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IT'S ALL ABOUT THE OILSANDS

CONNACHER OIL AND GAS LIMITED

Annual Report 2006

82-34954

ANNUAL GENERAL MEETING

Thursday, May 10, 2007 - 3:00 pm MDT
Devonian Room
Calgary Petroleum Club
329 - 5 Avenue SW
Calgary, AB

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 approximately 90,000 acres of oil sands leases at its Great Divide oil sands project near Fort McMurray, Alberta. It also maintains conventional production at Marten Creek and Three Hills, Alberta and at Battrum, Saskatchewan. Connacher presently owns 26 percent of and manages Petrolifera Petroleum Limited, which has interests in Argentina, Peru and Colombia. The Company also owns and operates a 9,500 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.

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Connacher made big steps in 2006 on our oil sands project at Great Divide, Alberta.

THE DEVELOPMENT OF THE HIGH QUALITY OIL SANDS RESERVOIR AT GREAT DIVIDE'S POD ONE IS WELL ADVANCED. START-UP IS EXPECTED TO COMMENCE IN THE SUMMER OF 2007. MEANWHILE, OTHER PODS HAVE BEEN IDENTIFIED FOR POTENTIAL GROWTH.

OUR CONVENTIONAL NATURAL GAS PRODUCTION AND OUR OIL REFINERY ARE SUPPORTING OUR OIL SANDS INITIATIVE AS PLANNED. CONNACHER'S INVESTMENT IN PETROLIFERA PETROLEUM HAS PERFORMED EXCEPTIONALLY WELL, PROVIDING A FINANCIAL SAFETY VALVE.

CONNACHER'S GOAL
IS TO MAXIMIZE SHAREHOLDER VALUE

STRATEGY

Operate with large focused interests

Be financially disciplined

Focus on projects with characteristics of repeatability and sustainability

Mitigate and manage risks of a smaller company in the oil sands with an integrated approach

82-34954

FINANCIAL AND OPERATING HIGHLIGHTS

	2006	2005	% Change
FINANCIAL			
($000 except per share amounts) - Unaudited			
Revenues net of royalties	$244,684	$9,795	2400
Cash flow from operations (1)	40,196	4,358	822
Basic, per share (1)	0.22	0.04	450
Diluted, per share (1)	0.21	0.04	425
Net earnings (loss)	6,953	991	602
Basic and diluted, per share	0.04	0.01	300
Capital expenditures and acquisitions	451,525	16,807	2,587
Proceeds on disposal of oil and gas properties	10,000	-	-
Bank debt	229,254	-	-
Working capital	118,626	75,427	59
Cash on hand	142,391	75,511	89
Shareholders' equity	385,398	129,108	198
Total assets	712,930	134,813	429
OPERATING			
Production			
Natural gas (mcf/d)	10,473	827	1,166
Crude oil (bbl/d)	980	729	34
Equivalent (boe/d) (2)	2,725	867	214
Pricing			
Crude oil ($/bbl)	53.85	42.33	27
Natural gas ($/mcf)	5.85	1.37	327
Selected Highlights ($/boe) (2)			
Weighted average sales price	41.83	36.91	13
Royalties	9.87	8.16	21
Operating and transportation costs	8.32	7.73	8
Netback	24.67	23.23	6
Reserves (mboe) (3)			
Proved (1P)	50,381	1,501	3,256
Probable	42,555	70,598	(40)
Total proved plus probable (2P) (4)	92,936	72,099	29
COMMON SHARE INFORMATION			
Shares outstanding at end of period (000)	197,894	139,940	41
Weighted average shares outstanding			
Basic (000)	184,469	106,114	74
Diluted (000)	188,432	111,846	68
Volume traded during the year (000)	323,825	338,402	(4)
Common share price ($)			
High	6.07	4.20	45
Low	3.09	0.49	531
Close, end of year	3.49	3.84	(9)

(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's 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.

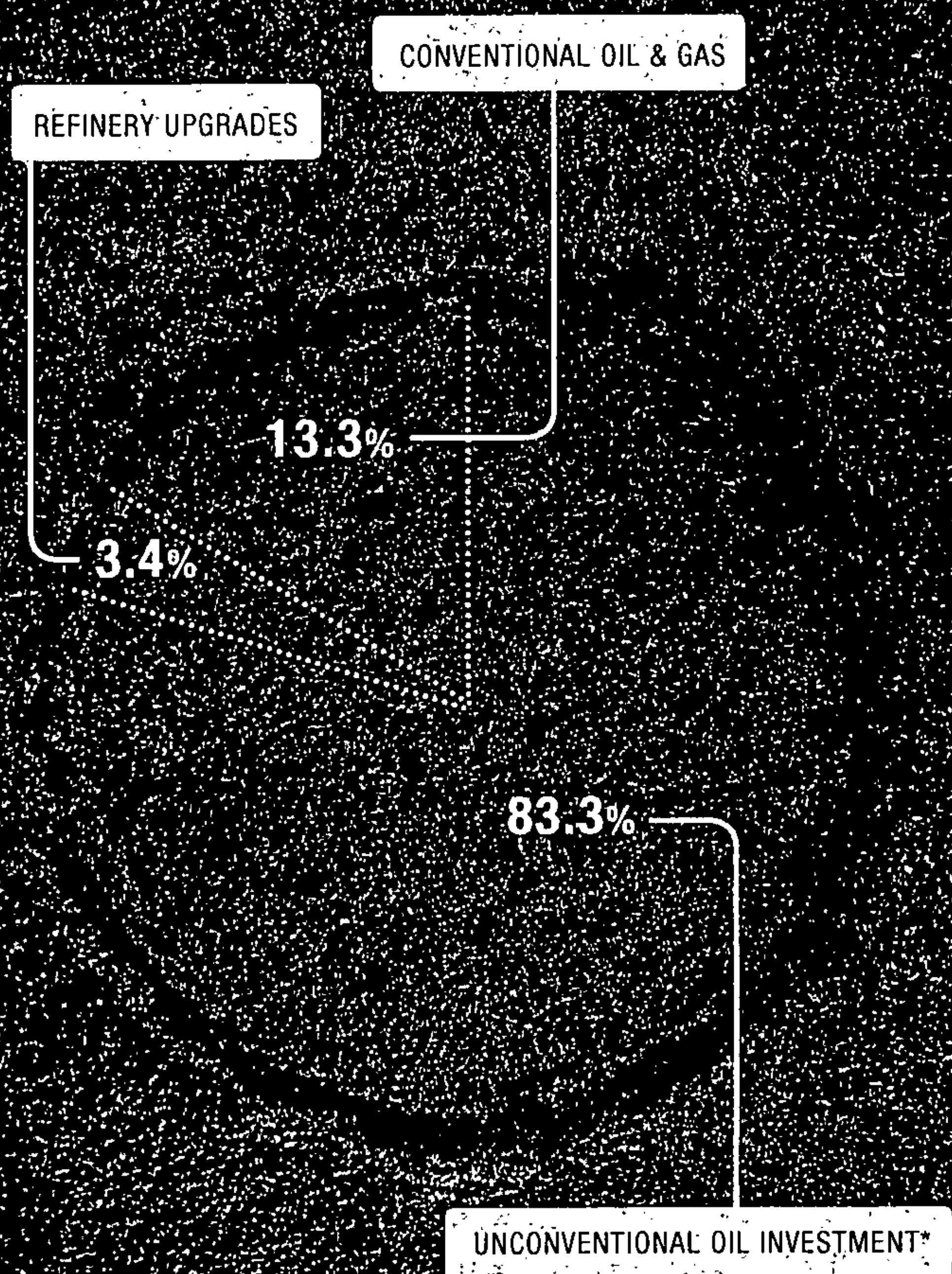
(3) The reserve estimates for 2006 and 2005 were prepared by an independent professional petroleum engineering firm in accordance with National Instrument 51-101 (NI 51-101). Under NI 51-101, proved reserve assignments are based on a 90 percent certainty that total quantities received will equal or exceed proved reserve estimates. Proved plus probable reserves are the most likely case and are based on a 50 percent certainty that they will equal or exceed estimates. Proved plus probable plus possible reserves have a 10 percent probability that they will equal or exceed estimates.

(4) After production of 1 million boe in 2006.

(5) No dividends have been declared by the company since its incorporation.

INVESTING FOR THE LONG TERM:

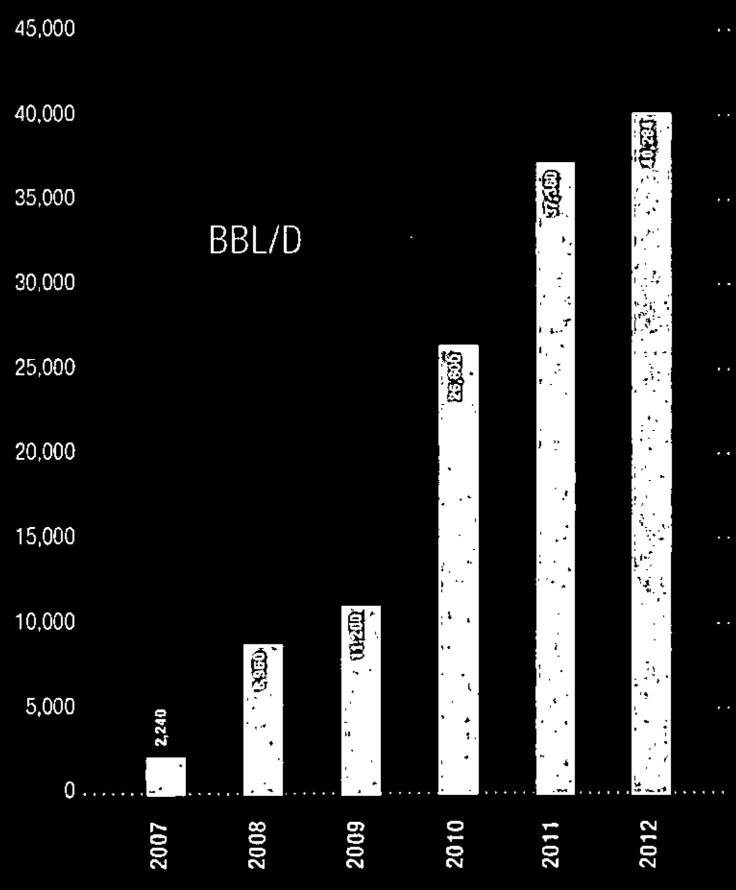
2006 CAPITAL EXPEDITURES (EXCLUDING ACQUISITIONS)



* The term "unconventional" is used interchangeably with oil sands and bitumen throughout this report.

Prospectively, Connacher anticipates a great future at Great Divide.

PROJECTED GREAT DIVIDE PRODUCTION — GLJ REPORT



NOTE:
The graph above is derived from the GLJ Report as at December 31, 2006 and represents their 3P reserves plus High Estimate Total Resource Forecast. See page 37 in the MD&A for a discussion of forward-looking information. Readers are cautioned that these forecasted volumes involve higher risks than GLJ's proved (1P) or proved + probable (2P) reserves.

Connacher is increasing returns and lowering risk through an integrated approach to the oil sands.

2006/2007 RISK MANAGEMENT & FINANCING STRATEGY

Operating risk	– bought Luke Energy
Differential risk	– bought refinery assets in Montana
Balance sheet risk	– completed accretive equity financing with attractively structured term debt
Execution risk	– plan to control costs through modular approach
Environmental risk	– implement effective “green” strategy
Liberated value	– created and financed Petrolifera providing value appreciation and a financial safety valve

CORPORATE STRUCTURE

CONNACHER OIL AND GAS LIMITED (CLL)

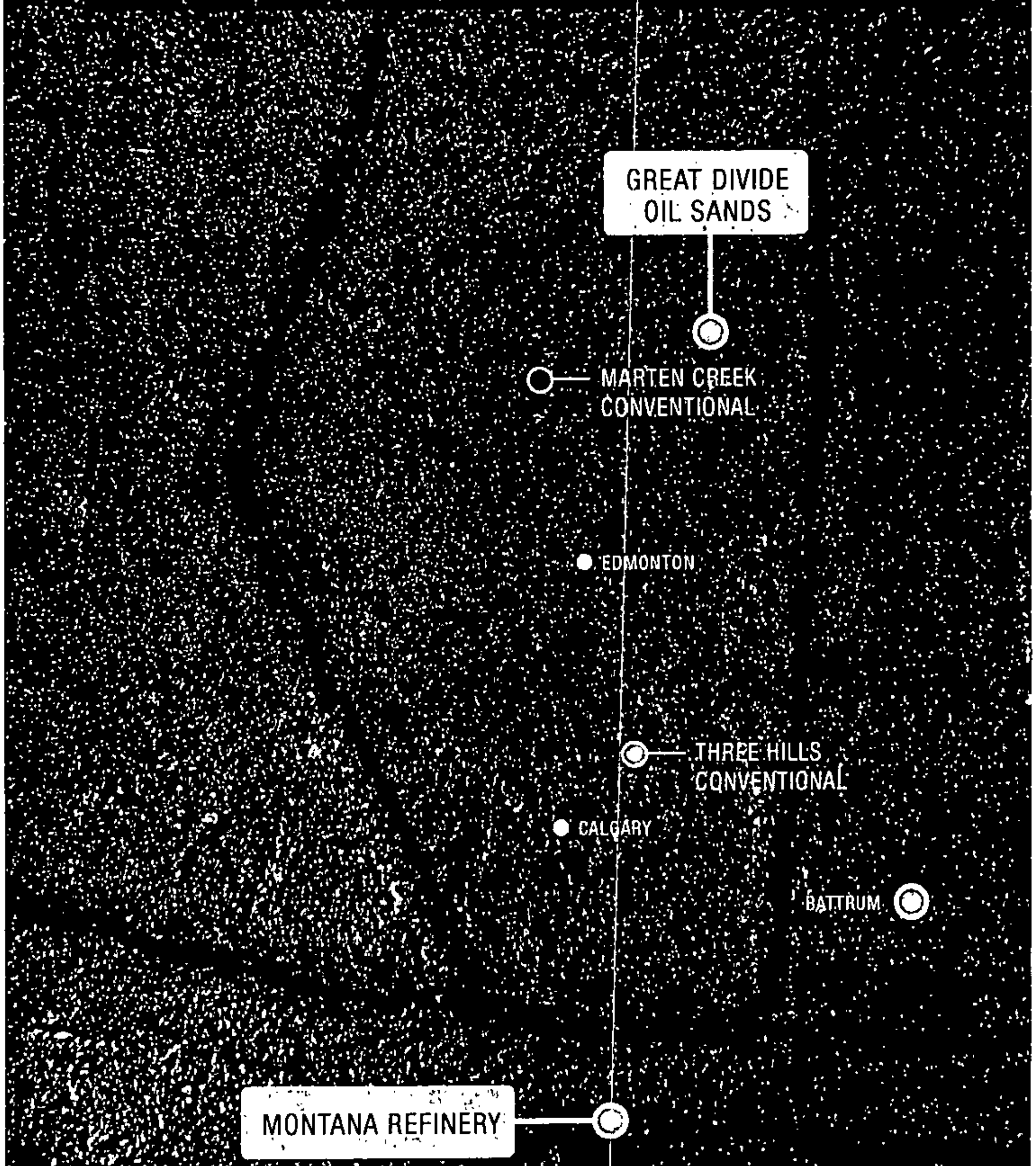
PETROLIFERA EQUITY INTEREST (26% F/D) ARGENTINA, PERU & COLOMBIA

CONVENTIONAL

CONNACHER FINANCE CORPORATION

OIL SANDS (GREAT DIVIDE)

MONTANA REFINING COMPANY, INC. (REFINERY)



Letter to Shareholders

R.A. GUSELLA
President and Chief Executive Officer

CONNACHER'S MAJOR FOCUS DURING 2006 WAS ITS WELL-POSITIONED AND VALUABLE GREAT DIVIDE OIL SANDS PROPERTY. AS STATED ON THE COVER, 2006 WAS ALL ABOUT THE OIL SANDS.

CONNACHER APPLIED TO VARIOUS ALBERTA REGULATORY AUTHORITIES DURING 2005 FOR APPROVAL TO PROCEED WITH A SMALL-SCALE 10,000 BBL/D COMMERCIAL DEVELOPMENT AT POD ONE ON OUR ORIGINAL OIL SANDS LEASE BLOCK. WE WERE GRATIFIED TO RECEIVE SUCH APPROVALS DURING THE SUMMER OF 2006, AS FINALLY CONFIRMED BY AN ORDER IN COUNCIL ON JULY 12, 2006.

This followed timely resolution of outstanding issues with interested stakeholders and the thorough review of our application by the Alberta Energy and Utilities Board ("EUB"), Alberta Environment ("AE") and Alberta Sustainable Resource Development ("ASRD").

Everything we did as a company prior to this approval and subsequent thereto — from buying Luke Energy Ltd. for its natural gas production, reserves and exploration potential — to purchasing a refinery in Great Falls, Montana and all financing related thereto — was directly connected to the integrated approach we adopted in developing our oil sands properties.

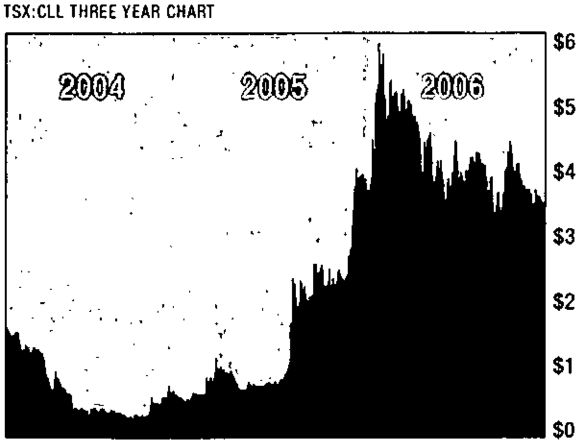
We had a successful year in 2006, accomplishing everything we set out to do. While the stock market reaction was not as supportive as we would have preferred, there were influences over which we had little control which adversely affected our share price performance in the latter part of 2006. Not the least of these was negative sentiment towards the oil sands sector following pronouncements of cost overruns for those pursuing oil sands exploitation through mining megaprojects. Nevertheless, our financial and operating results grew to record levels and we believe Connacher is extremely well-positioned for continuing growth in years ahead.

Fundamental to our integrated approach in developing our oil sands property was the execution of a risk management program to ensure that Connacher could withstand the exposure associated with being a relatively small bitumen producer in a volatile oil price environment. The general risks were identified once we established our high quality resource at Pod One and concluded it could be commercially developed. This led to our application to the EUB, AE and ASRD. Early on in the process, we were able to manage planning risk and prepare for execution risk by hiring and contracting experienced individuals and reputable engineering and design firms. The financial risks we focused on mitigating were upstream operating costs (including natural gas supplies and pricing); downstream differential risk for heavy oil, especially in a rising price environment; and ensuring that we had the capital to sustain our company through the construction phase while retaining our undivided 100 percent ownership of our project. We also needed to streamline our asset base to be focused on Great Divide and its potential. This had led to the creation of Petrolifera Petroleum Limited by Connacher as a means of securitizing and monetizing our foreign assets while participating in the upside.

Nothing, of course, could have proceeded without having the high-quality oil sands assets to develop and it is a credit to our technical staff that we were able to confirm that Pod One at Great Divide had the right stuff – excellent reservoir, sufficient reserves to support a 25 year project at targeted rates of 10,000 bbl/d and other logistical and infrastructure advantages which were identified and described in last year's report and will again be reviewed this year. Our independent reservoir engineering consultant has identified 110 million barrels of recoverable reserves at Pod One as at December 31, 2006. It is anticipated these reserves will support a long-life viable project. To this end we are constructing our plant, drilling related horizontal well pairs and plan to start steam injection during the summer of 2007.

Our exploration and core hole drilling program on the main lease block surrounding Pod One also suggests that, following appropriate regulatory approval and stakeholder consultation, the potential exists to expand our reserve and production base in this region with additional Pods to be developed. We continue to be extremely optimistic about our future at Great Divide.

TSX:CLL THREE YEAR CHART



EVERYTHING WE DID AS A COMPANY — FROM BUYING LUKE FOR ITS NATURAL GAS PRODUCTION, RESERVES AND EXPLORATION POTENTIAL — TO PURCHASING A REFINERY IN GREAT FALLS, MONTANA AND ALL FINANCING RELATED THERETO — WAS DIRECTLY CONNECTED TO OUR INTEGRATED APPROACH IN DEVELOPING THE COMPANY'S OIL SANDS PROPERTIES.

PHOTO: EVAPORATOR INSTALLATION AT POD ONE - GREAT DIVIDE OIL SANDS PROJECT

While we waited for the regulatory process to be completed for Pod One, following our application in August 2005, Connacher focused on the aforementioned risks and how best to mitigate them. In late 2005 we had initiated a multi-pronged strategy aiming at ensuring we would have the necessary capital to maintain sole ownership of Great Divide while addressing the best solutions to risk management. This entailed raising new equity at attractive prices in a robust capital market; identifying an upstream acquisition candidate primarily for a natural gas hedge in view of the significance of the costs for natural gas necessary to make steam in a steam assisted gravity drainage ("SAGD") oil sands project; identifying a downstream hedge to deal with the historical reality of heavy oil differentials, which appeared to be rising in a high price environment for crude oil and diluents; and nurturing a substantial investment in Petrolifera, so Connacher could concentrate on the challenges of becoming an oil sands producer. While cognizant of the need for capital, we wanted to limit the amount of new equity and resist the temptation of using short-term debt for a long-term project. In so doing, we avoided the risk that lenders could change course midstream and leave shareholders vulnerable to a credit squeeze.

I am pleased to report that we found solutions to the challenges identified in late 2005 with a myriad of completed transactions during 2006.

I AM PLEASED TO REPORT THAT WE FOUND SOLUTIONS TO THE CHALLENGES IDENTIFIED IN LATE 2005 WITH A MYRIAD OF COMPLETED TRANSACTIONS DURING 2006.

In mid-March 2006 we completed the acquisition of Luke, a conventional oil and gas production company, for cash and Connacher shares. This transaction provided the company with significant natural gas production and reserves, cash flow and credit capacity. It also gave our company extensive undeveloped acreage holdings in the Marten Creek, Simonette and Three Hills areas of Alberta and we have since expanded our resource and reserve position in these regions. The acquired production was sufficient to physically hedge our anticipated natural gas use and related costs at Pod One. While Connacher may never directly burn a single molecule of Marten Creek natural gas at Pod One, our company is immunized from natural gas price spikes which could otherwise impair our project economics in the oil sands. Luke has since been amalgamated into Connacher and has ceased to exist as a corporate entity. Certain selected Luke employees also joined the company at the conclusion of the transaction.

The acquisition of Luke early in 2006 helped to balance Connacher's conventional oil production and positioned Connacher to successfully divest certain high-cost, non-core conventional oil and gas properties for $10 million cash on favorable terms near the end of the year. The proceeds were used to supplement working capital and the transaction further streamlined Connacher's operations as the pace of activity on our key core properties accelerated.

Following an extensive process, in late March 2006 Connacher acquired an 8,300 bbl/d refinery and related assets, including product and other inventory. The refinery is situated in Great Falls, Montana. Although small by international standards, this highly sophisticated refinery is actually the plant in the United States situated in closest proximity to the Alberta oil sands. Historically reliant on heavy Canadian crude for its feedstock, the refinery is connected to pipelines originating in Canada and could, with modifications, process and refine Great Divide bitumen. If necessary, it potentially could also provide diluent to Great Divide, in order to meet pipeline specifications for transportation of production from the oil sands. As with Luke, it also provided a new source of cash flow, added credit capacity and is a solid profitable business. It effectively serves as a proxy for an on-site upgrader at Pod One.

The refinery purchase converted Connacher into a mini-integrated oil company and provided the essential elements of our hedging strategy to deal with downstream differential risk. Connacher's refinery can deliver favorable operating margins, even with widened differentials in an increasingly volatile crude oil price environment, as was experienced in 2006. Subsequent to closing the transaction, Connacher expanded the throughput at the Montana refinery to approximately 9,500 bbl/d, at low cost and with attractive financial returns. This is a credit to the management and staff in both Calgary and Great Falls, Montana. Many of our Montana-based management and staff elected to remain with Connacher following the change of ownership. As will be noted later, ownership of the refinery also played a significant role in our ability to secure long-term debt financing for Pod One, reinforcing the soundness of this strategic initiative.

A third major element of our risk management program during 2006 was to ensure we had the financing to proceed with developing Pod One on our own. Following an examination of many joint venture alternatives, including with larger international oil companies, our conclusion was to make every effort to retain our sole ownership and control. As a small company, to the extent we could, we knew we had to compress our timetable from first identification of an economically-exploitable asset (Pod One) to first production and cash flow. We concluded this process was best served by retaining 100 percent ownership, provided it did not result in undue equity dilution. Fortunately, capital markets were strong during the early portion of 2006 and we were able to raise new funds. As a consequence, our new and existing shareholders became and remained our equity partners and indirect owners of Great Divide.

Later in 2006 we successfully completed a limited recourse US$195 million term loan financing in US capital markets. This project financing was structured to give Connacher the remaining capital it needed to fully complete the development of Pod One and to provide US$15 million of working capital for our refining operation in Montana. A portion of the term debt proceeds were also used to discharge a bridge loan incurred to acquire the refining assets. The security for the term loan was comprised of Connacher's oil sands and refining assets; it is non-recourse to Connacher's conventional oil and gas assets and its investment in Petrolifera. The loan has a term of seven years with minimal annual repayment requirements. Furthermore, an "accordion feature" of the term loan facility provides Connacher access to a further US$150 million on identical terms and conditions to help finance the development of its next Pod. Interest rates were set based on ratings assigned by Moody's and S&P to this structured debt.

Having secured an expanded base of conventional properties, Connacher devoted capital to facilitate conventional reserve replacement and production growth during the year by participating in 16 net wells on its properties in 2006. An expanded 2007 program is already well underway.

It would be remiss not to mention the great success enjoyed by Petrolifera Petroleum Limited ("Petrolifera") during late 2005 and throughout 2006. Connacher created this company in late 2004 to enable its operating management to focus on the oil sands, as Connacher did not have the capital, personnel and wherewithal to conduct foreign ventures while also pursuing oil sands opportunities in Canada. When Petrolifera was created, there was limited interest in Argentinean assets or prospects and raising capital was challenging. With the addition of new technical expertise and the Peruvian explorations licenses, additional capital was secured to facilitate a 3D seismic program over a portion of the Puesto Morales/Rinconada concession in Argentina, leading to the definition of numerous drillable prospects. Petrolifera went public in the fall of 2005 at $1.75 per unit (one share and one-half warrant, with each full warrant exercisable into one Petrolifera common share at $3.00 until

May 8, 2007), with Connacher participating as the major buyer of the financing to assure a successful initial public offering. The rest is history - 15 successive well completions with no dry holes; dramatic production growth which reached 13,700 boe/d of overall production in December 2006 and a share price which was among the best performers on the Toronto Stock Exchange during 2006. Connacher's net cash investment of approximately $2 million for its 11.4 million common shares and 1.7 million warrants reached a peak market value exceeding $300 million during the year. Connacher remains committed to supporting Petrolifera as that company proceeds with its growth strategy, including exploratory drilling of world-class prospects in Peru. At the same time, this investment provides Connacher with an important financial safety valve in the event of changed financial or industry circumstances.

As fellow shareholders, you can see our year was really "all about the oil sands." We are now executing our biggest project to date – converting our Pod One assets into production and cash flow. The early drilling program on Pod One has gone exceedingly well. We have been able to extend the horizontal reach of our SAGD well pairs by about 25 percent over initial plans. This should help per well productivity and reserve recovery. Due to the absence of bottom water, we have also been able to drill our horizontal producers in a manner which enhances the prospect of higher overall recovery by minimizing the standoff from basement.

Our modular construction approach has also served us well. We were able to institute more cost controls than many other oil sands operators (especially those with mining mega projects) by pre-ordering key component parts and constructing them off site. The proximity of established infrastructure (Highway #63, utilities and pipelines) also assists in this regard. We will have reduced the time frame for conversion of assets to cash flow by about half for SAGD operations of this scale, which is quite an accomplishment for a company our size. Again, full credit is due to our management and staff for their focus and dedication.

OUR FIRST ORDER OF BUSINESS IS TO COMPLETE POD ONE IN A TIMELY AND COST-EFFICIENT MANNER. OUR NEXT ORDER OF BUSINESS IS TO CAPTURE THE OPPORTUNITIES FOR FURTHER DEVELOPMENT ON OUR GREAT DIVIDE PROPERTIES.

Every one of our team plays an important role in these accomplishments, especially against the backdrop of the rapid growth, diversification and integration undertaken by Connacher in 2006.

We have a strong, compact, committed and focused Board of Directors. During the year we were fortunate in attracting new talent to our company. New hires at the officer level included Steve Marston, Cam Todd, Grant Ukrainetz, Darren Jackson and Steve De Maio, with responsibility for Exploration, Refining and Marketing, Treasury, Operations, and Project Development, respectively. We also rebuilt and strengthened our conventional exploration group in Calgary, hired and retained most of the personnel and management associated with the refinery in Montana, attracted select personnel from Luke and also attracted and solidified relationships with experienced contract employees who are assisting us at Pod One. People are critical to the success of any company and we appreciate the efforts of all of our officers, managers, employees and consultants who are advancing the Connacher cause. We also appreciate our healthy relationships with our suppliers who are providing products and services to our company.

OUTLOOK

As we move ahead, our priorities are well defined. Our first order of business is to complete Pod One in a timely and cost-efficient manner. In this regard we are on schedule at this stage. We expect to commission our plant some time this summer, and start injecting steam with a view to the earliest possible date for first production. Startup of this long-life project will be entirely consistent with our goal of developing sustainable production which can be maintained with high plant utilization through the various oil price cycles.

Our next order of business is to capture the opportunities for further development on our Great Divide properties. Repeatability is the second cornerstone of our strategy and we have already initiated the process to apply for development of Pod Two on our main lease block. Simultaneously, we are in the midst of a planned 80 well core hole drilling program this year, likely to be repeated or expanded next year, following interpretation of the extensive 3D seismic coverage we are presently shooting. We anticipate this activity has the potential to result in further reserve and resource recognition and further growth.

