2009, $38 million of deductible resource pools and $6 million of deductible financing costs.

NET EARNINGS

For the year ended December 31

	2005		2004		% change	
	Total	Per boe	Total	Per boe	Total	Per boe
Operating netback	**$7,349,729**	**$23.23**	$5,311,441	$13.75	38	69
General & administrative	**(2,659,599)**	**(8.40)**	(2,016,578)	(5.22)	32	61
Stock-based compensation	**(1,191,971)**	**(3.77)**	(180,661)	(0.47)	560	702
Financing charges	**(307,574)**	**(0.97)**	(770,026)	(1.99)	(60)	(51)
Foreign exchange gain (loss)	**29,852**	**0.09**	(45,524)	(0.12)	-	-
Depletion, depreciation and accretion	**(5,796,820)**	**(18.32)**	(6,876,110)	(17.81)	(16)	3
Loss applicable to non-controlling interest	**-**	**-**	(8,930)	(0.02)	-	-
Dilution gain	**4,464,700**	**14.11**	1,353,199	3.51	230	302
Equity interest in Petrolifera loss	**(27,434)**	**(0.09)**	-	-	-	-
Income tax recovery (provision)	**(869,993)**	**(2.75)**	256,778	0.66	-	-
Net earnings (loss)	**$990,890**	**$3.13**	$(2,976,411)	$(7.71)	-	-

In 2005 the company reported earnings of $991,000 ($0.01 per basic and diluted share outstanding). This compares to a net loss of $3 million or $0.06 loss per basic and diluted share for 2004. Earnings per boe produced were $3.13 compared to a loss last year of $7.71.

SHARES OUTSTANDING

For 2005, the weighted average number of common shares outstanding was 106,113,563 (2004 – 50,907,947) and the weighted average number of diluted shares outstanding, as calculated by the treasury stock method, was 111,845,687 (2004 – 53,328,551). The substantial increase in shares outstanding year over year reflects the November and December 2004 issuance from treasury of 41,706,663 common shares for gross cash proceeds of $21.3 million and the combined September and December 2005 issues of 45,541,000 common shares for gross cash proceeds of $90 million.

As at March 23, 2006, the company had the following securities issued and outstanding:

- 190,256,659 common shares;
- 361,057 share purchase warrants; and
- 8,641,234 share purchase options.

Details of the exercise provisions and terms of the warrants and options are noted in the consolidated financial statements, included in this annual report.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow from operations before working capital changes ("cash flow"), cash flow per share and cash flow per boe do not have standardized meanings prescribed by GAAP and therefore may not be comparable to similar measures used by other companies. Cash flow from operations before working capital changes includes all cash flow from operating activities and is calculated before changes in non-cash working capital. The most comparable measure calculated in accordance with GAAP would be net earnings. Cash flow from operations before working capital changes is reconciled with net earnings on the Consolidated Statement of Cash Flows and below. Cash flow per share is calculated by dividing cash flow by the weighted average shares outstanding; cash flow per boe is calculated by dividing cash flow by the quantum of crude oil and natural gas (expressed in boes) sold in the period. Management uses these non-GAAP measurements for its own performance measures and to provide its shareholders and investors with a measurement of the company's efficiency and its ability to fund a portion of its future growth expenditures. Management believes that available cash, together with proceeds from an equity financing completed in March 2006 and new and anticipated debt facilities and cash flow from operations before working capital changes, are expected to provide sufficient funding for working capital purposes and for

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the company's anticipated capital program in 2006. The company's only financial instruments are accounts receivable and payable; it maintains no off-balance sheet financial instruments.

Reconciliation of net earnings to cash flow from operations before working capital changes:

Year ended December 31

	2005	2004
	$	$
Net earnings (loss)	**990,890**	(2,976,411)
Items not involving cash:		
Depletion, depreciation and accretion	**5,796,820**	6,876,110
Stock-based compensation	**1,191,971**	180,661
Financing charges	**150,000**	-
Future income tax provision (recovery)	**768,090**	(372,250)
Foreign exchange (gain) loss	**(29,852)**	45,524
Lease inducement amortization	**(72,905)**	-
Dilution gain	**(4,464,700)**	(1,353,199)
Income applicable to non-controlling interests	**-**	8,930
Equity interest in Petrolifera loss	**27,434**	-
Cash flow from operations before working capital changes	**4,357,748**	2,409,365

For 2005, cash flow was $4.4 million ($0.04 per basic and diluted share), 81 percent higher than $2.4 million ($0.05 per basic and diluted share) in 2004.

Cash flow per boe was $13.77 in 2005 compared to $6.24 in 2004. This represents 37 percent of the average company selling price per boe compared to 22 percent in 2004 and an increase of 121 percent over 2004.

CAPITAL EXPENDITURES AND FINANCING ACTIVITIES

For 2005, capital expenditures totaled $16.8 million. A breakdown of these expenditures for the year follows:

- $9.1 million, for drilling 19 oil sands delineation core holes, 7.35 net conventional oil wells and for workovers of conventional wells at Battrum, Saskatchewan;
- $5.0 million for seismic and research studies;
- $1.7 million for property acquisitions; and
- $1.0 million for other expenditures.

Except for a commitment to incur $200,000 of capital expenditures on behalf of joint ventures in the Tompkins area of southwest Saskatchewan, the company's capital program is entirely discretionary and may be expanded or curtailed based on drilling results and the availability of capital. This is reinforced by the fact that Connacher operates most of its wells and holds an average 92 percent working interest, providing the company with operational and timing controls.

Great Divide Oil Sands Project, Northern Alberta

The company holds a 100 percent working interest in 70,400 acres of oil sands leases in northern Alberta. To date, the focus has been on an approximate 2,000 acre tract ("Pod One") on which approximately $11 million has been invested to acquire the oil sands leases, to delineate the oil bearing reservoir, and to prepare and file an application for regulatory approval to develop a project capable of producing up to 10,000 bbl/d using steam assisted gravity drainage ("SAGD"). Capital development costs for Pod One are expected to approximate $160 million. Over 75 percent of these forecast expenditures are anticipated to be for surface facilities with the balance of the costs to drill the initial horizontal well pairs. Full development of Pod One will commence upon receiving regulatory approval. Additionally, the company is attempting to drill 50 additional delineation wells in the 2006 winter drilling season to define further oil bearing reservoirs on some of the remaining 68,400 acres at Great Divide.

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Recent Financing

In September 2005, the company issued 40,541,000 common shares at $1.85 per share for gross proceeds of $75 million to fund a portion of its Great Divide Oil Sands Project. Proceeds of the financing were utilized as follows:

	As stated at the time of the financing	As actually applied
Gross proceeds	$75,000,850	$75,000,850
Underwriters commission and issue costs	4,900,000	4,877,844
Applied to reduce indebtedness	2,300,000	2,300,000
Available for Great Divide Oil Sands Project and general corporate purposes	$67,800,850	$67,823,006

In December 2005, the company issued five million flow-through common shares at $3.00 per share for gross proceeds of $15 million to fund the company's planned 50 well program in the winter of 2005-2006. Proceeds of the financing were utilized as follows:

	As stated at the time of the financing	As actually applied
Gross proceeds	$15,000,000	$15,000,000
Underwriters commission and issue costs	1,175,000	1,105,120
Available for/applied to delineation drilling and seismic	$13,825,000	$13,894,880

In February 2006 the company entered into financing commitment letters with BNP Paribas, a major international bank, for the following lending facilities:

(i) a $45 million reserve-based loan and a $10 million revolving operating loan to finance conventional petroleum and natural gas projects in Canada. This facility was established on March 16, 2006.

(ii) a commitment letter to secure a US$51 million bridge loan to fund a significant portion of the proposed acquisition of the Montana refinery. It is also anticipated this facility will be established immediately prior to the closing of the refinery purchase, scheduled for March 31, 2006.

BNP Paribas has also proposed a US$148 million term loan which would be used in part to repay the US$51 million bridge loan drawn. If the proposed term debt facility is completed on satisfactory terms, forecast surplus proceeds would be utilized to supplement the company's available cash flow and cash balances to finance forecast capital expenditures of the company's Great Divide Oil Sands Project.

In March 2006 subsequent to year end 2005, the company issued 19,047,800 common shares at $5.25 per share for gross proceeds of $100 million to fund exploration and development activities associated with conventional crude oil and natural gas activities and the Great Divide Oil Sands Project, for general corporate purposes, for working capital and to possibly partially fund the acquisition of Luke Energy Ltd. Proceeds of the financing were utilized as follows:

	As stated at the time of financings	As actually applied
Gross proceeds	$100,000,950	$100,000,950
Underwriters commission and issue costs	6,250,000	6,250,000
Available for exploration and development, general corporate purposes, for working capital and to possibly fund a portion of the Luke acquisition	$93,750,950	$93,750,950

Acquisition of Luke Energy Ltd. ("Luke")

In December 2005 the company entered into a binding letter agreement to purchase, by way of a Plan of Arrangement, all of the shares of Luke for a cash consideration of $2.31 plus 0.75 of a Connacher common share for each Luke common share. On March 15, 2006 the Luke shareholders voted to approve the arrangement and on March 16, 2006 the arrangement was completed by the payment in total of $91.5 million and the issuance of 29.7 million Connacher common shares from treasury.

Luke is now a wholly-owned subsidiary of Connacher and produces approximately 2,800 boe/d (90 percent natural gas), largely at Marten Creek in northern Alberta. It operates most of its high working interest properties. This production was considered strategic to Connacher, as it provides a physical hedge to its initial requirements for natural gas to create steam for the company's proposed SAGD oil sands project at Great Divide. Based on current Luke production volumes and anticipated results of further development programs, the Luke purchase could also provide surplus volumes for sale in the marketplace and meet future Connacher requirements at Great Divide.

Proposed acquisition of refining assets in Montana

In March 2006, the company announced its intention to acquire all of the assets of an 8,300 bbl/d refinery located in Great Falls, Montana, USA for approximately US$55 million, comprised of cash and one million Connacher common shares to be issued from treasury. Closing is scheduled for March 31, 2006, subject to normal conditions for a transaction of this nature. Full employment of the existing workforce is expected for the continued, operation of the refinery.

This acquisition was considered strategic to provide Connacher with protection against wider and more volatile crude oil price differential swings. These have become increasingly frequent in the current higher oil price environment for the heavy oil which would be produced at Great Divide. The refinery is anticipated to be a profitable and strong business unit which, based on recent experience, has the potential to contribute to the company's cash flow growth in 2006 and beyond.

RELATED PARTY TRANSACTIONS

In 2005 the company paid professional legal fees of $539,004 (2004 - $250,800) to a law firm in which officers or directors of the company are related parties. Transactions with the foregoing related parties occurred within the normal course of business and have been measured at their exchange amount on normal business terms. The exchange amount is the amount of consideration established and agreed to by the related parties.

SIGNIFICANT ACCOUNTING POLICIES AND APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

The significant accounting policies used by the company are described below. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Changes in these judgments and estimates may have a material impact on the company's financial results and condition. The following discusses such accounting policies and is included in the MD&A to aid the reader in assessing the critical accounting policies and practices of the company and the likelihood of materially different results being reported. Management reviews it estimates regularly. The emergence of new information and changed circumstances may result in changes to estimates which could be material and the company might realize different results from the application of new accounting standards promulgated, from time to time, by various rule-making bodies.

The following assessment of significant accounting polices is not meant to be exhaustive.

Oil and Gas Reserves

Under Canadian Securities Regulators' "National Instrument 51-101-Standards of Disclosure for Oil and Gas Activities" ("NI 51-101") proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. In accordance with this definition, the level of certainty should result in at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated reserves. In the case probable reserves, which are less certain to be recovered than proved reserves, NI 51-101 states that it must be equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. Possible reserves are those reserves less certain to be recovered than probable reserves. There is at least a 10 percent probability that the quantities actually recovered will exceed the sum of proved plus probable plus possible reserves.

The oil and gas reserve estimates are made using all available geological and reservoir data as well as historical production data. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in the company's plans. The reserve estimates are also used in determining the company's borrowing base for its credit facilities and may impact the same upon revision or changes to the reserve estimates. The effect of changes in proved oil and gas reserves on the financial results and position of the company is described under the heading "Full Cost Accounting for Oil and Gas Activities".

FULL COST ACCOUNTING FOR OIL AND GAS ACTIVITIES

Depletion Expense

The company uses the full cost method of accounting for exploration and development activities. In accordance with this method of accounting, all costs associated with exploration and development are capitalized whether successful or not. The aggregate of net capitalized costs and estimated future development costs less estimated salvage values is amortized using the unit-of-production method based on estimated proved oil and gas reserves.

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Major Development Projects and Unproved Properties

Certain costs related to major development projects and unproved properties are excluded from net capitalized costs subject to depletion until proved reserves have been determined or their value is impaired. These costs are reviewed quarterly and any impairment is transferred to the costs being depleted or, if the properties are located in a cost centre where there is no reserve base, the impairment is charged directly to income.

Full Cost Accounting Ceiling Test

The company is required to review the carrying value of all property, plant and equipment, including the carrying value of oil and gas assets, for potential impairment. Impairment is indicated if the carrying value of the long-lived asset or oil and gas cost centre is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings.

The ceiling test is based on estimates of reserves, production rate, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements could be material.

Asset Retirement Obligations

The company is required to provide for future removal and site restoration costs by estimating these costs in accordance with existing laws, contracts or other policies. These estimated costs are charged to earnings and the appropriate liability account over the expected service life of the asset. When the future removal and site restoration costs cannot be reasonably determined, a contingent liability may exist. Contingent liabilities are charged to earnings only when management is able to determine the amount and the likelihood of the future obligation. The company estimates future retirement costs based on current estimates adjusted for inflation and credit risk. These estimates are subject to management uncertainty.

Income Taxes

The company follows the liability method of accounting for income taxes. Under this method tax assets are recognized when it is more than likely realization will occur. Tax liabilities are recognized for temporary differences between recorded book values and underlying tax values. Rates used to determine asset and liability amounts are rates in future periods when the timing differences change. The period in which a timing difference reverses are impacted by future income and capital expenditures. Rates are also affected by legislation changes. These components can impact the charges to future income for taxes.

Stock-Based Compensation

The company uses the fair value method to account for stock options. The determination of the amounts for stock-based compensation are based on assumption of stock volatility, interest rates and the term of the option. Assumptions by their nature are subject to measurement uncertainty.

Legal, Environment Remediation and Other Contingent Matters

In respect of these matters, the company is required to determine whether a loss is probable based on judgment and interpretation of laws and regulations and determine if such a loss can be estimated. When any such loss is determined, it is charged to earnings. Management continually monitors known and potential contingent matters and makes appropriate provisions by charges to earnings when warranted by circumstance.

COMMITMENTS, CONTINGENCIES, GUARANTEES, CONTRACTUAL OBLIGATIONS AND OFF BALANCE SHEET ARRANGEMENTS

The company's annual commitments under leases for office premises and operating costs, field compression equipment, software license agreements and other equipment are as follows:

2006 - $497,000; 2007 - $399,000; 2008 - $549,000; 2009 - $543,000; 2010 - $224,000

Additionally, the company has various guarantees and indemnifications in place in the ordinary course of business, none of which are expected to have a significant impact on the company's financial statements or operations. The company has not entered into any off-balance sheet arrangement.

CHANGES IN ACCOUNTING POLICIES

The company changed its method of accounting for stock options in 2004 to the fair value method. Stock option expenses in 2004 reflected this change. Also, in 2004 the company retroactively adopted the method of accounting for asset retirement obligations.

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Prior year figures reflect this change. Further, in 2004 the company commenced applying the new requirements for ceiling test calculations. This change had no impact for 2004.

CONTROL CERTIFICATION

Connacher has designed disclosure controls and procedures to provide reasonable assurance that material information related to the company is included in the company's annual filings. Additionally, Connacher has evaluated the effectiveness of the company's disclosure controls and procedures as of the end of the filing period of December 31, 2005 and concluded that these controls are effective.

BUSINESS RISKS

Connacher is exposed to certain risks and uncertainties inherent in the oil and gas business. Furthermore, being a smaller independent company, it is exposed to financing and other risks which may impair its ability to realize on its assets or to capitalize on opportunities which might become available to it. Additionally, through the company's investment in Petrolifera which operates in various jurisdictions, it has become exposed to other risks including currency fluctuations, political risk, price controls and varying forms of fiscal regimes or changes thereto which may impair Petrolifera's ability to conduct profitable operations.

The risks arising in the oil and gas industry include price fluctuations for both crude oil and natural gas over which the company has limited control; risks arising from exploration and development activities; production risks associated with the depletion of reservoirs and the ability to market production. Additional risks include environmental and safety concerns.

The company relies on access to capital markets for new equity to supplement internally generated cash flow and bank borrowings to finance its growth plans. Periodically, these markets may not be receptive to offerings of new equity from treasury, whether by way of private placement or public offerings. This may be further complicated by the limited market liquidity for shares of smaller companies, restricting access to some institutional investors. An increased emphasis on flow-through share financings may accelerate the pace at which junior oil and gas companies become cash-taxable, which could reduce cash flow available for capital expenditures on growth projects. Periodic fluctuations in energy prices may also affect lending policies of the company's banker, whether for existing loans or new borrowings. This in turn could limit growth prospects over the short run or may even require the company to dedicate cash flow, dispose of properties or raise new equity to reduce bank borrowings under circumstances of declining energy prices or disappointing drilling results.

The success of the company's capital programs as embodied in its productivity and reserve base could also impact its prospective liquidity and pace of future activities. Control of finding, development, operating and overhead costs per boe is an important criterion in determining company growth, success and access to new capital sources.

The company attempts to mitigate its business and operational risk exposures by maintaining comprehensive insurance coverage on its assets and operations, by employing or contracting competent technicians and professionals, by instituting and maintaining operational health, safety and environmental standards and procedures and by maintaining a prudent approach to exploration and development activities. The company also addresses and regularly reports on the impact of risks to its shareholders, writing down the carrying values of assets that may not be recoverable.

Furthermore, the company generally relies on equity financing and a bias towards conservative financing of its operations under normal industry conditions to offset the inherent risks of domestic and international oil and gas exploration, development and production activities. In the past the company has entered into forward sale, fixed price contracts to mitigate reduced product price risk and foreign exchange risk during periods of price improvement, primarily with a view to assuring the availability of funds for capital programs and to enhance the creditworthiness of its assets with its lenders. While hedging activities may have opportunity costs when realized prices exceed hedged pricing, such transactions are not meant to be speculative and are considered within the broader framework of financial stability and flexibility. Management continuously reviews the need to utilize such financing techniques.

OUTLOOK

The company's business plan anticipates substantial growth. Emphasis will continue to be on delineating and developing the Great Divide Oil Sands Project in Alberta while continuing to develop the company's recently-expanded conventional production base and profitably operating the Montana refinery, assuming its proposed acquisition is completed as anticipated. Timing for development and first production from the Great Divide Oil Sands Project is subject to regulatory approvals which are beyond the control of Connacher.

There can be no assurance that regulatory approvals will be granted on terms acceptable to the company or at all. The timing for start-up of production is dependent on, among other things, regulatory approvals, availability of the component equipment, access to skilled personnel and availability of drilling rigs. Additional financing may be required for the Great Divide Oil Sands Project, the company's conventional petroleum and natural gas assets and for the proposed Montana refinery.

Additional information relating to Connacher, including Connacher's Annual Information Form is on SEDAR at www.sedar.com.

QUARTERLY RESULTS

	2004				2005			
Three Months Ended	Mar 31	Jun 30	Sept 30	Dec 31	Mar 31	Jun 30	Sept 30 [3]	Dec 31
Financial Highlights ($000 except per share amounts) - Unaudited								
Total revenue	3,290	3,556	2,383	1,987	1,857	2,796	4,183	3,542
Cash flow from operations before								
working capital changes [1]	944	516	478	471	265	877	1,978	1,238
Basic, per share [1]	0.02	0.01	0.01	0.01	-	0.01	0.02	0.01
Diluted, per share [1]	0.02	0.01	0.01	0.01	-	0.01	0.02	0.01
Net earnings (loss)	(689)	(1,268)	(869)	(150)	1,673	(230)	(1,034)	582
Basic, per share	(0.01)	(0.03)	(0.02)	-	0.02	-	(0.01)	-
Diluted, per share	(0.01)	(0.03)	(0.02)	-	0.02	-	(0.01)	-
Capital expenditures	10,391	2,603	681	3,954	6,047	5,649	2,870	2,241
Proceeds on disposal of PNG properties	-	89	17,564	(49)	-	-	-	-
Bank debt	20,600	23,655	7,563	-	-	250	-	-
Working capital surplus (deficiency)	(9,850)	(8,357)	(6,644)	3,549	5,588	854	67,440	75,427
Cash on hand (net debt)	(30,450)	(32,012)	(14,207)	3,914	8,286	2,629	67,708	75,511
Shareholders' equity	21,528	20,806	20,090	40,375	41,079	41,090	113,081	129,108
Operating Highlights								
Production / sales volumes								
Natural gas - mcf/d	2,268	1,860	1,068	1,290	1,328	1,416	497	86
Crude oil - bbl/d	859	1,004	636	646	629	702	808	775
Equivalent - boe/d [2]	1,237	1,314	814	861	850	938	891	789
Pricing								
Crude oil - $/bbl	30.41	29.46	36.58	30.68	30.02	41.23	53.40	41.54
Natural gas - $/mcf	4.42	5.11	2.21	1.29	1.18	0.99	1.88	7.55
Selected Highlights - $/boe [2]								
Weighted average sales price	29.22	29.74	31.48	24.93	24.04	32.35	49.48	41.61
Other income	-	-	0.33	0.15	0.24	0.41	1.57	7.15
Royalties	5.37	5.95	6.06	4.64	4.82	8.06	11.73	7.76
Operating costs	10.09	11.26	8.70	7.98	7.01	7.42	7.69	8.90
Operating netback [4]	13.76	12.53	17.05	12.47	12.45	17.28	31.63	32.09
Common Share Information								
Shares outstanding at end of period (000's)	46,153	47,368	47,668	89,627	92,753	93,013	134,236	139,940
Weighted average shares outstanding for the period								
Basic (000's)	46,067	47,042	47,400	50,908	91,189	92,875	103,851	136,071
Diluted (000's)	50,119	48,496	47,504	53,329	94,197	95,555	106,397	142,507
Volume traded during quarter (000's)	20,706	30,108	8,880	25,256	40,486	16,821	180,848	100,246
Common share price ($)								
High	1.75	1.08	0.44	0.80	1.22	1.05	2.69	4.20
Low	0.73	0.30	0.28	0.29	0.49	0.68	0.76	1.09
Close (end of period)	0.78	0.40	0.32	0.55	0.93	0.82	2.54	3.84

(1) Cash flow from operations before working capital changes and cash flow per share do not have standardized meanings prescribed by Canadian generally accepted accounting principles ("GAAP") and therefore may not be comparable to similar measures used by other companies. Cash flow from operations before working capital changes includes all cash flow from operating activities and is calculated before changes in non-cash working capital. The most comparable measure calculated in accordance with GAAP would be net earnings. Cash flow from operations before working capital changes is reconciled with net earnings on the Consolidated Statement of Cash Flows and in the accompanying Management Discussion & Analysis. Management uses these non-GAAP measurements for its own performance measures and to provide its shareholders and investors with a measurement of the company's efficiency and its ability to fund a portion of its future growth expenditures.