Recently, we have been presented with a number of new opportunities to expand our base in the oil sands. In addition, we have quietly but consistently added to our land base in the region at low cost. As we establish and confirm our

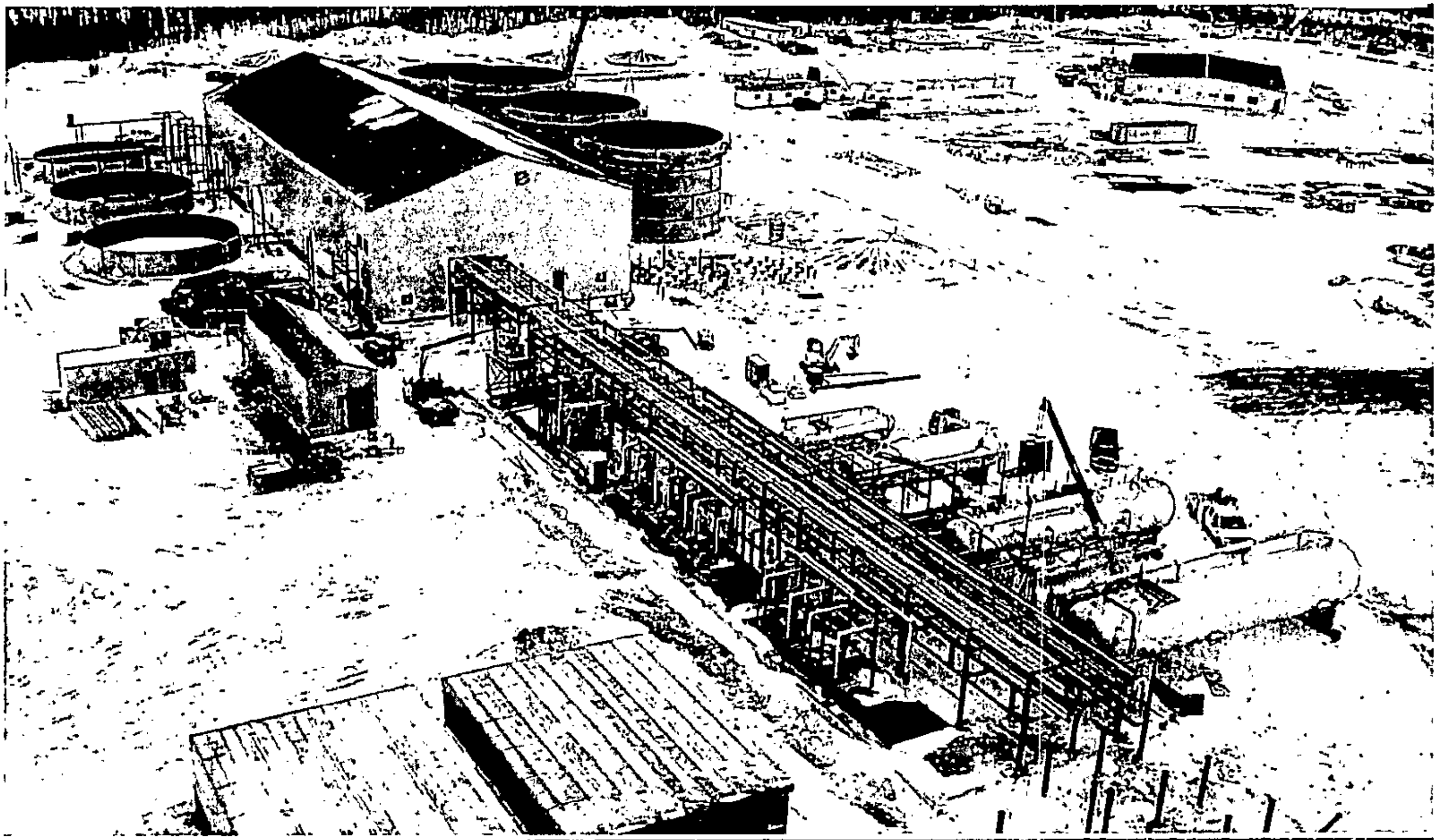


PHOTO: TANKS AND TREATERS AT GREAT DIVIDE - POD ONE.

reputation as a company utilizing SAGD technology in the oil sands with the ability to get things done in a timely and cost efficient manner, we expect to see more opportunities outside our current asset base and we will examine and pursue those which meet our criteria. Key to this will be quality reservoir, even if it means a scale of operations which may not be a headline grabber but instead can result in good, solid profitable business.

We will endeavor to continue running our conventional business in a focused and profitable manner, as a desirable adjunct to our consumption of natural gas in the production of value added bitumen. In so doing, we will remain vigilant and mindful of the recent emphasis on environmental issues and concerns, as we have been in the past. We support the introduction of new approaches which focus on such matters as water conservation, efficient recycling and a minimal environmental footprint while minimizing what are considered harmful emissions. Additionally, Connacher continues to stress work safety in its business, good corporate governance and constructive relationships with regulators and with stakeholders, including First Nations people in the region.

Connacher anticipates it will continue to evaluate new growth opportunities in the refining and wholesale marketing sector. As we expand our upstream productive capacity, we will endeavor to retain an integrated balance in our operations. This can be accomplished through new acquisitions or through expansion of or upgrading of our existing refinery in Great Falls, Montana. We also are finalizing our transportation infrastructure to ensure our Great Divide production gets to market in the most cost-effective manner at the best possible price.

Our outlook is strong and buoyant. Our commitment is considerable. Our staff is dedicated to success with appropriate financial and equity incentives in place to minimize turnover and participate in the achievements which lie ahead. Our shareholders have been loyal and supportive. We think 2007 will be another banner year for Connacher Oil and Gas Limited and we look forward to constructive and positive results and having capital markets translate those results into attractive returns for you, our shareholders.

Respectfully submitted on behalf of the Board of Directors,

signed,

"R.A. Gusella"

Richard A. Gusella
President and Chief Executive Officer

82-34954

Review of Operations

PETER D. SAMETZ
Executive Vice President and
Chief Operating Officer

Connacher
OIL AND GAS LIMITED

GreatDivide
OIL SANDS

MRC
MONTANA REFINING COMPANY

CONNACHER'S PRINCIPAL ASSET CONTINUES TO BE ITS 100 PERCENT INTEREST IN APPROXIMATELY 90,000 NET ACRES OF OIL SANDS LEASES, RESERVES AND RESOURCES AT ITS GREAT DIVIDE PROJECT IN NORTHEASTERN ALBERTA. FOLLOWING RECEIPT OF REGULATORY APPROVAL DURING 2006, YOUR COMPANY IS IN THE MIDST OF DEVELOPING POD ONE. THIS PARTICULAR OIL SANDS ACCUMULATION COVERS AN AREA OF APPROXIMATELY 2,000 ACRES AND CONTAINS SUFFICIENT RECOVERABLE RESERVES TO SUPPORT A 10,000 BBL/D OPERATING PLANT FOR APPROXIMATELY 25 YEARS. UTILIZING SAGD TECHNOLOGY, THIS WOULD ENABLE THE COMMERCIAL RECOVERY OF APPROXIMATELY 90 MILLION BARRELS OF BITUMEN FROM THIS SINGLE ACCUMULATION.

Currently, a plant to generate steam and to process the oil and water produced in the process is being constructed at a cost of approximately $125 million. It is anticipated the plant will be commissioned and placed into operation during the summer of 2007.

During 2006 and into 2007, Connacher also continued its evaluation of additional portions of its extensive landholdings in the Divide region. This was comprised of both 3D seismic programs and core hole drilling programs. The company's land base was also expanded with selective purchases at Crown sales during the year.

Connacher's operations also include conventional upstream crude oil and natural gas reserves, production, undeveloped acreage and facilities, primarily in Alberta and Saskatchewan. This asset and revenue-generating base was recently expanded with the March 2006 purchase of Luke Energy Ltd. for cash and Connacher shares. Luke's principal assets consisted of natural gas properties, located in the Marten Creek area of north central Alberta, almost due west of our oil sands properties. The purchase was pursued because of our oil sands involvement. Considerable volumes of natural gas will be utilized, at least in the early stages of operations, as fuel for generating the steam required for a SAGD project. While Connacher may never directly burn Marten Creek gas at Pod One, the ownership of offsetting production provides the company with a physical hedge against natural gas price fluctuations.

Successful drilling at Three Hills, Alberta and at Battrum, Saskatchewan, our legacy conventional producing region, when combined with the acquired Luke production, resulted in a 214 percent increase in production during 2006 to 2,725 boe/d, compared to only 867 boe/d in 2005. Our proved and probable conventional reserve growth resulted in a conventional reserve replacement ratio of 732 percent. This is calculated by adding annual production to the change in 2005 and 2006 year-end 2P reserves, dividing by 2006 production and expressing the result as a percentage. Our increased production markedly contributed to the company's cash flow growth during the year.

The third leg of our operations is our 100 percent ownership of an operating 9,500 bbl/d refinery in Great Falls, Montana. This was also purchased on favorable terms during 2006 and was pursued and acquired by Connacher to mitigate the crude oil price differential risk associated with heavy oil or bitumen production. Our initial oil sands project was considered to be too small to support a commercial upgrader on site. The refinery was purchased to avoid the economic pressures of high oil prices but wide price differentials, which could impair the economic returns of bitumen production. Refining operations accordingly were expected to provide a physical hedge against these possible adverse circumstances. Even prior to the

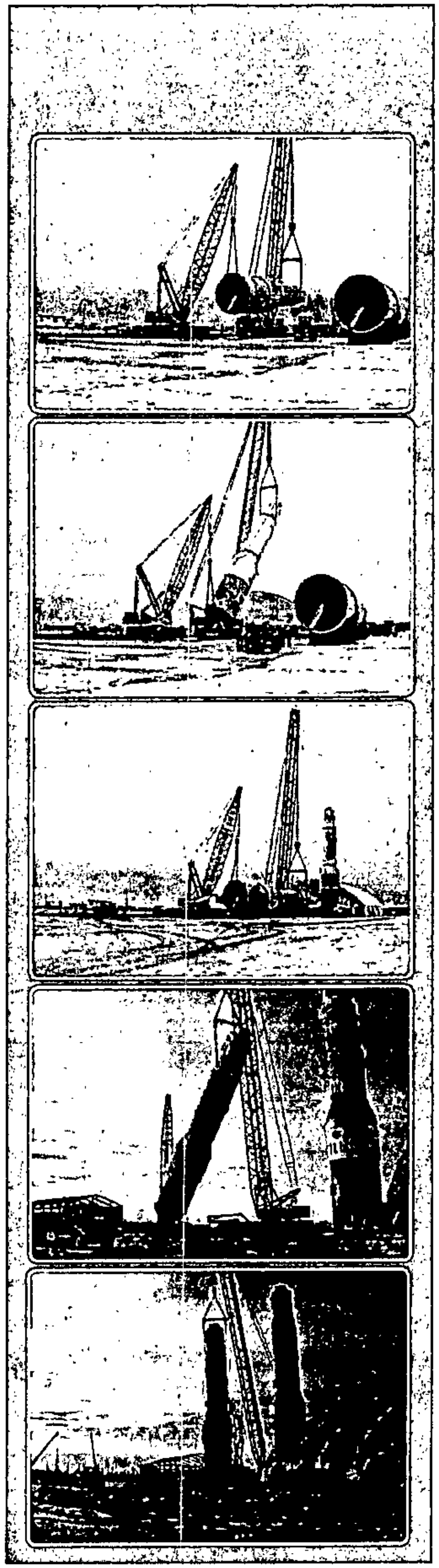
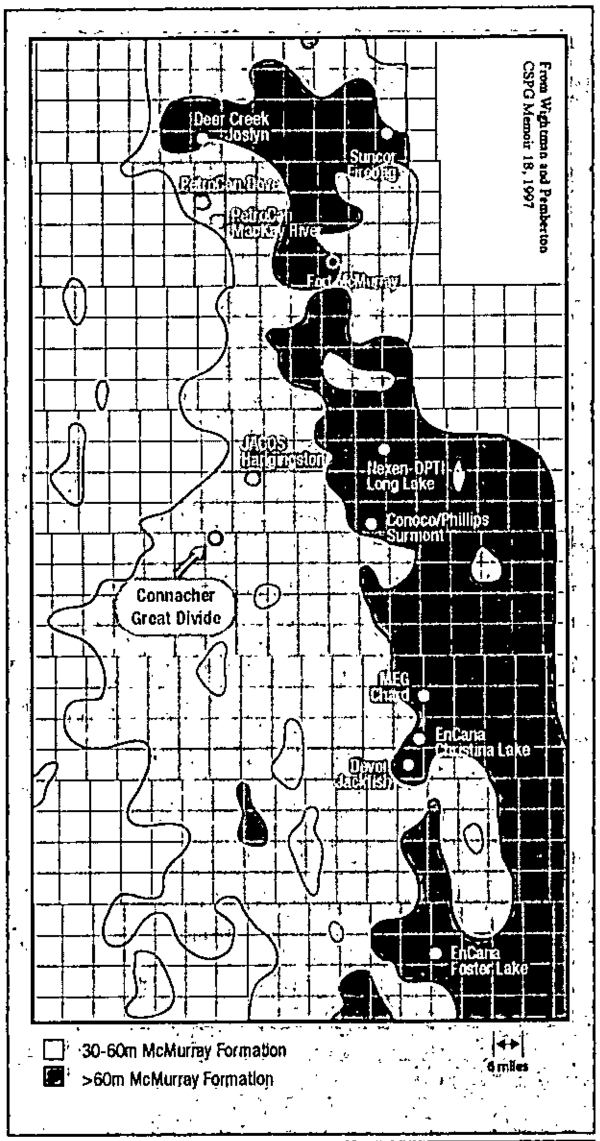


PHOTO SERIES - RAISING THE EVAPORATORS INTO PLACE AT GREAT DIVIDE POD ONE - JANUARY 24, 2007 commencement of bitumen production at Great Divide, the refinery was a significant cash flow and profit generator during 2006. Ownership of the refinery also was a contributing factor to our successful placement of term debt to finance development Pod One at Great Divide.

During 2006, Connacher's total capital budget, including acquisitions, was the substantial sum of $452 million. Of this amount, $271 million of cash and stock was spent on the purchase of Luke and the refinery, including approximately $20 million of product inventory. A total of $145 million was invested at Great Divide, $23 million in conventional land acquisition, drilling and facilities and $6 million was invested in upgrading the refinery, with capacity expanded to current levels of approximately 9,500 bbl/d of throughput compared to approximately 8,300 bbl/d at the time of purchase. The balance of $7 million was invested in minor property acquisitions during the year. This compares to an outlay of only $17 million during 2005 and reflects the dramatic growth of the company during the year.



MAP: MCMURRAY FORMATION DEPOSITION - ALBERTA OIL SANDS

As a consequence of our expansion, we successfully expanded our operating staff. A strong exploration department was developed, with the hiring of a new Vice President, Exploration as well as two new geologists and a new geophysicist. Our Operations Group was expanded with the addition of a new Vice President, Operations and additional engineering capability to enable more effective management of our producing assets and expanded drilling, completion and facility programs. These individuals will coordinate our exploration, development and production programs.

Significantly, we were also able to attract a strong group of experts with recent oil sands plant construction experience to assist us with site and plant construction at Great Divide Pod One. Simultaneously, we have been successfully recruiting the operating personnel who will run and manage the oil sands plant once it is up and running. We elected to hire these individuals, most of whom came with conventional heavy oil experience, early in the game. This was to ensure they were familiar with all aspects of our plant and facilities during the critical construction phase. This should help to minimize any disruptions or dislocation on startup and thereafter. This pre-planning sensibility, which also characterized our approach to the construction of our plant at Great Divide, is expected to yield considerable dividends going forward.

As the year and developments progressed, we also added a Vice President, Project Development. His initial responsibility will be to focus on related infrastructure requirements and subsequent pod development as our oil sands expansion progresses throughout 2007 and beyond.

During 2006, our conventional and unconventional reserve base expanded considerably. The results of independent assessments will be discussed in greater detail in this report. However, in summary it should be noted our conventional proved and probable reserves increased over 2.5 times to reach 8.8 million boe, of which approximately 63 percent is natural gas. Our proved and probable bitumen reserves increased 21 percent to reach 84.1 million barrels. For the first time, 43.8 million barrels of our reserve base at Great Divide were upgraded to proved status. We are one of the few independent public oil and gas exploration and production companies with proved bitumen reserves in its inventory. This is expected to grow further in 2007 as our plant becomes operative and probable reserves can sequentially be reclassified and upgraded to proved status. Our 3P reserve and high estimate total reserve and resource base is estimated at close to 500 million barrels, underlining Connacher's growth potential, primarily associated with our oil sands properties.

We intend to continue exploring and delineating our resources to foster accelerated growth during the balance of the decade.

GREAT DIVIDE

Connacher holds a 100 percent working interest in approximately 90,000 acres of oil sands leases in the Divide region of northeastern Alberta. Connacher is the operator of these properties. We renamed our area Great Divide to underscore its potential impact on Connacher's prospective reserves, production and underlying valuation.

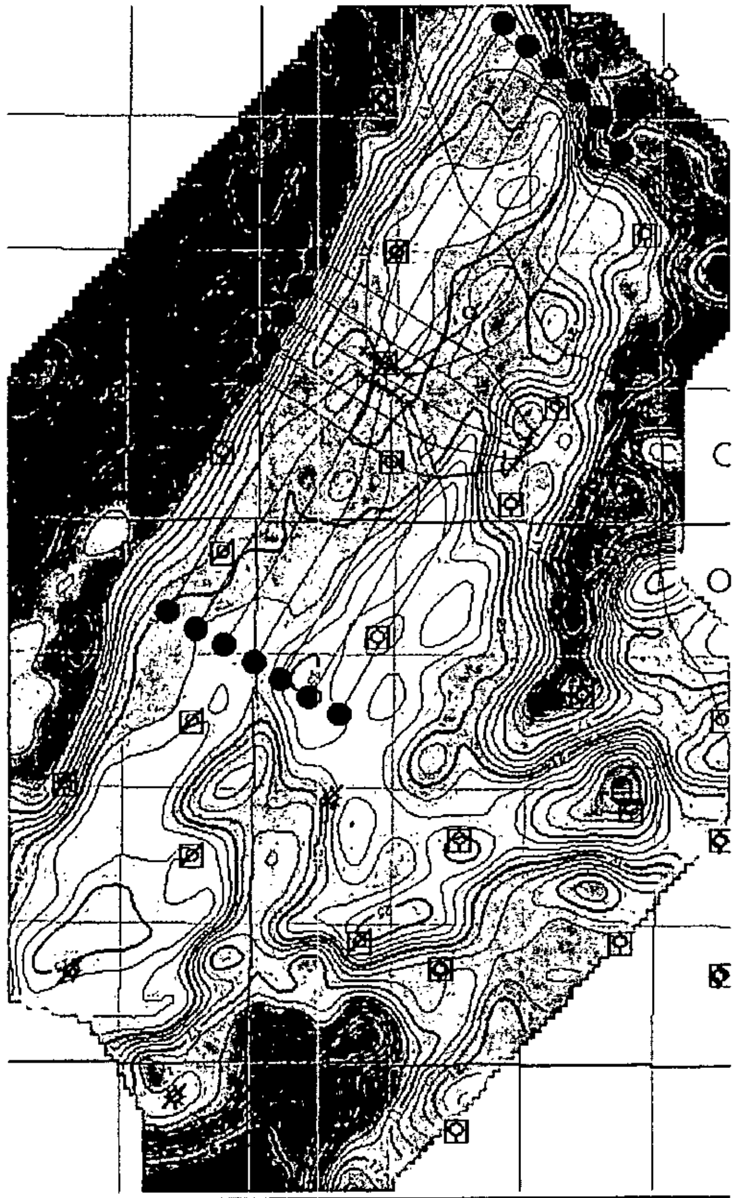
Highway 63, the main highway that runs from Edmonton, the capital of Alberta, to Fort McMurray, the unofficial capital of the oil sands, bisects the original lease blocks. All of our leases are within 12 miles of this highway.

Pod One

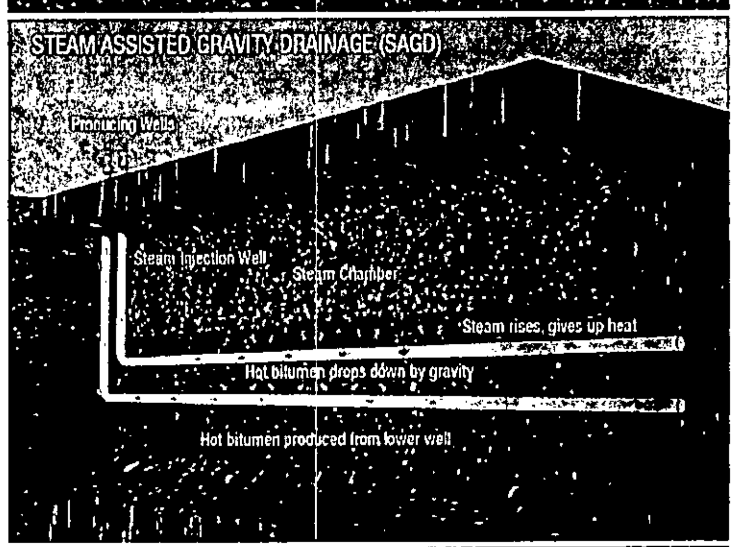
In 2005 Connacher applied to the regulatory authorities for permission to proceed with the small-scale commercial development of its Pod One McMurray "C" Channel, situated on the company's original lease block acquired in early 2004. The channel had been identified and delineated using a combination of 3D seismic, core hole drilling and geological interpretation. It was assigned the identifier "Pod One" by the company, as other accumulations were also recognized on Connacher's principal lease block at the time of application.

Connacher was satisfied Pod One contained sufficient recoverable reserves to support a 10,000 barrel per day SAGD project which could produce at these levels for approximately 25 years. This reserve volume assessment was subsequently confirmed by independent consultants.

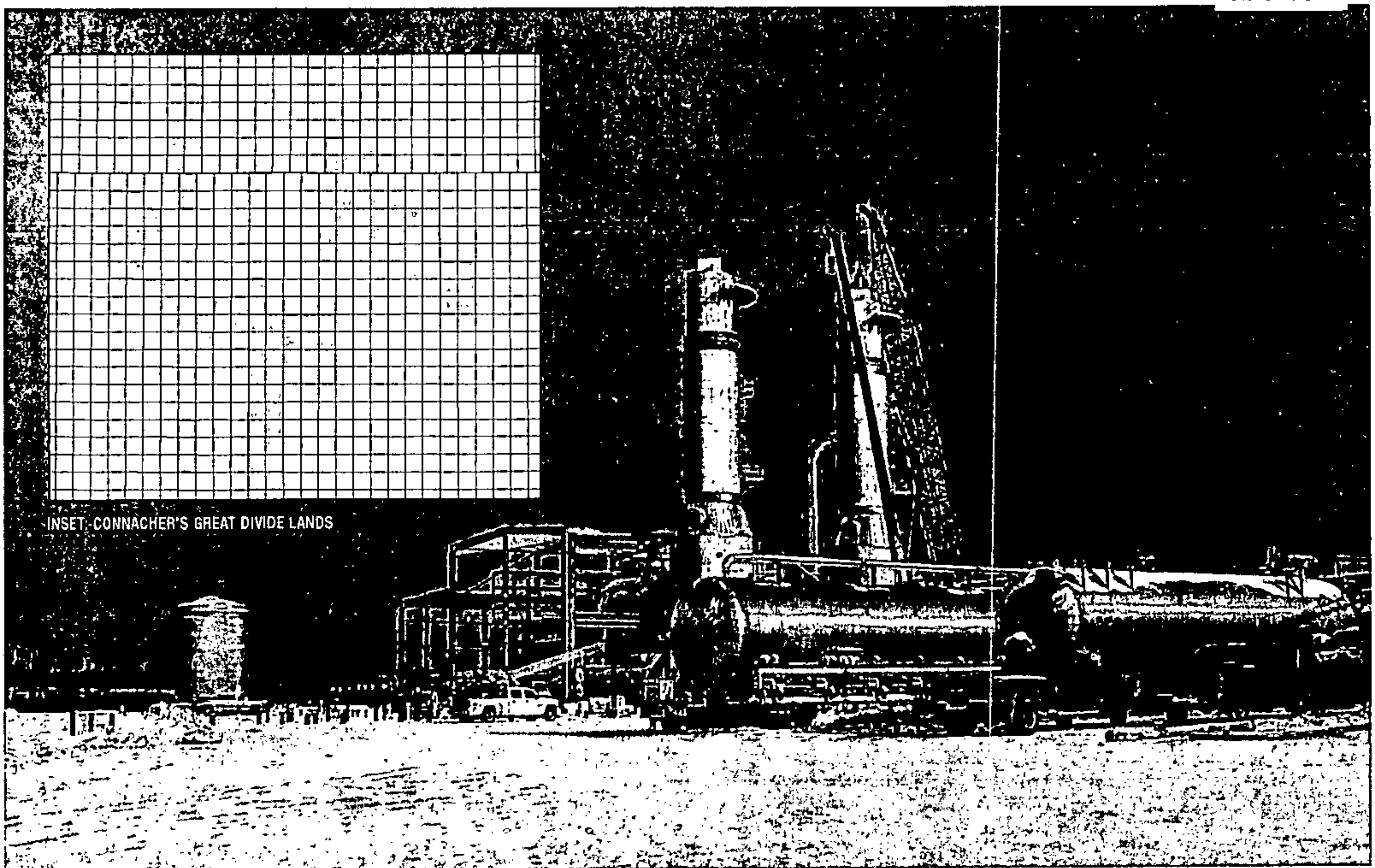
Following receipt of regulatory approval from the Energy Utility Board ("EUB") and other authorities, including Alberta



MAP: INTERPRETATION OF 3D SEISMIC - POD ONE



GRAPHIC: SAGD PROCESS - SCHEMATIC



INSET: CONNACHER'S GREAT DIVIDE LANDS

PHOTO: FREE WATER KNOCKOUT UNITS

Environment ("AE') and Alberta Sustainable Resource Development ("ASRD"), an Order in Council was issued by the Government of Alberta in July 2006 authorizing Connacher to proceed with the development project. This had been preceded by required public consultation with interested stakeholders, including First Nations and owners of petroleum and natural gas rights in the region. All outstanding issues which were advanced were resolved prior to the EUB approval being granted. Minor delays of several months were encountered prior to receiving requisite surface access, following which Connacher was ready to proceed. This entailed the preparation of the site, which was designed with a relatively small footprint of approximately 42 acres. It also entailed construction of a water and oil processing and treatment plant with related steam generating capacity. The project also included the drilling of the initial 15 SAGD well pairs to enable steam injection and then production from the high quality bitumen-bearing McMurray C channel which constitutes the reservoir.

The estimated total cost of the Great Divide Pod One project is in the order of $256 million, including work done to delineate and define the Pod, engineering and design work, site preparation and plant construction, the initial phase of drilling the first 15 SAGD well pairs, capitalized interest related to indebtedness incurred to fund construction, startup operating costs and contingencies. Clearly this was to become the major undertaking in the company's history.

Considerable pre-planning was undertaken to streamline the procedure and control costs, especially important in the heated environment associated with activity in the Fort McMurray oil sands region. An early decision was made to modularize a significant portion of the plant construction in order to achieve the dual and sometimes competing objectives of being "on time" and "on budget." Through modularization and by introducing an oilfield approach, cost control could be more readily achieved. Many of the critical component parts of the SAGD plant which required sophisticated machining and specialized fabrication were built on skids in shops outside of the proposed plant site.

At this writing, Connacher was virtually complete in this process. As and when required for completion of various parts of our plant and facility, critical components can be trucked to the site for installation. We are also benefiting from our logistical advantage of being located on Highway 63, one of the busiest highways in the province at this time.

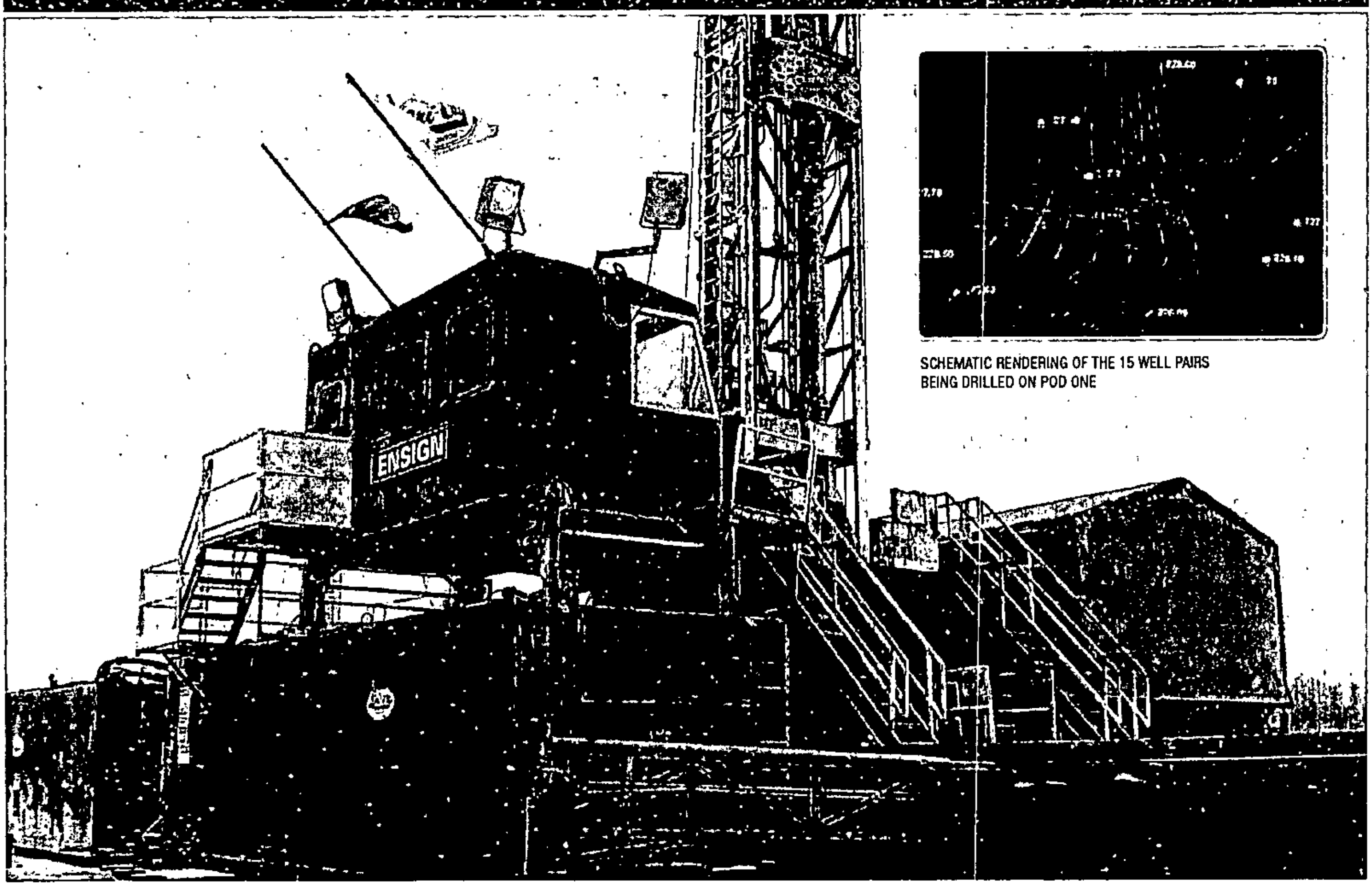
During the construction process we have continued to inform our shareholders about the progress with regular operational updates and the posting of pictures on our website, www.connacheroil.com, demonstrating almost daily progress.

The progress made is a credit to our staff, contractors and suppliers who have shown considerable dedication to the task at hand. Throughout this report are pictures showing the critical components of the Great Divide Pod One Plant. It is hoped we can commission the plant in mid-2007 with a view to first steam going into the ground at that time. It will then take approximately three months to heat up the reservoir and the injector and producer well bores before meaningful production can start. However, the quality of reservoir encountered at Pod One suggests that the production ramping can be optimized. Of benefit is that the reservoir is approximately 475 meters subsurface, which will assist in the efficiency of the steam injection process.