(2) All references to barrels of oil equivalent (boe) are calculated on the basis of 6 mcf : 1 bbl. Boes may be misleading, particularly if used in isolation. This conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(3) In the third quarter of 2005, the company discontinued consolidating the financial and operational results of Petrolifera Petroleum Limited. Comparative figures have not been restated.

(4) Operating netback is a non-GAAP measure used by management as a measure of operating efficiency and profitability. It is calculated as petroleum and natural gas revenue less royalties and operating costs.

CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT

To the Shareholders of Connacher Oil and Gas Limited:

The consolidated financial statements of Connacher Oil and Gas Limited were prepared by and are the responsibility of management. The consolidated financial statements have been prepared in conformity with Canadian generally accepted accounting principles appropriate in the circumstances and include some amounts that are based on managements' best estimates and judgments. Information contained elsewhere in the Annual Report is consistent, where applicable, with information contained in the financial statements.

The company maintains systems of internal accounting controls designed to provide reasonable assurance that all transactions are properly recorded in the company's books and records, that policies and procedures are adhered to and that the assets are protected from unauthorized use. The systems of internal accounting controls are complemented by the selection, training and development of qualified staff. Management believes that the system of internal controls that the company has installed has operated effectively in 2005.

The consolidated financial statements have been audited by the independent accounting firm Deloitte & Touche LLP whose appointment is ratified annually by the shareholders at the annual shareholders' meeting. The independent accountants perform such tests and related procedures as they deem necessary to arrive at an opinion on the fairness of the financial statements.

The audit committee of the board of directors periodically meets with the independent accountants and management to satisfy itself that it is properly discharging its responsibilities. The independent accountants have unrestricted access to the audit committee, without management present, to discuss the results of their examination and the quality of financial reporting and internal accounting controls.

Signed

"R.A. Gusella"

President and Chief Executive Officer
March 23, 2006

Signed

"R. R. Kines"

Vice President, Finance and Chief Financial Officer
March 23, 2006

AUDITORS' REPORT

To the Shareholders of Connacher Oil and Gas Limited:

We have audited the consolidated balance sheets of Connacher Oil and Gas Limited as at December 31, 2005 and 2004 and the consolidated statements of operations and retained earnings 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 consolidated 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 consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2005 and 2004 and the result of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Signed,
"DELOITTE & TOUCHE LLP"
Chartered Accountants

Calgary, AB
March 23, 2006

CONSOLIDATED BALANCE SHEETS

Connacher Oil and Gas Limited

December 31

	2005	2004
	$	$
		(Restated Note 6)
ASSETS		
CURRENT		
Cash and cash equivalents	75,510,593	3,914,181
Accounts receivable	1,604,948	1,773,005
Due from Petrolifera (Note 3(b))	221,131	-
Prepaid expenses	406,748	309,062
	77,743,420	5,996,248
Investment in Petrolifera (Note 3(b))	10,495,532	-
Deferred charges (Note 4)	257,599	-
Property and equipment (Note 5)	45,241,510	37,265,595
Future income tax asset (Note 6)	1,075,038	2,828,270
	134,813,099	46,090,113
LIABILITIES		
CURRENT		
Accounts payable	2,315,960	2,446,947
Asset retirement obligations (Note 8)	3,108,538	2,905,477
Deferred credits (Note 9)	280,866	353,771
Non-controlling interests (Note 3)	-	8,930
	5,705,364	5,715,125
SHAREHOLDERS' EQUITY		
Share capital and contributed surplus (Note 10)	127,032,676	39,290,819
Retained earnings	2,075,059	1,084,169
	129,107,735	40,374,988
	134,813,099	46,090,113

Commitments, contingencies and guarantees (Note 14)

Approved by the Board

Signed "D.H. Bessell", Director

Signed "C.M. Evans", Director

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CONSOLIDATED STATEMENTS OF OPERATIONS AND RETAINED EARNINGS

Connacher Oil and Gas Limited
Years Ended December 31

	2005	2004
	$	$
		(Restated Note 6)
REVENUE		
Petroleum and natural gas sales	11,677,649	11,179,404
Interest and other income	700,034	36,484
	12,377,683	11,215,888
Royalties	(2,582,561)	(2,138,916)
	9,795,122	9,076,972
EXPENSES		
Operating	2,445,393	3,765,531
General and administrative	2,659,599	2,016,578
Stock-based compensation (Note 10)	1,191,971	180,661
Finance charges	307,574	770,026
Foreign exchange loss (gain)	(29,852)	45,524
Depletion, depreciation and accretion (Note 5)	5,796,820	6,876,110
Dilution gain (Note 3(c))	(4,464,700)	(1,353,199)
Equity interest in Petrolifera loss (Note 3(b))	27,434	-
	7,934,239	12,301,231
Earnings (loss) before taxes and non-controlling interests	1,860,883	(3,224,259)
Current income tax provision (recovery)	101,903	115,472
Future income tax provision (recovery)	768,090	(372,250)
	869,993	(256,778)
Earnings (loss) before non-controlling interests	990,890	(2,967,481)
Non-controlling interests (Note 3)	-	8,930
NET EARNINGS (LOSS)	990,890	(2,976,411)
RETAINED EARNINGS, BEGINNING OF YEAR (Note 6)	1,084,169	4,060,580
RETAINED EARNINGS, END OF YEAR	2,075,059	1,084,169
EARNINGS (LOSS) PER SHARE (Note 13)		
Basic and diluted	0.01	(0.06)

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CONSOLIDATED STATEMENTS OF CASH FLOW

Connacher Oil and Gas Limited

Years Ended December 31

	2005	2004
	$	$
Cash provided by (used in) the following activities:		
OPERATING		
Net earnings (loss)	990,890	(2,976,411)
Items not involving cash:		
Depletion, depreciation and accretion	5,796,820	6,876,110
Stock-based compensation	1,191,971	180,661
Financing charges	150,000	-
Future income tax provision (recovery)	768,090	(372,250)
Foreign exchange loss (gain)	(29,852)	45,524
Dilution gain	(4,464,700)	(1,353,199)
Lease reducement amortization	(72,905)	
Income applicable to non-controlling interests	-	8,930
Equity interest in Petrolifera loss	27,434	-
Cash flow from operations before working capital changes	4,357,748	2,409,365
Changes in non-cash working capital (Note 13 (b))	(484,927)	(42,896)
	3,872,821	2,366,469
FINANCING		
Issue of common shares, net of share issue costs	86,512,147	20,411,953
Issue of shares by Petrolifera, net of share issue costs	6,227,717	1,385,037
Deferred financing costs	(257,599)	-
Increase in (repayment of) bank loans	-	(12,100,000)
Lease inducement received	-	353,771
	92,482,265	10,050,761
INVESTING		
Purchase of Petrolifera shares	(6,000,000)	-
Collection of Petrolifera note	750,000	-
Capital expenditures	(16,807,302)	(17,628,534)
Change in non-cash working capital (Note 13(b))	396,109	(9,385,827)
Proceeds on disposal of oil and gas properties (Note 5)	-	17,604,310
Deposit on facilities	-	279,700
	(21,661,193)	(9,130,351)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	74,693,893	3,286,879
Impact on cash resulting from de-consolidation of Petrolifera (Note 3(b))	(3,097,481)	-
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	3,914,181	627,302
CASH AND CASH EQUIVALENTS, END OF YEAR	75,510,593	3,914,181

Supplementary information – Note 13

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Connacher Oil and Gas Limited
Years Ended December 31. 2005 and 2004

1. FINANCIAL STATEMENT PRESENTATION

The consolidated financial statements include the accounts of Connacher Oil and Gas Limited and its subsidiaries (collectively "Connacher" or the "company") and are presented in accordance with Canadian generally accepted accounting principles. In Canada the company is in the business of exploring, producing and marketing conventional petroleum and natural gas and has recently commenced exploration and development of bitumen in the oil sands of northern Alberta. Prior to the de-consolidation of Petrolifera in 2005 (Note 3(b)) it also conducted a conventional petroleum and natural gas business in Argentina.

2. SIGNIFICANT ACCOUNTING POLICIES

Joint venture operations

A part of the company's activities are conducted with others, and these consolidated financial statements reflect only the company's proportionate interest in such activities.

Cash and cash equivalents

Cash and cash equivalents include short-term deposits with initial maturities of three months or less.

Petroleum and natural gas operations

The company follows the full cost method of accounting whereby all costs relating to the exploration for and development of crude oil and natural gas reserves are capitalized on a country by country cost centre basis.

Capitalized costs of petroleum and natural gas properties and related equipment within a cost centre are depleted and depreciated using the unit-of-production method based on estimated proved crude oil and natural gas reserves as determined by independent consulting engineers. For the purpose of this calculation, production and reserves of natural gas are converted to equivalent units of crude oil based on relative energy content (6:1).

The company applies a "ceiling test" to the net book value of petroleum and natural gas properties to ensure that such carrying value does not exceed the estimated fair value of the properties. The carrying value is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves and the lower of cost and market of unproved properties exceeds the carrying value. If the carrying value is assessed to not be recoverable, the calculation compares the carrying value to the sum of the discounted cash flows expected from the production of proved and probable reserves and the lower of cost and market of unproved properties. Should the carrying value exceed this sum, an impairment loss is recognized. The cash flows are estimated using projected future product prices and costs and are discounted using the credit adjusted risk-free interest rate.

Costs of acquiring and evaluating unproved properties and major development projects are excluded from costs subject to depletion and depreciation until it is determined whether or not proved reserves are attributable to the properties or impairment occurs. These costs are reviewed quarterly and any impairment is transferred to the costs being depleted or, if the properties are located in a cost centre where there is no reserve base, the impairment is charged directly to income.

Gains or losses on sales of properties are recognized only when crediting the proceeds to cost would result in a change of 20 percent or more in the depletion and depreciation rate.

Furniture, equipment and leaseholds

Furniture and equipment are recorded at cost and are being depreciated on a declining balance basis at rates of 20 percent to 30 percent per year. Leaseholds are amortized over the lease term.

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Financial instruments

Financial instruments include accounts receivable and accounts payable. All carrying values of financial instruments approximate fair value unless otherwise noted.

Deferred charges

Costs incurred in respect of transactions not completed have been temporarily capitalized and will be recognized on completion of the transactions.

Credit risk

The majority of the accounts receivable is in respect of oil and gas operations. The company generally extends unsecured credit to customers and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions. Management believes the risk is mitigated by the size and reputation of the companies to which credit has been extended. The company has not historically experienced any material credit loss in the collection of accounts receivable.

Commodity and financial risk management

The company periodically enters into fixed price crude oil sales contracts for the physical delivery of its crude oil to reduce the exposure to commodity price fluctuations; and occasionally these contracts are denominated in Canadian dollars to mitigate foreign exchange risks. At December 31, 2005 there were no such contracts in place. Additionally, the company's bank loans are subject to floating interest rates.

Equity accounting

The investment in Petrolifera Petroleum Limited is accounted for on an equity basis, whereby the carrying value reflects the company's investment, at the lower of cost and fair value, and the company's equity interest share of its income and losses. Any permanent decline in value would be charged to earnings.

Foreign currency translation

The company translates its foreign denominated monetary assets and liabilities at the exchange rate prevailing at year end. Non-monetary assets, liabilities and related depletion and depreciation were translated at historic rates. Revenues and expenses were translated at the average rate of exchange for the year and any resulting foreign exchange gains or losses are included in operations.

Asset retirement obligations

The company recognizes an asset retirement obligation liability for abandoning oil and natural gas wells, related facilities, compressors and gas plants, removal of equipment from leased acreage and returning such land to its original condition by estimating and recording the fair value of each asset retirement obligation arising in the period a well or related asset is drilled, constructed or acquired. This fair value is estimated using the present value of the estimated future cash outflows to abandon the asset at the company's credit adjusted risk-free interest rate and includes estimates for inflation. The obligation is reviewed regularly by management based upon current regulations, costs, technologies and industry standards. The discounted obligation is initially capitalized as part of the carrying amount of the related oil and natural gas properties and a corresponding liability is recognized. The liability is accreted against income until it is settled or the property is sold and is included as a component of depletion and depreciation expense. The increase in oil and natural gas properties is depleted and depreciated on the same basis as the remainder of the oil and natural gas properties. Actual restoration expenditures are charged to the accumulated obligation as incurred and costs for properties disposed are removed.

Flow-through shares

The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. Accordingly, share capital is reduced and the future income tax asset is decreased by the tax benefits related to the expenditures at the time they are renounced.

Revenue recognition

Petroleum and natural gas sales are recognized as revenue at the time the respective commodities are delivered to purchasers. Gains and losses on forward fixed price commodity contracts are included in petroleum and natural gas sales revenue when the gain or loss occurs.

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Stock-based compensation

The fair value of each stock option granted is estimated on the date of grant using the Black-Scholes option pricing model. The amount is credited to contributed surplus and expensed over the vesting period. Upon exercise of the options, the exercise proceeds together with amounts credited to contributed surplus, are credited to share capital.

Income taxes

The company follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributed to differences between the amounts reported in the financial statements and their respective tax bases, using substantively enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. Future tax assets recognized are assessed by management at each balance sheet date for impairment. Any impairment is recognized when the recovery is more than likely and when the recovery is more than likely and through a valuation allowance.

Measurement uncertainty

The timely preparation of the consolidated financial statements in conformity with Canadian generally accepted accounting principles requires that management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Income taxes are subject to re-assessment by tax authorities.

Amounts recorded for depreciation, depletion and accretion, asset retirement costs and obligations, amounts used for ceiling test and impairment calculations and amounts used in the determination of the future tax asset are based on estimates of natural gas and crude oil reserves and future costs required to develop those reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs, and the related future cash flows are subject to measurement uncertainty.

Per share amounts

Basic per share amounts are calculated using the weighted average number of common shares outstanding for the year. The company follows the treasury stock method to calculate diluted per share amounts. The treasury stock method assumes that any proceeds from the exercise of in-the-money stock options and other dilutive instruments would be used to purchase common shares at the average market price during the period.

3. ARGENTINIAN OPERATIONS AND PETROLIFERA PETROLEUM LIMITED

(a) Reorganization of Argentinean operations

In 2004 the company reorganized its Argentinean oil and gas properties by acquiring the non-owned 50 percent operated working interest from its joint venture partner in an arms length transaction for US $1.5 million. Late in 2004, Connacher incorporated a subsidiary, Petrolifera Petroleum Limited ("Petrolifera") and sold its Argentinean assets to Petrolifera for eight million Petrolifera common shares and a $4 million promissory note. Concurrent with acquiring the Argentinean assets from Connacher, Petrolifera closed a $1.5 million private placement equity financing. The financing had the effect of reducing Connacher's equity interest in Petrolifera from 100 percent to 61 percent, as Connacher did not participate in the financing. The 39 percent reduction resulted in a dilution gain to the company of $1,353,199. Immediately after the transaction, Petrolifera paid $1.25 million in partial satisfaction of the promissory note.

In March 2005 Petrolifera completed a $7 million private placement financing. As Connacher did not participate in the financing, its equity interest in Petrolifera was reduced to 40 percent from 61 percent.

In March 2005 and in consideration for the assistance provided to Petrolifera in securing Peruvian licenses for exploratory lands and for the provision of financial guarantees respecting Petrolifera's annual work commitments in two licensed blocks, Connacher was granted an option to acquire 200,000 common shares at $0.50 per share and was granted a 10 percent carried working interest ("CWI") through the drilling of the first well on each block. Petrolifera has the right of first purchase of this interest should Connacher elect to sell it at some future date. The CWI is convertible at the holder's election into a two percent gross overriding royalty on each license after the drilling of the first well on each block. These interests were effective upon the issuance of the licenses. The guarantees are limited to amounts specified over the terms of the licenses. Over the first 24 months of the licenses, the guarantee is limited to US $200,000. Connacher was subsequently indemnified by Petrolifera for this guarantee.

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(b) Deconsolidation of and investment in Petrolifera

In the third quarter of 2005 the company discontinued consolidating the financial results of Petrolifera, as the company was no longer considered to control Petrolifera due to the election of independent directors and other factors. The investment in Petrolifera has since been accounted for following the equity basis of accounting. Comparative figures have not been restated.

The impact of not consolidating Petrolifera had the effect of reducing the company's net assets by $4,125,653 as follows:

	$
Cash	(3,097,481)
Current assets	(321,251)
Future income tax asset	(985,000)
Property and equipment	(4,110,144)
Current liabilities	381,694
Asset retirement obligations	442,172
Non-controlling interests	3,564,357
Changes in net assets	(4,125,653)

	$
Connacher's initial investment in Petrolifera at the time of deconsolidation	4,125,653
Increases/decreases in investment:	
Equity interest in Petrolifera's loss from the time of deconsolidating to December 31, 2005	(27,434)
Collection of Promissory Note and reclassification of amounts due from Petrolifera	(1,047,058)
Purchase of shares in Petrolifera (Note 3(c))	6,000,000
Dilution gain on shares issued by Petrolifera to unrelated parties after de-consolidation (Note 3(c))	1,444,371
Investment in Petrolifera at December 31, 2005	10,495,532

The company now records its investment in Petrolifera on an equity basis.

Under the terms of a Management Services Agreement with Petrolifera, Connacher provides all management, operational, accounting and general and administrative services necessary or appropriate to manage and operate Petrolifera. The fee for this service was $10,000 per month prior to Petrolifera's equity securities being listed and posted for trading on a recognized stock exchange and $15,000 per month thereafter for a further 18 months. The agreement may be immediately terminated for performance failure by the aggrieved party or upon 30 days prior written notice by Connacher, or by mutual agreement.

At December 31, 2005, Connacher was owed $221,131 for these services, and for other amounts advanced and other amounts paid on their behalf (2004 - $106,843).

(c) Dilution gain

Dilution gains were recognized upon changes to Connacher's equity interest in Petrolifera that occurred during 2005, as follows:

In March 2005 Petrolifera completed a $7 million private placement financing and repaid $2 million of the $4 million promissory note. As Connacher did not participate in the financing, its equity interest in Petrolifera was reduced to 40 percent from 61 percent. The 21 percent reduction resulted in a dilution gain of $3,020,329 in the first quarter of 2005.

In November 2005 Petrolifera completed a $21.3 million initial public offering. Connacher purchased $6 million of the issue to bring its ownership in Petrolifera to 35 percent. This five percent reduction in Connacher's equity interest in Petrolifera resulted in dilution gain of $1,636,453.

Throughout 2005, Petrolifera share purchase rights and share purchase warrants were exercised by other investors to further reduce Connacher's equity interest in Petrolifera to 33 percent at December 31, 2005. The exercise of these rights and warrants generated a dilution loss in the amount of $192,082 as these rights and warrants were exercised at a price less than Connacher's per share carrying value of its investment in Petrolifera.

4. DEFERRED CHARGES

Deferred charges of $257,599 relate to costs incurred in respect of transactions not completed at December 31, 2005. These transactions are described in Note 15, Subsequent Events. When these transactions are completed these costs will be recognized.

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5. PROPERTY AND EQUIPMENT

	Cost $	Accumulated Depletion, Depreciation and Amortization $	Net Book Value $
2005			
Petroleum and natural gas properties and equipment	**60,290,558**	**15,679,685**	**44,610,873**
Furniture, equipment and leaseholds	**1,058,286**	**427,649**	**630,637**
	61,348,844	**16,107,334**	**45,241,510**
2004			
Petroleum and natural gas properties and equipment	47,339,971	10,654,358	36,685,613
Furniture, equipment and leaseholds	806,314	226,332	579,982
	48,146,285	10,880,690	37,265,595

Included in Property and Equipment are estimated future asset retirement costs of $1,910,894 (2004 - $1,851,300).

In July 2004 the company sold certain petroleum and natural gas properties for gross proceeds of $17.6 million. As there was no significant change in the rate of depletion, no gain or loss was recognized. These financial statements reflect operating results from these properties until the date the sale closed. The asset retirement obligation was also reduced to reflect this disposition.

In 2004 the company acquired the non-owned 50 percent interest in an oil and gas concession in Argentina for US $1.5 million. The purchase price was negotiated at arms-length with the operator of the property. The company's 100 percent interest in the properties was subsequently sold to a related party, Petrolifera. The company's carrying value was used to record the sale. As consideration for the properties sold, Connacher received a $4 million promissory note and eight million Petrolifera common shares. Immediately after the transaction, Petrolifera paid $1.25 million in partial satisfaction of the promissory note from proceeds of an equity sale, which reduced Connacher's interest in Petrolifera to 61 percent (see Note 3(a)).

In 2005, the company capitalized $615,000 (2004 - $71,000) of general and administrative expenses, including stock-based compensation of $410,000, related to exploration and development activities and nil (2004 – $113,000) of interest costs related to major development projects.

Capital costs of $11.2 million (2004 – $4.4 million) related to major development projects principally related to oil sands assets in a pre-production state have been excluded from depletable costs. No proved reserves have been assigned to those projects. Undeveloped land acquisition costs of $2.5 million (2004 - $3.4 million) were also excluded from the depletion calculation.

Depletion, depreciation and accretion expense includes a charge of $165,150 (2004 - $178,000) to accrete the company's estimated asset retirement obligations (Note 8).

The ceiling test as at December 31, 2005 excludes $2.5 million of undeveloped land and $11.2 million of major development projects which have been separately evaluated by management for impairment. Based on the ceiling test and other assessments, no impairment has been recorded at December 31, 2005.

Connacher's oil and natural gas reserves were evaluated by qualified evaluators as at December 31, 2005 in a report dated March 8, 2006. The evaluation was conducted in accordance with Canadian Securities Administrators' National Instrument 51-101 ("NI 51-101"), using the following base price assumptions adjusted for the company's product quality and transportation differentials:

	WTI @ Cushing ($US/bbl)	Alberta Spot ($/mcf)
2006	58.00	10.37
2007	56.38	9.65
2008	52.53	8.53
2009	51.69	7.86
2010	52.72	7.12
	+ approximately 2% thereafter	+ approximately 2% thereafter

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6. INCOME TAXES

The 2005 current income tax provision of $101,903 is comprised of Large Corporation tax of $119,059 offset by other tax recoveries of $17,156. The 2004 tax provision of $115,472 was comprised of Argentinean income taxes.

The following table reconciles income taxes calculated at the Canadian statutory rate with recorded income taxes:

Years Ended December 31	2005	2004
	$	$
Earnings (loss) before income taxes and non-controlling interests	1,861,000	(3,224,000)
Canadian statutory rate	39.0%	39.1%
Expected income taxes (recoverable)	726,000	(1,261,000)
Non-deductible Canadian crown payments	555,000	692,000
Canadian resource allowance	(371,000)	(367,000)
Benefit (reduction) of tax deductions not previously recognized	-	269,000
Impact of reduction in Canadian tax rates and other	245,000	294,000
Foreign taxes (recovery)	(17,000)	116,000
Capital taxes	119,000	-
Tax effect of dilution gain	(852,000)	-
Non deductible stock-based compensation	465,000	-
Provision for taxes (recovery)	870,000	(257,000)

The company had the following future tax assets relating to temporary timing differences:

As at December 31	2005	2004
	$	$
Tax basis in excess (deficiency) of book value of property and equipment	(2,370,000)	903,000
Non-capital losses carried forward	1,075,000	1,925,000
Share issue costs	2,370,000	-
	1,075,000	2,828,000

As a result of a recent adjustment proposed by Canada Revenue Agency to resource tax pools respecting assets acquired in 2002, the December 31, 2002 balance of property and equipment was increased by $850,000 and the future income tax asset balance was reduced by $850,000. Additional depletion of $124,000 ($72,000 net of tax) for 2002 and $92,000 ($55,000 net of tax) for 2003 was recorded as an adjustment to the opening balance of retained earnings for 2004. There was no significant impact to the Statements of Operations for 2004 and 2005.

At December 31, 2005 the company had approximately $3 million of non-capital losses which do not expire before 2009, $38 million of deductible resource pools and $6 million of deductible financing costs.

7. BANK LOANS

As at December 31, 2005, the company had available an $8.4 million Revolving Reducing Demand Loan Facility ("LOC") with no scheduled monthly reductions. The LOC bears interest at the bank's prime lending rate plus 3/4 percent on borrowed amounts. At December 31, 2005, the company had not drawn any amount on this facility.

Additionally, the company had a $3 million Non-Revolving Acquisition/Development Demand Loan Facility ("AD Facility"). At December 31, 2005, the company had not drawn any amount on this facility. Interest is charged at prime plus one percent on borrowed amounts of the AD Facility.

These facilities were secured by a $50,000,000 fixed and floating charge debenture and a general assignment of book debts.

Refer to Note 15, Subsequent Events.

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8. ASSET RETIREMENT OBLIGATIONS

The following tables present the reconciliation of the beginning and ending aggregate carrying amount of the obligation associated with the retirement of petroleum and natural gas properties and facilities.

Year ended December 31	2005	2004
	$	$
Asset retirement obligations, beginning of year	**2,905,477**	4,784,000
Liabilities incurred	**301,091**	663,406
Liabilities settled with Petrolifera deconsolidation	**(442,172)**	-
Liabilities settled	**-**	(206,773)
Liabilities disposed	**(24,054)**	(2,466,660)
Change in estimated future cash flows	**203,046**	(46,496)
Accretion expense	**165,150**	178,000
Asset retirement obligations, ending of period	**3,108,538**	2,905,477

At December 31, 2005 the estimated total undiscounted amount required to settle the asset retirement obligations was $5.4 million (2004 - $3.9 million). These obligations are expected to be settled over the useful lives of the underlying assets, which currently extend up to 20 years into the future. This amount has been discounted using a credit-adjusted risk-free interest rate of six percent and inflation rate of 1.5 percent.

9. DEFERRED CREDITS

During 2004, the company received an office lease inducement which is being amortized against office rent expense over the six year term of the lease.

10. SHARE CAPITAL AND CONTRIBUTED SURPLUS

Authorized

The authorized share capital is comprised of the following:

- Unlimited number of common voting shares
- Unlimited number of first preferred shares
- Unlimited number of second preferred shares

Issued

Only common shares have been issued by the company.

	Number of Shares	Amount $
Share Capital:		
Balance, December 31, 2003	45,902,925	19,616,172
Issued for cash by private placement (a)	41,706,663	20,832,298
Assigned value of warrants issued (a)		441,700
Issued upon exercise of options (c)	575,000	178,236
Issued upon exercise of warrants (d)	1,442,155	766,788
Assigned value of warrants exercised		(45,700)
Tax effect of expenditures renounced pursuant to the issuance of flow through common shares (e)		(1,970,000)
Share issue costs		(1,737,633)
Tax effect of share issue costs		673,700
Balance, Share Capital, December 31, 2004	89,626,743	38,755,561

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Issued for cash in public offerings (b)	45,541,000	90,000,850
Issued upon exercise of options (c)	981,000	665,908
Issued upon exercise of warrants (d)	3,791,705	1,986,388
Share issue costs		(5,979,861)
Tax effect of share issue costs		2,339,300
Tax effect of expenditures renounced pursuant to the issuance of flow through common shares		(2,697,500)
Balance, Share Capital, December 31, 2005	139,940,448	125,070,646

Contributed Surplus:	
Balance, December 31, 2003	378,333
Fair value of share options granted	180,661
Assigned value of options exercised	(23,736)
Balance, Contributed Surplus, December 31, 2004	535,258
Fair value of options granted	1,587,910
Assigned value of options exercised	(161,138)
Balance Contributed Surplus, December 31, 2005	1,962,030

Total Share Capital and Contributed Surplus:	
December 31, 2004	39,290,819
December 31, 2005	127,032,676

(a) Private Placement – 2004

In November and December 2004 the company issued from treasury 30,000,000 common shares at $0.475 per share and 11,706,663 common shares on a flow-through basis at $0.60 per share, renouncing resource expenditures of $7,023,998 effective December 31, 2004. As partial compensation for distributing the shares, selling agents were issued 2,487,368 warrants, with each warrant entitling the holder to acquire one common share from treasury at a price of $0.59 anytime before June 7, 2006 and 2,400 warrants exercisable at $0.61 anytime before June 7, 2006. For accounting purposes a fair value of $441,700 was assigned to the issued warrants. In the current year 1,005,948 of these warrants were exercised (2004-nil).

(b) Public Offerings – 2005

In September 2005 the company issued from treasury 40,541,000 common shares at $1.85 per share. In December 2005 issued the company from treasury another five million common shares on a flow-through basis at $3.00 per share, renouncing resource expenditures of $15 million effective December 31, 2005.

(c) Stock Options

A summary of the company's outstanding stock option grants, as at December 31, 2005 and 2004 and changes during those years is presented below:

	2005		2004	
	Number of Shares	**Weighted Average Exercise Price**	Number of Shares	Weighted Average Exercise Price
		$		$
Outstanding, beginning of year	**3,988,600**	**0.53**	2,830,000	0.45
Granted	**5,994,000**	**1.94**	2,138,000	0.57
Expired	**(409,000)**	**1.05**	(404,400)	0.53
Exercised	**(981,000)**	**0.51**	(575,000)	0.27
Outstanding, end of year	**8,592,600**	**1.49**	3,988,600	0.53
Exercisable, end of year	**3,159,869**	**1.03**	2,030,000	0.57

All stock options have been granted for a period of five years. Of the stock options granted in 2005, 4,104,000 stock options vest one-third upon grant, one-third one year after grant, and one-third two years after grant and 1,890,000 stock options vest one-third one year after grant, one-third two years after grant, and one-third three years after grant. The table below summarizes unexercised stock options.

Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life at December 31, 2005
$0.20 - $0.70	2,285,600	3.0
$0.71 - $1.00	1,751,000	3.8
$1.01 - $1.61	2,126,000	4.4
$1.62 - $3.91	2,430,000	4.9
	8,592,600	

In 2005 a compensatory non-cash expense of $1,601,631 (2004 - $180,661) was recorded, reflecting the fair value of stock options granted and vested during the year. Of the current amount of $1,191,971 was expensed and the balance was capitalized to property and equipment.

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

	2005	2004
Risk free interest rate	**3.0%**	3.0%
Expected option life (years)	**3**	3
Expected volatility	**50%**	53%

The weighted average fair value at the date of grant of all options granted in 2005 was $0.65 per option (2004 - $0.22).

(d) Share purchase warrants

A summary of the company's outstanding share purchase warrants, as at December 31, 2005 and 2004 and changes during the years is presented below:

	2005	2004
Outstanding, beginning of year	**5,300,525**	4,984,145
Issued	**-**	2,499,768
Exercised	**(3,791,705)**	(1,442,155)
Expired	**(15,000)**	(741,233)
Outstanding, end of year	**1,493,820**	5,300,525

The 1,493,820 warrants outstanding are exercisable to purchase common shares from treasury as follows:

(i) 1,481,420 common shares at $0.59 per share until their expiry on June 7, 2006;
(ii) 2,400 common shares at $0.61 per share until their expiry on June 7, 2006; and
(iii) 10,000 common shares at $0.52 per share until their expiry on December 1, 2006;

(e) Flow-through shares

In 2004 the company incurred all of its $5 million resource expenditures commitment related to its 2003 flow-through common share financing and recognized the related tax effect of $1,970,000.

The company renounced $7,023,998 of resource expenditures to flow-through share investors effective December 31, 2004. The related tax effect of those expenditures has been recorded in 2005 in the amount of $2,697,500 and the company incurred the expenditures in 2005 as required.

In 2006 the company renounced a further $15 million of resource expenditures to flow-through investors effective December 31, 2005. The related tax effect of those expenditures will be recorded in 2006 and the company has until December 31, 2006 to incur those expenditures.

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11. SEGMENTED INFORMATION

In Canada the company is in the business of exploring, producing and marketing conventional petroleum and natural gas and has recently commenced exploration and development of bitumen in the oil sands of northern Alberta. Prior to the de-consolidation of Petrolifera in 2005 (Note 3(b)) it also conducted a conventional petroleum and natural gas business in Argentina. The significant aspects of these operating segments are presented below. Included in total Canadian conventional assets is the company's carrying value of its investment in Petrolifera.

	Canada			Argentina	
	Conventional	Oil Sands	Total	Conventional	Total
	$	$	$	$	$
2005					
Revenue, gross	**11,366,293**	**-**	**11,366,293**	**1,011,390**	**12,377,683**
Net earnings (loss)	**1,010,116**	**-**	**1,010,116**	**(19,226)**	**990,890**
Property and equipment	**34,058,249**	**11,183,261**	**45,241,510**	**-**	**45,241,510**
Capital expenditures	**7,959,099**	**7,081,078**	**15,040,177**	**1,767,125**	**16,807,302**
Total assets	**123,382,911**	**11,183,261**	**134,566,172**	**246,927**	**134,813,099**
2004					
Revenue, gross	10,184,516	-	10,184,516	1,031,372	11,215,888
Net earnings (Notes 2 & 8)	(3,049,181)	-	(3,049,181)	72,770	(2,976,411)
Property and equipment (Notes 2 & 8)	30,344,486	4,102,183	34,446,669	2,818,926	37,265,595
Capital expenditures	12,911,038	4,102,183	17,013,221	615,313	17,628,534
Total assets (Notes 2 & 8)	38,985,544	4,102,183	43,087,727	3,002,386	46,090,113

12. RELATED PARTY TRANSACTIONS

In 2005 the company paid professional legal fees of $539,004 (2004 - $250,800) to a law firm in which officers or directors of the company are related parties. Transactions with the related party occurred within the normal course of business and have been measured at their exchange amount on normal business terms. The exchange amount is the amount of consideration established and agreed to with the related parties.

13. SUPPLEMENTARY INFORMATION

(a) Per share amounts

The following table summarizes the common shares used in per share calculations.

For the years ended December 31	2005	2004
Weighed average common shares outstanding	**106,113,563**	50,907,942
Dilutive effect of stock options and stock purchase warrants	**5,732,124**	2,420,609
Weighed average common shares outstanding – diluted	**111,845,687**	53,328,551

(b) Net change in non-cash working capital

For the years ended December 31	2005	2004
	$	$
Accounts receivable	**(276,581)**	711,424
Petrolifera current account	**61,355**	-
Loan receivable	**-**	135,848
Prepaid expenses	**(124,299)**	(12,053)
Accounts payable	**250,707**	(10,263,942)
Total	**(88,818)**	(9,428,723)

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Summary of working capital changes:

	2005	2004
	$	$
Operations	(484,927)	(42,896)
Investing	396,109	(9,385,827)
	(88,818)	(9,428,723)

(c) Supplementary cash flow information

For the years ended December 31	2005	2004
	$	$
Interest paid	67,179	883,026
Income taxes paid	2,516	76,006
Stock-based compensation capitalized	409,660	-

14. COMMITMENTS, CONTINGENCIES AND GUARANTEES

The company's annual commitments under leases for office premises and operating costs, field compression equipment, software license agreements and other equipment are as follows:

2006 - $497,000; 2007 - $399,000; 2008 - $549,000; 2009 - $543,000; 2010-$224,000

Additionally, the company has various guarantees and indemnifications in place in the ordinary course of business, none of which are expected to have a significant impact on the company's financial statements or operations.

15. SUBSEQUENT EVENTS

(a) February equity issuance

In February 2006 the company issued, on a private placement basis, 19,047,800 common shares from treasury at $5.25 per common share for gross proceeds of $100 million. The proceeds were initially added to working capital and were subsequently partially utilized to complete the acquisition of Luke Energy Ltd.

(b) New banking facilities

Subsequent to December 31, 2005 the company has entered into new loan agreements providing the following borrowing facilities:

(i) a $45 million reserve-based revolving loan and a $10 million revolving operating loan to finance conventional petroleum and natural gas projects in Canada. These facilities have a renewable one year term and are secured by a fixed and floating charge debenture in the principal amount of $500 million. Interest at bank prime plus ¼ percent is to be charged on amounts borrowed. No amounts have been drawn on these facilities.

The LOC and AD Facility lines described in Note 7 were terminated.

(ii) A commitment letter for a US$ 51 million bridge loan has been executed. If the loan is drawn, proceeds will be issued to partially fund the acquisition of the Montana refinery assets, scheduled to close on March 31, 2006. See Note 15 (d). If drawn, the loan will bear interest at LIBOR + ½ percent for the first 90 days (adjusted for subsequent quarterly periods), will be secured by a US$500 million demand debenture and pledge agreement and should be repayable around 364 days after being drawn.

(iii) The company has executed a mandate letter ("Mandate") with an international bank. The Mandate contemplates the arrangement of a US$148 million term loan, subject to completion of the acquisition of the Montana refining assets, negotiation of satisfactory terms and acceptable market conditions. If arranged, proceeds would be used to repay the US$51 million bridge loan, if concluded, and for anticipated capital expenditures at Great Divide.

(c) Luke acquisition

On March 16, 2006 the company closed the acquisition of Luke Energy Ltd. by the payment of cash of $91.5 million, the assumption of debt of $8 million and by issuance of 29.7 million common shares from treasury. The debt was immediately discharged from cash balances.

(d) Montana refinery asset purchase

In March 2006 the company entered into an Asset Purchase Agreement to acquire the assets of a refinery located in Great Falls, Montana from a US public company. The consideration for this acquisition will be approximately US$55 million, comprised of cash and one million common shares from treasury. Closing is scheduled to occur on March 31, 2006.

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THREE-YEAR HISTORICAL SUMMARY

	2005	2004	2003
FINANCIAL HIGHLIGHTS			
($000 except per share amounts) - Unaudited			
Total revenue	12,378	11,216	9,982
Cash flow from operations (1)	4,358	2,409	3,353
Basic, per share (1)	0.04	0.05	0.10
Diluted, per share (1)	0.04	0.05	0.10
Net earnings (loss)	991	(2,976)	4,055
Basic, per share	0.01	(0.06)	0.13
Diluted, per share	0.01	(0.06)	0.12
Capital expenditures	16,807	17,629	35,790
Proceeds on disposal of oil and gas properties	-	17,604	-
Bank debt and note payable	-	-	12,100
Working capital deficiency	75,427	3,549	(8,994)
Net debt	75,511	3,914	(21,094)
Shareholders' equity	129,108	40,375	24,055
Total assets	134,813	46,090	53,650
OPERATING HIGHLIGHTS			
Production			
Natural gas (mcf/d)	827	1,620	1,190
Crude oil (bbl/d)	729	785	789
Equivalent (boe/d) (2)	867	1,055	987
Pricing			
Crude Oil ($/bbl)	42.33	31.42	30.03
Natural gas ($/mcf)	1.37	3.62	2.95
Selected Highlights ($/boe) (2)			
Weighted average sales price	36.91	28.95	27.56
Royalties	8.16	5.54	4.98
Operating and transportation costs	7.73	9.75	8.47
Netback (1),(2),(3)	23.23	13.75	14.25
Reserves (mboe) (2)			
Proved	1,501	2,078	3,085
Probable	70,598	1,763	2,489
Possible	39,788	53,070	1,484
Total	111,887	56,912	7,058
COMMON SHARE INFORMATION			
Shares outstanding at end of period (000)	139,940	89,627	45,903
Weighted average shares outstanding			
Basic (000)	106,114	50,908	32,362
Diluted (000)	111,846	53,329	35,333
Volume traded during the year (000)	338,402	84,950	39,445
Common share price ($)			
High	4.20	1.75	1.60
Low	0.49	0.28	0.30
Close, end of year	3.84	0.55	1.60

(1) Cash flow from operations, cash flow per share and netback are not measures that have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable to similar measures presented by other companies.

(2) Per barrel of oil equivalent (boe) amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil (6:1). The conversion is based on an energy equivalent conversion method primarily applicable to the burner tip and does not represent a value equivalency at the wellhead.

(3) For detailed netbacks by product type and by country, see MD&A - "Operating Expenses and Operating Netbacks".

(4) No cash dividends were declared.

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CORPORATE INFORMATION

board of directors

Richard A. Gusella
President and Chief Executive Officer
Connacher Oil and Gas Limited, Calgary

Charles W. Berard [2,4]
Chairman, Governance Committee,
Chairman, Health, Safety and Environment Committee
Partner, Macleod Dixon LLP, Calgary

D. Hugh Bessell [1,2,3]
Chairman, Audit Committee
Retired Executive Chairman of KPMG, LLP

Colin M. Evans [1,3,4,5]
Chairman, Human Resources Committee
Vice-President, Finance, Milestone Exploration Inc., Calgary

Stewart D. McGregor [3]
Lead Director
President, Camun Consulting Ltd.

W.C. (Mike) Seth [1,4,5]
Chairman, Reserves Committee
President, Seth Consultants Ltd.

(1) Audit Committee
(2) Governance Committee
(3) Human Resources Committee
(4) Health, Safety and Environment Committee
(5) Reserves Committee

officers

Richard A. Gusella
President and Chief Executive Officer

Peter D. Sametz
Executive Vice President and
Chief Operating Officer

Richard R. Kines
Vice President, Finance and
Chief Financial Officer

Stephen A. Marston
Vice President, Exploration

Timothy J. O'Rourke
Vice President, Oil Sands Operations

Jennifer K. Kennedy
Corporate Secretary
Partner, Macleod Dixon LLP

head office

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Canada

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stock exchange listing

Toronto Stock Exchange
Trading symbol - CLL

CUSIP number

205884

ISIN

CA20588Y1034

subsidiaries

Great Divide Holding Corporation
Great Divide Oil Corporation
Great Divide Pipeline Corporation
Luke Energy Ltd.
Connacher Finance Corp.
Montana Refining Company, Inc.

related company

Petrolifera Petroleum Limited (33%)

auditors

Deloitte & Touche LLP, Calgary

bankers

National Bank of Canada, Calgary
BNP Paribas, Toronto and New York

solicitors

Macleod Dixon LLP, Calgary

reservoir engineers

DeGolyer and MacNaughton
Canada Limited, Calgary
GLJ Petroleum Consultants, Calgary

registrar and transfer agent

Valiant Trust Company, Calgary
BNY Trust Company of Canada, Toronto

abbreviations

ARTC
Alberta Royalty Tax Credit

bbls
barrels

bbl/d
barrels per day

bcf
billion cubic feet

boe
barrels of oil equivalent

boe/d
barrels of oil equivalent per day

DCF
discounted cash flow

GJ
gigajoule

mbbls
thousand barrels

mboe
thousand barrels of oil equivalent

mcf
thousand cubic feet

mcf/d
thousand cubic feet per day

mmbbls
million barrels

mmboe
million barrels of oil equivalent

mmcf
million cubic feet

mmcf/d
million cubic feet per day

NGLs
natural gas liquids

PV
present value

WI
working interest

WTI
West Texas Intermediate

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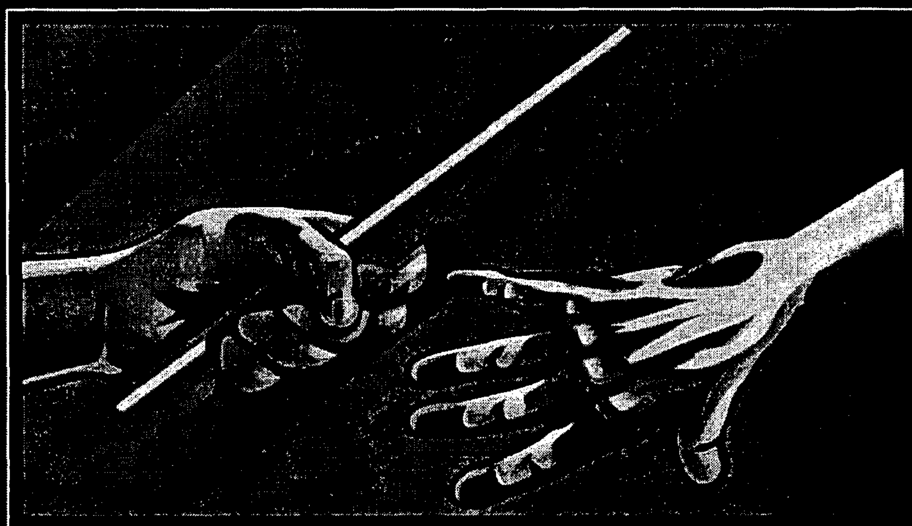

TRANSFERRING PERFORMANCE TO VALUE
FOR OUR SHAREHOLDERS

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OIL AND GAS LIMITED

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OIL AND GAS LIMITED

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2005

March 27, 2006

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FORWARD LOOKING STATEMENTS

Certain statements in this Annual Information Form are "forward looking statements". Forward looking statements are frequently characterized by words such as "plan", "expect", "project", "intend", "believe", "anticipate", "estimate", or other similar words, or statements that certain events or conditions "may" or "will" occur. Forward looking statements are not based on historical facts but rather on Management's expectations regarding the Corporation's future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof), competitive advantages, plans for and results of drilling activity, environmental matters, business prospects and opportunities. Such forward looking statements reflect Management's current beliefs and assumptions and are based on information currently available to Management. Forward looking statements involve significant known and unknown risks and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward looking statements including risks associated with the impact of general economic conditions, industry conditions, governmental regulation, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources, the risks discussed under "Risk Factors" and elsewhere in this Annual Information Form and in the Corporation's other public disclosure documents, and other factors, many of which are beyond the control of the Corporation. Although the forward looking statements contained in this Annual Information Form are based upon assumptions which Management believes to be reasonable, the Corporation cannot assure investors that actual results will be consistent with these forward looking statements. Assumptions relating to the reserves and resources of the Corporation are discussed under "Oil and Gas Reserves and Resources". These forward looking statements are made as of the date of this Annual Information Form, and the Corporation assumes no obligation to update or revise them to reflect new events or circumstances, except as required by law. Because of the risks, uncertainties and assumptions inherent in forward looking statements, prospective investors in the Corporation's securities should not place undue reliance on these forward looking statements. See "Risk Factors".

ABBREVIATIONS AND DEFINITIONS

In this Annual Information Form, the abbreviations set forth below have the following meanings:

"bbl"	barrels	**"mcf"**	1,000 cubic feet
"bbl/d"	barrel or barrels per day	**"mcf/d"**	1,000 standard cubic feet per day
"bcf"	1 billion cubic feet	**"mmcf"**	1,000,000 cubic feet
"boe"	Barrels of oil equivalent	**"mmcf/d"**	1,000,000 cubic feet per day
"boe/d"	Barrel or barrels of oil equivalent per day	**"mmstb"**	1,000,000 stock tank barrels
		"mmbtu"	1,000,000 British thermal units
"mboe"	1,000 barrels of oil equivalent	**"NGL"**	Natural gas liquids
"mbbl"	1,000 barrels		

Note: For the purposes of this document, 6 mcf of natural gas and 1 boe of NGL each equal 1 bbl of oil. BOEs 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.