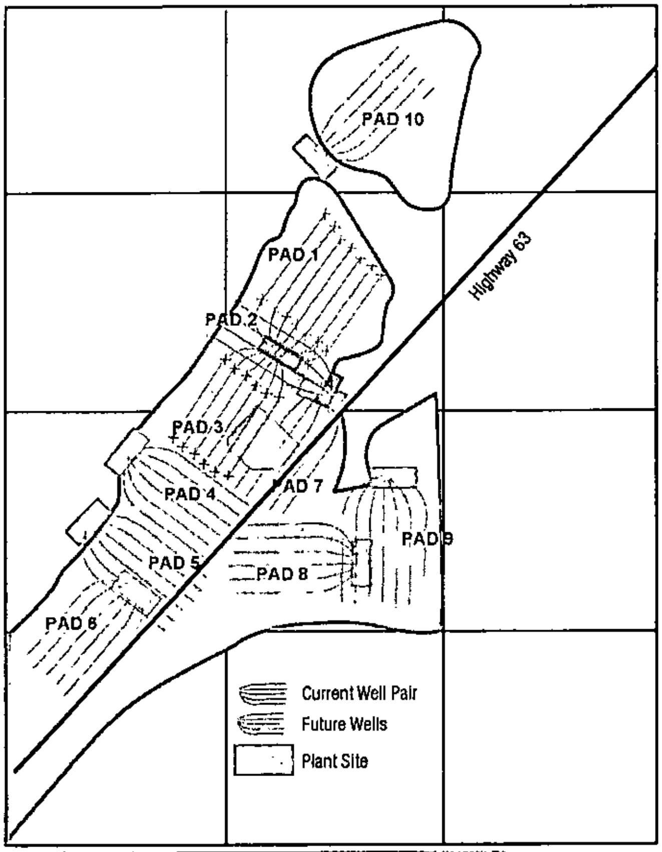
Connacher will initially drill 15 SAGD well pairs on Drilling Pads 101 and 102 in the northern portion of the accumulation. These pairs consist of 15 producers and 15 injectors, which will be drilled approximately five meters vertically apart in the horizontal section. This process is well advanced and we have also been able to extend the horizontal reach of the early production and injector wells, as we continued to encounter excellent reservoir while drilling. At the same time we did not want to or need to extend the reach of the wells beyond acceptable limits, as determined by our assessment of the efficiency of steam recovery.

From the perspective of eventually determining ultimate recovery factors, it is interesting to note that the production well bores are being favorably positioned within one meter of basement, thereby avoiding a significant standoff which has characterized some other SAGD projects. This has been accomplished because the Paleozoic basement in the area, on which our productive sands are deposited, is relatively

PHOTO: DRILLING RIG ON PAD 102 - POD ONE



SCHEMATIC RENDERING OF THE 15 WELL PAIRS BEING DRILLED ON POD ONE



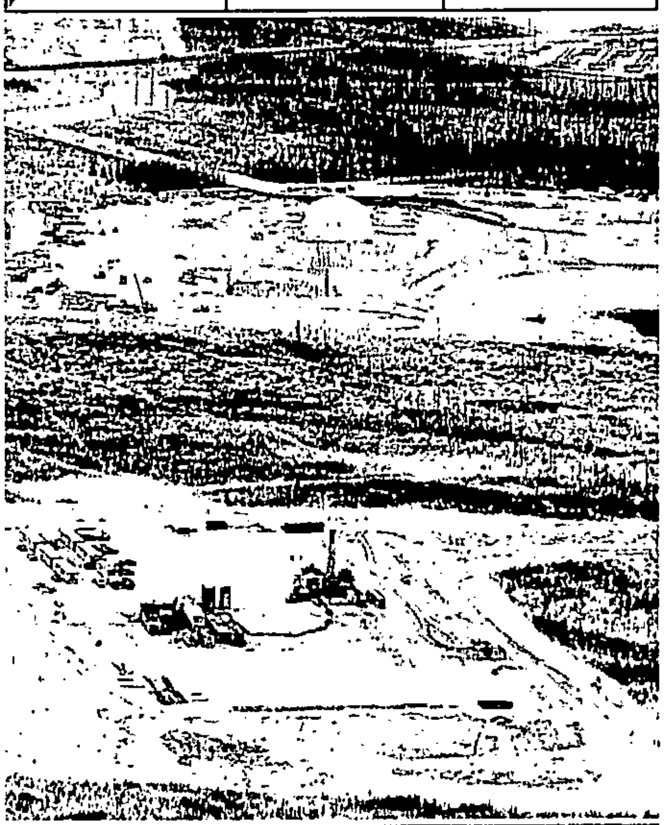


PHOTO: WORK IN PROGRESS AT POD ONE PLANT SITE

flat and not undulating in nature. We also do not have any evidence of bottom water in the reservoir; this also facilitates the minimal standoff. Finally, because our deposit is comprised of what appears to be a single McMurray C channel, we do not have the geological complexity characteristic of a series of interbedded channel deposits.

The drilled well pairs will be tied into our plant during the summer of 2007, when final commissioning is anticipated to occur. Steam will then be injected into both the horizontal injector and producer wells to warm up the reservoir and prepare for early start up of production from the lower well bore. A combination of hot water and bitumen will be produced. Based on independent assessments and internal simulation work, relatively low steam/oil ratios ranging between two and three are anticipated. This augers well for favorable economics, as steam will be created by burning natural gas as the fuel of choice in the initial stages. The better the reservoir and lower the steam/oil ratio, the less the natural gas costs will be. This is important as gas costs are the biggest component of forecasted operating expenses. Later, if technology permits, other alternatives may be introduced, such as direct burning of bitumen. This will depend upon advances in dealing with related emissions. Other options to liberate the bitumen from the reservoir are continuously being examined, driven by the desire to control and lower operating costs.

The cost of drilling, completing and equipping the initial 15 well pairs or 30 wells initial is forecast at approximately 15 percent of the total anticipated cost for the project. A significant percentage of the costs associated with the Pod One plant are related to water handling and the need to purify the water source for steam generation. Our water source is non-potable water extracted from a subsurface zone above the McMurray. More than 95 percent of water used will be recycled. Also, surface disturbance is minimized by a small footprint so the plant is ecologically attuned to an increasing emphasis on environmental and related considerations. Simultaneously, Connacher has placed a significant emphasis on safety in the workplace, in keeping with adopted corporate policy and prevailing standards in the industry.

Over time, as the reserves within a radius of influence of each well pair are depleted, Connacher will phase in additional well pairs from newly-built drilling pads. This will occur in a timely scheduled manner to ensure optimum plant utilization on a 24/7, 365 day per year basis, until all the recoverable reserves are produced. A total of approximately forty new full-time jobs will be established once the plant is up and running and, we have already successfully recruited in this space. Our production staff is participating in the plant and well evolution to enhance familiarity with the workings of our operation. We believe this will significantly enhance operating efficiency and productivity.

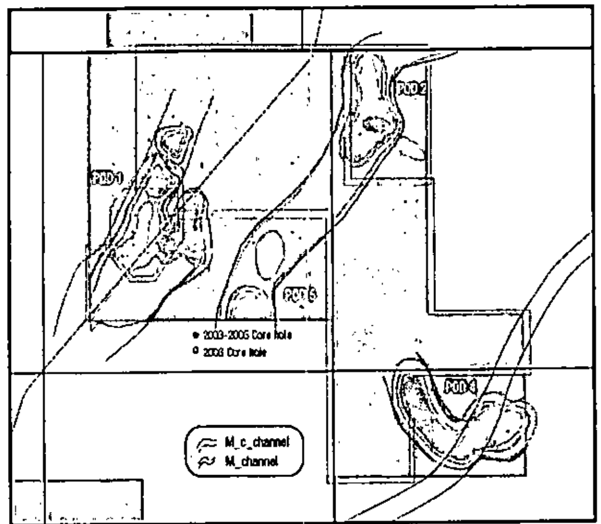
Connacher anticipates trucking its oil in the early phases of its operations, until ramp up of production occurs. Numerous permanent pipeline alternatives are being evaluated at this time, with the view of finalizing the selection of the optimum route and capacity in the near future. This will in part be driven by finalization of plans with respect to Pod Two and also after determining the plans of other operators in the region. It now appears that Connacher will proceed on its own for the initial phases due to its pace of progress compared to its competitors.

Connacher's management is proud if its accomplishments at Great Divide and extends its appreciation to all the employees, contract employees, contractors and suppliers who have contributed to the advanced status of the Pod One Project.

Other 2006 Great Divide Activity

In addition to its work at Pod One, Connacher continued to evaluate its main oil sands lease during 2006. This entailed drilling of 26 core holes (including six in December) and the shooting of approximately 53 square kilometers of 3D seismic, including a unique summer program which was a first for the company.

Numerous prospects and leads have been determined from the 3D coverage which the company has secured over its main lease block. Seismic has proven to be a useful tool for Connacher due to the depth of deposition in the Great Divide area and the clear marker provided by the Paleozoic basement. Part of the objective of securing 3D coverage is to contribute to the effective placement of core holes, which are expensive to drill. It also enables easier definition of channel boundaries, thereby reducing the incidence of core holes with little or no sand present. While exploration remains a



MAP: INDICATED MCMURRAY PODS AT GREAT DIVIDE.

small component of overall oil sands development, all efforts to control costs must be pursued in the current environment.

Our 2006 core hole program resulted in fewer wells than we had originally anticipated. However, when combined with our 3D seismic it established the basis for our aggressive 2007 winter program. For the first time in several years, an early start to the core hole program was achieved. Favourable. weather conditions in December 2006 facilitated rigs being on location earlier than we had previously experienced. As a consequence, we have now completed 80 core holes in our 2007 winter program. Results of this program contributed to our decision to proceed with an application to develop Pod Two.

We also completed a 68 square kilometer 3D program over the balance of our main lease block, such that Connacher now has coverage over all of this original lease block. Along with the results of our 2007 core hole program, this seismic will determine our core hole locations for 2008 as we follow up leads to determine if other indicated channels or accumulations can be exploited in future years. It is likely that another 80 exploration and delineation core holes will be scheduled for our leases during the 2008 winter drilling program. We also purchased over 300 kilometres of 2D seismic data over the other Connacher lands.

During 2006, Connacher selectively added 15,000 acres to its oil sands lease holdings at periodic Crown Sales held by the Government of Alberta. We have now acquired a total of approximately 20,000 acres of rights in the oil sands in addition to our original core holdings. This expanded

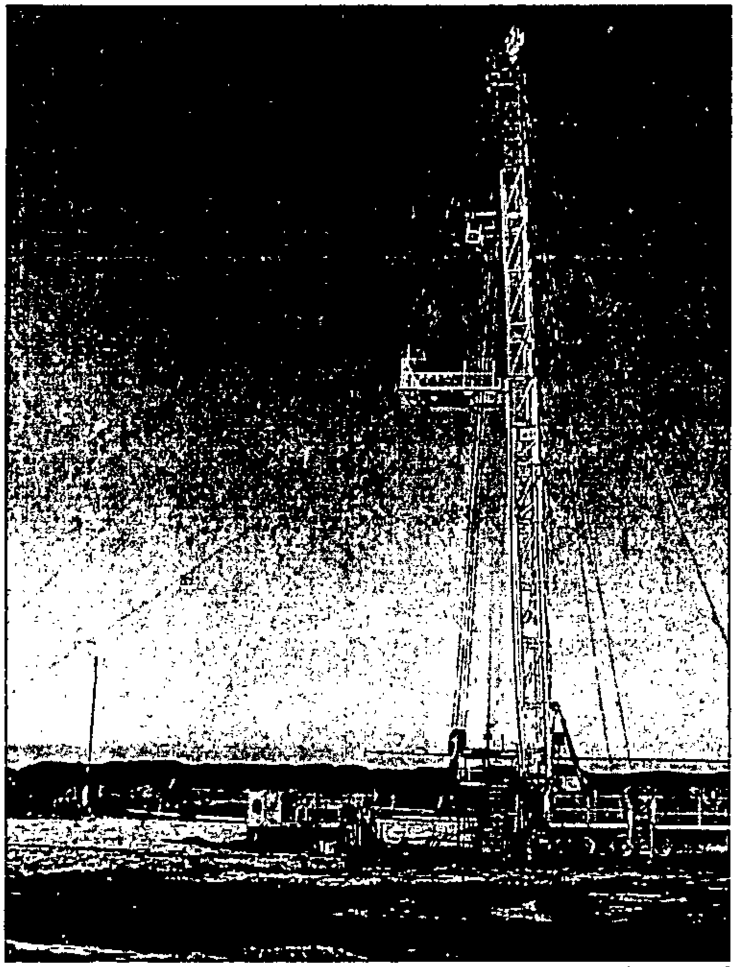


PHOTO: COMPLETING A NEW OIL WELL AT THREE HILLS, ALBERTA.

Connacher's excellent track record of securing a 100 percent ownership and operatorship of its oil sands exposure. Exploratory evaluation of these lands will be scheduled in upcoming years.

OTHER CANADIAN CRUDE OIL AND NATURAL GAS PROPERTIES

Connacher's principal conventional crude oil and natural gas properties are located at Marten Creek (natural gas) and Three Hills (natural gas and crude oil) in northern and central Alberta, respectively and at Battrum, Saskatchewan (crude oil). Our conventional reserves and production expanded considerably during March 2006 with the successful purchase of Luke. As a result, our 2006 production increased 214 percent to reach an average daily level of 2,725 boe/d compared to only 867 boe/d in 2005. Similarly, our conventional 2P reserve base increased 252 percent to reach 8.8 million boe at year end. Approximately two thirds of our conventional reserve base is now comprised of natural gas, with the balance crude oil.

During 2006 we replaced our conventional production over seven times (732 percent), achieved even while we were experiencing considerable daily production growth from our expanded reserve base. This is calculated by adding annual production to year-end 2P reserves; dividing by 2006 production and expressing the result as a percentage.

Our conventional properties provided a source of revenue, cash flow and credit capacity. This contributed to the overall liquidity and financial strength of Connacher and represent an essential part of our risk management strategy for unconventional oil. Over the long run, it is our goal to have this important component of our asset base remain self-sufficient in financing growth expenditures. During 2006, a total of $23 million was invested in our conventional programs, exclusive of acquisitions. Net operating income from conventional production was approximately $24 million during the year.

Marten Creek, Alberta

Connacher's largest reserve and producing property is situated at Marten Creek, located due west of our oil sands properties in north central Alberta. The region is essentially a winter-access only area, so almost all the company's drilling and remedial field activity must be conducted between approximately January and March of any given year. Heavy equipment such as drilling rigs can only be introduced to the region via ice roads after freeze up has occurred. As such, considerable planning must take place during the summer months to ensure seismic programs, drilling programs, infrastructure and facility construction and remedial programs are well established before the winter months. Also, because of the region's location, considerable coordination is required with regulatory authorities and indigenous people of the region in order to ensure access and timely development of the properties. This also includes securing prior approval of programs due to the presence of caribou and other ungulates in the region.

Having acquired Luke in mid-March 2006, during the past year Connacher's focus was largely on its proposed new programs for the winter of 2007 and on positioning itself to conduct requisite remedial work on existing wells to ensure stable production could be maintained.

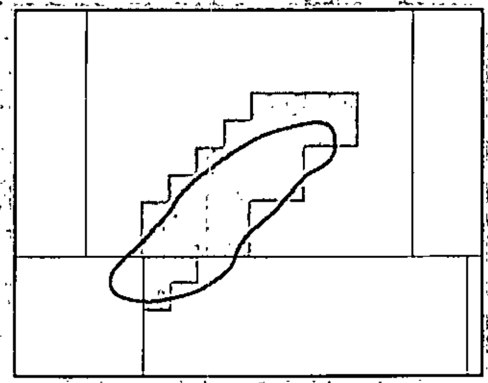
The downturn in natural gas prices during 2006 contributed to increased seismic crew and rig availability for 2007 and an extensive seismic program to evaluate existing and newly-acquired undrilled lands was developed.

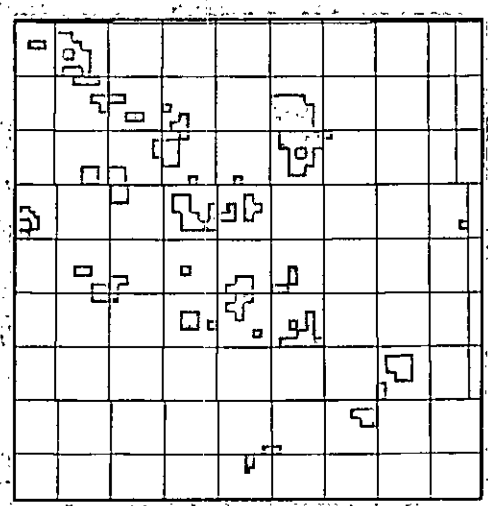
Connacher contracted three drilling rigs with a view to drilling approximately 17 gross (16 net) wells, mostly at Marten Creek, in the winter of 2007. We also prepared a 216 kilometer 2D seismic exploration program over open Crown acreage and our own holdings. These programs were completed during the first quarter of 2007.

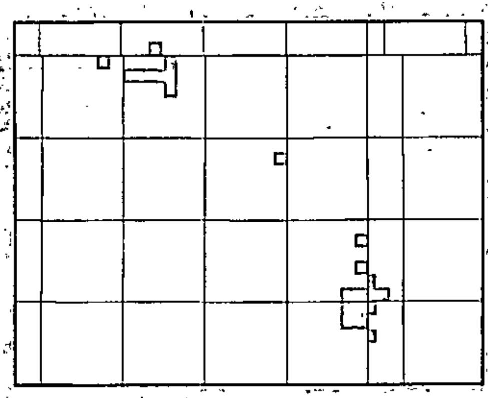
From the date of acquisition, production from Marten Creek during 2006 averaged 10.5 mmcf/d of natural gas. A peak monthly level of 16.3 mmcf/d was achieved in May 2006. As is customary for these regions like this, with minimal to limited access during nine months of the year, production and sales tend to decline until the winter months of the ensuing year. Remedial work can then be completed and new wells can be tied in during this brief window of opportunity.

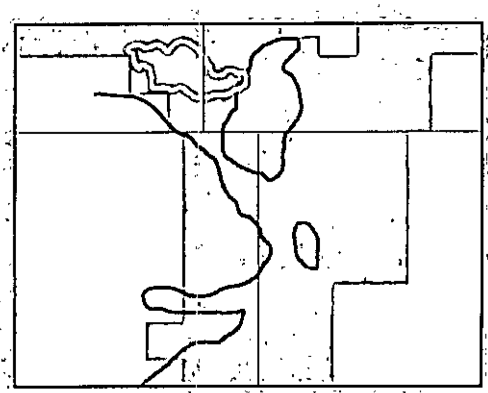
The Marten Creek area continues to be a priority region for Connacher. There is growth potential in the area through new Crown land availability and continued processing of lands we already own. There are multiple objectives to evaluate, and with a 100 percent interest in, and operatorship of, most lands Connacher can control its own pace of development and its destiny in the region.

Connacher's longer term objective for the area is to develop sufficient reserves and deliverability to retain a representative physical hedge of the cost of natural gas volumes it anticipates consuming as its develops additional pods at Great Divide. For example, it is the company's opinion that with its winter 2007 drilling program within the Marten Creek region, it developed about 6 to 7 mmcf/d of deliverability or approximately 60 percent of the fuel requirements of the next pod in the oil sands. Expressed another way, by the time Pod Two would be ready to come onstream, likely sometime in 2008 if a timely application is submitted, this spring, Connacher expects it will have developed its gas potential in the Marten Creek region to remain in balance by effectively remaining self-sufficient in its fuel requirements. Balancing corporate natural gas production with anticipated oil sands usage for steam generation is a cornerstone of Connacher's risk management and mitigation program. However, there can be no assurance that the application will be processed in accordance with this timeline or that additional natural gas production will be established to meet this objective.


THREE HILLS, ALBERTA


MARTEN CREEK, ALBERTA


SIMONETTE, ALBERTA


BATTRUM, SASKATCHEWAN

Other Areas

Connacher's other key conventional areas are Three Hills, Alberta and Battrum, Saskatchewan. Production from these areas during 2006 averaged 978 boe/d.

During 2006 four prospective oil wells and one prospective natural gas well were drilled at Three Hills, resulting in three successful oil wells. These oil wells are judged to have productive potential approaching 200 bbl/d of crude oil but are presently constrained by regulatory rulings. These rulings are expected to be amended shortly, thereby allowing Connacher to further expand its current production base.

At Battrum, three infill wells and two exploration wells were drilled during the year, thereby enabling Connacher to not only sustain its production base but also to expand the evaluated reserve base for this property.

MONTANA REFINING COMPANY INC.

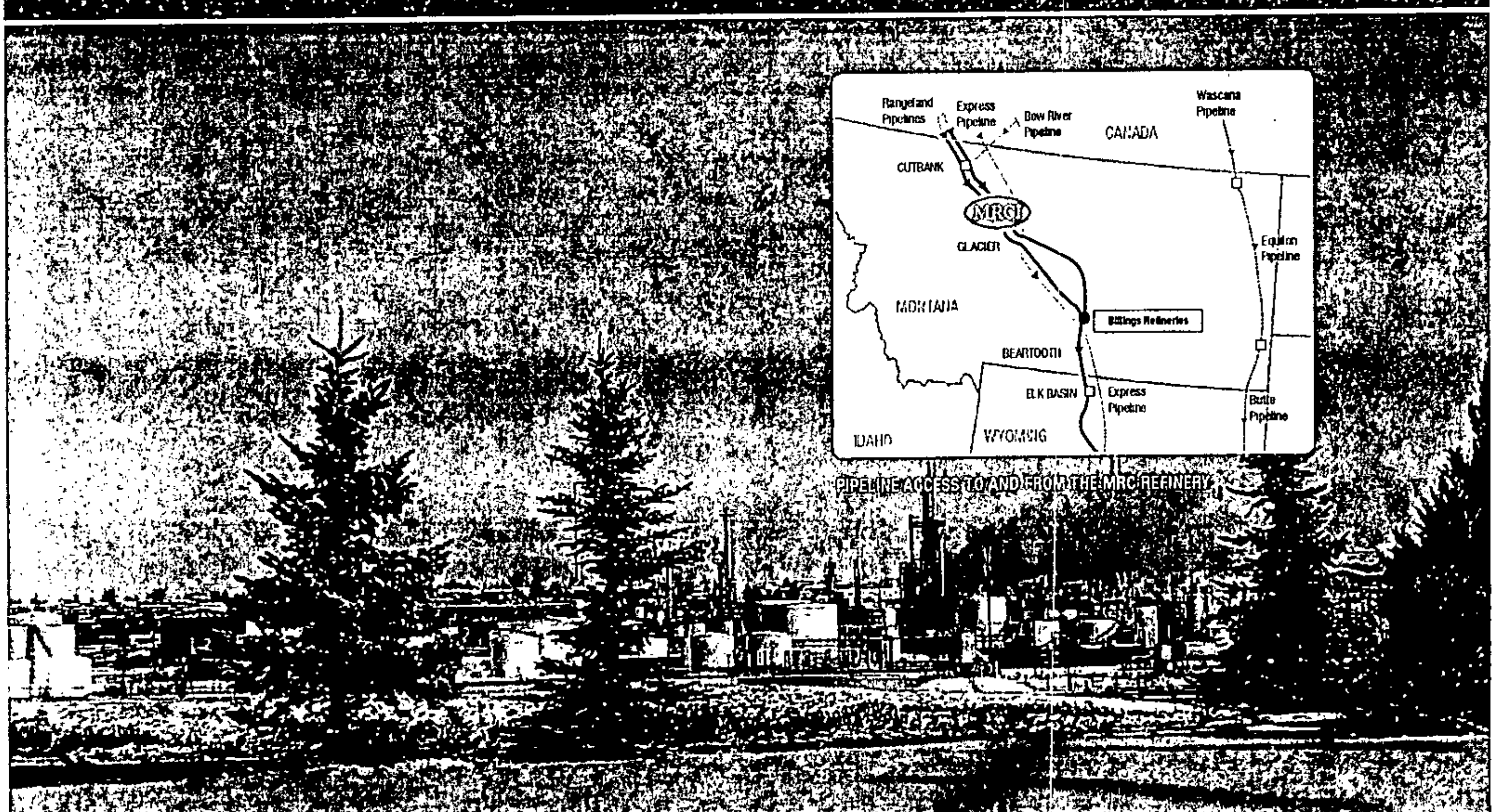
On March 31, 2006, Connacher acquired a refinery and related assets situated in Great Falls, Montana from Holly Corp., the vendor. At purchase, the refinery was processing approximately 8,300 bbl/d of heavy crude oil ("Bow River Crude"), sourced in southern Alberta.

Subsequently, and as anticipated, a low cost but regularly scheduled turnaround was completed during the spring of 2007 and as a consequence, throughput reached a high of approximately 9,900 bbl/d and is now generally averaging about 9,500 bbl/d. The purchase price, which aggregated $66 million, was comprised of $61 million of cash and one million Connacher common shares. Product inventory with an attributed value of some $20 million was acquired as part of the purchase price. Connacher considers the purchase to have been an attractive business transaction.

The asset purchase was completed by a newly-incorporated subsidiary, Montana Refining Company Inc., ("MRCI"), a wholly-owned Delaware corporation. Most of the 80 or so employees associated with the assets continued as MRCI employees and Connacher also appointed a new Vice President, Refining and Marketing to oversee its considerable investment in this business.

As a standalone business, MRCI had a very successful year. As indicated elsewhere in this report, MRCI recorded $212 million of revenue, recorded a 94 percent utilization rate, generated a pre-tax netback of approximately $30 million, and contributed $17 million of after-tax earnings to Connacher during the nine month period of ownership. Based on recent history, Connacher was able to generate a

PHOTO: GREAT FALLS, MONTANA REFINERY



PIPELINE ACCESS TO AND FROM THE MRC REFINERY record refining margin at the Great Falls, Montana refinery. This was accomplished due to both improved efficiencies at the refinery as well as higher product prices and differentials for the heavy crude feedstock used. It is also a credit to the commitment of the management and staff of the refinery for its successful operation.

The refinery is a complex operation that includes reforming, isomerization and alkylation processes for formulation of gasoline blends and hydro-treating for sulphur removal. It also includes fluid catalytic cracking for conversion of heavy gas oils to gasoline and distillate products. As a consequence of the type of crude processed, it is also a major supplier of paving grade asphalt, polymer modified grades and asphalt emulsions for road construction. Products are marketed to retailers in Montana and in neighboring states and the refinery is well-serviced by truck and rail transport.

In addition to its importance as a profitable business, the refinery was a good strategic fit with Connacher's oil sands business. It is well located, being the closest US based refinery to the oil sands. It currently processes Canadian heavy crude into a range of higher value products, including gasoline, jet fuel, diesel, home heating oil and asphalt. As such, it effectively provides Connacher with a physical hedge against widened differentials for heavy oil, such as will be produced at the oil sands.

During 2006, Connacher made significant environmental improvements to the operation. These included capital projects to remove excess sulphur from boiler fuel. Also, an existing wastewater pond was recovered and remediated during the year. Sulphur removal in the boiler fuel is improved now over 200 times from the previous operation. This is accomplished by means of a unique process which converts sulphur to a product now being used commercially for environmental remediation in other parts of the United States.

Other improvements initiated during 2006 included the design and startup of construction of a new 150,000 barrel asphalt tank, which became operative in March 2007. We also initiated expansion of rail loading facilities. These were undertaken to facilitate the increased throughput which Connacher introduced at the refinery, which can now be accomplished on a year round basis.

In addition to integrating the well-trained and experienced staff, Connacher has recruited additional personnel and also has been able to effect internal promotions at the refinery. Key processes and systems have been fully integrated with the parent company. Connacher's operational approach emphasizes a strong training and development program, as well as rigorous procedures for safety and environmental protection.

Prospectively, during 2007 Connacher anticipates further environmental and capacity enhancements at the Great Falls refinery. We are designing new high efficiency boilers, increasing rail load-out capability, and expect to further improve waste water treatment facilities and sulphur treatment processes.

Connacher has also initiated a major Clean Fuels project targeted to allow the production of ultra-low diesel and gasoline by the end of 2008. Engineering and marketing studies have also been initiated to assess the possibility of major expansion of the refinery's processing capacity.

The ownership of the refinery assisted Connacher in its establishment of a term loan facility to finance its Great Divide Pod One development. The refinery assets also provide a portion of the collateral for the Great Divide term loan. As an adjunct thereto, a US$15 million working capital facility was arranged for MRCI to provided requisite liquidity in the conduct of its business. Connacher also anticipates certain synergies will evolve in respect of its refining/marketing activities as it realizes increases in the overall productive capacity at both Great Divide and downstream at the Montana refinery.

INVESTMENT IN PETROLIFERA PETROLEUM LIMITED

Connacher was the founding shareholder of Petrolifera, a public Canadian oil and natural gas exploration and production company active in Argentina, Peru and Colombia in South America. Petrolifera was established in late 2004 when Connacher decided to focus its attention on the oil sands in Canada.

Initially Connacher acquired a 100 percent interest in the Puesto Morales /Rinconada Concession in Argentina under favorable terms and then sold this interest to Petrolifera for 8 million common shares and a $4 million promissory note. This note was subsequently repaid and discharged. To finance the purchase and discharge its indebtedness to Connacher, Petrolifera raised capital from third parties and then went public in late 2005. Connacher was called upon to support the initial public offering of Petrolifera in October 2005 due to weak market conditions, and has maintained

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an approximate 26 percent fully-diluted stake in the company. Pursuant to a management contract, Connacher also provides certain management services to Petrolifera and certain officers of Connacher are currently officers of Petrolifera. A majority of Petrolifera's Board of Directors is composed of independent directors.

During late 2005 and throughout 2006 Petrolifera has enjoyed considerable success in its drilling program at Puesto Morales. During this time, total of 15 wells have been drilled and completed as indicated hydrocarbon-bearing wells since new drilling was initiated and there have been no dry holes. Crude oil sales have grown from a modest 145 bbl/d in 2005 to 7,000 bbl/d in 2006 with an exit rate in December 2006 approaching 11,500 bbl/d, having reached a peak daily production of 13,400 bbl/d of crude oil and 13,700 boe/d on an equivalent basis.

Permanent production and transportation facilities are under construction in Argentina and Petrolifera also plans an active drilling program during 2007, with up to 50 wells envisaged for Argentina within the company's announced financial plan and budget. A total self-financed capital program of $153 million is anticipated for 2007. This will also include new land acquisition in Argentina, extensive geophysical programs in Peru, where Petrolifera holds extensive acreage in two licenses in the Maranon and Ucayali Basins and programs in Colombia, where new concessions and related agreements are being finalized.

Petrolifera is strong financially, with very healthy working capital, no short or long term debt and an anticipated growing cash flow base to finance activities. Additionally, the company is negotiating a reserve-based line of credit which will further enhance its financial flexibility. Proceeds from the exercise of outstanding $3.00 share purchase warrants are also expected to augment cash balances prior to May 8, 2007.

Connacher intends to exercise the outstanding warrants it acquired from the purchase of units issued under the Petrolifera IPO. We remain a strong supporter of the company and its initiatives. Our holdings have a current market value in excess of $200 million, which compares favorably with our net cash investment of $2 million. Connacher has lent its corporate support and sponsorship to Petrolifera, thereby enabling Petrolifera to pursue and secure new opportunities in Peru and Colombia. Otherwise, these would not have become available to Petrolifera. For such support, Connacher received a carried interest in the first wells to be drilled on Petrolifera's licenses in Peru. As there was no material operating or financial risk to the support granted for Colombia, no economic interest was sought or received by Connacher.