"**2P**" means the proved and probable reserve categories as defined in the COGE Handbook;

"**3P**" means the proved, probable and possible reserve categories as defined in the COGE Handbook;

"**ABCA**" means the *Business Corporations Act* (Alberta), S.A. 2000, c. B-9, together with any amendments thereto and all regulations promulgated thereunder;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining Metallurgy & Petroleum (Petroleum Society);

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"**Common Shares**" or "**Connacher Shares**" means the common shares in the share capital of the Corporation;

"**Connacher**" or the "**Corporation**" means Connacher Oil and Gas Limited and its subsidiaries;

"**Connacher D&M Report**" means the independent engineering evaluation of the oil and natural gas interests of the Corporation prepared by DeGolyer and MacNaughton Canada Ltd. ("**D&M**"), independent petroleum engineering consultants of Calgary, Alberta, dated March 8, 2006 and effective December 31, 2005;

"**D&M Reports**" means collectively the Connacher D&M Report and the Petrolifera D&M Report;

"**GLJ Reserve Report**" means the independent engineering evaluation of the bitumen reserves of the Corporation prepared by GLJ Petroleum Consultants Ltd. ("**GLJ**"), independent petroleum engineering consultants of Calgary, Alberta, dated March 16, 2006 and effective December 31, 2005;

"**Holly**" means Holly Corporation;

"**Luke**" means Luke Energy Ltd.;

"**Luke Acquisition**" means the acquisition by Connacher of all the outstanding common shares of Luke by way of a business combination under a Plan of Arrangement;

"**Luke GLJ Report**" means the independent engineering evaluation of the oil and natural gas interests of Luke prepared by GLJ, independent petroleum engineering consultants of Calgary, Alberta, dated March 7, 2006 and effective December 31, 2005;

"**Luke Shares**" means the common shares in the share capital of Luke;

"**MRC**" means Montana Refining Company;

"**MRC Acquisition**" means the acquisition by Connacher of an 8,300 bbl/d refinery situated in Great Falls, Montana operated by Holly's Montana Refinery Company;

"**Management**" means management of the Corporation;

"**NI 51-101**" means National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities*;

"**Petrolifera**" means Petrolifera Petroleum Limited;

"**Petrolifera AIF**" means the annual information form of Petrolifera for the year ended December 31, 2005 dated March 28, 2006;

"**Petrolifera D&M Report**" means the independent engineering evaluation of the crude oil and natural gas interests of Petrolifera prepared by D&M, independent petroleum engineering consultants of Calgary, Alberta, dated March 20, 2006 and effective December 31, 2005;

"**Puesto Morales Concession**" or "**Concession**" means the interests in the Puesto Morales and Rinconada blocks in the Neuquén Basin in Argentina;

"**Reserve Reports**" means the GLJ Reserve Report and the Connacher D&M Report;

"**SAGD**" means steam-assisted gravity drainage;

"**SOR**" means steam-oil ratio;

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"**Seaton-Jordan Report**" means the independent evaluation of the Canadian undeveloped land acreage of the Corporation prepared by Seaton-Jordan & Associates Ltd. ("**Seaton-Jordan**"), independent mineral management consultants of Calgary, Alberta, dated February 14, 2006 and effective December 31, 2005; and

"**TSX**" means the Toronto Stock Exchange.

In this Annual Information Form, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

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THE CORPORATION

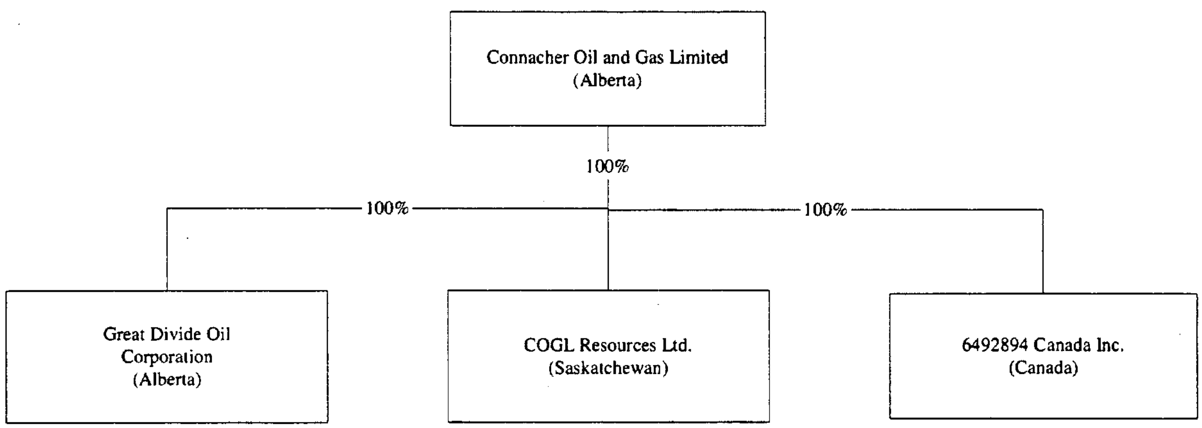
Incorporation and Organization

The Corporation was formed on July 3, 1997 through the amalgamation pursuant to the ABCA of Petro Power Energy Inc. and Justinian Explorations Ltd. and continued as Justinian Explorations Ltd., a public corporation listed on the TSX Venture Exchange. On January 23, 2001 the outstanding Connacher Shares were consolidated on a ten-for-one basis and the name of the Corporation was changed to Connacher Oil and Gas Limited. Trading in the Connacher Shares under the symbol "CLL" commenced on the TSX Venture Exchange on March 23, 2001. This listing was surrendered on August 1, 2003 when the Corporation graduated to and commenced trading on the TSX.

As of December 31, 2005, the Corporation had three wholly-owned subsidiaries, 6492894 Canada Inc., a corporation incorporated under the *Canada Business Corporations Act*, Great Divide Oil Corporation, a corporation incorporated under the ABCA, and COGL Resources Ltd., a corporation incorporated pursuant to the *Business Corporations Act* (Saskatchewan). 6492894 Canada Inc. was incorporated for the sole purpose of participating in the Luke Acquisition. The Corporation also has a significant equity interest in Petrolifera. See "Business of the Corporation - Ownership of Petrolifera".

The Corporation has its head and principal office at Suite 2600, 530 – 8th Avenue S.W., Calgary, Alberta, T2P 3S8 and its registered office at 3700, 400 Third Avenue S.W., Calgary, Alberta, T2P 4H2.

The following chart illustrates the Corporation's organizational structure as at December 31, 2005:



Subsequent to December 31, 2005 the Corporation incorporated the following four subsidiaries: Connacher Finance Corporation and Great Divide Holding Corporation, each of which are incorporated under the laws of Alberta, and Montana Refining Company, Inc. and Great Divide Pipeline Corporation, each of which are incorporated under the laws of Delaware.

On January 1, 2006 Connacher amalgamated with COGL Resources Ltd. pursuant to the ABCA. On March 16, 2006, the Corporation and Great Divide Oil Corporation created Great Divide Oil Sands L.P. for the purposes of holding all of the Corporation's oil sands leases and related assets.

The following chart illustrates the Corporation's organizational structure as of the date of this Annual Information Form:

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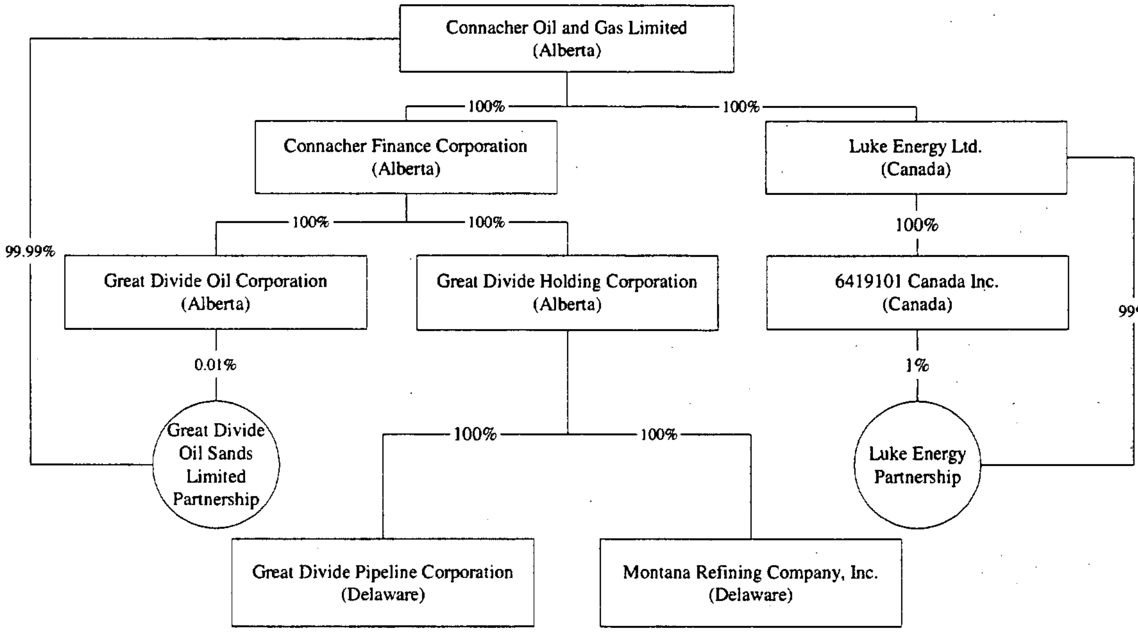

General Development of the Corporation

In January 2003, Connacher completed a $7.3 million acquisition of certain oil and natural gas reserves, production and undeveloped land in the Battrum, Steelman and Cypress Hills areas of Saskatchewan from a large Canadian independent producer. The transaction had an effective date of December 1, 2002 and was financed from the Corporation's credit facility with a Canadian chartered bank.

In February 2003, the Corporation completed a further acquisition in the Battrum area for a purchase price of $3.1 million from an arm's length vendor. The purchase was effective January 1, 2003 and was also financed from the Corporation's credit facility with a Canadian chartered bank.

The Corporation completed a private placement offering in March 2003 of 4,542,155 units comprised of one Common Share and one Common Share purchase warrant at $0.45 per unit for gross proceeds of $2.04 million.

Connacher acquired a 100% working interest in 12,320 acres of petroleum and natural gas rights in the Cabri/Shackleton region of south-western Saskatchewan in April 2003. The lands were prospective for shallow natural gas accumulations and were within the Corporation's core area of Battrum.

The Corporation completed a private placement offering in December 2003 of 5,162,000 Common Shares at a price of $1.05 per Common Share, and 3,703,800 flow-through Common Shares at a price of $1.35 per flow-through Common Share for aggregate gross proceeds of $10.4 million.

Throughout 2003, a total of 7,785,636 Common Share purchase warrants and broker warrants and 534,000 stock options were exercised, resulting in the Corporation receiving cash proceeds of $3.3 million.

The Corporation sold its conventional heavy oil properties at Islay and Lloydminster in eastern Alberta, and its Cabri North natural gas properties and related undeveloped shallow gas rights under approximately 35,000 net acres in south-west Saskatchewan in two separate transactions which were completed in July 2004 for aggregate gross proceeds of $17.8 million. Proceeds from these sales were used to repay bank debt and trade payables.

In November 2004, the Corporation acquired the 50% working interest it did not already own in the Puesto Morales Concession in Argentina and immediately thereafter sold its 100% working interest to its then subsidiary,

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Petrolifera, for eight million common shares of Petrolifera and a $4 million promissory note. Prior to Petrolifera's purchase of those assets, Petrolifera completed a $1.5 million equity financing issuing units comprised of one common share of Petrolifera and one common share purchase warrant of Petrolifera and used $1.25 million of the net proceeds to reduce its promissory note indebtedness to the Corporation to $2.75 million. As a consequence of Petrolifera's equity financing, the Corporation's equity interest in Petrolifera was reduced to 61%. This equity interest further reduced to 40% in March 2005, upon the completion of another equity financing by Petrolifera, which raised $7 million by issuing units comprised of one common share of Petrolifera, one half of one common share purchase warrant of Petrolifera and a right. Of the gross proceeds, $2 million was used to reduce the promissory note indebtedness owing to Connacher to $750,000.

In December 2004, Connacher completed an equity offering of 30,000,000 Common Shares and 11,706,663 flow-through Common Shares, for aggregate gross proceeds of $21.3 million. Proceeds from the financing were used to repay all of the Corporation's indebtedness and provide working capital.

Throughout 2004, a total of 1,442,155 Common Share purchase warrants and broker warrants and 575,000 stock options were exercised, resulting in the Corporation receiving cash proceeds of $945,000.

Commencing in the third quarter of 2005, based upon Connacher's then equity interest in Petrolifera and as a result of the election of independent directors to the board of directors of Petrolifera and certain other factors, Connacher was no longer considered to control Petrolifera and, accordingly, Connacher discontinued consolidating Petrolifera's accounts with Connacher's financial results and began accounting for its investment in Petrolifera on an equity basis.

In September 2005, Connacher completed a public financing on a "bought-deal" basis of 27,027,400 Connacher Shares at a price of $1.85 per share. An additional 13,513,600 Connacher Shares were issued to the underwriters in connection with such financing upon exercise of their over-allotment option for total gross proceeds of $75,000,850. Proceeds from the financing were used to fund development of Connacher's Great Divide oil sands project and for general corporate purposes.

Petrolifera completed an initial public offering of its common shares and warrants in November 2005. Following completion of the initial public offering (and after giving effect to Connacher's investment of $6 million in securities offered pursuant to the initial public offering), Connacher held an undiluted 35% equity interest (26% equity interest on a fully-diluted basis) in Petrolifera, reduced from a 40% equity interest Connacher held in Petrolifera prior to completion of the initial public offering and a 61% equity interest as at December 31, 2004.

In December 2005, Connacher completed the sale to a syndicate of underwriters of 5,000,000 flow-through Common Shares at a price of $3.00 per share. Net proceeds from this financing will be used by Connacher to incur eligible Canadian exploration expenses and, in that regard, primarily to further delineate and define Connacher's Great Divide oil sands properties through the drilling of additional core holes and shooting additional 3-D seismic.

In December 2005, Connacher and Luke entered into a binding letter agreement pursuant to which Connacher agreed to acquire the outstanding common shares of Luke by way of a business combination under a proposed plan of arrangement. In February 2005 Connacher, Luke and 6492894 Canada Inc. entered into an arrangement agreement that set out the terms pursuant to which Connacher was to complete the Luke Acquisition. The Luke Acquisition was completed in March 2006 resulting in the payment of approximately $91.5 million and the issuance form treasury of approximately 30 million Connacher Shares to Luke shareholders.

In December 2005, Connacher entered into an exclusivity agreement with MRC, a subsidiary of Holly to negotiate the terms of a purchase and sale agreement to acquire an 8,300 bbl/d refinery situated in Great Falls, Montana operated by Holly's Montana Refinery Company. In January 2006 Connacher entered into a further agreement with MRC and Holly extending the term of the exclusivity agreement. On March 2, 2006 Montana Refining Company, Inc., a wholly-owned subsidiary of the Corporation, signed an asset purchase agreement pursuant to which it will complete the MRC Acquisition. The consideration for the purchase is approximately US$55 million, comprised of cash and one million Common Shares to be issued from treasury. Closing of the MRC Acquisition is expected to occur on or before March 31, 2006. See "Forward Looking Statements" and "Risk Factors".

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Throughout 2005, a total of 3,791,705 Common Share purchase warrants and broker warrants and 981,000 stock options were exercised, resulting in the Corporation receiving cash proceeds of $2,652,296.

Trends

There are some trends that have been developing in the oil and gas industry during the past two years.

The first trend is the consolidation that the industry has been experiencing. Consolidation has affected companies of all sizes from the small emerging companies to the senior integrated companies. Because of the relatively high commodity prices in the industry in recent history and the increased demand for producing properties, the trend in the industry is for larger entities to continue to acquire smaller entities. Oil and gas royalty trusts have also been a significant acquirer of producing oil and gas properties and companies.

The second trend is the significant access to external capital that the industry has been experiencing. Oil and gas royalty trusts have become increasingly popular and have been able to access significant capital. As well, numerous junior oil and gas companies have had access to debt and equity capital which they have invested in both acquisition and exploration activities.

The third trend is the focus on Canada's oil sands deposits. In 2005 the market for crude oil saw record high prices which persisted in the context of volatile geopolitical conditions, largely related to the war in Iraq. Strong demand growth and the forecast of continued growth from China, India and other developing nations also contributed to the quantum jump in crude oil prices. These strong prices brought into focus the relentless issue of reserve replacement and the continuing debate about the reliability of supply from established petroleum-producing regions. These rising oil prices and the need for dependable long-term supplies coalesced during 2005 and brought Canada's oil sands deposits into focus. The unofficial oil sands "press index" reached an all-time high, with financial papers reporting almost relentlessly on the projects under development and the potential importance to North American certainty of supply of the oil sands. As a result of the foregoing there was a significant increase in the prices being paid for oil sands properties in 2005.

A fourth trend is the high level at which the industry is operating and the resulting intense competition for services and personnel to meet corporate capital expenditure programs. See "Risk Factors".

BUSINESS OF THE CORPORATION

The Corporation is engaged in the exploration for, and the development, production and marketing of, crude oil and natural gas. The Corporation's principal properties are oil sand leases located in the Divide region, south-west of Fort McMurray, Alberta. It also holds producing and non-producing properties at Battrum, Tompkins and Steelman, all in Saskatchewan, and a significant equity interest in Petrolifera. Subsequent to December 31, 2005, the Corporation acquired all of the outstanding shares of Luke. Luke's principal properties are located in Marten Creek and Three Hills, both in Alberta. See "Significant Acquisition".

Principal Properties

The following paragraphs describe the Corporation's principal properties. Readers are cautioned that the estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Battrum, Saskatchewan

The Corporation holds interests ranging from 75% to 100% in unitized and non-unitized lands in the Battrum region of south-western Saskatchewan. The Corporation is the operator of the properties which produce medium gravity crude oil. The properties were acquired in two transactions with effective dates of December 1, 2002 and January 1, 2003 which were completed on January 31, 2003 and February 28, 2003, respectively. For the year ended December 31, 2005 the Corporation's production from this area averaged 678 bbls/d and current production is approximately 700 bbls/d. There are presently 43 (39.8 net) producing oil wells and no producing gas

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wells in this area, which comprises 26,922 gross (26,695 net) acres. At December 31, 2005 the Connacher D&M Report estimates the Corporation's working interest share of crude oil reserves to be 2,105 million bbls of oil, of which 1,396 million bbls is proved.

Great Divide, Alberta

The Corporation owns a 100% working interest in 110 sections (70,400 acres) of oil sands leases at its Great Divide project in the Divide area of north-eastern Alberta. Several oil accumulations in the McMurray formation have been identified on the leases.

At December 31, 2005 the GLJ Reserve Report estimated the Corporation's proved plus probable plus possible recoverable reserves to be 108.3 million barrels for one such accumulation, referred to by the Corporation as "Pod One". This estimate was based on core hole drilling in the winters of 2004 and 2005 and a 3-D seismic program shot over Pod One in March 2005 that assisted in identifying the size and geometry of the accumulation. All geological, geophysical, engineering and environmental data was integrated into a resource study which formed the basis for an application submitted by the Corporation in August, 2005 to the Alberta Energy and Utilities Board and Alberta Environment to drill and produce from the accumulation at a targeted rate of up to 10,000 bbl/d. Subject to receipt of regulatory approvals, development of the accumulation is planned for early 2007.

In 2005, seven additional core holes were drilled on what the Corporation labels "Pod Three", situated on Connacher's land south-west of Pod One. Three other accumulations have been identified and further evaluation work including core holes and seismic is ongoing during the first quarter of 2006. Evaluation and interpretation of this new data will take place in the second and third quarters of 2006.

Ownership of Petrolifera

As of the date of this Annual Information Form Connacher owns an undiluted 30.8% equity interest in Petrolifera. Petrolifera commenced a drilling program in late 2005 and has since completed six wells in its 100% owned Puesto Morales Concession located in the Neuquén Basin in Argentina and has made six significant light crude oil discoveries.

Petrolifera is a publicly traded crude oil and natural gas exploration and production company active in Argentina and Peru with its common shares listed for trading on the TSX under the symbol "PDP". Connacher discontinued consolidating Petrolifera's accounts with Connacher's financial results commencing in the third quarter of 2005 and now accounts for its investment in Petrolifera on an equity basis. See "The Corporation - General Development of the Corporation". As of the date hereof, Connacher owns 11.4 million common shares of Petrolifera, warrants to purchase 1.7 million common shares of Petrolifera and options to purchase 200,000 common shares of Petrolifera. Based on the closing trading price of Petrolifera on March 27, 2006 of $12.80, Connacher's ownership of common shares of Petrolifera (excluding common shares issuable upon the exercise of options and warrants) represents a $146 million investment.

Petrolifera has forecasted an active drilling and facility installation program during 2006, including initiation of exploration activity on its significant acreage in Peru and drilling of up to 24 new wells on its Argentinean acreage.

Pursuant to NI 51-101 the Corporation is required to state the Corporation's share of Petrolifera's oil and gas reserves, future net revenue and costs incurred during 2005 separately from its own corresponding reserves data and other oil and gas information. Set out in Schedule C to this Annual Information Form is a summary of the Corporation's 33.2% interest in Petrolifera's oil and gas reserves and future net revenue as at December 31, 2005 as evaluated by D&M in the Petrolifera D&M Report. The Petrolifera D&M Report was prepared using assumptions and methodology guidelines outlined in the COGE Handbook and in accordance with NI 51-101. The pricing used in the forecast and constant price evaluations is set forth in the notes to the tables. All of the reserves assigned to Petrolifera in the Petrolifera D&M Report are located in the Puesto Morales Concession in Argentina. Readers are cautioned that as a result of the exercise of any outstanding options and warrants of Petrolifera and the issuance by

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Petrolifera of additional securities, the Corporation's interest in Petrolifera's reserves will decrease, unless the Corporation participates in such issuances of securities.

The attached Schedule C has been prepared based on the publicly disclosed information that is contained in the Petrolifera AIF. For additional information beyond what is set forth in Schedule C reference should be made to the Petrolifera AIF which is posted on SEDAR (www.sedar.com) and is not incorporated by reference in this Annual Information Form.

OIL AND GAS RESERVES AND RESOURCES

Connacher engaged GLJ and D&M to prepare reports relating to the Corporation's reserves and resources as at December 31, 2005. The information set forth below relating to the Corporation's reserves and resources constitutes forward looking statements which are subject to certain risks and uncertainties. See "Forward Looking Statements" and "Risk Factors".

Oil and Gas Reserves

Connacher's crude oil and natural gas reserves are primarily located in south-west and south-east Saskatchewan. Connacher's bitumen reserves are located in the Great Divide region. Set out below is a summary of the crude oil, natural gas and bitumen reserves and the value of future net revenue of the Corporation as at December 31, 2005 as evaluated by D&M in the Connacher D&M Report, in the case of the crude oil and natural gas reserves, and as evaluated by GLJ in the GLJ Reserve Report, in the case of the bitumen reserves. The preparation date of the Connacher D&M Report is March 8, 2006 and the preparation date of the GLJ Reserve Report is March 16, 2006. The pricing used in the forecast and constant price evaluations is set forth in the notes to the tables.

Under NI 51-101, proved reserve assignments are based on a 90% probability that total quantities recovered will equal or exceed proved reserve estimates. Proved plus probable reserves are the most likely case and are based on a 50% probability that they will equal or exceed estimates.

GLJ Reserve Report

The following is a summary of the bitumen reserves and the value of future net revenue of the Corporation as at December 31, 2005 as evaluated by GLJ in the GLJ Reserve Report. The GLJ Reserve Report was prepared using assumptions and methodology guidelines outlined in the COGE Handbook and in accordance with NI 51-101. The pricing used in the forecast and constant price evaluations is set forth in the notes to the tables.

Reserves were only assigned to Pod One, in the 2P and 3P categories, although no proved reserves were assigned pending start-up of production. The study assumed 45 SAGD well pairs for the 2P case and 74 well pairs for the 3P case, with cumulative SORs of 2.6 in both cases, but declining to 2.3 during peak production periods. The cutoffs used by GLJ for probable reserves were 15 metres of net pay for 2P reserves and 10 metres of net pay for 3P reserves.

The evaluations based on constant prices and costs utilize a net bitumen price derived from pricing data posted as of December 31, 2005. Although December 31, 2005 prices are utilized, production of bitumen is not anticipated to commence until 2007. Accordingly, if product prices from which the net bitumen price is derived decline, then the present value of future net revenue associated with reserves and the associated reserves volumes will be less than those estimated in the GLJ Reserve Report and such reductions may be significant. All evaluations of future revenue are after the deduction of royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenues contained in the following tables do not necessarily represent the fair market value of the Corporation's reserves. There is no assurance that the forecast and constant price and cost assumptions contained in the GLJ Reserve Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the GLJ Reserve Report. The recovery and reserves estimates of the

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Corporation's properties described herein are estimates only. The actual reserves on the Corporation's properties may be greater or less than those calculated.

RESERVES AND NET PRESENT VALUE OF FUTURE NET REVENUE BASED ON FORECAST PRICES AND COSTS(6)(8)

	Bitumen		Before Deducting Income Taxes Discounted At					After Deducting Income Taxes(9) Discounted At				
	Gross(1) (mbbl)	Net(1) (mbbl)	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)
Proved Plus Probable Undeveloped(2)(3)(5)	69,604	62,677	705	346	168	71	14	467	215	89	20	(21)
Proved Plus Probable Plus Possible Undeveloped (2)(3)(4)(5)	108,327	96,449	1,329	525	228	95	27	881	333	129	37	(11)

RESERVES AND NET PRESENT VALUE OF FUTURE NET REVENUE BASED ON CONSTANT PRICES AND COSTS(7)(8)

	Bitumen		Before Deducting Income Taxes Discounted At					After Deducting Income Taxes(9) Discounted At				
	Gross(1) (mbbl)	Net(1) (mbbl)	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)
Proved Plus Probable Undeveloped(2)(3)(5)	69,604	68,162	167	36	(30)	(66)	(87)	110	7	(45)	(75)	(92)
Proved Plus Probable Plus Possible Undeveloped (2)(3)(4)(5)	108,327	104,589	283	73	(13)	(55)	(78)	186	32	(33)	(66)	(84)

Notes:

(1) "Gross Reserves" are the Corporation's working interest (operating or non-operating) share before deducting royalties and without including any royalty interests of the Corporation. "Net Reserves" are the Corporation's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interests in reserves.

(2) "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is 90% likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(3) "Probable" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

(4) "Possible" reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

(5) "Undeveloped" reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

(6) The pricing assumptions used in the GLJ Reserve Report with respect to values of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

	Heavy Oil Proxy (12 API) at Hardisity ($Cdn/bbl)	Natural Gas Alberta Spot Gas ($/mcf)	Inflation Rate %/year	Exchange Rate $US/$Cdn
Forecast				
2007	32.75	9.00	2.0	0.850
2008	32.50	7.75	2.0	0.850
2009	32.00	7.25	2.0	0.850
2010	32.00	6.95	2.0	0.850
2011	33.50	6.65	2.0	0.850
2012	33.50	6.65	2.0	0.850
2013	34.00	6.80	2.0	0.850
2014	34.75	6.95	2.0	0.850
2015	35.25	7.15	2.0	0.850
2016	36.00	7.30	2.0	0.850
Thereafter	+2%/yr	+2%/yr	2.0	0.850

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(7) The product prices used in the constant price and cost evaluations in the GLJ Reserve Report were as follows: West Texas Intermediate crude oil at Cushing, Oklahoma: $61.04 $USD/bbl; Alberta Spot gas at AECO-C: $9.71/mmbtu; and light crude oil at Edmonton: $68.27/bbl and a bitumen wellhead price of $20.97/bbl.

(8) Includes estimated capital costs, in the 2P case over the 25 year forecast life of the project (10.9 years half-life) of $300 million and, in the 3P case over the 36 year forecast life of the project (16.2 years half-life) of $458 million.

(9) Estimations of future income tax expenses included in the GLJ Reserve Report relate solely to estimated unclaimed costs and tax losses, tax credits and allowances in respect of the Great Divide project. Estimated unclaimed costs and tax losses, tax credits and allowances relating to Connacher's other oil and gas activities are included in the Connacher D&M Report. See "Connacher D&M Report".

Connacher D&M Report

The following is a summary of the crude oil and natural gas reserves and the value of future net revenue of the Corporation as at December 31, 2005 as evaluated by D&M in the Connacher D&M Report. The Connacher D&M Report was prepared using assumptions and methodology guidelines outlined in the COGE Handbook and in accordance with NI 51-101. The pricing used in the forecast and constant price evaluations is set forth in the notes to the tables below.

All evaluations of future revenue are after the deduction of royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenues contained in the following tables do not necessarily represent the fair market value of the Corporation's reserves. There is no assurance that the forecast price and cost assumptions contained in the Connacher D&M Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the Connacher D&M Report. The recovery and reserves estimates of the Corporation's properties described herein are estimates only. The actual reserves on the Corporation's properties may be greater or less than those calculated.

RESERVES DATA - FORECAST PRICES AND COSTS

CRUDE OIL AND NATURAL GAS RESERVES BASED ON FORECAST PRICES AND COSTS[10]

	Light Crude Oil		Natural Gas		Natural Gas Liquids	
	Gross[2] (mbbl)	Net[2] (mbbl)	Gross[2] (mmcf)	Net[2] (mmcf)	Gross[2] (bbl)	Net[2] (bbl)
Proved Developed Producing[3][6]	1,220	973	124	112	2,115	1,560
Proved Developed Non-Producing[3][7]	-	-	160	124	-	-
Proved Undeveloped[3][8]	232	188	-	-	-	-
Total Proved[3]	1,451	1,161	284	236	2,115	1,560
Total Probable[4]	936	744	348	282	623	445
Total Proved Plus Probable[3][4]	2,387	1,905	632	518	2,738	2,005
Total Possible[5]	1,044	922	125	115	118	103
Total Proved Plus Probable Plus Possible[3][4][5]	3,430	2,826	757	633	2,856	2,108

NET PRESENT VALUE OF FUTURE NET REVENUE BASED ON FORECAST PRICES AND COSTS[10]

	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes Discounted At				
	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Proved Developed Producing[3][6]	26,416	22,273	19,261	16,982	15,198	24,416	22,273	19,261	16,982	15,198
Proved Developed Non-Producing[3][7]	806	754	707	663	623	806	754	707	663	623
Proved Undeveloped[3][8]	4,544	3,599	2,858	2,272	1,805	4,544	3,599	2,858	2,272	1,805
Total Proved[3]	31,766	26,626	22,826	19,917	17,626	31,766	26,626	22,826	19,917	17,626
Total Probable[4]	22,909	16,552	12,424	9,575	7,516	21,586	15,790	11,970	9,298	7,343
Total Proved Plus Probable[3][4]	54,675	43,178	35,250	24,492	25,142	53,352	42,416	34,796	29,215	24,969
Total Possible[5]	24,779	16,929	11,710	8,164	5,700	15,043	10,331	7,152	4,960	3,414

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	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes Discounted At				
	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Total Proved Plus Probable Plus Possible(3)(4)(5)	79,454	60,107	46,960	37,656	30,842	68,395	52,747	41,948	34,175	28,383

FUTURE NET REVENUE (UNDISCOUNTED) BASED ON FORECAST PRICES AND COSTS(10)

	Revenue(11) (M$)	Royalties(12) (M$)	Operating Expenses (M$)	Capital Costs (M$)	Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Total Proved(3)	67,514	14,479	17,366	1,751	2,621	31,765	-	31,765
Total Proved Plus Probable(3)(4)	116,073	24,676	28,444	5,849	2,965	54,675	1,322	53,353
Total Proved Plus Probable Plus Possible(3)(4)(5)	164,493	30,544	38,757	13,136	3,149	79,454	11,060	68,394

FUTURE NET REVENUE BY PRODUCTION GROUP BASED ON FORECAST PRICES AND COSTS(10)

	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M$)
Total Proved(3)	Light crude oil	21,710
	Associated gas and non-associated gas	1,050
	Bitumen	-
Total Proved Plus Probable(3)(4)	Light crude oil	32,974
	Associated gas and non-associated gas	2,197
	Bitumen	167,802
Total Proved Plus Probable Plus Possible(3)(4)(5)	Light crude oil	44,381
	Associated gas and non-associated gas	2,499
	Bitumen	227,566

RESERVES DATA - CONSTANT PRICES AND COSTS

CRUDE OIL AND NATURAL GAS RESERVES BASED ON CONSTANT PRICES AND COSTS(9)

	Light Crude Oil		Natural Gas		Natural Gas Liquids	
	Gross(2) (mbbl)	Net(2) (mbbl)	Gross(2) (mmcf)	Net(2) (mmcf)	Gross(2) (bbl)	Net(2) (bbl)
Proved Developed Producing(3)(6)	1,214	967	110	98	2,115	1,559
Proved Developed Non-Producing(3)(7)	-	-	160	124	-	-
Proved Undeveloped(3)(8)	232	188		-	-	-
Total Proved(3)	1,446	1,155	270	222	2,115	1,559
Total Probable(4)	935	743	347	280	623	445
Total Proved Plus Probable(3)(4)	2,381	1,898	617	502	2,738	2,004
Total Possible(5)	1,044	921	124	114	118	103
Total Proved Plus Probable Plus Possible(3)(4)(5)	3,424	2,819	741	616	2,856	2,107

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NET PRESENT VALUE OF FUTURE NET REVENUE BASED ON CONSTANT PRICES AND COSTS(9)

	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes Discounted At				
	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Proved Developed Producing(3)(6)	22,393	18,901	16,338	14,385	12,850	22,393	18,901	16,338	14,385	12,850
Proved Developed Non-Producing(3)(7)	682	635	592	552	516	682	635	592	552	516
Proved Undeveloped(3)(8)	3,814	2,988	2,339	1,827	1,419	3,814	2,988	2,339	1,827	1,419
Total Proved(3)	26,889	22,524	19,269	16,764	14,785	26,889	22,524	19,269	16,764	14,785
Total Probable(4)	15,402	10,832	7,861	5,812	4,337	15,402	10,832	7,861	5,812	4,337
Total Proved Plus Probable(3)(4)	42,291	33,356	27,130	22,576	19,122	42,291	33,356	27,130	22,576	19,122
Total Possible(5)	18,824	12,562	8,399	5,573	3,615	14,850	10,166	6,930	4,661	3,041
Total Proved Plus Probable Plus Possible(3)(4)(5)	61,115	45,918	35,529	28,149	22,737	57,141	43,522	34,060	27,237	22,163

FUTURE NET REVENUE (UNDISCOUNTED) BASED ON CONSTANT PRICES AND COSTS(9)

	Revenue(11) (M$)	Royalties(12) (M$)	Operating Expenses (M$)	Capital Costs (M$)	Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Total Proved(3)	58,565	12,761	15,388	1,751	2,244	26,889	-	26,889
Total Proved Plus Probable(3)(4)	95,202	20,562	24,600	5,849	2,436	42,291	-	42,291
Total Proved Plus Probable Plus Possible(3)(4)(5)	134,988	25,203	33,680	12,981	2,556	61,115	3,975	57,140

FUTURE NET REVENUE BY PRODUCTION GROUP BASED ON CONSTANT PRICES AND COSTS(9)

	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M$)
Total Proved(3)	Light crude oil	18,307
	Associated gas and non-associated gas	893
	Bitumen	-
Total Proved Plus Probable(3)(4)	Light crude oil	25,053
	Associated gas and non-associated gas	1,994
	Bitumen	(30,444)
Total Proved Plus Probable Plus Possible(3)(4)(5)	Light crude oil	33,141
	Associated gas and non-associated gas	2,303
	Bitumen	(12,885)

RECONCILIATION OF COMPANY RESERVES BY PRINCIPAL PRODUCT TYPE BASED ON FORECAST PRICES AND COSTS(10)

The following table sets forth a reconciliation of the changes in Connacher's working interest, after royalties, of light crude oil (including NGL's), associated and non-associated natural gas (combined) and bitumen reserves as at December 31, 2005 against such reserves as at December 31, 2004 based on the forecast price and cost assumptions set forth in Note 10.

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	Light Oil			Associated and Non-Associated Natural Gas			Bitumen		
	Net Proved (mbbl)	Net Probable (mbbl)	Net Proved Plus Probable (mbbl)	Net Proved (mmcf)	Net Probable (mmcf)	Net Proved Plus Probable (mmcf)	Net Proved (mbbl)	Net Probable (mbbl)	Net Proved Plus Probable (mbbl)
At December 31, 2004	1,480	1,242	2,722	1,789	1,625	3,414	-	-	-
Extensions	-	-	-	-	-	-	-	-	-
Improved Recovery	22	92	114	-	-	-	-	-	-
Technical Revisions	87	(156)	(243)	31	(66)	(97)	-	62,667	62,667
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	78	110	94	-	-	-	-	-	-
Dispositions[2]	(300)	(266)	(566)	(1,554)	(1,214)	(2,768)	-	-	-
Economic Factors	(8)	(10)	(18)	(4)	(1)	(5)	-	-	-
Production	(198)	-	(198)	(26)	-	(26)	-	-	-
At December 31, 2005	1,161	744	1,905	236	282	518	-	62,667	62,667

Notes:

(1) The reserves data presented above for the period ended December 31, 2004 includes Petrolifera's reserves as Connacher was previously required pursuant to NI 51-101 to include the reserves owned by Petrolifera in the Corporation's oil and gas reserves disclosure. Connacher discontinued consolidating Petrolifera's accounts with Connacher's financial results commencing in the third quarter of 2005 and now accounts for its investment in Petrolifera on an equity basis. As a result, Connacher no longer includes Petrolifera's reserves in its oil and gas reserves disclosure. See "Business of the Corporation - Ownership of Petrolifera".

(2) Reflects the deconsolidation of Petrolifera's reserves in the third quarter of 2005. See "Business of the Corporation".

RECONCILIATION OF CHANGES IN NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT 10% BASED ON CONSTANT PRICES AND COSTS[9]

The following table sets forth changes between future net revenue estimates attributable to Connacher's net proved reserves as at December 31, 2005 against such reserves as at December 31, 2004 based on constant prices and cost assumptions set forth in Note 9 and calculated using a discount rate of 10%.

	(M$)
Estimated Future Net Revenue after income taxes at December 31, 2004[1]	17,240
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties	(6,075)
Net Change in Prices, Production Costs and Royalties Related to Future Production	2,482
Changes in Previously Estimated Future Development Costs	2,508
Changes in Estimated Future Development Costs	(3,610)
Net Change from Extensions and Improved Recovery	387
Net Change from Discoveries	-
Acquisitions of Reserves	1,765
Dispositions of Reserves	(178)
Net Change Resulting from Revisions in Quantity Estimates	1,509
Accretion of Discount	1,614
Net Change in Income Taxes	-
Other	1,627
Estimated Future Net Revenue after income taxes at December 31, 2005	19,269

Notes:

(1) The reserves data presented above for the period ended December 31, 2004 includes Petrolifera's reserves as Connacher was previously required pursuant to NI 51-101 to include the reserves owned by Petrolifera in the Corporation's oil and gas reserves disclosure. Connacher discontinued consolidating Petrolifera's accounts with Connacher's financial results commencing in the third quarter of 2005 and now accounts for its investment in Petrolifera on an equity basis. As a result, Connacher no longer includes Petrolifera's reserves in its oil and gas reserves disclosure. See "Business of the Corporation - Ownership of Petrolifera".

(2) "Gross Reserves" are the Corporation's working interest (operating or non-operating) share before deducting royalties and without including any royalty interests of the Corporation. "Net Reserves" are the Corporation's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interests in reserves.

(3) "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is 90% likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(4) "Probable" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

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(5) "Possible" reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.
(6) "Developed Producing" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
(7) "Developed Non-Producing" reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.
(8) "Undeveloped" reserves are those reserves expected to be recovered from know accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.
(9) The product prices used in the constant price and cost evaluations in the Connacher D&M Report were as follows: (1) Edmonton Light price: $38.90/bbl; (2) AECO Spot Gas price: $8.06/MMBTU; and (3) Condensate: $52.06/bbl.
(10) The pricing assumptions used in the Connacher D&M Report with respect to values of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below. D&M is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

	Light Crude Oil		Heavy Oil	Inflation	Exchange Rate
	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40^0 API ($Cdn/bbl)	Hardisty Heavy 12^0 API ($Cdn/bbl)	%/year	$US/$Cdn
Forecast					
2006	58.00	67.16	37.01	0.0	0.86
2007	56.38	65.26	36.66	2.5	0.86
2008	52.53	60.78	35.37	2.5	0.86
2009	51.69	59.80	36.85	2.5	0.86
2010	52.72	60.99	38.75	2.0	0.86
2011	53.78	62.21	39.66	2.0	0.86
2012	54.85	63.46	40.59	2.0	0.86
2013	55.95	64.73	41.55	2.0	0.86
2014	57.07	66.02	42.52	2.0	0.86
Thereafter	2%	2%	2%	2.0	0.86

(11) Values include processing and other income.
(12) Values include Alberta Royalty Tax Credit.

Weighted average historical prices realized by the Corporation for the year ended December 31, 2005 were $42.33/bbl for light and medium crude and $1.37/mcf for natural gas. Although gas prices are expected to move upward in the near term, there is no specific "price path" for the Corporation's gas because of its relatively small sales volumes and due to the possible influence other larger gas sales contracts negotiated with industrial buyers may have on the Corporation's realized prices. Although "price paths" represent generic expected trends, actual pricing may be specific to different producing areas. If additional volumes are developed in a particular area, more pricing power could accrue to the producer.

Undeveloped Reserves

Proved undeveloped reserves are generally those reserves related to wells that have been drilled and not yet tied in because of seasonal access issues, the need for further testing of the wells or construction of pipelines and production facilities for the well. Such reserves may also relate to planned infill drilling locations.

Connacher's net proved undeveloped reserves of 74 mbbls of oil are located at Battrum, Saskatchewan. The Corporation expects to drill a number of infill locations at Battrum during 2006 which, if successful, would result in new reserves qualifying for the proved developed category.

Probable undeveloped reserves relate to wells to be drilled, tied in and brought on-stream in future. The Connacher D&M Report estimates the Corporation's net probable undeveloped reserves to be 350 mbbls of light or medium oil and the GLJ Reserve Report estimates the Corporation's net probable undeveloped reserves to be 62,677 mbbls of bitumen. Of this total, 176 net probable undeveloped mbbls of oil are at Battrum, Saskatchewan and 62,677 net probable undeveloped mbbls of bitumen are at Great Divide, Alberta. The drilling of 15 SAGD well pairs and commencement of production should result in reserves qualifying in the proved category.

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Significant Factors or Uncertainties

In mid-August, 2005, Connacher submitted its application for the development of its Great Divide oil sands project to the Alberta Energy and Utilities Board and Alberta Environment for the necessary approvals required to produce bitumen using a SAGD process. The regulatory approval process can involve stakeholder consultation, including objections by mineral rights holders in the area, environmental impact assessments and public hearings, among other things. There can be no assurance that the required approvals will be obtained and, if obtained, will be obtained on terms and conditions acceptable to Connacher. Failure to obtain regulatory approvals, or failure to obtain them on a timely basis, may affect timing of production and realization of future net revenue.

The Corporation does not anticipate that any other important economic factors or significant uncertainties would affect particular components of the reserves data. Notwithstanding that, a number of factors which are beyond the Corporation's control can significantly affect the reserves, including product pricing, royalty and tax regimes, changing operating and capital costs, surface access issues, availability of services and processing facilities and technical issues affecting well performance. See "Risk Factors".

Future Development Costs

The following table sets forth the development costs deducted in the estimation of future net revenue attributable to each of the following reserves categories contained in the GLJ Reserve Report and the Connacher D&M Report:

	Total Proved Future Development Costs Using Constant Dollar Costs (M$)	Total Proved Future Development Costs Using Forecast Dollar Costs (M$)	Total Proved Plus Probable Future Development Costs Using Forecast Dollar Costs (M$)	Total Proved Plus Probable Plus Possible Future Development Costs Using Forecast Dollar Costs (M$)
2006	1,751	1,751	182,499	177,225
2007	3	3	3	6,343
2008	801	782	782	782
2009	149	190	3,237	2,812
2010	101	142	61	61
Total for all remaining years	1,189	1,504	122,406	286,886
Total, undiscounted	3,994	4,372	308,988	474,109
Total for all years discounted at 10%/year	2,911	3,065	225,180	239,457

Future development costs are expected to be funded from a combination of the following: operational cash flow, debt and equity financing and/or farmout arrangements with other companies. The timing of such funding may influence the timing of the developmental work expenditures.

Oil and Gas Properties and Wells

The following table sets forth the number of wells in which Connacher held a working interest as at December 31, 2005:

	Crude Oil		Natural Gas	
	Gross(1)	Net(1)	Gross(1)	Net(1)
Alberta				
Producing	-	-	-	-
Non-producing	2	2	-	-
Saskatchewan				
Producing	43	39.8	-	-
Non-producing	71	64.0	8	8

Note:

(1) "Gross Wells" are the total number of wells in which Connacher has an interest. "Net Wells" are the number of wells obtained by aggregating Connacher's working interest in each of its gross wells.

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Costs Incurred

The following table summarizes the capital expenditures made by Connacher on oil and natural gas properties for the year ended December 31, 2005.

Property Acquisition Costs ($)		Exploration Costs ($)	Development Costs ($)
Proved Properties	Unproved Properties		
1,255,029	115,665	4,976,315	9,140,401

Exploration and Development Activities

The following table sets forth the number of exploratory and development wells which Connacher completed during its 2005 financial year:

	Exploratory Wells		Development Wells	
	Gross[(1)]	Net[(1)]	Gross[(1)]	Net[(1)]
Oil Wells	-	-	5	4.75
Gas Wells	-	-	-	-
Service Wells	-	-	-	-
Dry Holes	-	-	3	2.60
Total Completed Wells	-	-	8	7.35

Note:

(1) "Gross Wells" are the total number of wells in which Connacher has an interest. "Net Wells" are the number of wells obtained by aggregating Connacher's working interest in each of its gross wells. Additionally, 19 "core holes" were drilled at Divide, Alberta.

In 2006, Connacher will focus on development of its oil sands leases at Divide, Alberta, including drilling additional core holes and proceeding with development of the project if regulatory approvals are received. The Corporation also anticipates enhancing oil production at Battrum, exploiting new oil and developing natural gas reserves in the Tompkins area of south-west Saskatchewan and evaluating light oil potential at Steelman in south-east Saskatchewan.

Properties with No Attributed Reserves

The following table sets out the Corporation's undeveloped land position effective December 31, 2005.

	Undeveloped Acreage	
	Gross[(1)]	Net[(1)]
Alberta	74,400	74,400
Saskatchewan	65,018	53,245
Total	139,418	127,645

Note:

(1) "Gross" means the total number of acres in which the Corporation has a working interest. "Net" means the sum of the products obtained by multiplying the number of gross acres by the Corporation's percentage working interest therein.