Connacher continues to equity account its interest in Petrolifera's income in its reporting to shareholders and remains a longer-term investor in Petrolifera under present conditions. Connacher remains keenly interested in the upcoming drilling programs in Peru, which it is anticipated will expose Petrolifera to significant reserve potential and the attendant value additions.

Production, Sales and Reserves

During 2006, Connacher produced and sold a total of 357,700 barrels of crude oil and 3.8 billion cubic feet of natural gas. Daily average sales were 980 bbl/d of crude oil compared to 729 bbl/d in 2005, for an increase of 34 percent. Daily natural gas sales were 10.5 mmcf/d, significantly above only 827 mcf/d in 2005. This reflects the impact of the purchase of Luke in March 2006. The increase in oil production reflects successful drilling and the Luke purchase which resulted in production growth which more than offset declines.

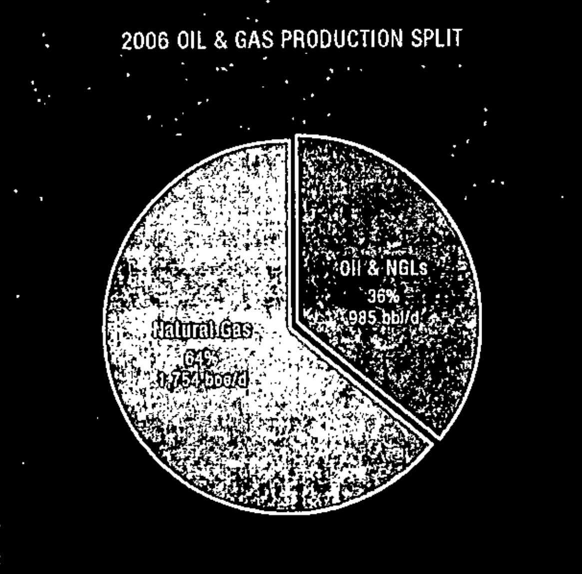
On an energy equivalent basis, sales were 2,725 boe/d in 2006 compared to only 867 boe/d in 2005, an increase of 214 percent.

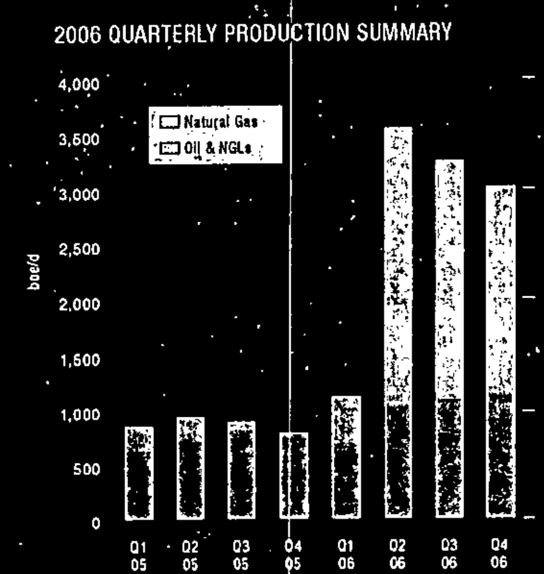
The average price received for crude oil in 2006 was $53.85 per barrel, compared to $42.33 per barrel in 2005. The increase is reflective of higher world oil prices during the current year. West Texas Intermediate ("WTI") crude prices averaged US$67.08 in 2006, an increase of 21 percent over US$55.40 in 2005. Volatile differentials for heavier crude oil produced by Connacher at Battrum, Saskatchewan and a stronger Canadian dollar combined to provide a 27 percent increase in Connacher's crude oil price on a year over year basis.

Natural gas prices averaged $5.85 per mcf in 2006 compared to $1.37 per mcf in 2005 when our natural gas prices were significantly influenced by Petrolifera's Argentina natural gas sales volumes in a regulated market. Peak selling prices of $8.23 per mcf in January 2006 were not realized again throughout the year, though they climbed back with seasonal conditions to reach $8.11 per mcf in December 2006, following a low of $4.43 per mcf in September 2006.

On an equivalent basis, prices averaged $41.83 per boe in 2006 compared to $36.91 per boe in 2005, for an increase of 13 percent, having regard for the changing product mix in 2006 with increased natural gas sales.

Most of Connacher's production is sold at spot prices in spot markets. There are no long term arrangements outstanding with respect to product sales. No hedges were contracted or outstanding during 2006.





Oil, Gas, and Bitumen Reserves and Resources

The following is a summary of the conventional crude oil and natural gas reserves and unconventional oil sands or bitumen reserves and resources and the value of future net revenue to the company for these properties as at December 31, 2006 as evaluated by GLJ Petroleum Consultants ("GLJ") in March 2007 reports dated March 9, 2007 (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 GLJ Report did not take into account or consider any winter drilling or core holes drilled after December 31, 2006. Accordingly, the results of Connacher's 2007 program will be assessed at a later date.

Unconventional Reserves and Resources

Great Divide SAGD Project (Bitumen)

In the proved undeveloped ("1P"), proved and probable ("2P") and proved, probable and possible ("3P") categories, reserves were only assigned at Great Divide only to Pod One which is currently under development. The report assumed 44 steam-assisted gravity drainage ("SAGD") well pairs for the 1P case, 62 well pairs for the 2P case and 76 well pairs for the 3P case, with cumulative steam-oil ratios ("SOR") of 2.7, 2.6, and 2.6, respectively, but declining to 2.4 during peak production periods. The project was assumed to commence production in mid-2007, with production peaking at 10,000 bbl/d by 2011 (1P) and 10,500 bbl/d by 2009 (2P) or 11,200 bbl/d by 2009 (3P). The cutoffs used by GLJ for probable reserves were 15 metres of net pay for 1P reserves, 13 metres of pay for 2P reserve 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 income tax and 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.

Bitumen 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]	43,841	39,808	521	313	191
Total Proved Plus Probable[2,3]	84,147	74,148	1,298	658	376
Total Proved Plus Probable Plus Possible[2,3,4]	109,861	95,774	1,911	858	464

(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.

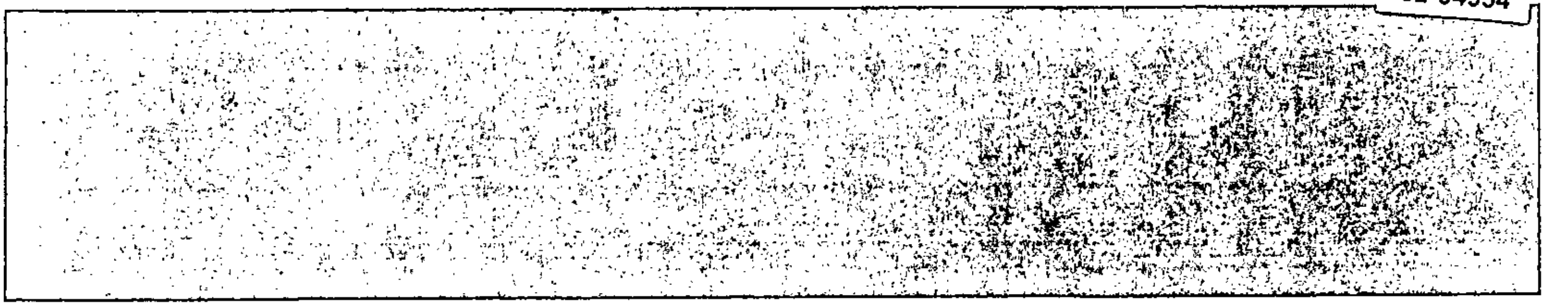
(2) "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is 90% likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(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) 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 on page 29. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

(6) Includes estimated capital costs, in the 1P case, of $269 million over the 17 year forecast life of the project (7.8 year half-life); of $412 million in the 2P case over the 28 year forecast life of the project (13.2 years half-life); and of $494 million in the 3P case over the 34 year forecast life of the project (16.0 years half-life).



The GLJ Report also provided calculations of Contingent Resources comprised of "Low Estimate Resources (>15 metre Pay) - higher certainty", together with "Best Estimate Resources (13 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 five 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 five 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 five pods had insufficient drilling density, seismic mapping or project definition at December 31, 2006 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 Best Estimate and High Estimate Prospective Resources attributable to undiscovered pods, utilizing average parameters from six identifiable pods, including Pod One. This year, calculations of the present value of the future cash flow from remaining recoverable reserves and remaining recoverable resources (Contingent and Prospective) were included for the total Great Divide lands and not as previously just for Pod One.

Summary of Unconventional Reserves and Resources and Values

Marketable Reserves, Resources	Total Company Interest (mmbbl)	Net After Royalty (mmbbl)	Before Tax Present Value at 0% ($MM)	Before Tax Present Value at 5% ($MM)	Before Tax Present Value at 10% ($MM)
1P Reserves and Low Estimate Contingent Resources (1,4,6)	70.5	65.1	766.4	437.7	243.2
2P Reserves and Best Estimate Contingent Resources (1,2,4,7)	187.8	167.3	2,884.9	1,216.7	584.0
3P Reserves and High Estimate Contingent Resources (1,2,3,4,6,8)	265.7	235.1	4,319.1	1,742.8	813.8
1P Reserves and Low Estimate Total Resources (1,6,9)	110.5	99.5	1,393.0	803.2	486.7
2P Reserves and Low Estimate Total Resources (1,2,6,9)	260.6	232.4	3,872.1	1,661.4	778.1
3P Reserves and Low Estimate Total Resources (1,2,3,6,9)	479.0	423.7	8,058.0	2,898.7	1,245.1

(1) 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.

(2) 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.

(3) Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is only a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves. Possible reserves were 26 million bbls and 39 million bbls in the GLJ 2006 report and the GLJ 2005 report, respectively.

(4) Contingent resources are those quantities of oil and gas estimated on a given date to be potentially recoverable from known accumulations but are not currently economic. GLJ has categorized these resources as contingent as additional delineation drilling, development planning, project design and further regulatory applications are required.

(5) Prospective resources are those quantities of oil and gas estimated on a given date to be potentially recoverable from undiscovered accumulations. If discovered, they would be technically and economically viable to recover. There is no certainty, however, that the prospective resources will be discovered.

(6) Low Estimate is considered to be a conservative estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used, this term reflects P90 confidence level.

(7) Best Estimate is considered to be the best estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used, this term is a measure of central tendency of the uncertainty distribution (P50).

(8) High Estimate is considered to be an optimistic estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used, the term reflects a P10 confidence level.

(9) Total resources includes contingent resources and prospective resources.

(10) Does not include undeveloped land value.

GLJ Report on 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, 2006 as evaluated in the March 2007 reports by GLJ dated March 9, 2007 (the "GLJ Report").

The 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 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 income tax and 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 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.

Connacher also owns a 26 percent equity stake in Petrolifera Petroleum Limited. See the company's Annual Information Form ("AIF") as posted on SEDAR (www.sedar.com) for more information related to that company's crude oil and natural gas reserves located in Argentina.

Conventional 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)	2,106	1,742	21,539	17,607	1.0	0.7
Proved Developed Non-Producing(2,6)	-	-	3,167	2,615	0.2	0.1
Proved Undeveloped(2,7)	315	240	-	-	-	-
Total Proved	2,421	1,983	24,706	20,221	1.2	0.8
Total Probable(3)	786	632	8,773	7,158	0.4	0.3
Total Proved Plus Probable(2,3)	3,207	2,615	33,479	27,379	1.6	1.1

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

	Before Deducting Income Taxes Discounted At		
	0% ($MM)	5% ($MM)	10% ($MM)
Proved Developed Producing(2,5)	160	127	106
Proved Developed Non-Producing(2,6)	16	13	10
Proved Undeveloped(2,7)	8	7	5
Total Proved(2)	183	146	122
Total Probable(3)	73	45	31
Total Proved Plus Probable(2,3)	256	191	152

(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 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.

(9) Values include processing and other income.

	Light and Medium Crude Oil	Exchange Rate	Bitumen Wellhead Current	Natural Gas	Inflation Rate
	WTI Cushing Oklahoma ($US/bbl)	$US/$Cdn	($Cdn/bbl)	Alberta Spot ($Cdn/mcf)	%/year
Forecast					
2007	62.00	0.87	31.50	7.00	2.0
2008	60.00	0.87	32.75	7.25	2.0
2009	58.00	0.87	33.50	7.55	2.0
2010	57.00	0.87	33.38	7.60	2.0
2011	57.00	0.87	34.50	7.65	2.0
2012	57.50	0.87	35.00	7.95	2.0
2013	58.50	0.87	35.50	8.10	2.0
2014	59.75	0.87	36.63	8.30	2.0
2015	61.00	0.87	37.38	8.50	2.0
2016	62.25	0.87	38.13	8.65	2.0
Thereafter	2%	0.87	2%	2%	2.0

Operating expenses, capital costs and abandonment costs utilized in the GLJ Report were as follows:

	Forecast Prices and Costs - Canada (Undiscounted)	
	Total Proved ($MM)	Proved Plus Probable ($MM)
Operating costs	79	97
Capital costs	3	1
Abandonment	4	4

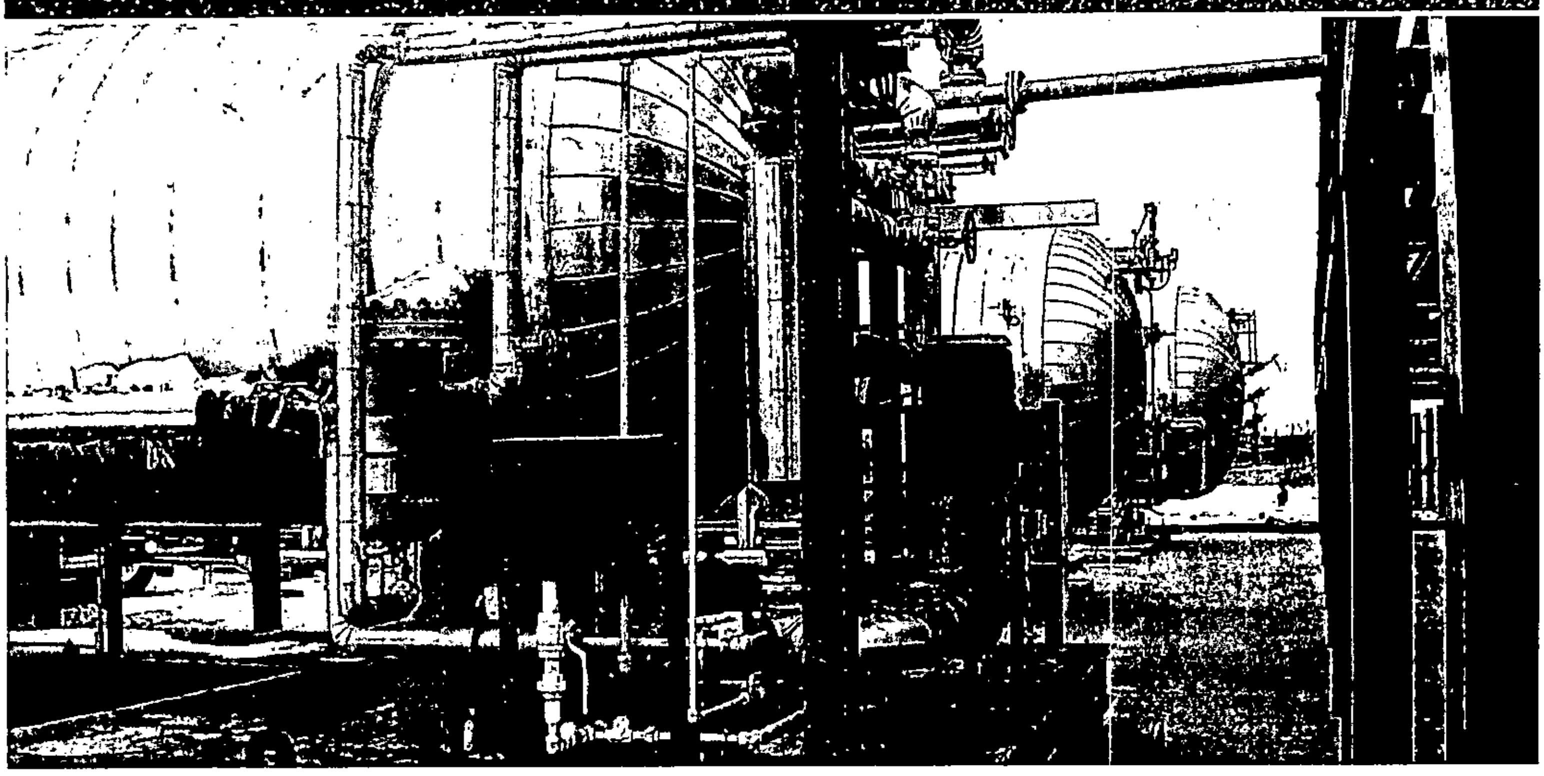
Total Company Combined Reserves (Conventional and Unconventional)

On a combined basis, Connacher's reserves grew at very significant rates. Total combined 1P equivalent reserves at December 31, 2006 were estimated by GLJ to be 50.4 million barrels, an increase of 3,254 percent over year end 2005.

Connacher's combined 2P equivalent reserves increased 29 percent to 93 million boe at December 31, 2006 compared to 72.1 million boe at year end 2005.

The company's combined 2P reserves are forecast to generate $1.6 billion of future net revenue with a 10 percent present value of $529 million, after future capital of $417 million and abandonment costs of $13.7 million. This represents a 160 percent year over year increase in the 10 percent present values.

PHOTO: TREATERS AND FREE WATER KNOCK OUT VESSELS - POD ONE



Combined Conventional and Unconventional Reserves

(mboe)	**December 31, 2006**	December 31, 2005	%
Proved Conventional[1]	**6,540**	1,501	
Proved Bitumen[1]	**43,841**	0	
Total Proved (1P) [1]	**50,381**	1,501	3,254%
Probable Conventional[2]	**2,248**	994	
Probable Bitumen[2]	**40,307**	69,604	
Total Probable[2]	**42,555**	70,598	-40%
Proved + Probable Conventional [1,2]	**8,788**	2,495	
Proved + Probable Bitumen[1,2]	**84,148**	69,604	
Total 2P [1,2]	**92,936**	72,099	29%

10% Present Value of Future Net Revenue
Total Company (Conventional and Unconventional) [4]

	2006	2005	%
	($MM)	($MM)	
Proved Conventional[1]	**122**	23	
Proved Bitumen[1]	**191**	0	
Total Proved (1P) [1]	**313**	23	1,269%
Probable Conventional[2]	**31**	12	
Probable Bitumen[2]	**186**	168	
Total Probable[2]	**217**	180	20%
Proved + Probable Conventional [1,2]	**152**	35	
Proved + Probable Bitumen [1,2]	**376**	168	
Total 2P [1,2]	**528**	203	160%

(1) 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.

(2) 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.

(3) Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is only a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves. Possible reserves were 26 million bbls and 39.8 million boe in the GLJ 2006 report and the GLJ 2005 and D&M 2005 reports, respectively.

(4) Does not include bitumen resources or undeveloped land value.

Conventional & Unconventional Combined

			Before Deducting Income Taxes Discounted At		
	Total Company Interest (MBOE)	Net After Royalty (MBOE)	0% ($MM)	5% ($MM)	10% ($MM)
Total Proved (1P)	50,381	45,162	704	460	312
Total Proved + Probable (2P)	92,936	81,327	1,554	849	529
Total Proved + Probable + Possible (3P)	118,649	102,953	2,167	1,050	616
Total 1P + Low Total Resources	117,018	104,876	1,576	949	608
Total 2P + Best Total Resources	269,414	239,596	4,128	1,853	931
Total 3P + High Total Resources	487,741	430,887	8,314	3,090	1,397

2006 Year End 2P Reserve Reconciliation [1,2,3]

By Principal Product Type Forecast Prices and Costs	Proved + Probable (Mboe)
December 31, 2005	64,660
Discoveries	0
Extensions	11,991
Infill Drilling	0
Improved Recovery	230
Technical Revisions	63
Acquisitions	5,410
Dispositions	(201)
Economic Factors	0
Production	(826)
December 31, 2006	81,327

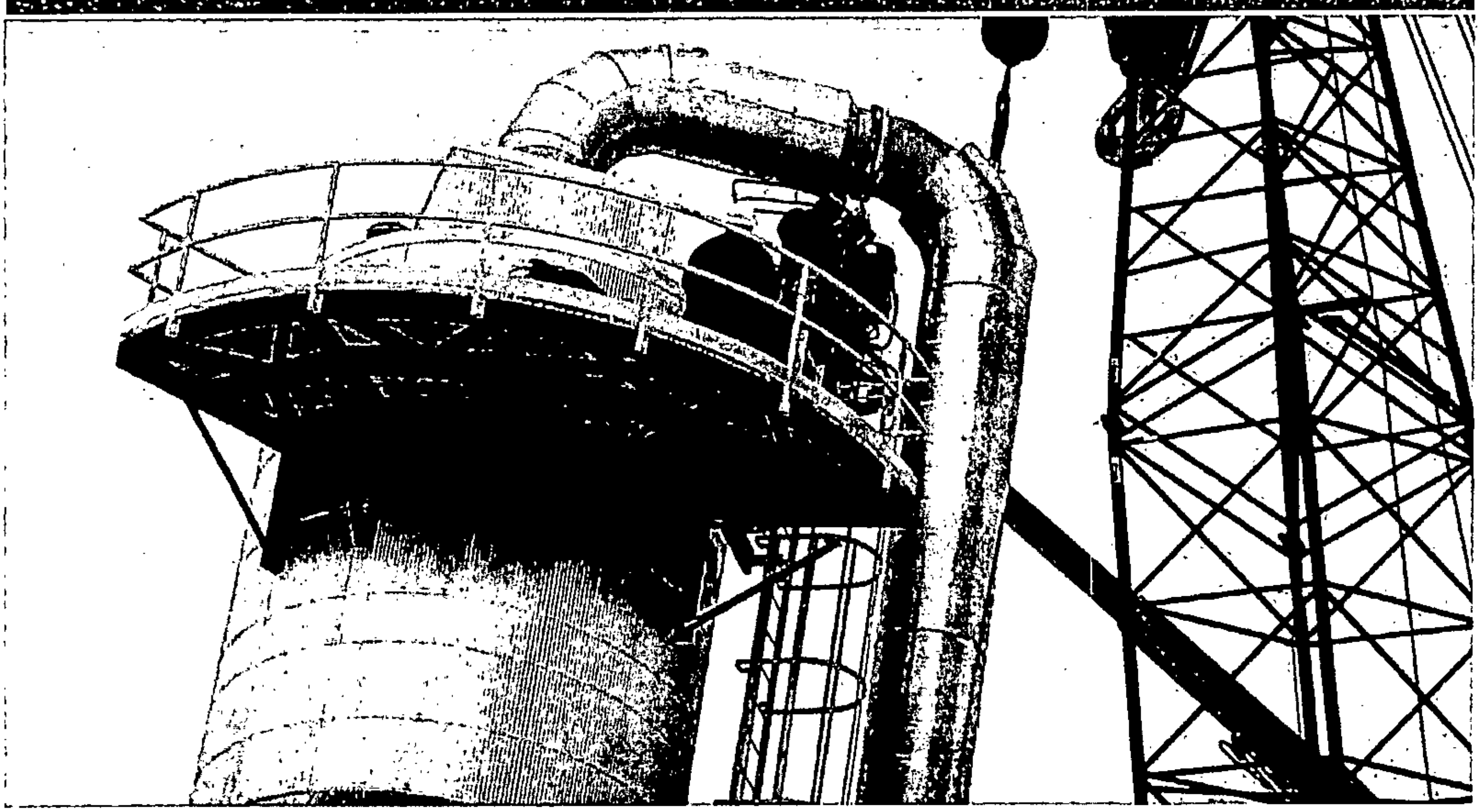
(1) May not add due to rounding.
(2) Calculated based on net reseves and forecast price case as at December 31, 2006.
(3) All references to barrels of oil equivalent (boe) are calculated on the basis of 6 mcf : 1bbl. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 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.

Unproved Property Valuation

Connacher retained Sayer Energy Advisors ("Sayer"), independent energy advisors of Calgary, Alberta, to conduct an evaluation of its unproved properties in Western Canada. Sayer completed a report (the "Sayer Report") with an effective date of December 31, 2006. It was prepared according to Standard of Disclosure for Oil and gas activities described in NI 51-101 and within the Code of Ethics of the Association of Profession Engineers, Geologists and Geophysicists of Alberta.

Sayer assigned a low value of $14.9 million, a median value of $16.2 million and a high value of $17.6 million to Connacher's 64,102.1 net hectares of petroleum and natural gas rights held in the Provinces of Alberta, British Columbia and Saskatchewan as at December 31, 2006. The valuation does not include any of Connacher's bitumen rights which are evaluated within the GLJ 2006 Report.

PHOTO: EVAPORATOR - POD ONE - GREAT DIVIDE



Corporate Governance and Social Responsibility

Connacher Oil and Gas Limited, its Board of Directors and its Management are committed to a high standard of corporate governance practices. This commitment is believed not only to be in the best interest of shareholders but that it also promotes effective decision making at all levels of the company's activities.

In its pursuit of effective governance, Connacher is mindful of prevailing recommendations with respect to best practices as advanced by Canadian regulatory authorities, non-regulatory organizations and other standard which are advanced from time to time by institutional and other investors.

Connacher's Board of Directors is comprised of six individuals. Five of these people are non-Management and four of the five so characterized are considered independent. All of the company's Board Committees are comprised of non-management individuals. All of Connacher's five Committees of the Board are composed of a majority of independent directors.

The Chairs of Connacher's Audit and Reserves Committees are considered experts. The Chair of our Audit Committee is a Chartered Accountant who held the position of Vice Chairman with a recognized national accounting firm prior to his retirement and subsequent appointment to Connacher's Board of Directors. The Chair of our Reserves Committee was the President of an independent engineering consulting firm prior to his retirement and subsequent appointment to Connacher's Board.

In total, Connacher has five Board committees, including Audit, Governance, Human Resources, Reserves and Health, Safety and the Environment ("HSE").

Connacher's Human Resources Committee, which oversees and makes recommendations with respect to the remuneration of management, is entirely comprised of independent directors. Connacher's Lead Director is an independent director and the majority of the members of its Governance Committee are independent directors. The Governance Committee considers the recommendations of the Human Resources Committee insofar as remuneration of Directors (other than management) is concerned, and advances these recommendations to the full Board. At Board level, management participates in voting upon the remuneration to be awarded to non-management directors.

Connacher has developed a mandate for its Board of Directors, each committee of the Board, the Lead Director, individual directors, the Chair of each committee and for the Chief Executive Officer. These are reviewed at least annually and updated to take into account changes or developments considered beneficial to good governance practices.

Additionally , the Governance Committee assesses individual performance of directors and numerous other items which are detailed in the company's Information circular and attachments thereto.

The company has also adopted various policies with respect to sound business conduct, especially with respect to Disclosure, Trading in Securities, Whistle Blower Policy, and additional Policies which deal with a Respectful Workplace, Violence in the Workplace, Inappropriate Activity and Privacy. Connacher also has a Code of Ethics. These are updated and reviewed on a regular basis by management, its Governance Committee and the Board.

Connacher also has a Disclosure Committee comprised of the Chief Executive Officer, counsel and internal operating and financial personnel with a sound understanding of various aspects of Connacher's business to ensure full, plain, true, and timely disclosure of material items based on reliable information. Our objective is to provide useful, understandable, correct and timely information to our shareholders.

Connacher is mindful of safety in the workplace and under the auspices of the HSE Committee, management has developed a Safety Program Manual and has adopted an Emergency Response Plan to deal with possible disasters, including sour gas emissions, for example. A safety video for presentation to all employees, trades, subtrades and suppliers has been developed and rolled out to our various field offices and activity sites, including in Montana where Connacher operates a refinery within the city limits of Great Falls. Our Montana operation has also developed its own safety and emergency response procedures in conjunction with local and State authorities as required by US law.

Connacher has a trading blackout policy which is imposed pursuant to its Disclosure and Insider Trading Policy. This is invoked by the Chief Executive Officer and applies to all employees, insiders as legally defined and related parties of such individuals, including partners. It is generally invoked as soon as a press release is issued and remains in full force and effect for at least two business days thereafter to allow for dissemination of information to the investing public. In some circumstances, the blackout period is extended, especially around the time of release of critical financial and operating results. Insiders also have an overriding obligation to adhere to all prevailing securities laws in respect of inside information and tipping.

Your company is an active supporter, directly and through staff participation and involvement, in various charitable causes in the regions in which it conducts activities. Our internal donations committee appropriately places an emphasis on children, older people, the disabled and the unfortunates in society who are in need of support or encouragement.

Connacher believes it is a fair and sound employer, a good corporate citizen and that it conducts its business in a proper manner. Its constituent parts – the company, the Board of Directors, management and staff – are supporters of good governance practices. An emphasis is placed on strong internal financial and operating controls and this commitment is manifested in the company's reputation as a good place to work, as a good company with which to do business and as a company in which to be a shareholder.

Mindful of its corporate obligations, Connacher regularly consults with stakeholders, including First Nations, in its conduct of business throughout Western Canada.

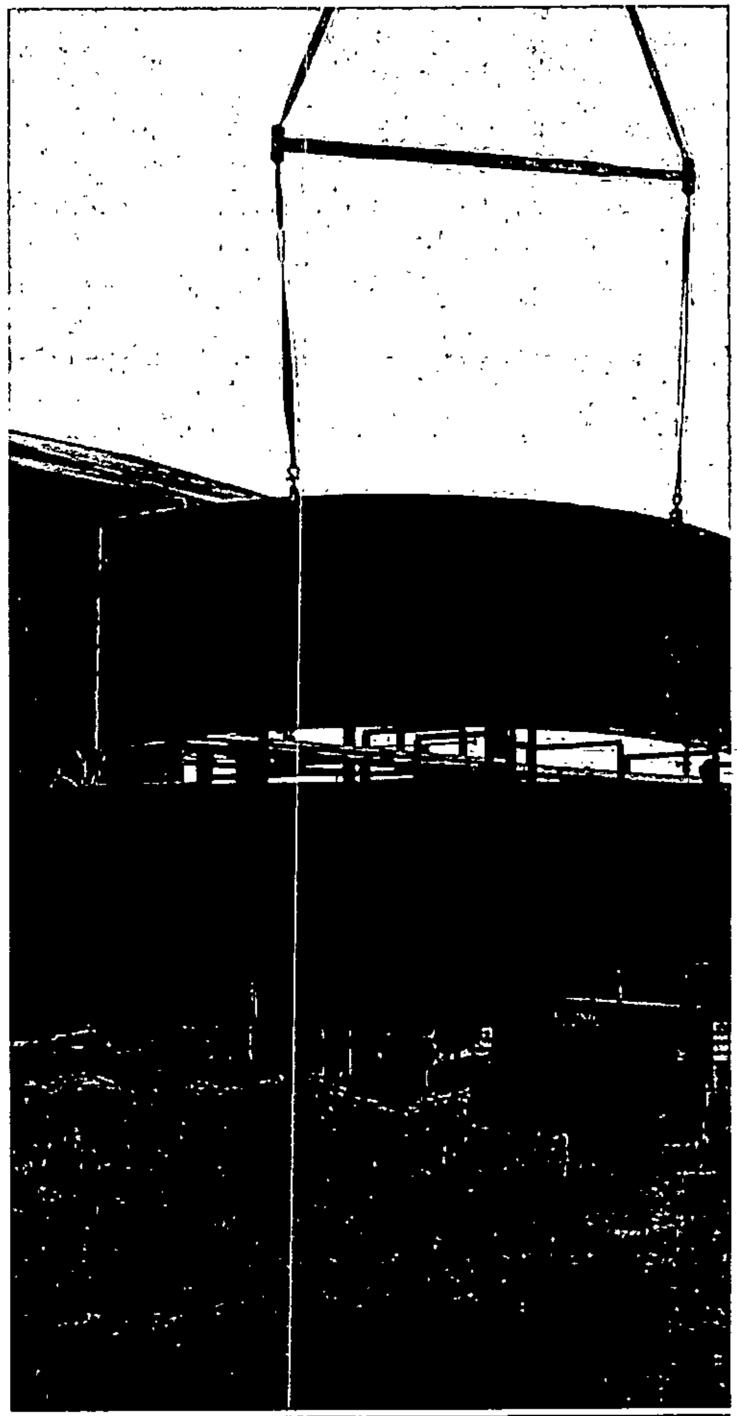


PHOTO: TANK RING INSTALLATION - POD ONE.