The Corporation engaged Seaton-Jordon to prepare an independent evaluation of the undeveloped land acreage of the Corporation as at December 31, 2005. In the Seaton-Jordan Report a fair value of approximately $7.9 million or approximately $142 per gross hectare was assigned to Connacher's non-reserve oil and gas properties. This equates to approximately $351 per gross acre. In determining the market value, Seaton-Jordan based their evaluation on the following factors:

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1. The acquisition cost, provided that there have been no material changes in the unproved property, the surrounding properties, or the general oil and gas climate since the acquisition;

2. Recent sales by others of interests in the same unproved property;

3. Terms and conditions, expressed in monetary terms, of recent farm-in agreements;

4. Terms and conditions, expressed in monetary terms, of recent work commitments related to the unproved property; and

5. Recent sales of similar properties in the same general area.

This complies with the criteria set out in paragraph (a), subsection (2), Section 5.10 of NI 51-101.

Pursuant to the Corporation's discretionary capital program for 2006, Connacher anticipates evaluating up to 1,500 gross (1,500 net) acres, largely in south-west Saskatchewan with the drilling of up to 8 wells. Certain of these wells will be contingent upon the outcome of wells drilled earlier in the year and subject to funding available. In Alberta 3,000 gross (3,000 net) acres of oil sands leases will be evaluated by the drilling of up to 30 core holes at Divide. The Corporation has interests in 640 gross (640 net) acres of non-reserve oil and gas properties in respect of which the Corporation's rights to explore, develop and exploit are expected to expire in 2006.

Except for a commitment to incur $200,000 of capital expenditures on behalf of joint ventures in the Tompkins area of south-west Saskatchewan, the Corporation's capital program is entirely discretionary and may be expanded or curtailed based on drilling results and the availability of capital. This is reinforced by the fact that Connacher operates most of its wells and holds an average 92 percent working interest, proving the Corporation with operational and timing controls.

Asset Retirement Obligations

Effective January 1, 2004, the Corporation adopted the Canadian Institute of Chartered Accountants' new standard on Asset Retirement Obligations. This new standard requires liability recognition for retirement obligations associated with long-lived assets, which would include abandonment of oil and natural gas wells, related facilities, compressors and gas plants, removal of equipment from leased acreage and returning such land to its original condition. Under the new standard, the estimated fair value of each asset retirement obligation is recorded in the period a well or related asset is drilled, constructed or acquired. Fair value is estimated using the present value of the estimated future cash outflows to abandon the asset at the Corporation's credit-adjusted risk-free interest rate. The obligation is reviewed regularly by management based upon current regulations, costs, technologies and industry standards. The discounted obligation is recognized as a liability and is accreted against income until it is settled or the property is sold and is included as a component of depletion and depreciation expense. Actual restoration expenditures are charged to the accumulated obligation as incurred. Prior to 2004, the Corporation estimated costs of dismantlement, removal and site restoration and recorded them over the remaining life of the proved reserves on the unit-of-production basis.

As at December 31, 2005, the estimated total undiscounted amount required to settle the asset retirement obligations in respect of the Corporation's 113.8 net producing and non-producing wells, net of estimated salvage recoveries, was $5.4 million. These obligations will be settled over the useful lives of the underlying assets, which currently extend up to 20 years. The 10% discounted present value of this amount is $2 million. Over the next three financial years, the Corporation expects to incur $804,000 ($600,000 discounted at 10%) of these expenditures.

In the Reserve Reports, abandonment costs for total proved plus probable plus possible reserves were estimated to be $3.1 million, undiscounted, and $1.4 million, discounted at 10%. These estimates are in respect of well costs only and do not include costs to abandon pipelines and facilities, which the Corporation has included in determining its asset retirement obligation.

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Tax Horizon

Income earned in Canada is not expected to attract taxes until the Corporation utilizes its accumulated tax pools and loss carry forwards, which exceed $46 million. Based on anticipated capital spending, which augment the tax pools, the Corporation does not expect to pay current income taxes for the 2005 fiscal year. Depending on production, commodity prices and capital spending levels, the Corporation may begin paying current income taxes in 2006.

Production Estimates

The following table sets forth the volume of working interest production, before royalties, estimated for 2006 which is reflected in the estimate of future net revenue disclosed in the tables of reserve information in respect of total proved reserves:

Light Crude Oil (bbl)	Natural Gas (mmcf)	Natural Gas Liquids (bbl)	Bitumen (mbbl)
248,013	28,393	-	-

The following table indicates the volume of working interest production, before royalties, estimated for 2006 from fields considered to be individually important:

	Light Crude Oil (bbl)	Natural Gas (mmcf)	Natural Gas Liquids (bbl)
Battrum, Saskatchewan	240,000	-	-

Production History

The following table sets forth certain information in respect of production, product prices received, royalties, production costs and netbacks received by the Corporation for each quarter of its most recently completed financial year:

	Three Months Ended March 31, 2005	Three Months Ended June 30, 2005	Three Months Ended September 30, 2005	Three Months Ended December 31, 2005
Average Daily Production				
Light and Medium Oil (bbl/d)	629	702	808	775
Heavy Oil (bbl/d)	-	-	-	-
Natural Gas (mcf/d)	1,328	1,416	497	86
Average Net Prices Received				
Light and Medium Oil ($/bbl)	30.02	41.23	53.41	41.54
Heavy Oil ($/bbl)	-	-	-	-
Natural Gas ($/mcf)	1.18	0.99	1.88	7.55
Royalties				
Light and Medium Oil ($/bbl)	6.37	10.57	12.86	7.91
Heavy Oil ($/bbl)	-	-	-	-
Natural Gas ($/mcf)	0.07	0.10	0.11	-
Production Costs				
Light and Medium Oil ($/bbl)	9.09	9.33	8.28	9.07
Heavy Oil ($/bbl)	-	-	-	-
Natural Gas ($/mcf)	0.18	0.28	0.32	-
Netback Received				
Light and Medium Oil ($/bbl)	14.56	21.33	32.27	24.56
Heavy Oil ($/bbl)	-	-	-	-
Natural Gas ($/mcf)	0.93	0.61	1.45	7.55

The following table indicates the Corporation's average daily production for the year ended December 31, 2005 from fields considered to be individually important:

	Light Crude Oil (bbls/d)	Gas (mcf/d)	Natural Gas Liquids (bbls/d)
Battrum, Saskatchewan	678	-	-

Competitive Conditions

The petroleum and natural gas industry is competitive in all aspects. Connacher competes with numerous other companies for access to capital to fund its exploration and development activities. It also competes with other companies in the search for exploration and development prospects and in the marketing of its production.

Connacher attempts to enhance its competitive position by:

- focusing on a limited number of core areas;
- maintaining high working interests;
- wherever possible, operating properties;
- securing control over infrastructure such as pipelines and gas processing facilities;
- employing highly competent professional staff who use leading-edge technology; and
- striving to be a low-cost producer.

SIGNIFICANT ACQUISITION

On March 16, 2006 the Corporation completed the Luke Acquisition. Pursuant to the terms of the Luke Acquisition, holders of Luke Shares received $2.31 in cash and 0.75 of one Connacher Share for each Luke Share held, resulting in the payment of approximately $91.5 million and the issuance from treasury of approximately 30 million Connacher Shares.

Luke's principal properties are located in Marten Creek and Three Hills, both in Alberta. Marten Creek accounted for approximately 90% of Luke's production in 2005. Marten Creek is a relatively shallow (1,925 feet) multi-zone Cretaceous natural gas area located about 300 miles north of Calgary and it is predominately 100% owned and operated by Luke. During the first quarter of 2005, Luke drilled 24 wells with 18 successes. In addition, 2 field compressors and a 7 mmcf/d sales compressor were installed to optimize production. Activities in the first half of 2005 resulted in an increase of 13.56 bcf total proved reserves and 20.2 bcf total proved plus probable reserves to Luke's account.

Gas production for 2005 averaged 11.9 mmcf/d with an exit rate of approximately 15 mmcf/d.

Luke's land position has grown to an average 84% interest in approximately 61,000 acres. Luke also holds an additional 4,480 acres under option. Luke has accumulated a seismic base in excess of 1,100 miles of 2D seismic data on which over 25 potential drilling locations have been identified on existing lands. Based on that information, Luke's third multi-well drilling program was commenced in late December 2005. Drilling, completion and pipelining activity is underway and anticipated to be complete in late March 2006. This is a winter work area and all work must be completed by the end of March, which is generally the start of spring break-up.

In July 2005, Luke acquired the Three Hills properties (Three Hills, Mikwan, Twining and Stettler) for $8.1 million. At the time of the acquisition the properties were producing approximately 175 boe/d. Luke acquired approximately 334 mboe of total proved reserves and 414 mboe of total proved plus probable reserves. In the fall of 2005, Luke drilled four wells on the Three Hills property resulting in two oil wells, one gas well and one injector. As a consequence, production with respect to this property exited 2005 at 330 boe/d.

The following is a summary of the oil, liquids and natural gas reserves of Luke effective December 31, 2005 and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs as evaluated by GLJ in the Luke GLJ Report.

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The Luke GLJ Report was prepared using assumptions and methodology guidelines outlined in the COGE Handbook and in accordance with NI 51-101. The pricing used in the forecast and constant price evaluations is set forth in the notes to the tables.

CRUDE OIL AND NATURAL GAS RESERVES BASED ON FORECAST PRICES AND COSTS(7)

	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
	Gross(1) (mbbl)	Net(1) (mbbl)	Gross(1) (mmcf)	Net(1) (mmcf)	Gross(1) (mbbl)	Net(1) (mbbl)
Proved Developed Producing(2)(4)	500	426	22,652	17,838	23	19
Proved Developed Non-Producing(2)(5)	66	61	5,117	4,203	1	1
Proved Undeveloped(2)(6)	-	-	-	-	-	-
Total Proved(2)	566	487	22,769	22,041	24	20
Total Probable(3)	400	296	10,360	8,249	17	12
Total Proved Plus Probable(2)(3)	967	783	38,129	30,290	40	32

NET PRESENT VALUE OF FUTURE NET REVENUE BASED ON FORECAST PRICES AND COSTS(7)

	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes Discounted At				
	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Proved Developed Producing(2)(4)	138,476	118,425	104,248	93,666	85,440	108,766	92,170	80,613	72,082	65,507
Proved Developed Non-Producing(2)(5)	28,754	22,957	19,128	16,408	14,376	19,538	15,222	12,533	10,681	9,293
Proved Undeveloped(2)(6)	-	-	-	-	-	-	-	-	-	-
Total Proved(2)	167,229	141,381	123,376	110,074	99,815	128,124	107,393	93,166	82,763	74,800
Total Probable(3)	62,639	39,236	27,814	21,228	17,034	42,282	26,170	18,423	13,991	11,181
Total Proved Plus Probable(2)(3)	229,868	180,618	151,189	131,302	116,849	170,405	133,563	111,588	96,754	85,981

CRUDE OIL AND NATURAL GAS RESERVES BASED ON CONSTANT PRICES AND COSTS(8)

	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
	Gross(1) (mbbl)	Net(1) (mbbl)	Gross(1) (mmcf)	Net(1) (mmcf)	Gross(1) (mbbl)	Net(1) (mbbl)
Proved Developed Producing(2)(4)	515	438	22,681	17,862	24	19
Proved Developed Non-Producing(2)(5)	70	64	5,118	4,205	1	1
Proved Undeveloped(2)(6)	-	-	-	-	-	-
Total Proved(2)	584	502	27,799	22,067	25	20
Total Probable(3)	406	302	10,365	8,254	17	12
Total Proved Plus Probable(2)(3)	991	804	38,164	30,322	41	32

NET PRESENT VALUE OF FUTURE NET REVENUE BASED ON CONSTANT PRICES AND COSTS(8)

	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes Discounted At				
	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Proved Developed Producing(2)(4)	170,414	141,493	121,516	106,924	95,811	130,394	107,714	92,232	81,008	72,499
Proved Developed Non-Producing(2)(5)	37,267	29,233	23,907	20,137	17,342	24,850	19,328	15,702	13,149	11,262
Proved Undeveloped(2)(6)	-	-	-	-	-	-	-	-	-	-
Total Proved(2)	207,680	170,726	145,423	127,062	113,154	155,245	127,042	107,934	94,156	83,761
Total Probable(3)	82,778	52,255	36,721	27,617	21,796	55,547	34,782	24,328	18,232	14,345
Total Proved Plus Probable(2)(3)	290,458	222,981	182,143	154,679	134,949	210,792	161,824	132,262	112,389	98,106

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Notes:

(1) "Gross Reserves" are the Corporation's working interest (operating or non-operating) share before deducting royalties and without including any royalty interests of the Corporation. "Net Reserves" are the Corporation's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interests in reserves.

(2) "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is 90% likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(3) "Probable" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

(4) "Developed Producing" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(5) "Developed Non-Producing" reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

(6) "Undeveloped" reserves are those reserves expected to be recovered from know accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

(7) The pricing assumptions used in the Luke GLJ Report with respect to values of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

	Light Crude Oil		**Heavy Oil**	**Inflation**	**Exchange Rate**
	WTI Cushing Oklahoma ($US/bbl)	**Edmonton Par Price 40^0 API ($Cdn/bbl)**	**Hardisty Heavy 12^0 API ($Cdn/bbl)**	**%/year**	**$US/$Cdn**
Forecast					
2006	57.00	66.25	33.25	2.0	0.85
2007	55.00	64.00	32.75	2.0	0.85
2008	51.00	59.25	32.50	2.0	0.85
2009	48.00	55.75	32.00	2.0	0.85
2010	46.50	54.00	32.00	2.0	0.85
2011	45.00	52.25	33.50	2.0	0.85
2012	45.00	52.25	33.50	2.0	0.85
2013	46.00	53.25	34.00	2.0	0.85
2014	46.75	54.25	34.75	2.0	0.85

(8) The product prices used in the constant price and cost evaluations in the Luke GLJ Report were as follows: (1) Light crude oil at Edmonton: $68.27/bbl; (2) Alberta Spot gas at AECO-C: $9.71/mmbtu; and (3) West Texas Intermediate crude oil at Cushing, Oklahoma: $61.04/bbl.

Oil and Gas Resources

The GLJ Reserve Report also provided calculations of Contingent Resources comprised of "Low Estimate Resources (>15 metre Pay) - higher certainty" together with "Best Estimate Resources (>15 metre Pay) - likely certainty" and "High Estimate Resources (>10 metre Pay) - lower certainty". Low Estimate recoverable resources are comprised of mapped original oil-in-place assigned to Pod One (>15 metre Pay) with a lower recovery factor than are applied to the estimate of 2P reserves. Best Estimate Resources are comprised of 2P remaining recoverable reserves together with an estimate of recoverable resources attributable to four other pods on Connacher's lands. High Estimate Resources (lower certainty) include 3P recoverable reserves at Pod One together with recoverable resources at the other four pods on Connacher's acreage, but with a larger arial extent and a higher recovery factor than attributable under the Best Estimate Category.

Only Pod One has sufficient well and seismic control to warrant the assignment of reserves. The other four pods have insufficient drilling density, seismic mapping or project definition to be categorized as reserves at this time. Additional drilling and seismic activity could result in upgrading these to reserve status over time. In the interim, a range of contingent resources was assigned to reflect uncertainties. The GLJ Reserve Report also recognized High Estimate (low certainty) prospective resources attributable to two undiscovered pods with attributable resources of 160.6 million barrels of original oil-in-place and 91.6 million barrels of initial and remaining recoverable resources, utilizing average parameters from five identifiable pods, including Pod One. No calculation was done of the present value of the future cash flow from remaining recoverable or prospective resources other than the reserves attributable to Pod One as detailed herein.

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The results contained in the GLJ Reserve Report contemplate Connacher proceeding with the filing of an application to develop Pod One at Great Divide with the relevant Alberta regulators. These applications were submitted on August 15, 2005. Necessary regulatory approvals are anticipated by the Corporation in mid 2006. Production start-up is forecast by GLJ to occur in 2007 and a peak rate of 10,000 barrels of oil per day is forecast to be achieved by 2009. See "Forward Looking Statements" and "Risk Factors".

LOW ESTIMATE RESOURCES (>15 METRE PAY, HIGHER CERTAINTY)

	ORIGINAL OIL-IN-PLACE (mmstb)	RECOVERABLE RESOURCES (mmstb)
POD 1	128.9	46.4
POD 2, POD 2 South	-	-
POD 3, POD 4	-	-
TOTAL	128.9	46.4

BEST ESTIMATE RESOURCES (>15 METRE PAY, LIKELY CERTAINTY)

	ORIGINAL OIL-IN-PLACE (mmstb)	RECOVERABLE RESOURCES (mmstb)
POD 1	128.9	69.6 (2P reserves)
POD 2, POD 2 South	53.8	21.8
POD 3, POD 4	79.5	36.1
TOTAL	262.2	127.5

HIGH ESTIMATE RESOURCES (>10 METRE PAY, LOWER CERTAINTY)

	ORIGINAL OIL-IN-PLACE (mmstb)	RECOVERABLE RESOURCES (mmstb)
POD 1	178.6	108.3 (3P reserves)
POD 2, POD 2 South	82.3	45.0
POD 3, POD 4	116.8	66.0
TOTAL	377.7	219.3

DIRECTORS AND OFFICERS

As of the date of this Annual Information Form the name, municipality of residence, positions held with the Corporation and principal occupation during the preceding five years of each of the directors and officers of the Corporation are as follows:

Name and Municipality of Residence	Positions Held	Principal Occupation During the Preceding Five Years	Director Since
Richard A. Gusella Calgary, Alberta Canada	President, Chief Executive Officer and Director	President and Chief Executive Officer of Connacher since May 2001 and Petrolifera from November 2004 to March 2005. Executive Chairman of Petrolifera since March 2005. Prior thereto, President of Gusella Oil Investments Limited, a private oil and gas corporation, since June 2000.	May 30, 2001
Charles W. Berard[(3)(5)] Calgary, Alberta Canada	Director	Partner, Macleod Dixon LLP, a law firm.	May 30, 2001

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Name and Municipality of Residence	Positions Held	Principal Occupation During the Preceding Five Years	Director Since
D. Hugh Bessell(1)(2)(3)(4) Toronto, Ontario Canada	Director	Businessman. Prior thereto, Deputy Chairman and Chief Operating Officer of KPMG LLP.	December 1, 2005
Colin M. Evans(1)(2)(4)(5) Calgary, Alberta Canada	Director	Vice President, Finance, Milestone Exploration Inc., a private oil and gas company. President of Evans & Co. Inc., a private consulting corporation providing financial and operating advisory services to oil and gas corporations.	April 5, 2004
Stewart D. McGregor(2)(3)(7) Calgary, Alberta Canada	Director	President of Camun Consulting Corporation, a private investment company, since 1994.	June 12, 2003
W.C. (Mike) Seth(1)(4)(5) Calgary, Alberta Canada	Director	President, Seth Consultants Ltd. Prior thereto Chairman of McDaniel & Associates Consultants Ltd. and prior thereto, President of McDaniel & Associates Consultants Ltd.	December 9, 2005
Richard R. Kines Calgary, Alberta Canada	Vice President, Finance and Chief Financial Officer	Vice President, Finance and Chief Financial Officer since December 2004 and Chief Financial Officer of Connacher since June 2003. Prior thereto, financial consultant of Connacher since April 2002. From May 2001 to January 2002, Chief Financial Officer of Integrated Production Services Ltd., an oil and gas services company that at that time was listed on the TSX. From June 1999 to May 2001, Chief Financial Officer of OTATCO Inc., a company that at that time was listed on the Alberta Stock Exchange.	--
Peter D. Sametz Calgary, Alberta Canada	Executive Vice President and Chief Operating Officer	Executive Vice President and Chief Operating Officer of Connacher since December 2004. From February 2004, Vice President Operations of Connacher. Prior thereto, simultaneously Chief Operating Officer and a director of Surge Petroleum Inc., a public oil company listed on the TSX Venture Exchange since July 2000 and a Principal of Inline Petroleum Management Incorporated from 1997 to February 2004.	--
Timothy J. O'Rourke Calgary, Alberta Canada	Vice President, Oil Sands Operations	Vice President, Oil Sands Operations of Connacher since December 2004. Prior thereto, General Manager, Production of Connacher since August 2001. Prior thereto, consultant to Connacher.	--
Stephen A. Marston Calgary, Alberta Canada	Vice President, Exploration	Vice President, Exploration of Connacher since January 2005. Prior thereto, Chief Geophysicist of Real Resources Inc. since January 2000.	--
Jennifer K. Kennedy Calgary, Alberta Canada	Secretary	Partner, Macleod Dixon LLP, a law firm, since January 2000.	--

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Notes:
(1) Member of the Audit Committee.
(2) Member of the Human Resources Committee.
(3) Member of the Governance Committee.
(4) Member of the Reserves Committee.
(5) Member of the Health, Safety and Environment Committee.
(6) Connacher does not have an Executive Committee.
(7) Lead Director.

As at March 27, 2006, the directors and executive officers of Connacher, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 3,116,487 Common Shares constituting approximately 1.65% of the issued and outstanding Common Shares.

AUDIT COMMITTEE

Composition and Qualifications

The Corporation's Audit Committee consists of three outside and independent directors, Messrs. Bessell, Chair, Seth and Evans, all of whom are considered to be "financially literate". In considering criteria for the determination of financial literacy, the board of directors of the Corporation looks at the ability to read and understand financial statements of a publicly traded corporation. The education and experience of each member of the Corporation's Audit Committee relevant to the performance of his responsibilities are as set forth below:

D. Hugh Bessell, Chair

Mr. Bessell is a chartered accountant by training and has an extensive accounting background. He retired as a partner of KPMG LLP in December, 1999 after holding the position of Deputy Chairman and Chief Operating Officer, which position he held for approximately six years. He spent a total of 33 years with KPMG LLP and its predecessor firms, and was Managing Partner of the firm's Calgary office immediately prior to assuming the role of Deputy Chairman in 1993. Mr. Bessell has been granted the FCA designation by both the Alberta and the Ontario Institutes of Chartered Accountants in recognition of his support and contributions to his profession and community. His expertise is particularly important in his capacity as Chairman of the Corporation's Audit Committee and Mr. Bessell has been determined to be an "audit committee financial expert".

W.C. (Mike Seth)

Mr. Seth is a geologist by training and holds a Bachelors of Science Degree in Mechanical Engineering from the University of British Columbia. He is President of Seth Consultants Ltd. and prior thereto he served as Chairman of McDaniel & Associates Consultants Ltd., one of the preeminent oil and natural gas reserve evaluators in Canada and internationally. Prior to becoming Chairman of McDaniel Mr. Seth was President of McDaniel for 37 years. Mr. Seth serves on the boards of various other junior oil and gas companies (reporting and non-reporting issuers) and of one senior oil and gas income fund. He is also the founder and a director of Energy Navigator Inc., a private software development firm servicing the petroleum industry.

Colin M. Evans

Mr. Evans holds a Bachelors Degree in Economics from the University of Alberta and has had an extensive business career in most facets of the oil and gas industry since the mid 1960's. He has worked in positions of increasing responsibility with both large and small private and public companies. He has also worked in the Canadian securities industry and more recently has advised a variety of oil companies on both operational and financial matters. Mr. Evans is currently Vice President, Finance of Milestone Exploration Inc. Mr. Evans served as Chair of the Corporation's Audit Committee from March 23, 2005 to December 1, 2005.

Responsibilities and Terms of Reference

The Audit Committee reviews with management and the external auditors, and recommends to the board of directors for approval, the annual financial statements of the Corporation and the reports of the external auditors

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thereon, the interim financial statements of the Corporation and related financial reporting, including management's discussion and analysis and earnings press releases on the annual and interim financial statements of the Corporation. The Audit Committee reviews and establishes, in conjunction with the external auditors and management, audit plans and procedures and meets with the auditors independently of management when considered appropriate. The Audit Committee is responsible for reviewing auditor independence, approving all non-audit services, reviewing and making recommendations to the board of directors on internal control procedures and management information systems. In addition, the Committee is responsible for assessing and reporting to the Board on financial risk management positions. Set out as Schedule D is the text of the Audit Committee's charter.

All permissible categories of non-audit services require pre-approval from the Audit Committee.

External Auditor Service Fees

The following summarizes the total fees paid to Deloitte & Touche LLP, the external auditor of the Corporation, for the years ended December 31, 2005 and December 31, 2004:

	2005	2004
Audit fees	$ 75,000	$ 67,000
Review engagement fees(1)	20,000	25,000
Tax fees(2)	1,750	5,500
All other fees(3)	84,057	6,800
TOTAL	$ 180,807	$ 104,300

Notes:
(1) Review of the Corporation's interim financial statements.
(2) Tax planning and compliance.
(3) Services related to corporate and property acquisitions and prospectus financings.

Deloitte & Touche LLP are independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

PERSONNEL

As at December 31, 2005, the Corporation had 15 employees at its head office in Calgary. The Corporation has one field office, with one employee and three contract operators.

DESCRIPTION OF SHARE CAPITAL

The Corporation is authorized to issue an unlimited number of Common Shares, an unlimited number of first preferred shares and an unlimited number of second preferred shares (together, "**Preferred Shares**"), issuable in series, of which as at December 31, 2005, 139,940,448 Common Shares and no Preferred Shares were issued and outstanding. The following is a summary of the rights, privileges, restrictions and conditions attaching to the Common Shares and Preferred Shares of the Corporation.

Common Shares

The holders of Common Shares are entitled to: dividends if, as and when declared by the board of directors; to one vote per share at meetings of the holders of Common Shares of the Corporation; and upon liquidation, dissolution or winding up of the Corporation to receive pro rata the remaining property and assets of the Corporation, subject to the rights of shares having priority over the Common Shares. All of the Common Shares currently outstanding are fully-paid and non-assessable.

Preferred Shares

The Preferred Shares are issuable in series and each class of Preferred Shares will have such rights, restrictions, conditions and limitations as the board of directors may from time to time determine. The holders of

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Preferred Shares are entitled, in priority to holders of Common Shares, to be paid rateably with holders of each other series of Preferred Shares the amount of accumulated dividends, if any, specified to be payable preferentially to the holders of such series and upon liquidation, dissolution or winding up of the Corporation, to be paid rateably with holders of each other series of Preferred Shares the amount, if any, specified as being payable preferentially to holders of such series.

DIVIDEND POLICY

The Corporation has not declared or paid any dividends on its Common Shares since incorporation. Any decision to pay dividends on the Common Shares will be made by the board of directors on the basis of the Corporation's earnings, financial requirements and other conditions that the board of directors may consider appropriate in the circumstances.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX under the trading symbol "CLL". The following table sets out the high and low price for, and the volume of trading in, the Common Shares on the TSX, as reported by the TSX, on a monthly basis for the financial year ended December 31, 2005.

		Monthly Price Range	
	Volume	**High**	**Low**
	(000's)	**($)**	**($)**
January	4,290,661	$0.69	$0.49
February	14,690,099	$0.92	$0.61
March	21,505,505	$1.22	$0.74
April	8,403,185	$1.05	$0.68
May	3,292,350	$0.88	$0.68
June	5,125,144	$0.85	$0.72
July	9,317,232	$1.12	$0.76
August	113,078,600	$2.60	$1.09
September	58,271,400	$2.69	$1.94
October	30,800,900	$2.62	$2.01
November	21,474,100	$2.95	$2.20
December	48,945,595	$4.20	$2.79

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Connacher Shares is Valiant Trust Company at its principal office in Calgary, Alberta and BNY Trust Company of Canada at its principal office in Toronto, Ontario.

RISK FACTORS

The Corporation

An investment in the Corporation is subject to certain risks related to the nature of the Corporation's business and its present stage of development. There are numerous factors which may affect the success of the Corporation's business which are beyond the Corporation's control including local, national and international economic and political conditions. The Corporation's business involves a high degree of risk which a combination of experience, knowledge and careful evaluation may not overcome. The Corporation's investment in Petrolifera exposes the Corporation to risks which may not exist for domestic operations such as political and currency risks. The Corporation has a limited history of operations and earnings and there can be no assurance that the Corporation's business will be successful or profitable or that commercial quantities of oil and natural gas will be discovered by the Corporation. The Corporation has not paid any dividends and it is unlikely to pay dividends in the immediate or foreseeable future.

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Additional Financing

Depending on future exploration, development, acquisition and divestiture plans, the Corporation will require additional financing. The ability of the Corporation to arrange such financing in the future will depend in part upon the prevailing capital market conditions as well as the business performance of the Corporation. There can be no assurance that the Corporation will be successful in its efforts to arrange additional financing on terms satisfactory to the Corporation. If additional financing is raised by the issuance of shares from treasury of the Corporation, control of the Corporation may change and shareholders may suffer additional dilution.

From time to time the Corporation may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may temporarily increase the Corporation's debt levels above industry standards.

Industry Conditions

The oil and gas industry is intensely competitive and the Corporation competes with other companies which possess greater technical and financial resources. Many of these competitors not only explore for and produce oil and natural gas but, also carry on refining operations and market petroleum and other products on an international basis. Oil and gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and invasion of water into producing formations.

The marketability and price of oil and natural gas which may be acquired or discovered by the Corporation will be affected by numerous factors beyond the control of the Corporation. The ability of the Corporation to market any natural gas discovered may depend upon its ability to acquire space on pipelines which deliver natural gas to commercial markets. The Corporation is also subject to market fluctuations in the prices of oil and natural gas, uncertainties related to the delivery and proximity of its reserves to pipelines and processing facilities and extensive government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and gas and many other aspects of the oil and gas business. The Corporation is also subject to a variety of waste disposal, pollution control and similar environmental laws.

The oil and gas industry in Canada, including the oil sands industry, operates under federal, provincial and municipal legislation and regulation governing such matters as land tenure, prices, royalties, production rates, environmental protection controls, income, the exportation of crude oil, natural gas and other products, as well as other matters. The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, oil sands or other interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields and mine sites (including restrictions on production) and possibly expropriation or cancellation of contract rights.

Government regulations may be changed from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations affecting the crude oil and natural gas industry could reduce demand for crude oil and natural gas, increase the Corporation's costs and have a material adverse impact on the Corporation.

The oil and natural gas industry is subject to varying environmental regulations in each of the jurisdictions in which the Corporation may operate. Environmental regulations place restrictions and prohibitions on emissions of various substances produced concurrently with oil and natural gas and can impact on the selection of drilling sites and facility locations, potentially resulting in increased capital expenditures.

Status of Great Divide and Stage of Development of Connacher

In mid-August, 2005, Connacher submitted its application for the development of its Great Divide oil sands project to the Alberta Energy and Utilities Board and Alberta Environment for the necessary approvals required to produce bitumen using a SAGD process. The regulatory approval process can involve stakeholder consultation, including objections by mineral rights holders in the area, environmental impact assessments and public hearings,

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among other things. There can be no assurance that the required approvals will be obtained and, if obtained, will be obtained on terms and conditions acceptable to Connacher. Failure to obtain regulatory approvals, or failure to obtain them on a timely basis, could result in delays, abandonment or restructuring of the project and increased costs, all of which could have a material adverse affect on Connacher.

If all regulatory approvals are obtained, there is a risk that design and construction of the facilities and infrastructure to support the project will not be completed on time, on budget or at all. Additionally, there is a risk that the Great Divide project may have delays, interruptions of operations or increased costs due to many factors, including, without limitation:

- inability to attract or retain sufficient numbers of qualified workers;
- breakdown or failure of equipment or processes;
- construction performance falling below expected levels of output or efficiency;
- design errors;
- non-performance by, or financial failure of, third-party contractors;
- labour disputes, disruptions or declines in productivity;
- increases in materials or labour costs;
- delays in obtaining, or conditions imposed by, regulatory approvals;
- delays induced by weather;
- disruption or delays in availability of transportation services;
- errors in construction;
- changes in Great Divide's scope;
- unforeseen site surface or subsurface conditions;
- transportation or construction accidents;
- permit requirement violation;
- reservoir performance;
- energy supply disruption;
- shortages of or delays in accessing drilling rigs and services; and
- catastrophic events such as fires, earthquakes, storms or explosions.

The Great Divide project is not being constructed on a turn-key basis. Additionally, given the state of development of the Great Divide project, various changes to the project may be made. Based upon current scheduling, the project is not expected to start commercial SAGD operations until 2007. The information contained herein, including, without limitation, reserve and economic evaluations is conditional upon receipt of all regulatory approvals and no material changes being made to the project or its scope. The industry is entering a period where unprecedented oil sands development and industrial activity is planned at a time when activity in many other sectors is also high. Connacher will need to compete for equipment, supplies, services, and labour in this environment which could result in increased costs, shortages of goods and services that delay progress, or both. Increased competition for equipment, materials and labour may result in increased costs that could have a material adverse effect on Connacher's business, financial condition or results of operations. As such, there are risks associated with project cost estimates provided by Connacher. Cost estimates are provided prior to completion of final scope design and detailed engineering needed to reduce the margin of error. Accordingly, actual costs may vary from estimates and these differences may be material.

Operating Costs

The operating costs of the Great Divide project, which have the potential to vary considerably, are significant components of the cost of production of the petroleum products produced by the Great Divide project. The operating costs of the Great Divide project may vary considerably during the operating period. The factors which could affect operating costs include, without limitation;

- the amount and cost of labour to operate the Great Divide project;
- the cost of catalyst and chemicals;
- the actual steam oil ratio required to operate the SAGD well pairs;

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- the cost of natural gas and electricity;
- reliability of the facilities;
- the maintenance cost of the facilities;
- the cost to transport sales products and the cost to dispose of certain by-products; and
- the cost of insurance.

Connacher's earnings may be reduced if increases in operating costs are incurred.

Infrastructure for the Great Divide Project

Connacher will depend, to a large extent, on third party designers, contractors and suppliers to design and construct the necessary facilities and infrastructure for the Great Divide project. Connacher also anticipates that it will rely on certain infrastructure owned and operated or to be constructed by others, including, without limitation, pipelines for the transportation of diluent and produced bitumen to the market, natural gas, water source and disposal pipelines and electrical grid transmission lines for the provision and/or sale of electricity to Connacher. The failure of any or all of these third parties to supply utilities, services or construct the infrastructure required to complete the Great Divide project on a timely basis and on acceptable commercial terms will negatively impact Connacher's operation and financial results.

In-situ Extraction

Current SAGD technologies for in-situ recovery of heavy oil and bitumen are energy intensive, requiring significant consumption of natural gas and other fuels in the production of steam which is used in the recovery process. The amount of steam required in the production process can also vary and impact costs. The performance of the reservoir can also impact the timing and levels of production using this technology. Commercial application of this technology is relatively new and accordingly in the absence of long-term operating history there can be no assurances with respect to the sustainability of SAGD operations.

Recovery of Bitumen

Recovering bitumen from oil sands involves particular risks and uncertainties. The project is susceptible to loss of production, slowdowns, or restrictions on its ability to produce higher value products due to the interdependence of its component systems. Severe weather conditions can cause reduced production and in some situations result in higher costs. SAGD bitumen recovery facilities and development and expansion of production can entail significant capital outlays. Equipment failures could result in damage to Connacher's facilities or wells and liability to third parties against which Connacher may not be able to fully insure or may elect not to insure because of high premium costs or for other reasons. The costs associated with synthetic crude oil production are largely fixed and, as a result, operating costs per unit are largely dependent on levels of production.

Access to Diluent Supplies at Favourable Prices

Bitumen is characterized by high specific gravity or weight and low viscosity or resistance to flow. Among its other uses, diluent is required to facilitate the transportation of bitumen. A shortfall in the supply of diluent may cause its price to increase thereby increasing the cost to transport bitumen to market and correspondingly increasing Connacher's operating cost, decreasing its net revenues and negatively impacting the overall profitability of the Great Divide oil sands project.

Operational Hazards

The operation of the Great Divide project and the other oil and gas properties of the Corporation will be subject to the customary hazards of recovering, transporting and processing hydrocarbons, such as fires, explosions, gaseous leaks, migration of harmful substances, blowouts and oil spills. A casualty occurrence might result in the loss of equipment or life, as well as injury or property damage. The Corporation will not carry insurance with respect to all potential casualty occurrences and disruptions. It cannot be assured that the Corporation's insurance will be sufficient to cover any such casualty occurrences or disruptions. The project could be interrupted by natural

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disasters or other events beyond the control of the Corporation. Losses and liabilities arising from uninsured or under insured events could have a material adverse effect on the project and on the Corporation's business, financial condition and results of operations.

Abandonment and Reclamation Costs

Connacher will be responsible for compliance with terms and conditions of environmental and regulatory approvals and all laws and regulations regarding the abandonment of the Great Divide project and reclamation of its lands at the end of its economic life, which abandonment and reclamation costs may be substantial. A breach of such legislation and/or regulations may result in the imposition of fines and penalties, including an order for cessation of operations at the site until satisfactory remedies are made. It is not possible to estimate the abandonment and reclamation costs since they will be a function of regulatory requirements at the time and the value of the salvaged equipment may be more or less than the abandonment and reclamation costs. In addition, in the future Connacher may determine it prudent or be required by applicable laws or regulations to establish and fund one or more reclamation funds to provide for payment of future abandonment and reclamation costs.

Independent Reviews

Although third parties have prepared reviews, reports and projections relating to the viability and expected performance of the Great Divide project, it cannot be assured that these reports, reviews and projections and the assumptions on which they are based will, over time, prove to be accurate.

Possible Failure to Realize Anticipated Benefits of the Luke Acquisition and the MRC Acquisition

The Luke Acquisition and the MRC Acquisition are components of Connacher's strategy to mitigate certain price differential risks relating to production of bitumen at Connacher's Great Divide oil sands project and provide a supply of natural gas to meet or exceed internal demands for natural gas consumption in Connacher's operations. Achieving the benefits of these acquisitions will depend in part on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as Connacher's ability to realize the anticipated opportunities and synergies resulting from these acquisitions. This integration will require the dedication of substantial management effort, time and resources which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect Connacher's ability to achieve the anticipated benefits of these acquisitions.

Volatility of Refinery Margins

Upon completion of the MRC Acquisition, Connacher will face certain risks associated with the volatility of refinery margins. Refinery operations are sensitive to wholesale and retail margins for refined products, including asphalt and gasoline. Margin volatility is influenced by overall marketplace competitiveness, weather, the cost of crude oil and fluctuations in supply and demand for refined products.

New U.S. Government Standards on Content of Refined Products

An initiative of the U.S. Environmental Protection Agency on gasoline would impose reductions in benzene content, volatility, sulphur, and other parameters. These new requirements, other requirements of the U.S. Federal Clean Air Act, or other presently existing or future environmental regulations could require Connacher to expend substantial amounts to permit MRC to produce products that meet such requirements.

Terrorist Attacks and the Threat of Terrorist Attacks

The long-term impact of terrorist attacks in the United States, such as the attacks on September 11, 2001, and in Canada and the threat of future terrorist attacks on the energy transportation industry in general, and on Connacher in particular, is not known at this time. The possibility that infrastructure facilities may be direct targets

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of, or indirect casualties of, an act of terror and the implementation of security measures as a precaution against possible terrorist attacks will result in increased costs to Connacher's business.

Debt Service

Connacher used, and intends to use, its credit facility and new bridge loans and term debt to finance the Luke Acquisition and the MRC Acquisition and to provide capital for the development of Pod One at Great Divide. Following completion of such acquisitions and deployment of capital, Connacher's debt-to-equity ratio will increase from its current debt to equity ratio. Restrictive covenants governing Connacher's debt will limit the amount of debt that Connacher may incur. Connacher's ability to make scheduled repayments or to re-finance its debt obligations will depend upon its financial and operating performance, which in turn will depend upon prevailing industry and general economic conditions which are beyond Connacher's control. There can be no assurance that Connacher's operating performance, cash flow and capital resources will be sufficient to repay its debt in the future, in which case Connacher may be required to sell assets to repay its debt, defer capital expenditures or raise additional equity, to the extent available.

Access to Human Resources

The labour force in the Fort McMurray and surrounding area is limited and the inability to access the necessary skilled labourers to construct and operate Connacher's Great Divide project could have an adverse affect on Connacher's development plans. In addition, rising personnel costs could result in increases in general and administrative expenses and labour costs associated with the development of the project.

Competition

When operations commence, the Great Divide project will compete with other producers of bitumen and conventional producers of oil and gas. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

A number of companies other than Connacher have announced plans to enter the oil sands business, or expand existing operations. Expansion of existing operations and development of new projects could materially increase the supply of bitumen in the marketplace. Depending on the levels of future demand, increased supplies could have a negative impact on prices.

Royalty Regime

In the event that the Great Divide project is developed and becomes operational, Connacher's revenue and expenses will be directly affected by the royalty regime applicable to the Great Divide project. The economic benefit of future capital expenditures at Great Divide is, in many cases, dependent on a satisfactory royalty regime. There can be no assurance that the federal government and the Province of Alberta will not adopt a new royalty regime which will make capital expenditures uneconomic or that the regime currently in place will remain unchanged.

Risks of Foreign Investment

Through its significant equity interest in Petrolifera, the Corporation is subject to political, economic, and other uncertainties, including, but not limited to, expropriation, changes in energy policies or the personnel administering them, currency fluctuations and devaluations, exchange controls and royalty and tax increases. In the event of a dispute arising in connection with Petrolifera's operations in Argentina or prospectively in Peru, Petrolifera may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdictions of the courts of Canada or enforcing Canadian judgements in such other jurisdictions. Petrolifera may also be hindered or prevented from enforcing its rights with respect to a governmental instrumentality because of the doctrine of sovereign immunity. Accordingly, Petrolifera's exploration, development and production activities in Argentina and Peru could be substantially affected by factors beyond Petrolifera's control, any of which could have a material adverse effect on the Corporation.

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Petrolifera's operations may be adversely affected by changes in government policies and legislation or social instability and other factors which are not within the control of Petrolifera including, among other things, a change in crude oil or natural gas pricing policy, the risks of war, terrorism, abduction, expropriation, nationalization, renegotiation or nullification of existing concessions and contracts, taxation policies, economic sanctions, the imposition of specific drilling obligations and the development and abandonment of fields. In addition, the natural gas produced by Petrolifera in Argentina must be sold locally at rates that may not be comparable to international rates.

Need to Add Reserves

The Corporation's oil and natural gas reserves and production, and therefore its cash flows and earnings are highly dependent upon the Corporation developing and increasing its current reserve base and discovering or acquiring additional reserves. Without the addition of reserves through exploration, acquisition or development activities, the Corporation's reserves and production will decline over time as reserves are depleted. To the extent that cash flow from operations is insufficient and external sources of capital become limited or unavailable, the Corporation's ability to make the necessary capital investments to maintain and expand its oil and natural gas reserves will be impaired. There can be no assurance that the Corporation will be able to find and develop or acquire additional reserves to replace production at commercially feasible costs.

Environmental Regulation and Risks

Extensive national, state and local environmental laws and regulations in foreign jurisdictions affect nearly all of the operations of the Corporation. These laws and regulations set various standards regulating certain aspects of health and environmental quality, provide for penalties and other liabilities for the violation of such standards and establish in certain circumstances obligations to remediate current and former facilities and locations where operations are or were conducted. In addition, special provisions may be appropriate or required in environmentally sensitive areas of operation. There can be no assurance that the Corporation will not incur substantial financial obligations in connection with environmental compliance.

The construction, operation and decommissioning of the Great Divide project and reclamation of the project's land are conditional upon various environmental and regulatory approvals issued by governmental authorities. There is no assurance such approvals will be issued, or once issued renewed, or that they will not contain terms and conditions which make the project uneconomic or cause the Corporation to significantly alter the project.

Significant liability could be imposed on the Corporation for damages, cleanup costs or penalties in the event of certain discharges into the environment, environmental damage caused by previous owners of properties purchased by the Corporation or non-compliance with environmental laws or regulations. Such liability could have a material adverse effect on the Corporation. Moreover, the Corporation cannot predict what environmental legislation or regulations will be enacted in the future or how existing or future laws or regulations will be administered or enforced. Compliance with more stringent laws or regulations, or more vigorous enforcement policies of any regulatory authority, could in the future require material expenditures by the Corporation for the installation and operation of systems and equipment for remedial measures, any or all of which may have a material adverse effect on the Corporation.

Kyoto Accord

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". The Government of Canada has put forward a Climate Change Plan for Canada which suggests further legislation will set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas production. Future federal legislation, together with existing provincial emission reduction legislation, such as in Alberta's *Climate Change and Emissions Management Act,* may require the reduction of emissions and/or emissions intensity from the Corporation's oil and gas exploration and development activities. The direct or indirect costs of such legislation may adversely affect the Corporation's operations. No assurance can be given that future environmental approvals, laws or regulations will not adversely impact (i) the ability of the Corporation to conduct its operations or (ii) the Corporation's production

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or (iii) the Corporation's unit costs of production. Equipment from suppliers which can meet future emission standards may not be available on an economic basis and other methods of reducing emissions to required levels in the future may significantly increase operating costs or reduce output. There is a risk that the federal and/or provincial governments could pass legislation which would tax such emissions or require, directly or indirectly, reductions in such emissions produced by energy industry participants, such as the Corporation. Mitigation of the risk of future legislative or regulatory limits on the emission of greenhouse gases may include the acquisition of emission reduction or off-set credits from third parties. However, emission reduction or off-set credits may not be available for acquisition by the Corporation or may not be available on an economic basis and may not be recognized or qualify under future legislative or regulatory regimes as mitigation for the emission of greenhouse gases by the Corporation.

Volatility of Oil and Gas Prices and Markets

The Corporation's financial condition, operating results and future growth are dependent on the prevailing prices for its oil and natural gas production. Historically, the markets for oil and natural gas have been volatile and such markets are likely to continue to be volatile in the future. Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes to the demand for oil and natural gas, whether the result of uncertainty or a variety of additional factors beyond the control of the Corporation. Any substantial decline in the prices of oil and natural gas could have a material adverse effect on the Corporation and the level of its oil and natural gas reserves. Additionally, the economics of producing from some wells may change as a result of lower prices, which could result in a suspension of production by the Corporation. No assurance can be given that oil and natural gas prices will be sustained at levels which will enable the Corporation to operate profitably. From time to time the Corporation may avail itself of forward sales or other forms of hedging activities with a view to mitigating its exposure to the risk of price volatility.

Reserve and Resource Estimates

There are numerous uncertainties inherent in estimating quantities of proved, probable and possible reserves and resources and cash flows to be derived therefrom, including many factors beyond the control of the Corporation. The reserve, resource and cash flow information set forth in this Annual Information Form represents estimates only. The reserves, resources and estimated future net cash flow from the Corporation's properties have been independently evaluated by D&M and GLJ with an effective date of December 31, 2005. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs, abandonment and salvage values, royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date of the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Corporation. Actual production and cash flows derived therefrom will vary from these evaluations, and such variations could be material.

Estimates with respect to reserves and resources that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be material, in the estimated reserves.