Management's Discussion and Analysis

RICHARD R. KINES
Vice President, Finance and
Chief Financial Officer

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.

The following is dated as of March 23, 2007 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 2006 and 2005 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. This MD&A provides management's view of the financial condition of the company and the results of its operations for the reporting periods.

FORWARD-LOOKING INFORMATION

Information in this report contains forward-looking information based on current expectations, estimates and projections of future production, capital expenditures and available sources of financing and estimates of reserves, resources and future net revenues and exploration and development plans. 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, 2006, which include, without limitation, changes in market conditions, law or governing policy, operating conditions and costs, operating performance, demand for crude oil and natural gas, price and exchange rate fluctuations, 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.

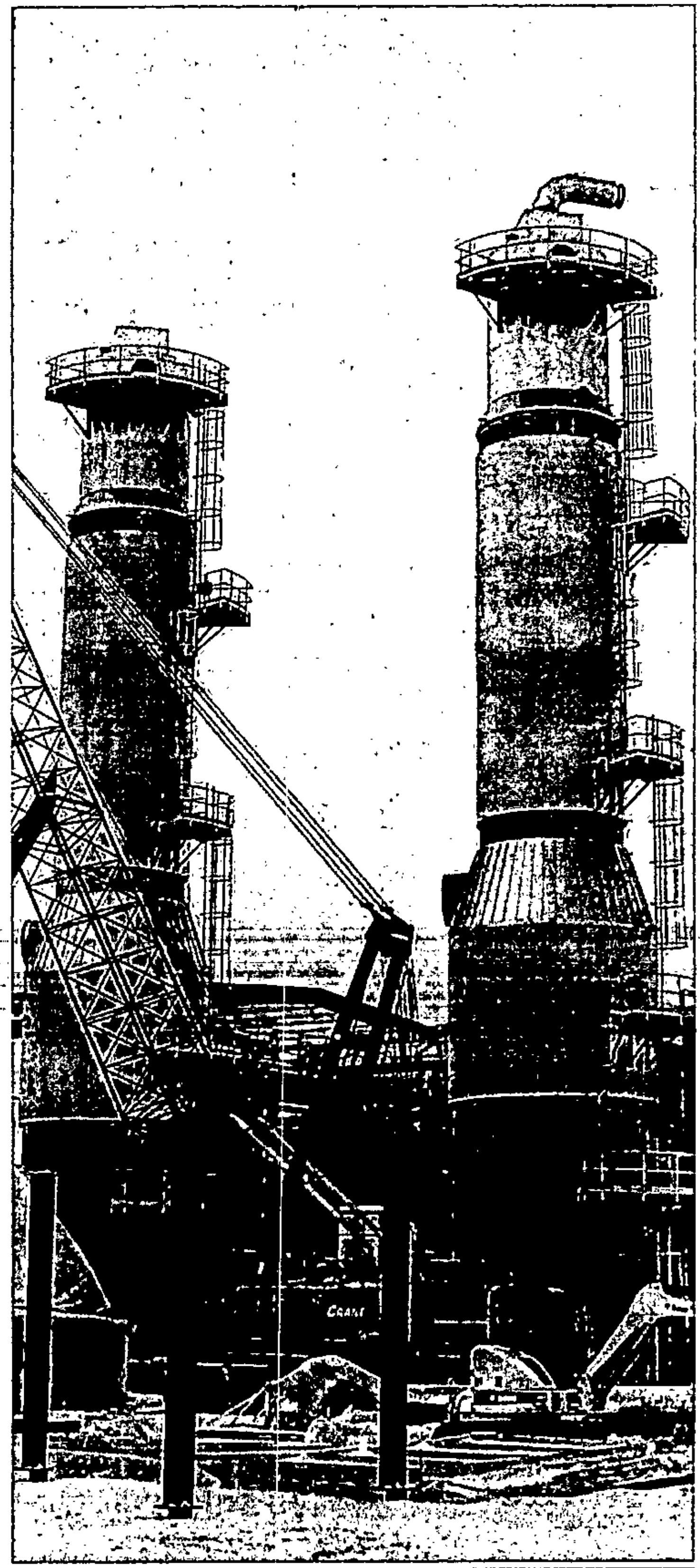


PHOTO: EVAPORATORS AT GREAT DIVIDE POD ONE WITH ONGOING CONSTRUCTION

BUSINESS STRATEGY

Strategic Priorities	Progress in 2006
Operate with large focused working interest	Great Divide – 100% working interest retained through the financing of Pod One Battrum Saskatchewan crude oil and Marten Creek natural gas
Apply financial discipline	Great Divide (Pod One) financing arranged with term debt – non-recourse to conventional assets & equity in Petrolifera Successful equity financings in 2005 and 2006 totalling $220 million Cash flow finances conventional and refinery projects; available banking lines of credit
Focus on projects with characteristics of sustainability, repeatability	Develop Great Divide Pod One and use as a template to develop additional pods
Mitigate and manage risks of smaller company in the oil sands -integrated approach	Purchased Luke Energy Ltd. ("Luke") (gas producer) for natural gas required for steaming Pod One at Great Divide Purchase of Montana refinery to mitigate price differential risk and potential for marketing Great Divide bitumen production Initiatives to mitigate environmental concerns -low impact seismic (minimum line width) -SAGD provides smaller surface footprint than mining -produced gas conserved -evaporator/package boiler

FINANCIAL AND OPERATING REVIEW

CONVENTIONAL PRODUCTION, PRICING AND REVENUE

For the years ended December 31	2006	2005	2004
Daily production / sales volumes			
Crude oil – bbl/d	**980**	729	785
Natural gas – mcf/d	**10,473**	827	1,620
Combined – boe/d	**2,725**	867	1,055
Product pricing ($)			
Crude oil – per bbl	**53.85**	42.33	31.42
Natural gas – per mcf	**5.85**	1.37	3.62
Boe – per boe	**41.83**	36.91	28.95
Revenue ($000)			
Petroleum and natural gas - gross	**41,607**	11,678	11,180
Royalties	**(9,821)**	(2,583)	(2,139)
Petroleum and natural gas revenue - net	**31,786**	9,095	9,041

In 2006, net petroleum and natural gas revenues were up 256.3 percent to $31.8 million from $9.1 million in 2005. This was primarily attributable to a substantial increase in natural gas production resulting from the Luke acquisition in March 2006. Natural gas sales volumes increased 1,166 percent and crude oil sales volumes increased 34 percent in 2006. As a consequence of increased world oil prices in 2006, the company's average crude oil selling price increased by 27 percent to $53.85 per barrel compared to $42.33 per barrel in 2005. Natural gas sales prices increased 327 percent in 2006, but this was primarily due to the influence of low natural gas prices received in Argentina in 2005 when the results of Petrolifera Petroleum Limited ("Petrolifera") were consolidated with those of Connacher. As a result of the Luke acquisition, the company's product mix is more balanced. Crude oil sales represented 46 percent of the company's total production revenue in 2006 and natural gas sales contributed 54 percent.

ROYALTIES ON CONVENTIONAL PETROLEUM AND NATURAL GAS SALES

For the years ended December 31 ($000)	2006		2005	
	Total	**Per boe**	Total	Per boe
Petroleum and natural gas royalties	**$9,821**	**$9.87**	$2,583	$8.16
Percentage of petroleum and natural gas revenue	**23.6%**		22%	

Royalties represent charges against production or revenue by governments and landowners. Royalties in 2006 were $9.8 million ($9.87 per boe, or 23.6 percent of petroleum and natural gas revenue) compared to $2.6 million in 2005 ($8.16 per boe, or 22 percent of petroleum and natural gas revenue).

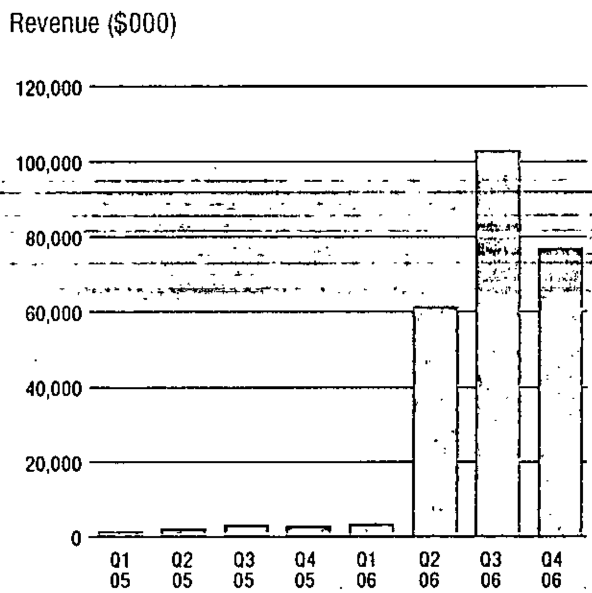
From year to year, royalties can change based on changes to the weighting in the product mix which is subject to different royalty rates, and rates usually escalate with increased product prices. The increase from 2005 to 2006 reflects market conditions related to increased product prices and production volumes.

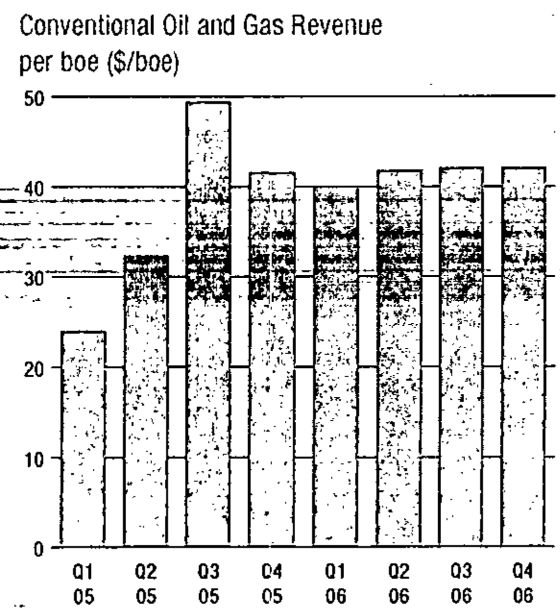
CONVENTIONAL OPERATING EXPENSES AND NETBACKS [1]

For the years ended December 31

($000 except per boe)	2006		2005		% Change	
	Total	Per boe	Total	Per boe	Total	Per boe
Average daily production (boe/d)		2,725		867		
Petroleum and natural gas revenue	**$41,607**	**$41.83**	$11,678	$36.91	256	13
Royalties	**(9,821)**	**(9.87)**	(2,583)	(8.16)	280	21
Net revenue	**31,786**	**31.96**	9,095	28.75	250	11
Operating costs	**(8,270)**	**(8.32)**	(2,445)	(7.73)	238	8
Operating netback	**$23,516**	**$23.64**	$6,650	$21.02	254	13

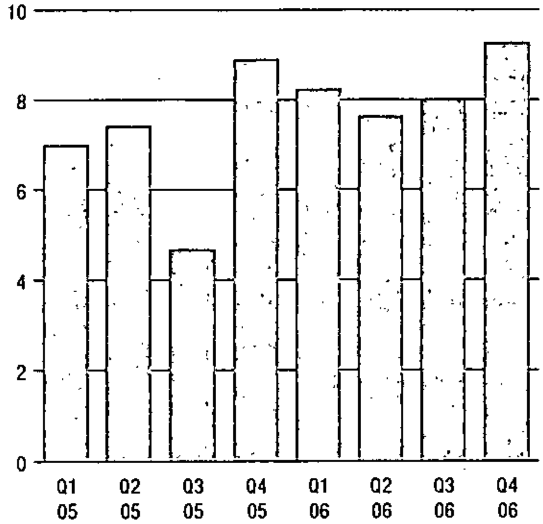
(1) Calculated by dividing related revenue and costs by total boe produced, resulting in an overall combined company netback. Netbacks do not have a standardized meaning prescribed by GAAP and, therefore, may not be comparable to similar measures used by other companies. This non-GAAP measurement is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



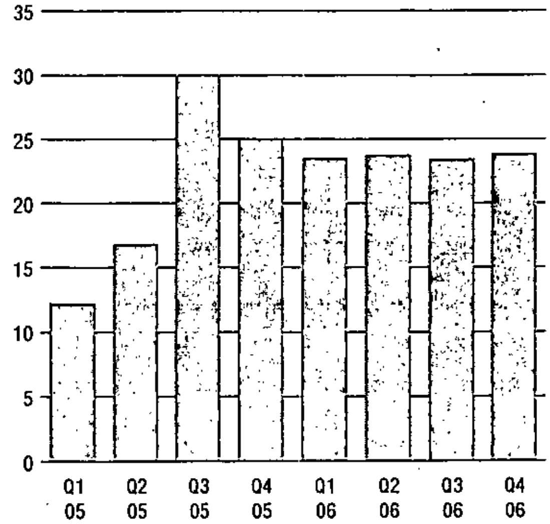


For 2006 operating costs of $8,270 were 238 percent higher than in the prior year, and on a per unit basis, increased by 7.6 percent to $8.32 per boe reflecting the higher cost environment in 2006 and the substantial increases in production volumes during the year. However, higher product prices resulted in higher operating netbacks in 2006.

Conventional Oil and Gas Operating Expense per boe ($/boe)



Conventional Oil and Gas Netbacks per boe ($/boe)



NETBACK BY PRODUCT TYPE

For the year ended December 31	2006			
($000, except per unit amounts)	Oil (bbl/d)		Gas (mcf/d)	
Average daily production	980		10,473	
Revenue	**$19,257**	**$53.86**	**$22,350**	**$5.85**
Royalties	**(4,534)**	**(12.68)**	**(5,287)**	**(1.38)**
Operating costs	**(3,829)**	**(10.71)**	**(4,441)**	**(1.16)**
Netback	**$10,894**	**$30.46**	**$12,622**	**$3.30**

Reconciliation of Operating Netback to Net Earnings

For the year ended December 31	2006		2005	
($000, except per unit amounts)	Total	Per boe	Total	Per boe
Operating netback as above	**$23,516**	**$23.64**	$6,650	$21.02
Interest income	**1,024**	**1.03**	700	2.21
Refining margin - net	**29,206**	**29.36**	-	-
General and administrative	**(3,886)**	**(3.91)**	(2,660)	(8.40)
Stock-based compensation	**(7,816)**	**(7.86)**	(1,192)	(3.77)
Finance charges	**(5,086)**	**(5.11)**	(308)	(0.97)
Foreign exchange (loss) gain	**(4,287)**	**(4.31)**	30	0.09
Depletion, depreciation and amortization	**(32,949)**	**(33.13)**	(5,797)	(18.32)
Income taxes	**(3,870)**	**(3.89)**	(870)	(2.75)
Equity interest in Petrolifera earnings and dilution gain	**11,101**	**11.16**	4,437	14.02
Net earnings	**$6,953**	**$6.98**	$991	$3.13

REFINING REVENUES AND MARGINS

The operating results of the Montana refinery since its acquisition on March 31, 2006 to December 31, 2006 are summarized below.

Seasonality of Refining Operations and Sales

The Montana refinery is subject to a number of seasonal factors which may cause product sales revenues to vary throughout the year. The refinery's primary asphalt market is paving for road construction which is predominantly a summer demand. Consequently, prices and volumes for our asphalt tend to be higher in the summer and lower in the colder seasons and during the winter most of the refinery's asphalt production is stored in tankage for sale in the subsequent summer. Seasonal factors also affect gasoline (higher demand in summer months) and distillate and diesel (higher winter demand). As a result, inventory levels, sales volumes and prices can be expected to fluctuate on a seasonal basis.

Refinery Throughput

Crude charged	8,713 bbl/d
Refinery production	9,498 bbl/d
Sales of produced refined products	9,661 bbl/d
Sales of refined products (includes purchased products)	10,053 bbl/d
Refinery utilization [1]	94%

(1) Note in Q4 refinery capacity was increased to 9,900 bbl/d.

Feedstocks

Sour crude oil	92%
Other feedstocks & blend	8%

Revenues and Margins

Refining sales revenue ($000)	211,874
Refining – crude oil and operating costs ($000)	182,668
Refining – margin ($000)	29,206
Refining margin (%)	13.8%

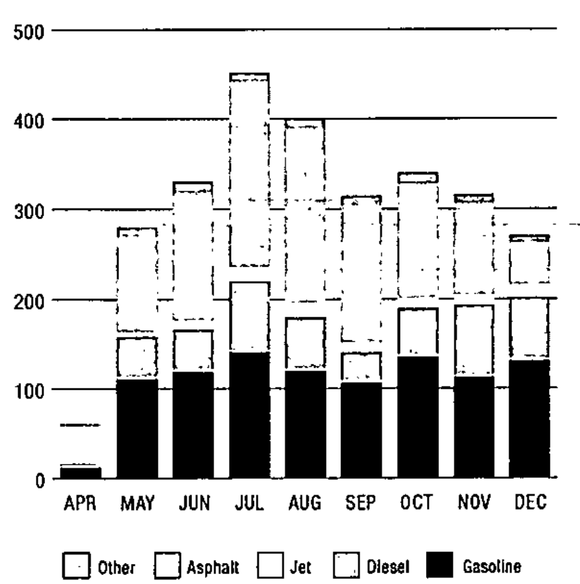
Sales of Produced Refined Products (Volume %)

Gasolines	35.6%
Diesel fuels	17.6%
Jet fuels	3.4%
Asphalt	40.2%
LPG and other	3.2%
Total	100%

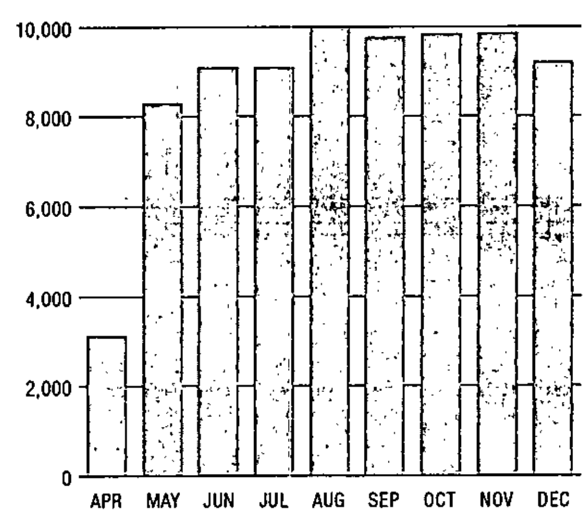
Averages Per Barrel of Refined Products Sold

Refining sales revenue	$76.63
Less: Refining – crude oil and operating costs	$66.07
Refining margin	$10.56

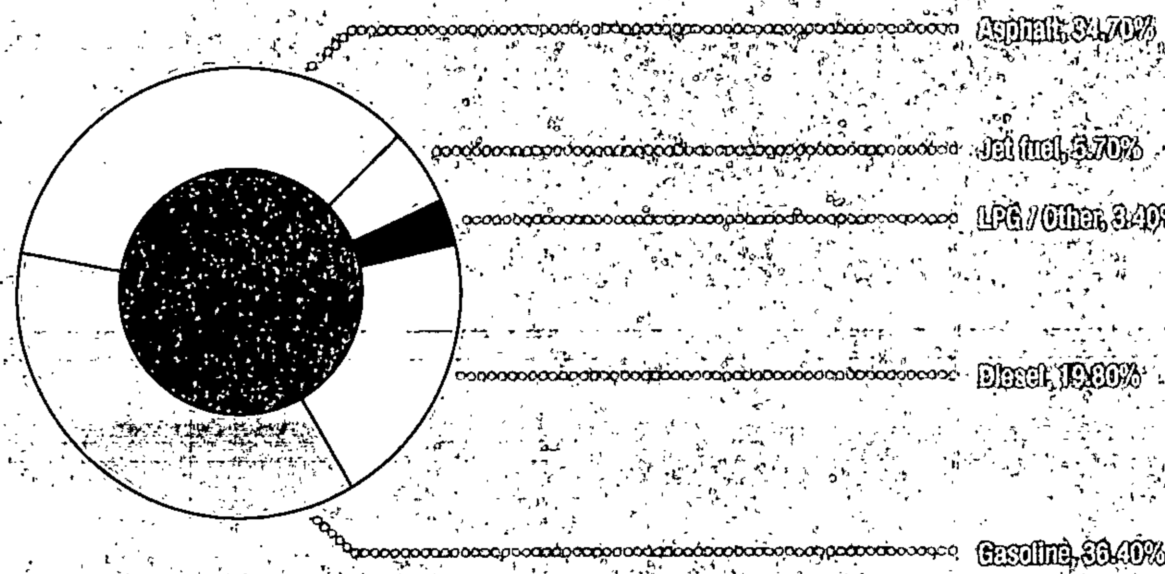
2006 Refined Product Sales (000 bbls/month)



2006 Montana Refining Crude Throughput (bbls/d)



2006 Refined Product Production (Volume %)



On March 31, 2006, Connacher completed the acquisition of an 8,300 bbl/d refinery and related assets, including substantial product inventory, in Great Falls, Montana.

The refinery is a good strategic fit with Connacher's oilsands development, as it is well-located – the closest U.S. refinery to Alberta's oilsands. It processes Canadian heavy crude into a range of higher value products including regular and premium gasoline, jet fuel, diesel, home heating oil and asphalt. The refinery thus provides a physical hedge protecting Connacher's future oil sands revenues against crude oil/bitumen price differentials.

The Montana refinery is a complex operation and includes reforming, isomerization and alkylation processes for formulation of gasoline blends, hydro-treating for sulphur removal and fluid catalytic cracking for conversion of heavy gas oils to gasoline and distillate products. It also is a major supplier of paving grade asphalt, polymer modified grades and asphalt emulsions for road construction. The Montana refinery markets products to retailers in Montana and neighbouring states by truck and rail transport.

Shortly after taking over the refinery, the company undertook a 20 day turnaround to complete normal maintenance and de-bottlenecking activities. As a result, throughput capacity was increased to 9,000 bbl/d. Through the year, subsequent optimizations have increased crude throughput capacity to 9,900 bbl/d. Since the turnaround, the refinery has operated continuously with no downtime and crude throughput has averaged 9,400 bbl/d with an average annual capacity utilization of 94%.

Connacher's refinery operation achieved an outstanding year in 2006 with record levels of throughput, profit and profit margin. This performance was due to improved efficiencies implemented subsequent to the acquisition, increased throughput and sales volumes, and high product prices and differentials for the heavy crude feedstocks used as a result of market conditions.

During the year, the company also made significant environmental improvements to the operation. These included capital projects to remove excess sulphur from boiler fuel and recovery and remediation of an old wastewater aeration pond. Sulphur removal in the boiler fuel has now been improved by over 200 times from the previous operation. Sulphur removal is accomplished by means of a unique process which converts the sulphur to a product now being used commercially for environmental remediation in other parts of the U.S.

Other improvements initiated during the year included the construction of a new 150,000 barrel asphalt tank (commissioned in March 2007) and expanded rail loading facilities, both undertaken to handle the increased throughput achieved during the year.

Connacher employs a well-trained and experienced staff in the Montana refinery. The company was successful in retaining most of the key personnel associated with the refinery, as well as recruiting a number of other experienced professionals. Key processes and systems have been fully integrated into the company. Connacher's operation includes a strong training and development program as well as rigorous procedures for safety and environmental protection.

In 2007, Connacher plans to continue making environmental and capacity enhancements at the Montana refinery. We are designing new high efficiency boilers, further increasing rail load-out capabilities, improving wastewater treatment facilities, and further enhancing our sulphur treatment process.

As well, Connacher has initiated a major Clean Fuels project targeted to allow the production of ultralow sulphur diesel and gasoline in 2008.

Engineering and marketing studies have also been initiated to assess the possibility of major expansion of the refinery's heavy oil capacity.

INTEREST AND OTHER INCOME

In 2006, the company earned interest of $1 million (2005 - $700,000) on excess funds invested in secure short-term investments.

GENERAL AND ADMINISTRATIVE EXPENSES

In 2006, general and administrative ("G&A") expenses were $3.9 million compared to $2.7 million in 2005, an increase of 46 percent, reflecting increased costs associated with being a public company as well as increased staffing that occurred in 2006 in connection with the acquisition of the Montana refinery and to support the development of Great Divide. G&A of $1.0 million was also capitalized in 2006 (2005 - $205,000).

Non-cash stock-based compensation costs of $11.8 million were recorded in 2006 (2005-$1.6 million). These charges reflect the fair value of all stock options granted and vested in each year. Of this amount, $7.8 million was expensed (2005 - $1.2 million), $3.5 million was capitalized (2005 - $410,000) and $500,000 was charged to refining operating costs in 2006.

FINANCE CHARGES

Financing charges were $5.1 million in 2006 compared to $308,000 reported in 2005. These charges increased significantly from 2005 due to the issuance of debt in 2006, including the US$51 million bridge loan used to fund the acquisition of the Montana refinery and the conventional line of credit. In addition, an unrealized foreign exchange loss of $4.3 million was incurred in 2006 primarily due to the conversion of US$180 million oil sands term loan to Canadian dollars for reporting purposes.

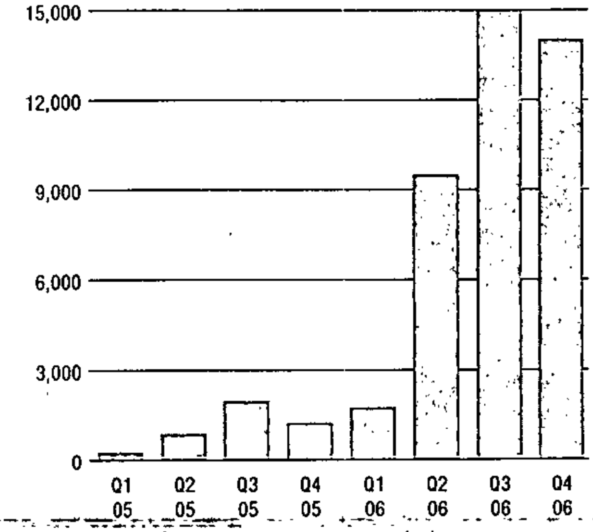
The company's main exposure to foreign currency risk relates to the pricing of its crude oil sales, which are denominated in US dollars, and the translation of the US$180 million oil sands term loan. On an economic basis, the company's crude oil and bitumen reserves hedge the company's exposure to foreign currency fluctuations of its US dollar denominated oil sands term loan.

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 2006 was $32.9 million, a 468 percent increase from last year due to increased production volumes and due to the significant additions made to capital assets in 2006. This equates to $33.13 per boe of production compared to $18.32 per boe last year.

Capital costs of $156.7 million (2005 – $11.3 million) related to the Great Divide oil sands project, which is in the pre-production stage and undeveloped land acquisition costs of $16.2 million (2005 – $2.5 million) were excluded from the depletion calculation; while future development costs of $3.2 million (2005 - $1.8 million) for proved undeveloped reserves were included in the depletion calculation.

Cash flow ($000)



Included in DD&A is a charge of $348,000 (2005 - $165,000) 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 $7.3 million to the estimated total undiscounted liability of $17.4 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 2006 or 2005.

TAXES

The income tax provision of $3.9 million in 2006 includes a current tax provision of $7.4 million, principally related to US refinery operations and a future income tax recovery of $3.5 million reflecting the benefit of increased tax pools during the year.

At December 31, 2006 the company had approximately $25.8 million of non-capital losses which do not expire before 2009, $253.5 million of deductible resource pools and $20.7 million of deductible financing costs.

EQUITY INTEREST IN PETROLIFERA PETROLEUM LIMITED

Connacher accounts for its 26 percent equity investment in Petrolifera on the equity method basis of accounting. Until the third quarter of 2005, Petrolifera was consolidated with Connacher. Connacher's equity interest share of Petrolifera's earnings in 2006 was $11.1 million (2005 - $27,000 loss)

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, in late 2005, it was reduced to 33 percent and in 2006 it was further reduced to 26 percent. These reductions resulted in a dilution gain to the company of $23,000 in 2006 and $4.5 million in 2005.

NET EARNINGS (LOSS)

In 2006 the company reported earnings of $7.0 million ($0.04 per basic and diluted share outstanding). This compares to earnings of $991,000 or $0.01 per basic and diluted share for 2005. Earnings per boe produced was $6.98 compared to $3.13 last year.

SHARES OUTSTANDING

For 2006, the weighted average number of common shares outstanding was 184,468,631 (2005 – 106,113,563) and the weighted average number of diluted shares outstanding, as calculated by the treasury stock method, was 188,431,809 (2005 – 111,845,687). The substantial increase in shares outstanding year over year reflects the issuance from treasury of 55,461,382 common shares for cash proceeds of $130 million and in connection with the acquisitions of Luke and the Montana refinery assets.

As at March 23, 2007, the company had the following securities issued and outstanding:

- 198,218,448 common shares; and
- 15,840,051 share purchase options.

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

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2006, the company had working capital of $118.6 million, including $121 million of cash dedicated to funding the remaining costs of completing Pod One.

In 2006 the company drew US$51 million on a bridge loan facility to partially fund the acquisition of the Montana refinery assets, which closed on March 31, 2006. This bridge loan was repaid in full on October 20, 2006 from the proceeds of a US$180 million term loan facility that was fully drawn on that date (the "oil sands term loan"). The primary purpose of the oil sands term loan is to fund the development of the company's first oil sands project at Great Divide in northern Alberta ("Pod One"). After also depositing US$14 million into an account to fund the estimated interest costs during the course of completing the Pod One project and after paying US$4 million in costs to complete the transaction, the balance of oil sands term loan proceeds have been designated solely to fund the total estimated remaining costs necessary to complete Pod One.

The oil sands term loan has a seven year term. Its principal is amortized by one percent per year commencing in 2008. Additional repayments will be due if certain cash flow performance thresholds are attained. Principal payments on the oil sands term loan are not expected to be significant in the first six years. The oil sands term loan is a floating-rate facility, bearing interest either at a US Dollar Base Rate plus a margin or a US Eurodollar rate plus a margin. In October 2006, the company entered into an interest rate swap with a financial institution whereby the floating rate on US$90 million of the oil sands term loan was fixed at an all-in rate of 8.516 percent over the term of the loan. All interest on the oil sands term loan is being capitalized until Pod One becomes operational.

On October 20, 2006 the company also secured a US$15 million revolving line of credit ("refining line of credit") to fund the working capital requirements of the refinery in Great Falls, Montana. The refining line of credit has a five year term and bears interest at a US Eurodollar rate plus a margin or at a US Dollar Base Rate plus a margin.

The oil sands term loan and the refining line of credit are secured by debenture and mortgage agreements covering all of the assets of the refinery and all of the company's interest in the Great Divide oil sands assets. These two facilities are non-recourse to the company's conventional petroleum and natural gas assets or to its investment in Petrolifera.

The company also has available a $55 million Extendible Revolving Loan Facility (the "Conventional line of credit") with no scheduled repayments. At December 31, 2006, $19.5 million was drawn in the form of bankers acceptances under this facility at an interest rate of 5.62 percent including margin. The facility matures on April 15, 2007 and is extendible upon request by the company, at the lender's option for 364 days. The conventional line of credit is secured by a $50 million fixed and floating charge debenture and a general assignment of book debts over the company's conventional crude oil and natural gas assets, and is non-recourse to the company's Great Divide oil sands, its refining assets or to its investment in Petrolifera.

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 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 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 boe) 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.

In addition to available cash, unused debt facilities and cash flow, additional sources of funding in the form of additional equity issuances or additional debt financing may be utilized to provide sufficient funding for working capital purposes and for the company's anticipated capital program in 2007.

The company's only financial instruments are cash, accounts receivable and payable, bank debt and the interest rate swap. The company maintains no off-balance sheet financial instruments.

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

	Twelve months ended December 31	
($000)	**2006**	2005
Net earnings	**$6,953**	$991
Items not involving cash:		
Depletion, depreciation and accretion	**32,949**	5,797
Stock-based compensation	**8,293**	1,192
Financing charges	**2,237**	150
Future income tax provision (recovery)	**(3,535)**	768
Employee future benefits	**381**	–
Foreign exchange (gain) loss	**4,287**	(30)
Lease inducement amortization	**(268)**	(72)
Dilution gain	**(23)**	(4,465)
Equity interest in Petrolifera loss (earnings)	**(11,078)**	27
Cash flow from operations before working capital changes	**$40,196**	$4,358

For 2006, cash flow was $40.2 million ($0.22 per basic and $0.21 per diluted share), 822 percent higher than the $4.4 million reported ($0.04 per basic and diluted share) in 2005.

Cash flow per boe was $40.41 in 2006 compared to $13.77 in 2005. This represents 97 percent of the average company selling price per boe compared to 37 percent in 2005 and an increase of 193 percent over 2005.

CAPITAL EXPENDITURES AND FINANCING ACTIVITIES

Capital expenditures totaled $452 million in 2006. A breakdown of the expenditures follows:

($000)	Twelve months ended December 31 2006	2005
Acquisition of Luke	**$204,658**	$-
Acquisition of refinery assets	**66,333**	-
Minor property acquisitions	**6,767**	1,700
Oil sands expenditures	**144,765**	7,224
Conventional oil and gas expenditures	**23,152**	7,783
Refinery expenditures	**5,850**	-
	$451,525	$16,807

Additionally, the company disposed of non-core properties for proceeds of $10 million in the fourth quarter of 2006.

Oil sands expenditures include exploratory core hole drilling, seismic, lease acquisition and facility costs. In 2006, 26 exploratory core holes were drilled.

Conventional oil and gas expenditures include costs of drilling, completing, equipping and working over conventional oil and gas wells as well as undeveloped land acquisition and seismic expenditures.

A significant part of the company's capital program is 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 approximate 87 percent working interest in its conventional properties, providing the company with operational and timing controls.

Recent Financings

In February 2006, 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 partially fund the acquisition of Luke. Proceeds of the financing were utilized as follows:

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

In September 2006, the company issued 5,714,300 common shares on a "flow-through" basis at $5.25 per common share for gross proceeds of $30 million to fund exploration activities including the further delineation of the company's oil sands properties through the drilling of additional core holes and shooting 3D seismic. Proceeds of the financing were utilized as follows:

($000)	As stated at the time of financing	As actually applied
Gross proceeds	$30,000	$30,000
Underwriters commission and issue costs	2,075	1,883
Available for exploration activities	$27,925	$28,117

Refer also to the "Liquidity and Capital Resources," above, for a discussion of the US$180 million and US$15 million debt facilities entered into in October 2006.

Great Divide Oil Sands Project, Northern Alberta

The company holds a 100 percent working interest in approximately 90,000 acres of oil sands leases in northern Alberta. To date, the focus has been on an approximate 1,586 acre tract ("Pod One") on which approximately $155 million has been invested to the end of 2006 to acquire the oil sands leases, to delineate the oil bearing reservoir, and for certain facilities related to the project. Capital development costs for Pod One are expected to approximate $256 million. These costs will be incurred in 2007.

Acquisition of Luke Energy Ltd. ("Luke")

In March 2006 the company closed the purchase of Luke for cash consideration of $92.7 million and the issuance of 29.7 million Connacher common shares from treasury.

Luke produced natural gas, largely at Marten Creek in northern Alberta and operated 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 SAGD oil sands project (Pod One) at Great Divide. Based on purchased production volumes and anticipated development programs, the Luke purchase is expected to provide surplus natural gas volumes for sale in the marketplace and meet future Connacher requirements at Great Divide. Luke was amalgamated with Connacher on January 1, 2007.

Acquisition of Refining Assets in Montana

In March 2006, the company acquired an 8,300 bbl/d refinery located in Great Falls, Montana, USA, for cash of $61 million and one million Connacher common shares issued from treasury.

This acquisition was considered strategic to provide Connacher with protection against wider and more volatile type of heavy crude oil price differential swings. These have become increasingly frequent in the current higher oil price environment for the type of heavy oil which would be produced at Great Divide. Since its acquisition, the refinery has been a profitable and strong business unit contributing to the company's cash flow.

Connacher completed the purchase of the refining assets and related inventory through a new wholly-owned subsidiary, Montana Refining Company, Inc. ("MRC"). Its continued profitability will depend largely on the spread between market prices for refined petroleum products and the cost of crude oil.

MRC's principal source of revenue is from the sale of high value light end products such as gasoline, diesel and jet fuel in markets in the western United States. Additionally, MRC sells a high grade asphalt into the local market. MRC's principal expenses relate to crude oil purchases and operating expenses.

In April 2006, MRC completed a scheduled plant "turnaround" maintenance program of its refinery facilities. Such turnarounds are normally scheduled every two to five years. Turnaround costs are capitalized and amortized over the period to the next scheduled turnaround.

With minimal additional anticipated capital investment, MRC will be capable of producing low sulfur gasoline and diesel as required in 2008.

The above mentioned regulatory compliance items or other presently existing or future environmental regulations, could cause management to make additional capital investments beyond those described above and/or incur additional operating costs to meet applicable requirements.

In 2004, the American Jobs Creation Act of 2004 was signed into law. Among other things, the Act creates tax incentives for small refiners preparing to produce low sulphur gasoline and diesel. The Act provides an immediate deduction of 75% of certain costs paid or incurred to comply with tthese standards and a tax credit based on production for up to 25% of those costs. Management intends to utilize these incentives when it makes these required expenditures.

RELATED PARTY TRANSACTIONS

In 2006 the company paid professional legal fees of $1.8 million (2005 - $539,000) to a law firm in which an officer and director of the company are partners. 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 estimates and assumptions may have a material impact on the company's financial results and condition. The following discusses such accounting policies and is included herein 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 its estimates and assumptions regularly. The emergence of new information and changed circumstances may result in changes to estimates and assumptions 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 regulatory 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 of 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 company's oil and gas reserve estimates are made by independent reservoir engineers 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

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 is depleted using the unit-of-production method based on estimated proved oil and gas reserves.

Major Development Projects and Unproved Properties

Certain costs related to acquiring and evaluating unproved properties are excluded from net capitalized costs subject to depletion until proved reserves have been determined or their value is impaired. Costs associated with major development projects are not depleted until commencement of commercial production. All capitalized 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.

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 prepared by qualified independent evaluators, 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 costs as estimated by the company's engineers adjusted for inflation and credit risk. These estimates are subject to management uncertainty.

Legal, Environmental 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.

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 income tax asset and liability amounts are enacted tax rates expected to be used in future periods when the timing differences reverse. 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 charge for future income 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 estimates of stock volatility, interest rates and the term of the option. These estimates by their nature are subject to measurement uncertainty.

NEW SIGNIFICANT ACCOUNTING POLICIES

The company has assessed new and revised accounting pronouncements that have been issued but that are not yet effective and has determined that the following may have a significant impact on the company.

Beginning with the year ending December 31, 2007 the company will be required to adopt, if applicable, the Canadian Institute of Chartered Accountants ("CICA") Sections 1530, 3251, 3855 and 3865 on "Comprehensive Income", "Equity", "Financial Instruments – Recognition and Measurement", and "Hedges" respectively, all of which were issued in January 2005. Under the new standards additional financial statement disclosure, namely Consolidated Statement of Other Comprehensive Income, has been introduced that will identify certain gains and losses, including the foreign currency translation adjustments and other amounts arising from changes in fair value, to be temporarily recorded outside the income statement. In addition, all financial instruments, including derivatives, are to be included in the company's Consolidated Balance Sheet and measured, in most cases, at fair values. Requirements for hedge accounting have been further clarified. Although Connacher is in the process of evaluating the impact of these standards, the company does not expect these standards to have a material impact on its Consolidated Financial Statements.

Over the next five years the CICA will adopt its new strategic plan for the direction of accounting standards in Canada, which was ratified in January 2006. As part of the plan, Canadian GAAP for public companies will converge with International Financial Reporting Stands ("IFRS") over the next five years. The company continues to monitor and assess the impact of the convergence of Canadian GAAP with IFRS.

MRC's financial results are reported in accordance with Canadian GAAP and are consolidated with Connacher's other business units. The preparation of MRC's financial results require certain estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities as of the date of the financial statements. Actual results may differ from those estimates under different assumptions or conditions. Connacher's management considers the following new MRC accounting policies to be the most critical to understanding the judgments that are involved and the uncertainties that could impact on the company's results of operations, financial condition and cash flows.

Inventory Valuation

Crude oil and refined product inventories are stated at the lower of cost or net realizable value. Since acquiring the refining assets in March 2006, management re-evaluated the inventory costing method and has chosen the average cost method in order to conform to impending Canadian GAAP changes. The effect of this change was to decrease inventory by $2.1 million at December 31, 2006 (see Note 4 to the Consolidated Financial Statements). Net realizable value is determined using current estimated selling prices.

Deferred Maintenance Costs

MRC's refinery units require regular major maintenance and repairs which are commonly referred to as "turnarounds". Catalysts used in certain refinery processes also require routine "change-outs". The required frequency of the maintenance varies by unit and by catalyst, but generally is every two to five years. Turnaround costs are capitalized and amortized over the period to the next scheduled turnaround or change-out. In order to minimize downtime during turnarounds, contract labor as well as maintenance personnel are utilized on a continuous 24 hour basis. Whenever possible, turnarounds are scheduled so that some units continue to operate while others are down for maintenance. The costs of turnarounds are recorded as deferred charges and are amortized over the expected periods of benefit.

Employee Future Benefits

As a consequence of the refinery acquisition and related employment of refinery personnel, the company's new US subsidiary, MRC, adopted new employee future benefit plans with effect from March 31, 2006.

A new non-contributory defined benefit retirement plan covers only MRC's employees from March 31, 2006. MRC's policy is to make regular contributions in accordance with the funding requirements of the United States Employee Retirement Income Security Act of 1974. Benefits are to be based on the employee's years of service and compensation.

MRC also established new defined contribution (US tax code "401(k)") plans that cover all of its employees from March 31, 2006. The company's contributions are based on employees' compensation and partially match employee contributions.

Long-lived Refining Assets

Depreciation and amortization is calculated based on estimated useful lives and salvage values. When assets are placed into service, estimates are made with respect to their useful lives that are believed to be reasonable. However, factors such as new technologies, competition, regulation or environmental matters could cause changes to estimates, thus impacting the future calculation of depreciation and amortization. Long-lived assets are also evaluated for potential impairment by identifying whether indicators of impairment exist and, if so, assessing whether the long-lived assets are recoverable from estimated future undiscounted cash flows. The actual amount of impairment loss, if any, to be recorded is equal to the amount by which a long-lived asset's carrying value exceeds its fair value. Estimates of future discontinued cash flows and fair values of assets require subjective assumptions with regard to future operating results and actual results could differ from those estimates.

Goodwill

Goodwill arose on the acqusition of Luke in 2006.

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed for impairment annually. Goodwill and all other assets and liabilities have been allocated to the company's segments, referred to as reporting units. To assess impairment, the fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount.

RISK MANAGEMENT - MRC

Certain strategies could be used to reduce some commodity prices and operational risks. No attempt will be made to eliminate all market risk exposures when it is believed the exposure relating to such risk would not be significant to future earnings, financial position, capital resources or liquidity or that the cost of eliminating the exposure would outweigh the benefit. MRC's profitability will depend largely on the spread between market prices for refined products sold and market prices for crude oil purchased. A substantial or prolonged reduction in this spread could have a significant negative effect on earnings, financial condition and cash flows.

Petroleum commodity futures contracts could be utilized to reduce exposure to price fluctuations associated with crude oil and refined products. Such contracts could be used principally to help manage the price risk inherent in purchasing crude oil in advance of the delivery date and as a hedge for fixed-price sales contracts of refined products. Commodity price swaps and collar options could also be utilized to help manage the exposure to price volatility relating to forecasted purchases of natural gas. Contracts could also be utilized to provide for the purchase of crude oil and other feedstocks and for the sales of refined products. Certain of these contracts may meet the definition of a hedge and may be subject to hedge accounting.

The supply and use of heavy crude oil from the company's Great Divide Oil Sands Project, as a feedstock for the refinery, would provide a physical hedge to this exposure, as planned.

MRC's operations are subject to normal hazards of operations, including fire, explosion and weather-related perils. Various insurance coverages, including business interruption insurance, are maintained in accordance with industry practices.

However, MRC is not fully insured against certain risks because such risks are not fully insurable, coverage is unavailable, or, in management's judgment, premium costs are prohibitive in relation to the perceived risks.

Additionally, the company has recently issued parental guarantees and indemnifications on behalf of MRC. This is considered to be in the normal course of business. The company has not entered into any off-balance sheet arrangements.

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 foreign 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 will require a significant amount of natural gas in order to generate steam for the SAGD process used at Great Divide. The company is exposed to the risk of changes in the price of natural gas, which could increase operating costs of the Great Divide project. This risk is mitigated to a certain extent by the production and sale of natural gas from the company's gas properties at Marten Creek acquired with the purchase of Luke.

Additionally, the company is exposed to exchange rate fluctuations since oil prices and its long term debt are denominated in US dollars, while the majority of its operating and capital costs are denominated in Canadian dollars. On an economic basis, the company's crude oil and bitumen reserves hedge the company's exposure to foreign currency fluctuations of its US dollar denominated oil sands term loan.

Bitumen is generally less marketable than light or medium crude oil, and prices received for bitumen are generally lower than those for crude oil. The company is therefore exposed to the price differential between crude oil and bitumen; fluctuations in this differential could have a material impact on the company's profitability. The purchase of the Montana Refinery was meant to help mitigate the risk exposure.

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.

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

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

Contractual obligations ($000)	2007	2008-2010	2011-2012	Subsequent to 2012	Total
Term debt and short-term loans	$19,500	$2,360	$4,079	$205,296	$231,235
Asset retirement obligations	166	31	75	7,050	7,322
Operating leases	1,426	6,355	3,323	7,649	18,753
Employee future benefits	488	-	-	-	488
Other long term obligations	638	1,069	-	-	1,707
Total	$22,218	$9,815	$7,477	$219,995	$259,505

The above table excludes ongoing crude oil and refined product purchase commitments of the Montana refinery which are in the normal course of business and are contacted at market prices, where the products are for resale into the market.

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 arrangements.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the company is accumulated, recorded, processed and reported to the company's management as appropriate to allow timely decisions regarding required disclosure. The company's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaulation as of the end of the period covered by this MD&A, that the company's disclosure controls and procedures as of the end of such period are effective to provide reasonable assurance that material information related to the company, including its consolidated subsidiaries, is communicated to them as appropriate to allow timely decisions regarding required disclosure.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of the company is responsible for designing adequate internal controls over the company's financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP.

It should be noted that while the company's Chief Executive Officer and Chief Financial Officer believe that the company's disclosure controls and procedures provide a reasonable level of assurance that they are effective and that the internal controls over financial reporting are adequately designed, they do not expect that the financial disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

FOURTH QUARTER

During the fourth quarter of 2006, the company drew down in full the US$180 million oil sands term loan in order to secure financing for the costs of completing Pod One at the Great Divide project and to repay the bridge loan incurred to purchase the Montana refinery. Spending during the fourth quarter related to Pod One amounted to approximately $65 million.

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. Additional financing may be required for the Great Divide Oil Sands Project, the company's conventional petroleum and natural gas assets and for the Montana refinery.

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

QUARTERLY RESULTS

Fluctuations in results over the previous eight quarters are due principally to variations in oil and gas prices and the acquisitions of Luke Energy and the Montana refinery in 2006, both of which increased revenues substantially. Additionally, operating and general and administrative costs increased due to higher staff levels necessitated by the company's growth. Depletion, depreciation and amortization increased as a result of higher production volumes and additions to capital assets.

	2005				2006			
Three Months Ended	Mar 31	Jun 30	Sept 30 [3]	Dec 31	Mar 31	Jun 30	Sept 30	Dec 31
Financial Highlights ($000 except per share amounts) – Unaudited								
Revenue net of royalties	1,488	2,107	3,222	2,978	3,635	61,239	103,110	76,700
Cash flow from operations before working capital changes [1]	265	877	1,978	1,238	1,725	9,499	14,957	14,015
Basic, per share [1]	-	0.01	0.02	0.01	0.01	0.05	0.08	0.08
Diluted, per share [1]	-	0.01	0.02	0.01	0.01	0.05	0.08	0.07
Net earnings (loss)	1,673	(230)	(1,034)	582	(666)	(2,419)	6,771	3,267
Basic and diluted per share	0.02	-	(0.01)	-	-	(0.01)	0.03	0.02
Capital expenditures	6,047	5,649	2,870	2,241	300,836	34,280	41,449	74,960
Proceeds on disposal of PNG properties	-	-	-	-	-	-	-	10,000
Bank debt	-	250	-	-	17,600	70,365	62,380	229,254
Working capital surplus (deficiency)	5,588	854	67,440	75,427	(11,061)	(42,483)	(39,942)	118,626
Cash on hand	8,286	2,629	67,708	75,511	-	7,505	14,450	142,391
Shareholders' equity	41,079	41,090	113,081	129,108	337,584	340,639	378,730	385,398
Operating Highlights								
Production / sales volumes								
Natural gas - mcf/d	1,328	1,416	497	86	2,600	15,172	12,711	11,291
Crude oil - bbl/d	629	702	808	775	689	1,026	1,059	1,139
Equivalent - boe/d [2]	850	938	891	789	1,122	3,554	3,177	3,021
Pricing								
Crude oil - $/bbl	30.02	41.23	53.40	41.54	40.93	61.45	62.53	46.65
Natural gas - $/mcf	1.18	0.99	1.88	7.55	6.34	5.66	5.33	6.57
Selected Highlights - $/boe [2]								
Weighted average sales price	24.04	32.35	49.48	41.61	39.83	41.88	42.16	42.15
Royalties	4.82	8.06	11.73	7.76	8.02	10.43	10.72	9.00
Operating costs	7.01	7.42	7.69	8.90	8.24	7.63	7.99	9.27
Operating netback [4]	12.21	16.87	30.06	24.95	23.57	23.82	23.45	23.88
Common Share Information								
Shares outstanding at end of period (000)	92,753	93,013	134,236	139,940	191,257	191,924	197,878	197,894
Weighted average shares outstanding for the period								
Basic (000)	91,189	92,875	103,851	136,071	154,152	191,672	193,587	193,884
Diluted (000)	94,197	95,555	106,397	142,507	160,574	198,931	200,572	204,028
Volume traded during quarter (000)	40,486	16,821	180,848	100,246	148,184	80,347	48,849	46,444
Common share price ($)								
High	1.22	1.05	2.69	4.20	6.07	5.05	4.55	4.43
Low	0.49	0.68	0.76	1.09	3.47	3.10	3.09	3.17
Close (end of period)	0.93	0.82	2.54	3.84	4.95	4.30	3.60	3.49

(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. Boe 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.

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 they are properly discharging their 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 21, 2007

Signed,

"R. R. Kines"

Vice President, Finance and Chief Financial Officer
March 21, 2007

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, 2006 and 2005 and the consolidated statements of operations and retained earnings and cash flow for the years then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Calgary, Alberta
March 21, 2007

Signed,
"DELOITTE & TOUCHE LLP"
Chartered Accountants

CONSOLIDATED BALANCE SHEETS

($000)	2006	2005
ASSETS		
CURRENT		
Cash and cash equivalents	**$19,603**	$75,511
Restricted cash (Note 15(c))	**122,788**	-
Accounts receivable	**30,956**	1,605
Refinery inventories (Note 4)	**24,437**	-
Due from Petrolifera (Note 5)	**32**	221
Prepaid expenses	**1,525**	407
	199,341	77,744
Property and equipment (Note 6)	**384,311**	45,242
Goodwill (Note 3)	**103,676**	-
Deferred charges (Note 7)	**4,005**	256
Investment in Petrolifera (Note 5)	**21,597**	10,496
Future income tax asset (Note 8)	**-**	1,075
	$712,930	$134,813
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities	**$57,571**	$2,184
Income taxes payable	**3,644**	132
Current portion of bank debt (Note 9)	**19,500**	-
	80,715	2,316
Asset retirement obligations (Note 10)	**7,322**	3,108
Deferred credits	**-**	281
Employee future benefits (Note 11)	**388**	-
Bank debt (Note 9)	**209,754**	-
Future income taxes (Note 8)	**29,353**	-
	327,532	5,705
SHAREHOLDERS' EQUITY		
Share capital and contributed surplus (Note 12)	**376,500**	127,033
Cumulative translation adjustment	**(130)**	-
Retained earnings	**9,028**	2,075
	385,398	129,108
	$712,930	$134,813

Commitments, contingencies and guarantees (Note 16)

Approved by the Board

Signed, "D.H. Bessell", Director

Signed, "C.M. Evans", Director

CONSOLIDATED STATEMENTS OF OPERATIONS AND RETAINED EARNINGS

($000, except per share amounts)	2006	2005
REVENUE		
Petroleum and natural gas revenue, net of royalties	$31,786	$9,095
Refining and marketing sales	211,874	-
Interest and other income	1,024	700
	244,684	9,795
EXPENSES		
Petroleum and natural gas operating costs	8,270	2,445
Refining – crude oil purchases and operating costs	182,668	-
General and administrative	3,886	2,660
Stock-based compensation (Note 12)	7,816	1,192
Finance charges	5,086	308
Foreign exchange loss (gain)	4,287	(30)
Depletion, depreciation and accretion	32,949	5,797
	244,962	12,372
Loss before income taxes and other items	(278)	(2,577)
Current income tax provision (Note 8)	7,405	102
Future income tax provision (recovery) (Note 8)	(3,535)	768
	3,870	870
Loss before other items	(4,148)	(3,447)
Equity interest in Petrolifera earnings (loss) (Note 5)	11,078	(27)
Dilution gain (Note 5)	23	4,465
NET EARNINGS	6,953	991
RETAINED EARNINGS, BEGINNING OF YEAR	2,075	1,084
RETAINED EARNINGS, END OF YEAR	$9,028	$2,075
EARNINGS PER SHARE (Note 15(a))		
Basic and diluted	$0.04	$0.01

CONSOLIDATED STATEMENTS OF CASH FLOW

($000)	2006	2005
Cash provided by (used in) the following activities:		
OPERATING		
Net earnings	**$6,953**	$991
Items not involving cash:		
Depletion, depreciation and accretion	**32,949**	5,797
Stock-based compensation (Note 12)	**8,293**	1,192
Financing charges	**2,237**	150
Employee future benefits	**381**	-
Future income tax provision (recovery)	**(3,535)**	768
Foreign exchange loss (gain)	**4,287**	(30)
Dilution gain	**(23)**	(4,465)
Lease inducement amortization	**(268)**	(72)
Equity interest in Petrolifera (earnings) loss	**(11,078)**	27
Cash flow from operations before working capital changes	**40,196**	4,358
Changes in non-cash working capital (Note 15(b))	**(9,271)**	(485)
	30,925	3,873
FINANCING		
Issue of common shares, net of share issue costs	**123,188**	86,512
Increase in bank debt	**280,078**	-
Repayment of bank debt	**(57,707)**	-
Issue of shares by Petrolifera, net of share issue costs	**-**	6,228
Deferred financing costs	**-**	(258)
	345,559	92,482
INVESTING		
Acquisition and development of oil and gas properties	**(175,033)**	(16,807)
Proceeds on disposal of oil and gas properties	**10,000**	-
Increase in restricted cash (Note 15(c))	**(122,788)**	-
Acquisition of Luke Energy Ltd. (Note 3)	**(92,692)**	-
Acquisition of refining assets (Note 3)	**(61,273)**	-
Acquisition of other assets	**(5,185)**	-
Purchase of Petrolifera shares (Note 5)	**-**	(6,000)
Collection of Petrolifera note (Note 5)	**-**	750
Change in non-cash working capital (Note 15(b))	**14,122**	396
	(432,849)	(21,661)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**(56,365)**	74,694
Impact on cash resulting from de-consolidation of Petrolifera (Note 5)	**-**	(3,097)
Impact of foreign exchange on foreign currency denominated cash balances	**457**	-
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	**75,511**	3,914
CASH AND CASH EQUIVALENTS, END OF YEAR	**$19,603**	$75,511

Supplementary information – Note 15

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

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. Operating in Canada, and in the U.S. through its subsidiary Montana Refining Company, Inc. ("MRC"), the company is in the business of exploring, developing, producing, refining 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 5) it also conducted a conventional petroleum and natural gas business in Argentina.

2. SIGNIFICANT ACCOUNTING POLICIES

Cash and cash equivalents

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

Inventory Valuation

Crude oil and refined product inventories are stated at the lower of cost or net realizable value. Subsequent to the acquisition of the refining assets, the company has adopted the average cost method; net realizable value is determined using current estimated selling prices.

Deferred charges

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

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 before royalties 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 less impairment 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 less impairment 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 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. Costs associated with major development projects are not depleted until commencement of commercial production. All capitalized 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.

To date, all costs, including financing costs, incurred in relation to the oil sands project in Northern Alberta have been capitalized as the project is considered to be in the pre-production stage. Judgment is required in order to determine when commercial operations have

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

commenced. Once commercial operations have been achieved, revenue will be recognized, operating costs will be expensed to earnings and the capitalized costs of the project will be added to the full cost pool and depleted using the unit-of-production method.

Gains or losses on sales of properties are recognized only when crediting the proceeds to the cost pool 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.

Refining Assets

Depreciation and amortization is calculated based on estimated useful lives and salvage values. When assets are placed into service, estimates are made with respect to their useful lives that are believed to be reasonable. However, factors such as competition, regulation or environmental matters could cause changes to estimates, thus impacting the future calculation of depreciation and amortization. Long-lived refining assets are also evaluated for potential impairment by identifying whether indicators of impairment exist and, if so, assessing whether the long-lived assets are recoverable from estimated future undiscounted cash flows. The actual amount of impairment loss, if any, to be recorded is equal to the amount by which a long-lived asset's carrying value exceeds its fair value. Estimates of future discontinued cash flows and fair values of assets require subjective assumptions with regard to future operating results and actual results could differ from those estimates.

Deferred Maintenance Costs

The refining assets require regular major maintenance and repairs which are commonly referred to as "turnarounds". Catalysts used in certain refinery processes also require routine "change-outs". The required frequency of the maintenance varies by asset type and by catalyst, but generally is every two to five years. The costs of turnarounds are recorded as deferred charges and are amortized over the period to the next scheduled turnaround or change-out.

Investment in Petrolifera Petroleum Limited

The investment in Petrolifera Petroleum Limited ("Petrolifera") 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 accumulated income and losses. Any permanent decline in value would be charged to earnings.

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 assets and liabilities 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. An impairment is recognized when management assesses that it's not more likely than not that the asset will be recovered.

Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed for impairment annually. Goodwill and all other assets and liabilities have been allocated to the company's segments, referred to as reporting units. To assess impairment, the fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount.

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 property 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 amount of the capitalized retirement obligation is depleted and depreciated on the same basis as the other capitalized oil and natural gas property costs. Actual restoration expenditures are charged to the accumulated obligation as incurred and costs for properties disposed are removed.

Employee future benefits

The costs of the defined benefit pension plan and other retirement benefits are actuarially determined using the projected benefit method prorated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. For the purpose of calculating the expected return on plan assets, those assets are valued at a market-related value. The cost of the company's portion of the defined contribution plan is expensed as incurred.

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 liability is increased by the tax benefits related to the expenditures at the time they are renounced.

Foreign currency translation

The company has assessed the operations of MRC to be self-sustaining. Assets and liabilities of self-sustaining foreign operations are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date and revenues and expenses are translated at the average monthly rates of exchange during the periods. Gains or losses on translation of self-sustaining foreign operations are included in currency translation adjustment in shareholders' equity.

Financial instruments

Financial instruments include cash and cash equivalents, restricted cash, accounts receivable, amounts due from/to Petrolifera, bank debt and accounts payable. All carrying values of financial instruments approximate fair value unless otherwise noted. The fair value of interest rate swaps and all payments received or made under interest rate swaps are recorded as part of financing costs.

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.

Revenue recognition

Petroleum and natural gas sales and refined product sales are recognized as revenue at the time the respective commodities are delivered to purchasers.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

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 expensed or capitalized and credited to contributed surplus over the vesting period. Upon exercise of the options, the exercise proceeds together with amounts credited to contributed surplus, are credited to share capital.

Segment reporting

Management has determined that the company operates in the following segments:

Canada	Oil and Gas includes the exploration, development, production and sales in western Canada of conventional and unconventional hydrocarbon reserves.
Canada	Administrative includes assets not related directly to any of the company's other business segments, being primarily the company's investment in Petrolifera. Income and expense in this segment are comprised mainly of equity in the earnings of Petrolifera, financing charges, stock-based compensation and general and administrative expenses.
USA	Refining includes the refining and marketing of refined petroleum products from the company's refinery in Great Falls, Montana.
Argentina	Oil and Gas includes the exploration, development, production and sales of conventional crude oil and natural gas in Argentina, through the company's investment in Petrolifera during the time its results were consolidated.

The above have been defined as the operating segments of the company because they (a) produce products which are sufficiently differentiated from each other so as to be separately identifiable; (b) are those whose operating results are regularly reviewed by the company's chief operating decision maker to make decisions about resources to be allocated to each segment and assess its performance; and (c) are those for which discrete financial information is available.

Segment accounting policies are the same as those described in this summary of significant accounting policies. Transfers of assets between segments are recorded at book amounts.

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. Estimates of the stage of completion of capital projects at the financial statement date affect the calculation of additions to property, plant and equipment and the related accrued liability.