Reserve and resource estimates may require revision based on actual production experience. Such figures have been determined based upon assumed oil prices and operating costs. Market price fluctuations of oil prices may render uneconomic the recovery of certain grades of bitumen. Moreover, short term factors relating to oil sands resources may impair the profitability of the Great Divide project in any particular period.

The present value of estimated future net cash flows referred to herein should not be construed as the current market value of estimated oil and natural gas reserves attributable to the Corporation's properties. The estimated discounted future cash flow from reserves are based upon price and cost estimates which may vary from actual prices and costs and such variance could be material. Actual future net cash flows will also be affected by

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factors such as the amount and timing of actual production, supply and demand for oil and natural gas, curtailments or increases in consumption by purchasers and changes in governmental regulations or taxation.

Title to Properties

Although title reviews will be done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of the Corporation which could result in a reduction of the revenue received by the Corporation.

Potential Conflicts of Interest

There are potential conflicts of interest to which some of the directors and officers of the Corporation will be subject in connection with the operations of the Corporation. Some of the directors and officers are engaged and will continue to be engaged in the search of oil and gas interests on their own behalf and on behalf of other corporations, and situations may arise where the directors and officers will be in direct competition with the Corporation. Additionally, certain officers and directors of the Corporation are also officers and directors of Petrolifera and receive compensation from Petrolifera for their services. Conflicts of interest, if any, which arise will be subject to and be governed by procedures prescribed by the ABCA which require a director or officer of a corporation who is a party to or is a director or an officer of or has a material interest in any person who is a party to a material contract or proposed material contract with the Corporation, to disclose his interest and to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

Exchange Rate Risk

Revenue received from the sale of crude oil is generally referenced to a price denominated in US$. As the Corporation reports its operating results in CDN$, fluctuations in product pricing and fluctuations in the rate of exchange between the US$ and CDN$ would affect reported revenues and reported results. To mitigate these risks, the Corporation has, in the past, fixed the price of a portion of its crude oil sales in CDN$.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of western Canada. Certain aboriginal peoples have filed a claim against the Government of Canada, the Province of Alberta, certain governmental entities and the regional municipality of Wood Buffalo (which includes the City of Fort McMurray, Alberta) claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray, including the lands on which the Great Divide project and most of the other oil sands operations in Alberta are located. Such claims, if successful, could have a significant adverse effect on Connacher and the Great Divide project.

LEGAL PROCEEDINGS

There are no material legal proceedings against the Corporation.

INTERESTS OF EXPERTS

Each of Seaton-Jordan, D&M and GLJ have prepared a report or valuation described herein. Neither Seaton-Jordan, D&M and GLJ held any interests in securities or other property of Connacher when it prepared its respective report or valuation, has received any such interest since such time or will receive any such interest. No director, officer or employee of Seaton-Jordan, D&M or GLJ is to be elected, appointed or employed by Connacher.

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ADDITIONAL INFORMATION

Additional information, including information as to directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans, if applicable, is contained in the Management Information Circular of the Corporation prepared in connection with the most recent annual meeting of shareholders of the Corporation that involved the election of directors. Additional financial information is provided in the Corporation's financial statements and management discussion and analysis for the year ended December 31, 2005, which are contained in the Annual Report of the Corporation for the year ended December 31, 2005.

Copies of this Annual Information Form, the Corporation's Annual Report, any interim financial statements of the Corporation subsequent to those statements contained in the Annual Report, the Corporation's Management Information Circular and other additional information relating to the Corporation are available on SEDAR at *www.sedar.com*.

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SCHEDULE A
REPORT ON RESERVES DATA BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR

To the board of directors of Connacher Oil and Gas Limited (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2005. The reserves data consist of the following:

   (a) (i) proved, proved plus probable and proved plus probable plus possible oil and gas reserves estimated as at December 31, 2005 using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

   (b) (i) proved, proved plus probable and proved plus probable plus possible oil and gas reserves, estimated as at December 31, 2005 using constant prices and costs; and

   (ii) the related estimated future net revenue

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy and Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves date are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2005, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors.

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (before income tax, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
			M$	M$	M$	M$
DeGolyer and MacNaughton Canada	Appraisal Report as of December 31, 2005 on certain properties owned by Connacher Oil and Gas Limited dated March 8, 2006	Canada	-	35,250	-	35,250

5. In our opinion, the reserves evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update this report referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

   Executed as to our report referred to above:

   DeGolyer and MacNaughton Canada Limited, Calgary, Alberta, dated March 8, 2006.

DEGOLYER and MACNAUGHTON CANADA LIMITED

(Signed) *"Colin P. Outtrim, P.Eng"*

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REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

To the board of directors of Connacher Oil and Gas Limited (the "Company"):

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2005. The reserves data consist of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2005, using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

   (b) (i) proved oil and gas reserves estimated as at December 31, 2005, using constant prices and costs; and

   (ii) the related estimated future net revenue.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2005, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors.

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate -$M)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	March 16, 2006	Canada	-	$167,802	-	$167,802

5. In our opinion, the reserves evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, March 16, 2006.

(Signed) *"Dana B. Laustsen"*
Dana B. Laustsen, P. Eng.
Executive Vice-President

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SCHEDULE B
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Connacher Oil and Gas Limited (the "**Corporation**") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2005 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated as at December 31, 2005 using constant prices and costs; and

(ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator is presented in Schedule B and will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Corporation has

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

(signed) *Richard A. Gusella*
Richard A. Gusella
President and Chief Executive Officer

(signed) *W.C. (Mike) Seth*
W.C. (Mike) Seth
Chairman, Reserves Committee and a Director

(signed) *Richard R. Kines*
Richard R. Kines
Vice President Finance and Chief Financial Officer

(signed) *D. Hugh Bessell*
D. Hugh Bessell
Director

March 27, 2006

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SCHEDULE C
CONNACHER'S 33.2% INTEREST IN PETROLIFERA'S OIL AND GAS RESERVES AND FUTURE NET REVENUE

The following is a summary of the Corporation's 33.2% interest in Petrolifera's oil and gas reserves and future net revenue as at December 31, 2005 as evaluated by D&M in the Petrolifera D&M Report. The information contained within this Schedule C has been derived from the Petrolifera AIF which is posted on SEDAR (www.sedar.com).

RESERVES DATA - FORECAST PRICES AND COSTS

CRUDE OIL AND NATURAL GAS RESERVES BASED ON FORECAST PRICES AND COSTS[(9)]

	Light Crude Oil		Natural Gas		Natural Gas Liquids	
	Gross[(1)] (mbbl)	Net[(1)] (mbbl)	Gross[(1)] (mmcf)	Net[(1)] (mmcf)	Gross[(1)] (bbl)	Net[(1)] (bbl)
Proved Developed Producing[(2)(5)]	1,386	1,199	463	400	-	-
Proved Developed Non-Producing[(2)(6)]	220	191	331	286	-	-
Proved Undeveloped[(2)(7)]	389	336	136	117	-	-
Total Proved[(2)]	1,995	1,726	929	804	-	-
Total Probable[(3)]	4,995	4,321	3,331	2,882	-	-
Total Proved Plus Probable[(2)(3)]	6,990	6,047	4,261	2,882	-	-
Total Possible[(4)]	2,776	2,401	570	493	-	-
Total Proved Plus Probable Plus Possible[(2)(3)(4)]	9,766	8,447	4,830	4,178	-	-

NET PRESENT VALUE OF FUTURE NET REVENUE BASED ON FORECAST PRICES AND COSTS[(9)]

	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes Discounted At				
	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Proved Developed Producing[(2)(5)]	49,285	44,157	40,125	36,836	34,080	33,408	29,944	27,212	24,982	23,114
Proved Developed Non-Producing[(2)(6)]	1,587	852	92	(543)	(1,038)	880	303	(296)	(794)	(1,182)
Proved Undeveloped[(2)(7)]	12,343	10,397	8,835	7,642	6,709	7,698	6,742	5,694	4,892	4,267
Total Proved[(2)]	63,215	55,406	49,052	43,935	39,751	42,264	36,990	32,610	29,080	26,199
Total Probable[(3)]	189,295	157,011	133,666	115,907	101,902	123,473	102,216	86,885	75,236	66,058
Total Proved Plus Probable[(2)(3)]	252,511	212,418	182,718	159,842	141,653	165,737	139,206	119,495	104,316	92,257
Total Possible[(4)]	103,151	88,889	78,413	69,956	62,884	67,331	57,875	50,994	45,452	40,823
Total Proved Plus Probable Plus Possible[(2)(3)(4)]	355,662	301,306	261,131	229,798	204,537	233,068	197,081	170,489	149,768	133,080

FUTURE NET REVENUE (UNDISCOUNTED) BASED ON FORECAST PRICES AND COSTS[(9)]

	Revenue[(11)] (M$)	Royalties[(12)] (M$)	Operating Expenses (M$)	Capital Costs (M$)	Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Total Proved[(2)]	91,871	12,403	10,593	5,396	265	63,215	20,952	42,264
Total Proved Plus Probable[(2)(3)]	322,629	43,555	15,106	10,878	595	252,511	86,774	165,737
Total Proved Plus Probable Plus Possible[(2)(3)(4)]	447,996	60,479	18,042	13,084	729	355,662	122,594	233,068

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FUTURE NET REVENUE BY PRODUCTION GROUP BASED ON FORECAST PRICES AND COSTS[9]

	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) ($000's)
Total Proved[2]	Light crude oil	48,159
	Associated gas and non-associated gas	892
Total Proved Plus Probable[2][3]	Light crude oil	179,226
	Associated gas and non-associated gas	3,492
Total Proved Plus Probable Plus Possible[2][3][4]	Light crude oil	256,902
	Associated gas and non-associated gas	4,228

RESERVES DATA - CONSTANT PRICES AND COSTS

CRUDE OIL AND NATURAL GAS RESERVES BASED ON CONSTANT PRICES AND COSTS[8]

	Light Crude Oil		Natural Gas		Natural Gas Liquids	
	Gross[2] (mbbl)	Net[2] (mbbl)	Gross[2] (mmcf)	Net[2] (mmcf)	Gross[2] (bbl)	Net[2] (bbl)
Proved Developed Producing[2][5]	1,386	1,199	461	399	-	-
Proved Developed Non-Producing[2][6]	220	191	312	270	-	-
Proved Undeveloped[2][7]	389	336	135	117	-	-
Total Proved[2]	1,996	1,726	908	786	-	-
Total Probable[3]	4,995	4,320	3,300	2,855	-	-
Total Proved Plus Probable[2][3]	6,991	6,047	4,210	3,641	-	-
Total Possible[4]	2,775	2,401	570	493	-	-
Total Proved Plus Probable Plus Possible[2][3][4]	9,766	8,448	4,780	4,134	-	-

NET PRESENT VALUE OF FUTURE NET REVENUE BASED ON CONSTANT PRICES AND COSTS[8]

	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes Discounted At				
	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Proved Developed Producing[2][5]	54,272	48,531	43,996	40,290	37,183	36,678	32,805	29,744	27,242	25,146
Proved Developed Non-Producing[2][6]	2,888	1,743	754	(30)	(630)	1,816	915	147	(455)	(914)
Proved Undeveloped[2][7]	14,070	11,709	9,946	8,608	7,556	9,117	7,585	6,411	5,518	4,818
Total Proved[2]	71,230	61,983	54,696	48,867	44,109	47,612	41,304	36,302	32,305	29,051
Total Probable[3]	206,507	172,457	147,260	127,821	112,365	134,632	112,264	95,738	82,999	72,878
Total Proved Plus Probable[2][3]	277,737	234,441	201,956	176,688	156,474	182,244	153,568	132,040	115,305	101,928
Total Possible[4]	113,824	98,691	87,101	77,642	69,706	74,207	64,246	56,649	50,457	45,266
Total Proved Plus Probable Plus Possible[2][3][4]	391,560	333,131	289,056	254,330	226,180	256,451	217,814	188,689	165,762	147,195

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FUTURE NET REVENUE
(UNDISCOUNTED)
BASED ON CONSTANT PRICES AND COSTS(8)

	Revenue(10) (M$)	Royalties(11) (M$)	Operating Expenses (M$)	Capital Costs (M$)	Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Total Proved(2)	99,358	13,413	9,149	5,370	196	71,230	23,618	47,612
Total Proved Plus Probable(2)(3)	349,087	47,127	12,981	10,795	448	277,737	95,492	182,244
Total Proved Plus Probable Plus Possible(2)(3)(4)	486,498	65,677	15,729	12,988	544	39,156	135,109	256,451

FUTURE NET REVENUE BY PRODUCTION GROUP
BASED ON CONSTANT PRICES AND COSTS(8)

	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) ($000's)
Total Proved(2)	Light crude oil	54,252
	Associated gas and non-associated gas	444
Total Proved Plus Probable(2)(3)	Light crude oil	200,430
	Associated gas and non-associated gas	1,522
Total Proved Plus Probable Plus Possible(2)(3)(4)	Light crude oil	287,139
	Associated gas and non-associated gas	1,917

Notes:

(1) "Gross Reserves" are the Corporation's working interest (operating or non-operating) share before deducting royalties and without including any royalty interests of the Corporation. "Net Reserves" are the Corporation's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interests in reserves.

(2) "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is 90% likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(3) "Probable" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

(4) "Possible" reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

(5) "Developed Producing" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(6) "Developed Non-Producing" reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

(7) "Undeveloped" reserves are those reserves expected to be recovered from know accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

(8) The product prices used in the constant price and cost evaluations in the Petrolifera D&M Report were as follows: (1) Light Argentina crude oil price: $49.29/bbl, (2) Argentina gas price: $1.07/mcf and (3) non-associated gas: $1.13/mcf.

(9) The pricing assumptions used in the Petrolifera D&M Report with respect to net values of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below and are as at December 31, 2005. D&M is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

	Light Crude Oil ($Cdn/stb)	Natural Gas ($Cdn/mcf)	Inflation Rate %/year	Exchange Rate $US/$Cdn
Year Forecast				
2006	46.81	1.53	0.0	0.860
2007	45.49	2.03	2.5	0.860
2008	42.36	2.06	2.5	0.860
2009	41.68	2.10	2.5	0.860
2010	42.51	2.14	2.0	0.860
2011	43.38	2.18	2.0	0.860
2012	44.25	2.21	2.0	0.860
2013	45.14	2.25	2.0	0.860
2014	46.06	2.30	2.0	0.860
2015	46.98	2.34	2.0	0.860
2016	47.94	2.39	2.0	0.860
Thereafter	48.90	2.44	2.0	0.860

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(10) Values include processing and other income.
(11) Values include Alberta Royalty Tax Credit.

The following table summarizes Connacher's share of the capital expenditures made by Petrolifera on oil and natural gas properties for the portion of the year ended December 31, 2005 during which Connacher consolidated Petrolifera's accounts with Connacher's financial results. See "General Development of the Business".

Property Acquisition Costs ($)		Exploration Costs ($)	Development Costs ($)
Proved Properties	**Unproved Properties**		
-	$115,665	$1,651,460	-

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SCHEDULE D
AUDIT COMMITTEE CHARTER

The Audit Committee (the "**Committee**") of the board of directors (the "**Board**") of Connacher Oil and Gas Limited (the "**Corporation**") shall have the oversight responsibility, authority and specific duties as described below.

Composition

The Committee will be comprised of three or more directors as determined by the Board. Each Committee member shall satisfy the independence, financial literacy and experience requirements of applicable securities laws, rules or guidelines, any applicable stock exchange requirements or guidelines and any other applicable regulatory rules. In particular, each member of the Committee shall have no direct or indirect material relationship with the Corporation which could reasonably be expected to materially interfere with the member's independent judgment. Determinations as to whether a particular Director satisfies the requirements for membership on the Committee shall be made by the full Board and shall be reviewed at least annually.

Members of the Committee shall be appointed from time to time by the Board. Each member shall serve until his successor is appointed, unless he shall resign or be removed by the Board or he shall otherwise cease to be a director of the Corporation. If a member of the Committee ceases to be independent for reasons outside that member's reasonable control, the member shall immediately notify the Chair of the Board as to this fact and shall resign his or her position as a member of the Committee on the earliest of (i) the appointment of his or her successor; (ii) the next annual meeting of shareholders of the Corporation; and (iii) the date that is six months from the occurrence of the event which caused the member to not be independent. The Board shall fill any vacancy if the membership of the Committee is less than three Directors.

The Chair of the Committee may be designated by the Board or, if it does not do so, the members of the Committee may elect a Chair by vote of a majority of the full Committee membership.

Operation

The Committee shall have access to such officers and employees of the Corporation and to the Corporation's independent external auditors, and to such information respecting the Corporation, as it considers to be necessary or advisable in order to perform its duties and responsibilities. The Committee has the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties and to set and pay the compensation for any such counsel and advisors, such engagement to be for the Corporation's sole account and expense.

Meetings of the Committee shall be conducted as follows:

1. The Committee shall meet at least four times annually at such times and at such locations as the Chair of the Committee shall determine, provided that meetings shall be scheduled so as to permit timely review of the quarterly and annual financial statements and reports. The independent auditors or any one member of the Committee may also request a meeting of the Committee.

2. The quorum for meetings shall be a majority of the members of the Committee, present in person or by telephone or by other telecommunication device that permits all persons participating in the meeting to hear each other.

3. The Chair shall, in consultation with management and the external auditors, establish the agenda for the meetings and instruct management to ensure that properly prepared agenda materials are circulated to the Committee with sufficient time for study prior to the meeting.

4. Every question at a Committee meeting shall be decided by a majority of the votes cast.

5. The Chief Executive Officer shall be available to advise the Committee, and may attend meetings at the invitation of the Chair of the Committee. Other management representatives may be invited to attend. The

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independent external auditors shall be given notice of, and shall be entitled to attend, each meeting of the Committee at the expense of the Corporation. The Chair of the Committee shall hold in camera meetings of the Committee, without management present, at every Committee meeting.

6. A Committee member, or any other person selected by the Committee, shall be appointed at each meeting to act as secretary for the purpose of recording the minutes of each meeting.

7. The Committee may delegate from time to time to any person or committee of persons any of the Committee's responsibilities that lawfully may be delegated.

The Committee provides an avenue for communication, particularly for outside directors, with the independent external auditors and financial and senior management and the Board. The independent external auditors shall have a direct line of communication to the Committee through its Chair. The Committee, through its Chair, may contact directly any employee in the Corporation as it deems necessary, and any employee may bring before the Committee on a confidential basis any matter involving financial practices or transactions.

Responsibilities

The Committee is part of the Board. Its primary function is to assist the Board in fulfilling its oversight responsibilities with respect to: (i) the preparation and disclosure of the financial statements, and accompanying reports, to be provided to shareholders and regulatory bodies; (ii) the system of internal control and management information systems of the Corporation that management has established; and (iii) the external audit process. In addition, the Committee shall assist the Board as requested in fulfilling its oversight responsibilities with respect to (i) financial policies and strategies; (ii) financial risk management practices; and (iii) transactions or circumstances which could materially affect the financial position or results of operations of the Corporation.

The role of the Committee is one of stewardship and oversight. Management is responsible for preparing the financial statements and financial reporting of the Corporation and for maintaining internal control and management information and risk management systems and procedures. The external auditors are responsible for the audit or review of the financial statements and other services they provide.

The Committee should have a clear understanding with the external auditors that the independent auditors must maintain an open and transparent relationship with the Committee and the Board, and that the ultimate accountability of the external auditors is to the shareholders of the Corporation.

The Committee shall provide the Board with a summary of all meetings together with a copy of the minutes from such meetings. Where minutes have not yet been prepared, the Chair shall provide the Board with oral reports on the activities of the Committee. All information reviewed and discussed by the Committee at any meeting shall be referred to in the minutes and made available for examination by the Board upon request to the Chair.

Specific Duties

1. Financial Statements and Financial Reporting.

   The Committee shall:

   (a) review with management and the external auditors, and recommend to the Board for approval, the annual financial statements of the Corporation, the reports of the external auditors thereon and related financial reporting, including Management's Discussion and Analysis and financial press releases;

   (b) review with management and the external auditors, and recommend to the Board for approval, the interim financial statements of the Corporation and related financial reporting, including Management's Discussion and Analysis and financial press releases;

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(c) review with management and recommend to the Board for approval, any financial statements of the Corporation which have not previously been approved by the Board and which are to be included in a prospectus of the Corporation;

(d) consider and be satisfied that adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements (other than disclosure referred to in clauses (a) and (b) above), and periodically assess the adequacy of such procedures;

(e) review with management, the external auditors and, if necessary, legal counsel, any litigation, claim or contingency, including tax assessments, that could have a material effect upon the financial position of the Corporation, and the manner in which these matters may be, or have been, disclosed in the financial statements;

(f) review the appropriateness of the accounting practices and policies of the Corporation, the use and effect of judgment on accounting measurements, the adequacy of accruals and estimates used by management in preparing financial statements and review any proposed changes in accounting policies and procedures;

(g) review accounting, tax and financial aspects of the operations of the Corporation as the Committee considers appropriate; and

(h) include in the annual information form each year, as required, a copy of the Terms of Reference of the Committee and a report to shareholders on the Committee's activities in satisfying its responsibilities during the year in compliance with these terms of reference.

2. Relationship with External Auditors.

The Committee shall:

(a) consider and make a recommendation to the Board as to the appointment or re appointment of the external auditors, ensuring that such auditors are participants in good standing pursuant to applicable securities laws;

(b) consider and make a recommendation to the Board as to the compensation of the external auditors;

(c) review and approve the annual audit plan of the external auditors;

(d) oversee the work of the external auditors in performing their audit or review services and oversee the resolution of any disagreements between management and the external auditors;

(e) review and discuss with the external auditors all significant relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the external auditors' independence, including, without limitation, (A) requesting, receiving and reviewing, on a periodic basis, a formal written statement from the external auditors delineating all relationships that may reasonably be thought to bear on the independence of the external auditors with respect to the Corporation, (B) discussing with the external auditors any disclosed relationships or services that the external auditors believe may affect the objectivity and independence of the external auditors, and (C) recommending that the Board take appropriate action in response to the external auditors' report to satisfy itself of the external auditors' independence;

(f) pre approve all non audit services (where such non audit services are considered to be above the *de minimus* level referred to in applicable law) to be provided to the Corporation (and any subsidiaries thereof) by the external auditors and review fee arrangements for such services (the Committee may delegate to one or more of its members the authority to pre approve non audit services so long as such pre approval is presented to the full Committee at its first scheduled meeting following such pre approval); and

(g) review and approve the hiring policies of the Corporation regarding employees and former employees of the present and former external auditors of the Corporation.

3. Internal Controls.

The Committee shall:

(a) review with management and the external auditors, the adequacy and effectiveness of the internal control and management information systems and procedures of the Corporation (with particular attention given to accounting, financial statements and financial reporting matters) and determine whether the Corporation are in compliance with applicable legal and regulatory requirements and with the Corporation's policies;

(b) review the external auditors' recommendations regarding any matters, including internal control and management information systems and procedures, and management's responses thereto;

(c) establish procedures for the receipt, retention and treatment of complaints, submissions and concerns regarding accounting, internal controls or auditing matters on an anonymous and confidential basis; and

(d) review with external auditors any corporate transactions in which Directors or officers of the Corporation have a personal interest.

4. Financial Risk Management.

The Committee shall:

(a) review with management and the external auditors their assessment of significant financial risks and exposures;

(b) review and assess the steps that management has taken to mitigate such risks;

(c) review annually the insurable risks and insurance coverages of the Corporation; and

(d) report the results of such reviews to the Board for the purpose of assisting the Board in identifying the principal business risks associated with the businesses of the Corporation.