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 future taxes 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.

Credit risk

The majority of the accounts receivable is in respect of refining operations. The company generally extends unsecured credit to customers and therefore, the collection of accounts receivable may be affected by changes in economics or other conditions. Management believes this 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, 2006 there were no such contracts in place. Additionally, the company is exposed to interest rate risk as a portion of the company's bank debt is subject to floating interest rates.

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 plus the amount of stock-based compensation not yet recognized would be used to purchase common shares at the average market price during the period.

3. BUSINESS ACQUISITIONS

During 2006, Connacher completed the following transactions:

(a) Acquisition of Luke Energy Ltd.

The company completed the acquisition of all of the outstanding shares of Luke Energy Ltd. ("Luke") on March 16, 2006. The results of operations of Luke have been included in the financial statements since that date. Net assets acquired and consideration paid were as follows:

($000)	
Net assets acquired:	
Petroleum and natural gas assets	$153,755
Goodwill	103,676
Asset retirement obligations (Note 10)	(2,109)
Working capital deficit	(19,308)
Future income tax liability	(31,356)
Net assets acquired	$204,658
Consideration paid:	
Cash	$92,692
Common shares (Note 13)	111,966
	$204,658

Included in cash consideration paid are transaction costs of $1.2 million. The value of the common share consideration paid was determined by reference to the market value of the company's shares at the time of announcing the acquisition.

Effective January 1, 2007, Luke was amalgamated with Connacher.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(b) Acquisition of refining assets

On March 31, 2006 the company acquired all of the assets of a refinery in Great Falls, Montana. The refinery's results of operations have been included in the consolidated financial statements from that date. Net assets acquired and consideration paid were as follows:

($000)	
Net assets acquired:	
Refining assets	$46,337
Inventory	19,996
Net assets acquired	$66,333
Consideration paid:	
Cash	$61,273
Common shares (Note 12)	5,060
	$66,333

Included in cash consideration paid are transaction costs of $1.2 million. The value of the common share consideration paid was determined by reference to the market value of the company's shares at the time of announcing the acquisition.

The purchase agreement commits the vendor to resolve any environmental liabilities arising over the next five years for environmental matters existing at the purchase date.

As a means to facilitate the expeditious transition of the ongoing refinery business, MRC assumed all of the ongoing purchase and sales contracts with suppliers and customers of the refinery. These contracts are all short-term in nature and necessitated some guarantees from Connacher, all considered to be in the normal course of business.

4. REFINERY INVENTORIES

Inventories at December 31 consist of the following:

($000)	2006	2005
Crude oil	**$3,520**	$-
Other raw materials and unfinished products (1)	**1,292**	-
Refined products (2)	**17,440**	-
Process chemicals (3)	**909**	-
Repairs and maintenance supplies and other	**1,276**	-
	$24,437	$-

(1) Other raw materials and unfinished products include feedstocks and blendstocks, other than crude oil. The inventory carrying value includes the costs of the raw materials and transportation.

(2) Refined products include gasoline, jet fuels, diesels, asphalts, liquid petroleum gases and residual fuels. The inventory carrying value includes the cost of raw materials including transportation and direct production costs.

(3) Process chemicals include catalysts, additives and other chemicals. The inventory carrying value includes the cost of the purchased chemicals and related freight.

Subsequent to the acquisition of the refinery, management changed the method of inventory cost determination from the last in, first out (LIFO) method to the average cost method. Had the LIFO method been used throughout 2006, inventory at December 31, 2006 would have been increased by $2.5 million, refinery cost of sales would have been decreased by $2.4 million and net income would have been increased by $1.5 million.

5. INVESTMENT IN PETROLIFERA PETROLEUM LIMITED ("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 the reduction in its ownership percentage below 50%. The investment in Petrolifera has since been accounted for following the equity basis of accounting.

The impact of not consolidating Petrolifera had the effect of reducing the company's net assets by $4.1 million as follows:

($000)	
Cash	$(3,097)
Other current assets	(321)
Future income tax asset	(985)
Property and equipment	(4,110)
Current liabilities	381
Asset retirement obligations	442
Non-controlling interests	3,564
Changes in net assets	$(4,126)

Connacher's investment in Petrolifera at the time of de-consolidation	$4,126
Increases (decreases) in investment:	
Equity interest in Petrolifera's loss from the time of deconsolidating to December 31, 2005	(27)
Collection of Promissory Note and reclassification of amounts due from Petrolifera	(1,047)
Purchase of shares in Petrolifera	6,000
Dilution gain on shares issued by Petrolifera to unrelated parties after de-consolidation	1,444
Investment in Petrolifera, December 31, 2005	10,496
Equity in Petrolifera's 2006 earnings	11,078
Dilution gain resulting from issuance of Petrolifera shares in 2006	23
Investment in Petrolifera, December 31, 2006	$21,597

Dilution gains have been recognized whenever changes have occurred in the company's equity interest in Petrolifera, most notably relative to Petrolifera's $7 million private placement financing completed in March 2005 when Connacher's equity interest holding was reduced from 61 percent to 40 percent, resulting in a dilution gain of $3 million. Although Connacher participated in Petrolifera's $21.3 million initial public offering in November 2005 by investing $6 million, Connacher's equity investment interest was reduced to 35 percent and a further dilution gain of $1.5 million was then recognized.

In consideration for the assistance provided to Petrolifera in securing two Peruvian licenses for exploratory lands and for the provision of financial guarantees respecting Petrolifera's annual work commitments in the two licensed blocks in 2005, 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 CWI 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.

Under the terms of a Management Services Agreement with Petrolifera which expires in May 2007, Connacher provides all management, operational, accounting and general and administrative services necessary or appropriate to manage and operate

Petrolifera. The fee for this service $15,000 per month. At December 31, 2006, Connacher was owed $32,000 for these services, and for other amounts paid on Petrolifera's behalf (2005 - $221,000).

6. PROPERTY AND EQUIPMENT

($000)	Cost	Accumulated Depletion, Depreciation and Amortization	Net Book Value
2006			
Petroleum and natural gas properties and equipment	**$377,172**	**$43,816**	**$333,356**
Refining assets	**51,959**	**2,319**	**49,640**
Furniture, equipment and leaseholds	**2,625**	**1,310**	**1,315**
	$431,756	**$47,445**	**$384,311**
2005			
Petroleum and natural gas properties and equipment	$60,291	$15,680	$44,611
Furniture, equipment and leaseholds	1,058	427	631
	$61,349	$16,107	$45,242

In 2006, the company capitalized $4.5 million (2005 - $615,000) of general and administrative expenses, including stock-based compensation of $3.5 million (2005 - $410,000), related to conventional petroleum and natural gas activities and oil sands activities and $7.9 million (2005 – $nil) of interest and financing costs related to major development projects.

Depletion, depreciation and accretion expense includes a charge of $348,000 (2005 – $165,000) to accrete the company's estimated asset retirement obligations (Note 10).

The ceiling test as at December 31, 2006 excludes $16.2 million (2005 – $2.5 million) of undeveloped land and $156.7 million (2005 – $11.2 million) of major development projects, principally related to oil sands assets in the pre-production stage, 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, 2006.

Connacher's oil and natural gas reserves were evaluated by qualified independent evaluators as at December 31, 2006 in a report dated March 9, 2007. The evaluation was conducted in accordance with the Canadian Securities Administrators' National Instrument 51-101, using the following base price assumptions adjusted for the company's product quality and transportation differentials:

	Bitumen Wellhead Current ($CDN/bbl)	WTI @ Cushing ($US/bbl)	Alberta Spot ($CDN/mcf)
2007	31.50	62.00	7.25
2008	32.75	60.00	7.50
2009	33.50	58.00	7.50
2010	33.37	57.00	7.50
2011	34.50	57.00	7.50
	+ approximately 2% thereafter	+ approximately 2% after 2012	+ approximately 2% thereafter

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

7. DEFERRED CHARGES

The balance of $4 million as at December 31, 2006 represents deferred maintenance costs. Deferred charges of $256,000 at December 31, 2005 relate to costs incurred in respect of transactions incomplete at that date and which were subsequently capitalized to property, plant and equipment.

8. INCOME TAXES

The income tax provision of $3.9 million in 2006 includes a current tax provision of $7.4 million, principally related to US refinery operations and a future income tax recovery of $3.5 million reflecting the benefit of increased tax pools during the year.

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

Years Ended December 31 ($000)	2006	2005
Earnings before income taxes	$10,823	$1,861
Canadian statutory rate	35.4%	39.0%
Expected income taxes (recovery)	3,831	726
Non-deductible Canadian crown payments	1,729	555
Canadian resource allowance	(945)	(371)
Impact of reduction in Canadian tax rates and other	(3,955)	245
Foreign taxes (recovery)	973	(17)
Capital taxes	502	119
Non taxable portion of capital gains	762	-
Equity income and dilution gain	(1,962)	(852)
Non deductible stock-based compensation	2,935	465
Provision for taxes	$3,870	$870

The company had the following future tax assets (liabilities) relating to temporary differences:

As at December 31 ($000)	2006	2005
Book value in excess of tax basis of property, plant and equipment	$(37,628)	$(2,370)
Non-capital losses carried forward	7,754	1,075
Foreign exchange gain on debt	882	-
Partnership deferral	(5,930)	-
Investment in Petrolifera	(1,980)	-
Deferred maintenance costs	(1,547)	-
Share issue costs	6,463	2,370
Asset retirement obligation	2,158	-
Other	475	-
Net future income tax asset (liability)	$(29,353)	$1,075

At December 31, 2006 the company had approximately $25.8 million of non-capital losses which expire at various periods to 2026, $253.5 million of deductible resource pools and $20.7 million of deductible financing costs.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

9. BANK DEBT

The company had the following loans outstanding, as at December 31:

($000)	2006	2005
Conventional line of credit	$19,500	$-
Refinery line of credit	-	-
Oil sands term loan	209,754	-
Total	229,254	-
Less current portion	19,500	-
Long-term portion	$209,754	$-

At December 31, 2006, the company had available a $55 million Extendible Revolving Loan Facility (the "Conventional line of credit"). Borrowings are available in the form of prime loans, bankers' acceptances, US dollar base rate loans, LIBOR loans and letters of credit. As at December 31, 2006, $19.5 million in bankers' acceptances were outstanding at a rate of 5.62 percent and $168 thousand in letters of credit were issued. The facility's borrowing base is redetermined semi-annually based on the lending value of the company's conventional crude oil and natural gas reserves, as determined by the company's lenders in accordance with customary practice. The facility matures on April 15, 2007 and is extendible upon request by the company and at the lender's option for 364 days. The Conventional line of credit is secured by a $50 million fixed and floating charge debenture and a general assignment of book debts over the company's conventional crude oil and natural gas reserves and assets, and is non-recourse to the company's Great Divide oil sands, its refining assets and its investment in Petrolifera.

At December 31, 2006 the company also had available a US$15 million revolving line of credit (the "Refinery line of credit") to fund the working capital requirements of the refinery in Great Falls, Montana. Borrowings are available under this facility in the form of US dollar base rate loans, US Eurodollar rate loans and letters of credit. As at December 31, 2006 no amounts were drawn on this facility other than US$1.7 million of letters of credit. This facility matures October 20, 2011 and is secured by debenture and mortgage agreements covering all of the assets of the refinery and all of the company's interest in its Great Divide oil sands assets but is non-recourse to the company's conventional petroleum and natural gas assets and investment in Petrolifera.

In October 2006, the company secured a US$180 million, seven-year term loan (the "Oil sands term loan"). The full amount of the loan was drawn to fund US$51 million of the acquisition cost of the Montana refinery, to fund a US $14 million debt-service reserve account and to fund all of the remaining budgeted costs to complete the development of Pod One, the company's first oil sands project at Great Divide in northern Alberta. The loan is a floating rate facility, bearing interest either at a US dollar base rate plus a margin or a US Eurodollar rate plus a margin. The loan's Eurodollar interest rate as at December 31, 2006 was 8.61 percent. In October 2006 the company entered into an interest rate swap with a financial institution whereby the floating rate on US$90 million of the loan was fixed at an all-in rate of 8.516 percent over the term of the loan. All interest on this loan is being capitalized until Pod One becomes operational. One percent of the principal is required to be repaid annually, commencing in the fourth quarter of 2008. The oil sands term loan is secured by debenture and mortgage agreements covering all of the assets of the refinery and all of the company's interest in its Great Divide oil sands assets, but is non-recourse to the company's conventional petroleum and natural gas assets and to its investment in Petrolifera.

As indicated above, at December 31, 2006, the company had in place an interest rate swap to convert the effective rate on one-half of the oil sands term loan to an all-in fixed interest rate of 8.516 percent. The fair value of this interest rate swap at December 31, 2006 was a liability of $1.4 million.

Principal repayments under the aforementioned loans are due as follows: ($000)

2007	$19,500
2008	524
2009	2,098
2010	2,098
2011	2,098
Thereafter	202,936
	$229,254

10. ASSET RETIREMENT OBLIGATIONS

The following table reconciles the beginning and ending aggregate carrying amount of the obligation associated with the company's retirement of its conventional petroleum and natural gas properties and facilities and its oil sands properties and facilities.

Year ended December 31 ($000)	2006	2005
Asset retirement obligations, beginning of year	**$3,108**	$2,905
Liabilities incurred	**2,384**	301
Liabilities acquired (Note 3(a))	**2,109**	-
Liabilities settled with Petrolifera deconsolidation	**-**	(442)
Liabilities disposed	**(864)**	(24)
Change in estimated future cash flows	**237**	203
Accretion expense	**348**	165
Asset retirement obligations, end of year	**$7,322**	$3,108

At December 31, 2006 the estimated total undiscounted amount required to settle the asset retirement obligations was $17.4 million (2005 - $5.4 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 an inflation rate of 2.0 percent.

The company has not recorded an asset retirement obligation for the Montana refinery as it is currently the company's intent to maintain and upgrade the refinery so that it will be operational for the foreseeable future. Consequently, it is not possible at the present time to estimate a date or range of dates for settlement of any asset retirement obligation related to the refinery.

11. EMPLOYEE FUTURE BENEFITS

During 2006, the company established the following retirement/savings plans for its employees: a defined benefit pension plan and a defined contribution savings plan for its new US-based employees and a defined contribution savings plan for its Canadian employees.

(a) The defined benefit pension plan

As a consequence of the refinery acquisition and related employment of refinery personnel, the company's new US subsidiary, Montana Refining Company, Inc. ("MRC"), adopted a new non-contributory defined benefit retirement plan (the "Plan") covering MRC's employees on March 31, 2006. MRC's policy is to make regular contributions in accordance with the funding requirements of

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

the United States Employee Retirement Income Security Act of 1974 as determined by regular actuarial valuations. The company's pension obligation is based on the employees' years of service and compensation, effective from, and after, March 31, 2006.

MRC is responsible for administering the plan. MRC has retained the services of an independent and professional investment manager, as fund manager, for the related investment portfolio. Among the factors considered in developing the investment policy are the Plan's primary investment goal, rate of return objective, investment risk, investment time horizon, role of asset classes and asset allocation.

Details of this Plan and the December 31, 2006 actuarial valuation are as follows:

($000)	
Pension benefits	
Components of net benefits cost	
Current service cost	$365
Interest cost	16
Net benefit cost	$381
Change in benefit obligation:	
Benefit obligation at acquisition of refinery	$-
Current service cost	365
Interest cost	16
Foreign currency translation	7
Benefit obligation at December 31, 2006	$388
Amount recognized in the consolidated balance sheet consists of:	
Accrued benefits	$(388)
Assumptions used to determine benefit obligations at December 31, 2006	
Discount rate	5.75%
Long-term rate of compensation increase	3.00%

(b) The MRC defined contribution savings plan for United States employees

MRC also established new defined contribution (US tax code "401(k)"), savings plans that cover all of its employees from March 31, 2006. MRC's contributions are based on employees' compensation and partially match employee contributions. In 2006, MRC contributed $201,000 to this plan.

(c) The defined contribution savings plan for Canadian employees

In 2006, the company established a new defined contribution savings plans for its Canadian employees, whereby the company matches employee contributions to a maximum of eight percent of each employee's salary. In 2006, the company contributed $121,500 to this plan.

12. SHARE CAPITAL AND CONTRIBUTED SURPLUS

Authorized

The authorized share capital comprises 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 ($000)
Balance, December 31, 2004	89,626,743	$38,756
Issued for cash in public offerings (a)	45,541,000	90,001
Issued upon exercise of stock options (d)	981,000	666
Issued upon exercise of warrants (e)	3,791,705	1,986
Share issue costs		(5,980)
Tax effect of share issue costs		2,339
Tax effect of expenditures renounced pursuant to the issuance of flow through common shares (f)		(2,697)
Balance, December 31, 2005	139,940,448	125,071
Issued for cash in private placement (b)	19,047,800	100,001
Issued for cash in public offerings (c)	5,714,300	30,000
Issued for Luke acquisition (Note 3)	29,699,282	111,966
Issued for refinery acquisition (Note 3)	1,000,000	5,060
Issued upon exercise of options (d)	998,365	1,017
Issued upon exercise of warrants (e)	1,493,820	881
Share issue costs		(8,390)
Tax effect of share issue costs		2,924
Tax effect of expenditures renounced pursuant to the issuance of flow through common shares (g)		(5,448)
Balance, December 31, 2006	197,894,015	$363,082

Contributed Surplus:	
Balance, December 31, 2004	$535
Fair value of share options granted in 2005(d)	1,588
Assigned value of options exercised in 2005	(161)
Balance, December 31, 2005	1,962
Fair value of options granted in 2006 (d)	11,777
Assigned value of options exercised in 2006	(321)
Balance, December 31, 2006	$13,418

Total Share Capital and Contributed Surplus:	
December 31, 2005	$127,033
December 31, 2006	$376,500

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(a) Public Offerings – 2005

In September 2005 the company issued from treasury 40,541,000 common shares at $1.85 per share. In December 2005 the company issued 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.

(b) Private Placement – 2006

In February 2006, the company issued 19,047,800 common shares from treasury at $5.25 per share on a private placement basis.

(c) Flow-through Share Issue - 2006

In September 2006, the company issued from treasury 5,714,300 common shares on a flow through basis at $5.25 per share. The company agreed to renounce the related resources expenditures of $30 million to the flow through investors effective December 31, 2006. The company has until December 31, 2007 to incur the eligible resource expenditures. As at December 31, 2006 $6.5 million of these expenditures have been incurred.

(d) Stock Options

A summary of the company's outstanding stock options, as at December 31, 2006 and 2005 and changes during those years is presented below:

	2006		2005	
	Number of Shares	**Weighted Average Exercise Price**	Number of Shares	Weighted Average Exercise Price
Outstanding, beginning of year	**8,592,600**	**$1.49**	3,988,600	$0.53
Granted	**8,739,255**	**$4.81**	5,994,000	$1.94
Exercised	**(998,365)**	**$0.70**	(981,000)	$0.51
Expired	**(121,000)**	**$3.68**	(409,000)	$1.05
Outstanding, end of year	**16,212,490**	**$3.31**	8,592,600	$1.49
Exercisable, end of year	**6,563,864**	**$2.14**	3,159,869	$1.03

All stock options have been granted for a period of five years. Options granted under the plan are generally fully exercisable after three years and expire five years after the date granted. The table below summarizes unexercised stock options.

Range of Exercise Prices	Number Outstanding	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Number Outstanding	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
At December 31			2006			2005
$0.20 - $0.99	3,137,235	$0.69	1.7	4,276,600	$0.67	3.2
$1.00 - $1.99	1,996,000	$1.61	2.4	1,886,000	$1.61	5.0
$2.00 - $3.99	3,679,000	$3.18	3.1	2,430,000	$2.84	4.9
$4.00 - $5.99	7,400,255	$4.99	3.3	-	$-	-
	16,212,490	$3.31		8,592,600	$1.49	

In 2006 a compensatory non-cash expense of $8.3 million (2005 - $1.2 million) was recorded, reflecting the fair value of stock options amortized over the vesting period. Of this amount, $7.8 million (2005 - $1.2 million) was expensed and $0.5 million was charged to refining operating costs. A further $3.5 million (2005 - $0.4 million) 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:

	2006	2005
Risk free interest rate	**4.1%**	3.0%
Expected option life (years)	**3**	3
Expected volatility	**50%**	50%

The weighted average fair value at the date of grant of all options granted in 2006 was $1.81 per option (2005 - $0.65).

(e) Share purchase warrants

A summary of the company's outstanding share purchase warrants, as at December 31, 2006 and 2005 and changes during the years is presented below:

	2006	2005
Outstanding, beginning of year	**1,493,820**	5,300,525
Exercised	**(1,493,820)**	(3,791,705)
Expired	**-**	(15,000)
Outstanding, end of year	**-**	1,493,820

(f) Flow-through shares (2004)

The company renounced $7 million 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 $2.7 million and the company incurred the expenditures in 2005 as required.

(g) Flow-through shares (2005)

Effective December 31, 2005, the company renounced $15 million of resource expenditures to flow-through investors. The related tax effect of $5,448,000 on those expenditures was recorded in 2006. The company incurred all of the required expenditures related to these flow-through shares in 2006.

13. RELATED PARTY TRANSACTIONS

In 2006 the company paid professional legal fees of $1.8 million (2005 - $539,000) to a law firm in which officers or directors of the company are partners. 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.

14. SEGMENTED INFORMATION

In Canada, the company is in the business of exploring and producing conventional petroleum and natural gas and has recently commenced exploration and development of bitumen in the oil sands of northern Alberta. In the U.S., the company is in the business of refining and marketing petroleum products. Prior to the de-consolidation of Petrolifera in 2005 (Note 5) it also conducted a conventional petroleum and natural gas business in Argentina. The significant aspects of these operating segments are presented below. Included in Canadian administrative assets is the company's carrying value of its investment in Petrolifera.

Year ended December 31 ($000)	Canada Oil and Gas	Canada Administrative	USA Refining	Argentina Oil and Gas	Total
2006					
Revenues, net of royalties	**$31,786**	**$-**	**$211,874**	**$-**	**$243,660**
Equity interest in Petrolifera earnings		**11,078**	**-**	**-**	**11,078**
Dilution gain		**23**			**23**
Interest and other income	**600**	**-**	**424**	**-**	**1,024**
Crude oil purchase and operating costs	**8,270**	**-**	**182,668**	**-**	**190,938**
General and administrative	**3,886**	**-**	**-**	**-**	**3,886**
Stock-based compensation	**-**	**7,816**	**-**	**-**	**7,816**
Finance charges	**4,992**	**-**	**94**	**-**	**5,086**
Foreign exchange loss	**4,287**	**-**	**-**	**-**	**4,287**
Depletion, depreciation and accretion	**29,366**	**-**	**3,583**	**-**	**32,949**
Taxes (recovery)	**(5,165)**	**-**	**9,035**	**-**	**3,870**
Net earnings (loss)	**(13,250)**	**3,285**	**16,918**	**-**	**6,953**
Property and equipment, net	**333,358**	**1,314**	**49,639**	**-**	**384,311**
Capital expenditures and acquisitions	**378,173**	**1,169**	**72,183**	**-**	**451,525**
Total assets	**582,325**	**22,795**	**107,548**	**262**	**712,930**
2005 [1]					
Revenues, net of royalties	$8,202	$-	$-	$893	$9,095
Equity interest in Petrolifera loss	-	(27)	-	-	(27)
Dilution gain	-	4,465	-	-	4,465
Interest and other income	678	-	-	22	700
Operating costs	2,126	-	-	319	2,445
General and administrative	-	2,348	-	312	2,660
Stock-based compensation	-	1,178	-	14	1,192
Finance charges	261	-	-	47	308
Foreign exchange loss (gain)	5	-	-	(35)	(30)
Depletion, depreciation and accretion	5,304	-	-	493	5,797
Taxes (recovery)	893	-	-	(23)	870
Net earnings (loss)	(3,282)	4,465	-	(212)	991
Property and equipment, net	44,611	631	-	-	45,242
Capital expenditures	14,771	269	-	1,767	16,807
Total assets	134,182	631	-	-	134,813

(1) The 2005 comparative figures have been restated to conform to the current year's presentation.

15. SUPPLEMENTARY INFORMATION

(a) Per share amounts

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

For the years ended December 31	2006	2005
Weighed average common shares outstanding	**184,468,631**	106,113,563
Dilutive effect of stock options and stock purchase warrants	**3,963,178**	5,732,124
Weighed average common shares outstanding – diluted	**188,431,809**	111,845,687

(b) Net change in non-cash working capital

For the years ended December 31 ($000)	2006	2005
Accounts receivable	**$(25,284)**	$(277)
Refinery inventories	**(4,441)**	-
Due from Petrolifera	**189**	61
Prepaid expenses	**(692)**	(124)
Accounts payable and accrued liabilities	**31,567**	251
Income taxes payable	**3,512**	-
Total	**$4,851**	$(89)

Summary of working capital changes:

($000)	2006	2005
Operations	**$(9,271)**	$(485)
Investing	**14,122**	396
	$4,851	$(89)

(c) Supplementary cash flow information

For the years ended December 31	2006	2005
($000)		
Interest paid	**$6,578**	$67
Income taxes paid	**3,655**	3
Stock-based compensation capitalized	**3,485**	410

At December 31, 2006 cash of $122.8 million is restricted for use in paying expenditures for a designated oil sands project under the terms of the oil sands term loan (Note 9).

16. 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:

2007 - $1.7 million; 2008 - $2.6 million; 2009 - $2.6 million; 2010 - $2.2 million; 2011 - $1.6 million; total thereafter $9.3 million.

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.

82-34954

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

TIMOTHY J. O'ROURKE
Vice President, Oil Sands Operations

STEPHEN A. MARSTON
Vice President, Exploration

CAMERON TODD
Vice President, Refining and Marketing

DARREN JACKSON
Vice President, Operations

STEVE DE MAIO
Vice President, Project Development

GRANT UKRAINETZ
Treasurer

JENNIFER K. KENNEDY
Corporate Secretary
Partner, Macleod Dixon LLP

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BOARD OF DIRECTORS

RICHARD A. GUSELLA

President and Chief Executive Officer
Connacher Oil and Gas Limited,
Calgary

CHARLES W. BERARD

Chairman, Governance Committee,
Chairman, Health, Safety and
Environment Committee
Partner, Macleod Dixon LLP, Calgary

D. HUGH BESSELL

Chairman, Audit Committee
Retired Deputy Chairman of
KPMG, LLP

COLIN M. EVANS

Chairman, Human Resources
Committee
Vice-President, Finance, Milestone
Exploration Inc., Calgary

STEWART D. MCGREGOR

Lead Director
President, Camun Consulting Ltd.

W.C. (MIKE) SETH

Chairman, Reserves Committee
President, Seth Consultants Ltd.

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

SAGD
Steam Assisted Gravity Drainage

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 Deputy 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

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

Stephen A. Marston
Vice President, Exploration

Cameron Todd
Vice President, Refining and Marketing

Darren Jackson
Vice President, Operations

Steve De Maio
Vice President, Project Development

Grant Ukrainetz
Treasurer

Jennifer K. Kennedy
Corporate Secretary
Partner, Macleod Dixon LLP

stock exchange listing

Toronto Stock Exchange
Trading symbol - CLL

head office

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cusip number

205884

isin

CA20588Y1034

subsidiaries

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

related company

Petrolifera Petroleum Limited (26%)

auditors

Deloitte & Touche LLP, Calgary

bankers

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

solicitors

Macleod Dixon LLP, Calgary

reservoir engineers

GLJ Petroleum Consultants, Calgary

registrar and transfer agent

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

Designed by Bryan Mills Iradesso

82-34954

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Connacher
OIL AND GAS LIMITED

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2006

March 23, 2007

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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/d"**	1,000 standard cubic feet per day
"bbl/d"	barrel or barrels per day	**"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	**"mmbtu"**	1,000,000 British thermal units
"mboe"	1,000 barrels of oil equivalent	**"NGL"**	Natural gas liquids
"mbbl"	1,000 barrels		
"mcf"	1,000 cubic feet		

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.

"**1P**" means the proved reserve category as defined in the COGE Handbook;

"**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);

"**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 GLJ Report**" means the independent engineering evaluation of the oil and natural gas interests of the Corporation prepared by GLJ Petroleum Consultants Ltd. ("**GLJ**"), independent petroleum engineering consultants of Calgary, Alberta, dated March 9, 2007 and effective December 31, 2006;

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

"**MRC**" means Montana Refining Company, Inc. (a wholly-owned subsidiary of the Corporation);

"**MRC Acquisition**" means the acquisition by Connacher of an 8,300 bbl/d refinery and related inventory 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, 2006 dated March 20, 2007;

"**Petrolifera GLJ Report**" means the independent engineering evaluation of the crude oil and natural gas interests of Petrolifera prepared by GLJ, independent petroleum engineering consultants of Calgary, Alberta, dated March 1, 2007 and effective December 31, 2006;

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

"**Pod One**" means the Corporation's 10,000 bbl/d of bitumen SAGD project located in northeastern Alberta;

"**Refinery**" means the refinery and related inventory located in Great Falls, Montana acquired by the Corporation pursuant to the MRC Acquisition;

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

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

"**Sayer Energy Advisors Report**" means the independent evaluation of the Canadian undeveloped land acreage of the Corporation prepared by Sayer Energy Advisors ("**Sayer**"), independent oil and gas investment firm of Calgary, Alberta, dated February 14, 2007 and effective December 31, 2006;

"**Total Recoverable Resources**" means reserves plus Contingent Resources and Prospective Resources; 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.

THE CORPORATION

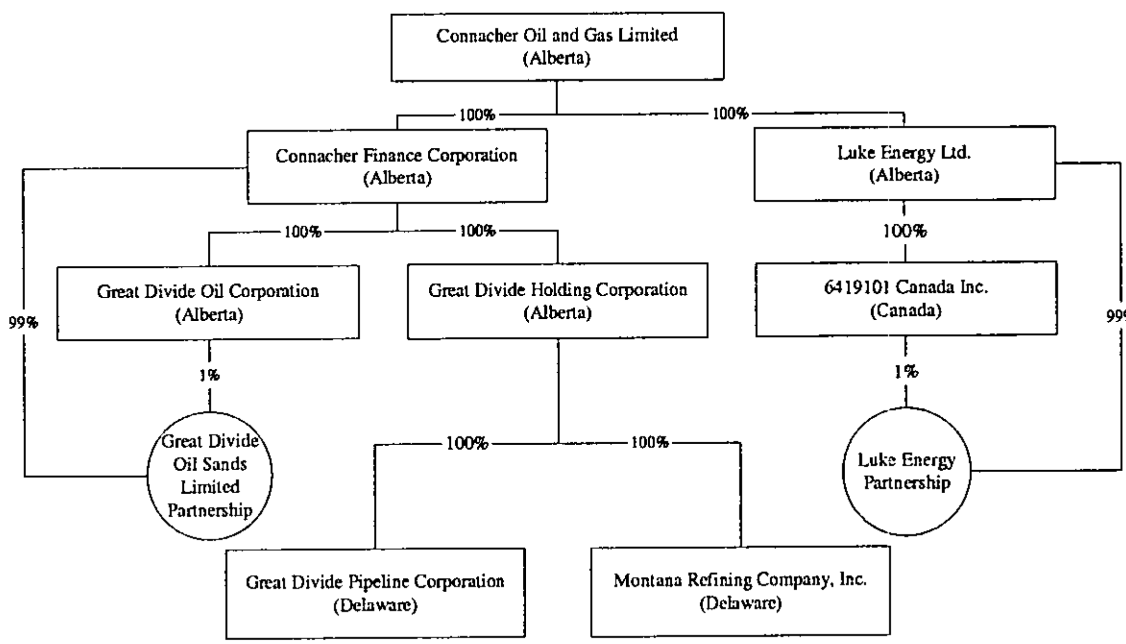
Incorporation and Organization

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, 2006, the Corporation had seven wholly-owned subsidiaries, 6419101 Canada Inc., a corporation incorporated under the *Canada Business Corporations Act*, Great Divide Oil Corporation, Connacher Finance Corporation, Luke Energy Ltd. and Great Divide Holding Corporation, all of which are corporations incorporated under the ABCA and Great Divide Pipeline Corporation and Montana Refining Company, Inc. both of which are organized pursuant to the laws of the State of Delaware. The Corporation also has a significant equity interest in Petrolifera. See "Business of the Corporation - Ownership of Petrolifera".

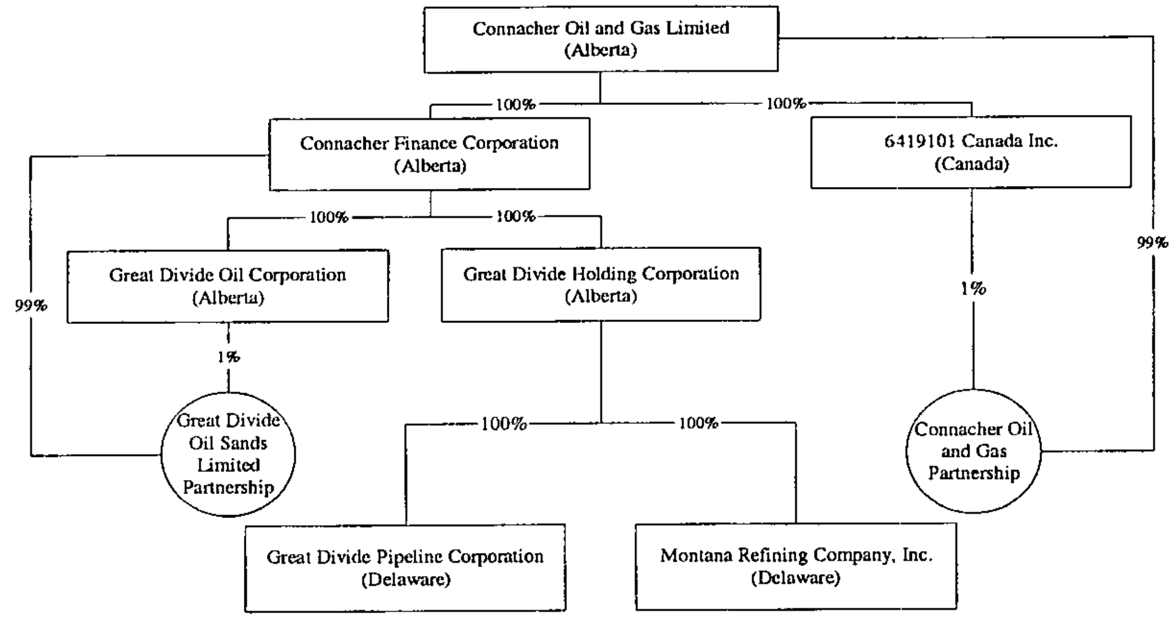
The Corporation has its head and principal office at Suite 2600, 530 – 8th Avenue S.W., Calgary, Alberta, T2P 3S8 and its registered office at 3700, 400 Third Avenue S.W., Calgary, Alberta, T2P 4H2.

The following chart illustrates the Corporation's organizational structure as at December 31, 2006:



On January 1, 2007 Connacher amalgamated with Luke Energy Ltd. pursuant to the ABCA and the name of the Luke Energy Partnership was changed to the Connacher Oil and Gas Partnership.

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



General Development of the Corporation

Connacher is primarily engaged in the exploration for, and the development, production and marketing of, crude oil and natural gas. The Corporation's principal asset is its interest in the Great Divide Pod One 10,000 bbl/d oil sands project and surrounding 90,000 acres of oil sands leases which are situated in northeastern Alberta. The Corporation also owns producing crude oil and natural gas properties at Battrum, Saskatchewan and at Marten Creek, Simonette and Three Hills, Alberta, a 9,400 bbl/d refinery located in Great Falls, Montana and a 26 percent equity interest in Petrolifera, a public Canadian oil and natural gas company active in Argentina, Peru and Colombia. The following is a general description of the development of the Corporation over the past three years.

In July 2004, 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 southwest Saskatchewan in two separate transactions 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, 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 were 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.

Also, in December 2005, Connacher entered into an exclusivity agreement with the Montana Refining Company, a subsidiary of Holly, to negotiate the terms of a purchase and sale agreement to acquire an 8,300 bbl/d refinery, together with related structures and specified tangible assets situated in Great Falls, Montana.

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.

In February 2006, 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 from treasury of approximately 30 million Connacher Shares to Luke shareholders.

In February 2006, Connacher completed a "bought-deal" private placement financing of 8,571,500 Common Shares at a price of $5.25 per share. An additional 10,476,300 Common Shares were issued to the underwriters in connection with the financing upon exercise of their over-allotment option for total gross proceeds of $100,000,950. Proceeds from the financing were used to fund Connacher's exploration and development activities, for general corporate purposes and for working capital.

In March 2006, MRC signed an asset purchase agreement pursuant to which it completed the MRC Acquisition. The MRC Acquisition was completed on March 31, 2006. The consideration for the purchase was US$55 million, comprised of cash and one million Connacher Shares from treasury. For further details with respect to the MRC Acquisition, reference should be made to the business acquisition report of the Corporation dated June 14, 2006 which is posted on SEDAR (www.sedar.com) and is not incorporated by reference in this Annual Information Form.

In June 2006, Connacher received a letter from the Alberta Energy and Utilities Board approving the Corporation's Great Divide oil sands project.

In July 2006, Connacher was granted an Order in Council approving its Great Divide oil sands project, representing the last formal approval requirement for the project to proceed.

In September 2006, Connacher completed a "bought-deal" financing of 5,000,000 flow-through common shares at a price of $5.25 per flow-through share. An additional 714,300 flow-through shares were issued to the underwriters in connection with the financing upon exercise of their over-allotment option for total gross proceeds of $30,000,075. Proceeds from the financing were used to fund exploration activities including the further delineation of the Corporation's oil sands properties.

In October 2006, Connacher completed a long term debt financing comprised of a US$180 million Term Loan B Facility (the "TLB Facility") and US$15 million Working Capital Facility (the "WC Facility") (collectively, the "Facilities"). The Facilities were syndicated to institutional investors located primarily in the United States and in Canada. The proceeds of the TLB Facility were used to discharge short-term indebtedness of US$51 million incurred in the MRC Acquisition, fund a one year debt service reserve during the construction phase of Pod One and pay expenses associated with the long-term debt financing. The balance of the approximately US$111 million of the proceeds was added to cash working capital and will be used to finance the remaining construction and related capital expenditures of Pod One. The WC Facility is available to fund ongoing working capital requirements at the Refinery.

Throughout 2006, a total of 1,493,820 Common Share purchase warrants and 998,365 stock options were exercised, resulting in the Corporation receiving cash proceeds of $1,898,000.

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. To date, oil and gas royalty trusts have also been a significant acquirer of producing oil and gas properties and companies. However, proposed legislation to change the taxation of trusts announced on October 31, 2006 has affected this trend.

The second trend is the significant access to external capital that the industry has been experiencing. Oil and gas companies have had access to debt and equity capital which they have invested in both acquisition and exploration activities. More recently, however, the access to external capital has become more restricted as a result of declining commodity prices and legislative changes in taxation applicable to trusts.

The third trend is the focus on Canada's oil sands deposits. In 2005 and 2006 the market for crude oil saw record high prices which persisted in the context of volatile geopolitical conditions. 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 2006 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 and 2006.

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. This has resulted in increased operating, exploration and development costs. See "Risk Factors".

BUSINESS OF THE CORPORATION

Connacher is primarily engaged in the exploration for, and the development, production and marketing of, crude oil and natural gas. The Corporation's principal asset is its interest in the Great Divide Pod One 10,000 bbl/d oil sands project and surrounding 90,000 acres of oil sands leases which are situated in northeastern Alberta. The Corporation also owns producing crude oil and natural gas properties at Battrum, Saskatchewan and at Marten Creek, Simonette and Three Hills, Alberta, a 9,400 bbl/d refinery located in Great Falls, Montana and a 26 percent equity interest in Petrolifera, a public Canadian oil and natural gas company active in Argentina, Peru and Colombia.

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.

Great Divide, Alberta

At Great Divide in northeastern Alberta, the Corporation owns and operates 148.5 sections of oil sands leases (148.2 sections or 95,000 acres net) and 11 gross sections (10 net sections or 6,400 acres) of petroleum and natural gas rights. Several bitumen accumulations or pods have been identified.

Pod One was delineated, evaluated, applied for and approved by all applicable regulatory bodies. It is currently under construction, and is scheduled for startup in mid-summer 2007. Additional pods are being delineated using core-hole drilling and 3D seismic in the first quarter 2007. At this time 81 coreholes are planned. This data will be integrated into the existing corehole and seismic data base to determine whether there is sufficient size, areal extent and reservoir quality to apply for additional new pods or SAGD developments. In addition, the Corporation is using this data to explore for and find additional new pods. The Corporation intends to proceed with an application to develop another 10,000 bbl/d small scale commercial operation (the "Algar Project") at Great Divide. It is anticipated the application for the Algar Project will be submitted in May, 2007 with a view to commencement of construction in early 2008, subject to final approval by the Board of Directors of the Corporation and following due consultation with stakeholders and receipt of regulatory approval.

As at December 31, 2006 the Connacher GLJ Report estimated the Corporation's Pod One proved reserves to be 43.8 million barrels, 2P reserves to be 84.1 million barrels and the 3P reserves to be 109.9 million barrels. Additional pods were assigned Contingent and Prospective Resources (as such terms are hereinafter defined) resulting in a 2P reserves and Best Estimate of Total Recoverable Resources of 260.6 million barrels. The 3P reserves and High Estimate of Total Recoverable Resources was estimated at 478.9 million barrels.

Marten Creek, Alberta

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 Connacher. Gas production for 2006 averaged 11.3 mmcf/d. Connacher's land position has grown to an average 80% interest in approximately 77,600 acres (62,124 acres net). Connacher also holds an additional 4,480 acres under option. Connacher 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. 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. At December 31, 2006, the Corporation estimates total 2P recoverable reserves as 5.0 million boes.

Three Hills, Alberta

In March 2006, Connacher acquired the Three Hills properties (Three Hills, Mikwan, Twining and Stettler) through the Luke Acquisition. At the time of the Luke Acquisition the Three Hills properties were producing approximately 225 boe/d. By drilling additional wells in 2006 these properties exited the year producing more than 375 boe/d. At December 31, 2006 the Connacher GLJ Report estimates the Corporation's working interest share of crude oil reserves rose to 728 mboe (proved) from 456 mboe (proved) at the time the Luke Acquisition was completed in March of 2006. The 2P recoverable reserves have risen from 582 mboe to 1,205 mboe during the same period.

Battrum, Saskatchewan

The Corporation owns and operates working interests of 100% in unitized and non unitized lands in the Battrum region of southwestern Saskatchewan. The properties produce medium gravity crude oil. The bulk of the properties were acquired in two transactions in 2003, with additional small transactions completed in 2005 and 2006. For the year ended December 31, 2006 the Corporation's production from this area averaged 710 bbls/d of oil and current production is approximately 650 bbl/d of oil. There are presently 56 net producing oil wells and no producing gas wells in this area, which comprises 26,922 gross acres and 26,842 net acres. At December 31, 2006 the Connacher GLJ Report estimates the Corporation's working interest share of crude oil reserves to be 2.4 million bbls of oil, of which 1.9 million bbls is proved.

The Refinery

On March 31, 2006, the Corporation completed the MRC Acquisition. See "The Corporation - General Development of the Corporation".

The MRC Acquisition was considered strategic to provide Connacher with protection against wider and more volatile type of heavy crude oil price differential swings. Since its acquisition, the Refinery has been a profitable and strong business unit contributing to the Corporation's cash flow. MRC's continued profitability will depend largely on the spread between market prices for refined petroleum products and the cost of crude oil.

MRC's principal source of revenue is from the sale of high value light end products such as gasoline, diesel, and jet fuel in markets in the western United States. Additionally, MRC sells a high grade asphalt into the local market. MRC's principal expenses relate to costs of products sold and operating expenses.

In April 2006, MRC completed a scheduled plant "turnaround" maintenance program of its refinery facilities. Such turnarounds are normally scheduled every two to five years. Turnaround costs are capitalized and amortized over the period to the next scheduled turnaround.

With minimal additional anticipated capital investment, MRC would be capable of producing low sulfur gasoline and diesel as required in 2008.

The above mentioned regulatory compliance items or other presently existing or future environmental regulations, could cause Management to make additional capital investments beyond those described above and/or incur additional operating costs to meet applicable requirements.

In 2004, the American Jobs Creation Act of 2004 was signed into law. Among other things, the legislation creates tax incentives for small refiners preparing to produce low sulfur gasoline and diesel. The legislation provides an immediate deduction of 75% of certain costs paid or incurred to comply with these standards and a tax credit based on production for up to 25% of those costs. Management intends to utilize these incentives when it is required to make these required expenditures.

Ownership of Petrolifera

As of the date of this Annual Information Form Connacher owns an undiluted 26% equity interest in Petrolifera. Petrolifera commenced a drilling program in late 2005 and has since completed 14 wells in its 100% owned Puesto Morales Concession located in the Neuquén Basin in Argentina, all of which have been completed as hydrocarbon discoveries.

Petrolifera is a publicly traded crude oil and natural gas exploration and production company active in Argentina, Colombia 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 which expire May 8, 2006 and options to purchase 200,000 common shares of Petrolifera. Based on the closing trading price of Petrolifera on March 23, 2007 of $19.07, Connacher's ownership of common shares of Petrolifera (excluding common shares issuable upon the exercise of options and warrants) represents a $217 million investment. Petrolifera has forecasted capital expenditures of $153 million to complete an active drilling and facility installation program during 2007.

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 2006 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 26% interest in Petrolifera's oil and gas reserves and future net revenue as at December 31, 2006 as evaluated by GLJ in the Petrolifera GLJ Report. The Petrolifera 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. All of the reserves assigned to Petrolifera in the Petrolifera GLJ 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 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 to prepare a report relating to the Corporation's reserves and resources as at December 31, 2006. 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 three areas, the Battrum area of Saskatchewan and the Marten Creek and Three Hills areas of Alberta. Connacher's bitumen reserves are located in the Great Divide region. Bitumen reserves were only assigned to Pod One, in the 2P and 3P categories. The Connacher GLJ Report assumed 44 SAGD well pairs for the proved undeveloped case, 62 SAGD well pairs for the 2P case and 76 well pairs for the 3P case, with cumulative SORs of 2.7, 2.6 and 2.6 in each case, but declining to 2.4 during peak production periods. The cutoffs used by GLJ for probable reserves were 15 metres of net pay for proved undeveloped reserves, 13 metres of net pay for 2P reserves and 10 metres of net pay for 3P reserves.

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, 2006 as evaluated by GLJ in the Connacher GLJ Report. The preparation date of the Connacher GLJ Report is March 7, 2007. The pricing used in the forecast and constant price evaluations is set forth in the notes to the tables. Detailed information with respect to the reserves and future net revenue attributable to the Corporation's crude oil and natural gas reserves and the Corporation's bitumen reserves is included in this Annual Information Form under the headings "Oil and Gas Reserves and Resources - Supplemental Information Regarding the Corporation's Bitumen Reserves" and "Oil and Gas Reserves and Resources - Supplemental Information Regarding the Corporation's Crude Oil and Natural Gas Reserves", respectively.

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. Proved plus probable plus possible reserves are the least likely case and are based on a 10% probability that they will equal or exceed estimates.

The evaluations of the Corporation's bitumen reserves based on constant prices and costs utilize a net bitumen price derived from pricing data posted as of December 31, 2006. Although December 31, 2006 prices are utilized, production of bitumen is not anticipated to commence until mid-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 Connacher GLJ 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 Connacher GLJ Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the Connacher GLJ 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

CONVENTIONAL AND NON-CONVENTIONAL RESERVES BASED ON FORECAST PRICES AND COSTS(9)

	Light/Medium Crude Oil		Natural Gas		Natural Gas Liquids		Bitumen	
	Gross(1) (mbbl)	Net(1) (mbbl)	Gross(1) (mmcf)	Net(1) (mmcf)	Gross(1) (mbbl)	Net(1) (mbbl)	Gross(1) (mbbl)	Net(1) (mbbl)
Proved Developed Producing(2)(5)	2,106	1,742	21,524	17,607	1	1	-	-
Proved Developed Non-Producing(2)(6)	-	-	3,167	2,615	-	-	-	-
Proved Undeveloped(2)(7)	315	240	-	-	-	-	43,841	39,808
Total Proved(2)	2,421	1,983	24,691	20,221	1	1	43,841	39,808
Total Probable(3)	786	632	8,769	7,158	-	-	40,307	34,340
Total Proved Plus Probable(2)(3)	3,207	2,615	33,460	27,379	2	1	84,147	74,178
Total Possible(4)	-	-	-	-	-	-	25,714	21,596
Total Proved Plus Probable Plus Possible(2)(3)(4)	3,207	2,615	33,460	27,379	2	1	109,861	95,774

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)	159,543	127,039	105,942	91,289	80,557	150,364	120,756	101,435	87,927	77,968
Proved Developed Non-Producing(2)(6)	15,782	12,554	10,237	8,518	7,209	11,170	8,885	7,241	6,021	5,092
Proved Undeveloped(2)(7)	528,477	319,949	196,214	118,765	67,960	410,037	245,832	147,487	85,325	44,145
Total Proved(2)	703,801	459,543	312,394	218,572	155,727	571,572	375,472	256,163	179,274	127,205
Total Probable(3)	850,214	389,295	216,420	144,432	110,810	603,624	277,682	158,003	109,383	87,218
Total Proved Plus Probable(2)(3)	1,554,015	848,838	528,813	363,004	266,537	1,175,196	653,154	414,165	288,657	214,423
Total Possible(4)	613,264	200,769	87,661	51,283	37,084	435,225	142,512	63,256	38,119	28,439
Total Proved Plus Probable Plus Possible(2)(3)(4)	2,167,279	1,049,607	616,474	414,287	303,621	1,610,421	795,666	477,421	326,776	242,862

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

	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)	1,954,696	215,170	754,150	271,753	9,822	703,801	132,230	571,572
Total Proved Plus Probable(2)(3)	3,923,893	505,718	1,433,916	416,529	13,715	1,554,015	378,819	1,175,196
Total Proved Plus Probable Plus Possible(2)(3)(4)	5,266,838	713,155	1,871,568	498,308	16,528	2,167,279	556,858	1,610,421

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) (M$)
Total Proved[2]	Light and medium crude oil (including solution gas and by-products)	40,124
	Associated gas and non-associated gas (including natural gas liquids and excluding solution gas)	81,548
	Bitumen	190,721
Total Proved Plus Probable[2][3]	Light and medium crude oil (including solution gas and by-products)	51,565
	Associated gas and non-associated gas (including natural gas liquids and excluding solution gas)	100,851
	Bitumen	376,398
Total Proved Plus Probable Plus Possible[2][3][4]	Light and medium crude oil (including solution gas and by-products)	51,565
	Associated gas and non-associated gas (including natural gas liquids and excluding solution gas)	100,851
	Bitumen	464,059

RESERVES DATA - CONSTANT PRICES AND COSTS

CONVENTIONAL AND NON-CONVENTIONAL RESERVES BASED ON CONSTANT PRICES AND COSTS[8]

	Light/Medium Crude Oil		Natural Gas		Natural Gas Liquids		Bitumen	
	Gross[1] (mbbl)	Net[1] (mbbl)	Gross[1] (mmcf)	Net[1] (mmcf)	Gross[1] (mbbl)	Net[1] (mbbl)	Gross[1] (mbbl)	Net[1] (mbbl)
Proved Developed Producing[2][5]	2,125	1,759	21,531	17,611	1	1	-	-
Proved Developed Non-Producing[2][6]	-	-	3,167	2,615	-	-	-	-
Proved Undeveloped[2][7]	315	240	-	-	-	-	43,841	39,607
Total Proved[2]	2,440	1,999	24,698	20,226	1	1	43,841	39,607
Total Probable[3]	794	640	8,769	7,157	-	-	40,307	33,958
Total Proved Plus Probable[2][3]	3,234	2,639	33,467	27,383	2	1	84,147	73,565
Total Possible[4]	-	-	-	-	-	-	25,714	21,425
Total Proved Plus Probable Plus Possible[2][3][4]	3,234	2,639	33,467	27,383	2	1	109,861	94,990

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]	127,893	103,715	87,603	76,174	67,665	127,532	103,517	87,491	76,109	67,627
Proved Developed Non-Producing[2][6]	10,939	8,770	7,194	6,012	5,104	7,768	6,559	5,610	4,852	4,236
Proved Undeveloped[2][7]	457,526	279,244	171,784	103,521	58,135	359,803	217,408	130,752	75,155	37,827
Total Proved[2]	596,357	391,730	266,581	185,707	130,905	495,103	327,484	223,853	156,116	109,690
Total Probable[3]	621,112	300,873	178,397	126,108	100,884	441,790	215,884	131,663	96,751	80,367
Total Proved Plus Probable[2][3]	1,217,469	692,603	444,978	311,815	231,788	936,892	543,368	355,516	252,867	190,057
Total Possible[4]	392,227	139,383	67,677	43,387	33,241	278,509	99,304	49,235	32,557	25,703

	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(2)(3)(4)	1,609,696	831,986	512,655	355,202	265,029	1,215,401	642,672	404,751	285,424	215,760

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)	1,631,014	181,930	587,495	257,509	7,721	596,359	101,256	495,103
Total Proved Plus Probable(2)(3)	2,974,322	396,859	999,768	350,562	9,651	1,217,482	280,590	936,892
Total Proved Plus Probable Plus Possible(2)(3)(4)	3,769,898	529,524	1,225,888	393,727	11,051	1,609,708	394,307	1,215,401

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) (M$)
Total Proved(2)	Light and medium crude oil (including solution gas and by-products)	41,117
	Associated gas and non-associated gas (including natural gas liquids and excluding solution gas)	59,179
	Bitumen	166,285
Total Proved Plus Probable(2)(3)	Light and medium crude oil (including solution gas and by-products)	52,640
	Associated gas and non-associated gas (including natural gas liquids and excluding solution gas)	72,018
	Bitumen	320,324
Total Proved Plus Probable Plus Possible(2)(3)(4)	Light and medium crude oil (including solution gas and by-products)	52,640
	Associated gas and non-associated gas (including natural gas liquids and excluding solution gas)	72,018
	Bitumen	388,002

RECONCILIATION OF COMPANY CONVENTIONAL AND NON-CONVENTIONAL RESERVES BY PRINCIPAL PRODUCT TYPE BASED ON FORECAST PRICES AND COSTS[9]

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, 2006 against such reserves as at December 31, 2005 based on the forecast price and cost assumptions set forth in Note 9.

	Light and Medium Oil			Associated and Non-Associated Natural Gas			Bitumen		
	Net Proved (1)(2) (mbbl)	Net Probable (1)(3) (mbbl)	Net Proved Plus Probable (1)(2)(3) (mbbl)	Net Proved (1)(2) (mmcf)	Net Probable (1)(3) (mmcf)	Net Proved Plus Probable (1)(2)(3) (mmcf)	Net Proved (1)(2) (mbbl)	Net Probable (1)(3) (mbbl)	Net Proved Plus Probable (1)(2)(3) (mbbl)
At December 31, 2005	1,161	744	1,905	236	282	518	-	62,667	62,667
Extensions	174	185	358	526	385	912	-	11,481	11,481
Improved Recovery	213	17	230	-	-	-	39,808	(39,808)	-
Technical Revisions	305	(306)	(1)	467	(95)	372	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	406	138	544	22,412	6,773	29,184	-	-	-
Dispositions	(8)	(145)	(153)	(83)	(187)	(270)	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
Production	(268)	-	(268)	(3,336)	-	(3,336)	-	-	-
At December 31, 2006	1,983	632	2,615	20,222	7,158	27,379	39,808	34,340	74,148

RECONCILIATION OF CHANGES IN NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT 10% BASED ON CONSTANT PRICES AND COSTS[8]

The following table sets forth changes between future net revenue estimates attributable to Connacher's net proved reserves as at December 31, 2006 against such reserves as at December 31, 2005 based on constant prices and cost assumptions set forth in Note 8 and calculated using a discount rate of 10%.

	(M$)
Estimated Future Net Revenue after income taxes at December 31, 2005	34,060
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties	(23,516)
Net Change in Prices, Production Costs and Royalties Related to Future Production	(1,776)
Changes in Previously Estimated Future Development Costs	167,917
Changes in Estimated Future Development Costs	(167,604)
Net Change from Extensions and Improved Recovery	175,359
Net Change from Discoveries	-
Acquisitions of Reserves	77,477
Dispositions of Reserves	-
Net Change Resulting from Revisions in Quantity Estimates	4,777
Accretion of Discount	3,553
Net Change in Income Taxes	(41,259)
Other	(5,134)
Estimated Future Net Revenue after income taxes at December 31, 2006	223,853

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. There is only a 10% probability that the quantities actually recovered will equal or exceed the sum of 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 Connacher GLJ Report were as follows: (1) Edmonton Light price: $67.58/bbl; (2) AECO Spot Gas price: $6.07/mmbtu; and (3) Alberta Sulphur at Plant Gate: $19.50/L.

(9) The pricing assumptions used in the Connacher 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
	Edmonton Par Price 40^{0}API ($Cdn/bbl)	Hardisty Heavy 12^0 API ($Cdn/bbl)	%/year	$US/$Cdn
Forecast				
2007	70.25	39.25	2.0	0.870
2008	68.00	40.00	2.0	0.870
2009	65.75	39.75	2.0	0.870
2010	64.50	39.75	2.0	0.870
2011	64.50	40.25	2.0	0.870
2012	65.00	41.50	2.0	0.870
2013	66.25	42.50	2.0	0.870
2014	67.75	43.50	2.0	0.870
2015	69.00	44.25	2.0	0.870
Thereafter	+2.0%/yr	+2.0%/yr	2.0	0.870

(10) Values include processing and other income.

(11) Values include Alberta Royalty Tax Credit.

Weighted average historical prices realized by the Corporation for the year ended December 31, 2006 were $53.85/bbl for light and medium crude and $5.85/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 planned infill drilling locations. Such reserves may also relate 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.

At December 31, 2006, Connacher's conventional net proved undeveloped reserves of 445 mbbls of oil are located at Battrum, Saskatchewan and Three Hills, Alberta. The Corporation expects to drill a number of infill locations at Battrum and Three Hills during 2007 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 GLJ Report estimates the Corporation's working interest probable undeveloped reserves to be 786 mbbls of light or medium oil and estimates the Corporation's working interest probable undeveloped reserves to be 40,307 mbbls of bitumen.

At Great Divide, proved undeveloped reserves of 43.8 million bbls of bitumen were assigned by GLJ in the Connacher GLJ Report. Proved undeveloped reserves will be converted to proved developed producing reserves over time once the Great Divide project is commissioned and as the steam injected in the SAGD well pairs heats up the reservoir enabling it to reach maximum production.

Significant Factors or Uncertainties

The Corporation does not anticipate that any 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 Connacher GLJ 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$)	Total Proved Plus Probable Plus Possible Future Development Costs Using Forecast Dollar Costs (M$)
2007	121,969	121,969	110,562	97,527
2008	40,530	41,341	1,255	1,255
2009	3,200	3,329	3,121	2,913
2010	40	42	32	32
2011	1,800	1,948	22	22
Total for all remaining years	140	188	186,126	293,689
Total, undiscounted	257,509	271,753	416,529	498,308
Total for all years discounted at 10%/year	199,841	207,195	204,438	196,977

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, 2006:

	Crude Oil		Natural Gas	
	Gross(1)	Net(1)	Gross(1)	Net(1)
Alberta				
Producing	12	11	42	40
Non-producing	8	8	4	4
Saskatchewan				
Producing	56	56	-	-
Non-producing	32	32	-	-
Total	108	107	46	44

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.

Costs Incurred

The following table summarizes the capital expenditures made by Connacher on oil and natural gas properties for the year ended December 31, 2006.

Property Acquisition Costs ($)		Exploration Costs ($)	Development Costs ($)
Proved Properties	Unproved Properties		
-	6,767,000	39,038,188	20,008,687

Exploration and Development Activities

The following table sets forth the number of exploratory and development wells which Connacher completed during its 2006 financial year:

	Exploratory Wells		Development Wells	
	Gross(1)	Net(1)	Gross(1)	Net(1)
Oil Wells (2)	27	27	9	8.8
Gas Wells	-	-	3	1.5
Service Wells	-	-	-	-
Dry Holes	2	2	1	1
Total Completed Wells	29	29	13	11.3

Notes:

(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.

(2) Includes 26 oil sands exploration delineation coreholes.

In 2007 focus will continue to be on Great Divide although other important work will be carried out on the Corporation's conventional acreage and at the Refinery. A capital budget approaching $250 million is envisaged for 2007, with approximately 80 percent directed to both Pod One development and startup and to anticipating continued evaluation of additional pods and undeveloped acreage in the Great Divide region. It is hoped a formal applications for the next pod at Great Divide will be submitted early in 2007. Conventional activity will focus on drilling for natural gas at Marten Creek and other selected regions in northern Alberta, oil development drilling at Three Hills, Alberta and ongoing projects at Battrum, Saskatchewan. It is also anticipated over $16 million will be invested in the operation of the Refinery during 2007.

Properties with No Attributed Reserves

The following table sets out the Corporation's undeveloped land position effective December 31, 2006.

	Undeveloped Acreage	
	Gross(1)	Net(1)
Alberta		
Conventional	114,116	94,948
Oil Sands	81,920	81,728
Saskatchewan	62,340	51,011
British Columbia	3,249	2,858
Total	261,625	230,545

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 does not expect its rights to explore, develop and exploit any of its unproved property to expire within the next year.

The Corporation engaged Sayer to prepare an independent evaluation of the undeveloped land acreage of the Corporation as at December 31, 2006. In the Sayer Report a fair value of approximately $16.2 million or approximately $206.85 per gross hectare was assigned to Connacher's non-reserve oil and gas properties. This equates to approximately $83.06 per gross acre. In determining the market value, Sayer based their evaluation on the following factors:

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 related to the unproved properties;

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 2007, Connacher anticipates directing the majority of its 2007 capital budget on the completion of its development project at Great Divide. Additional capital and related budgetary allocations will be required during 2007 once a final determination is made regarding transportation and development of the Corporation's next Pod.

Asset Retirement Obligations

The Corporation follows the Canadian Institute of Chartered Accountants' standard on Asset Retirement Obligations. This 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 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.

As at December 31, 2006, the estimated total undiscounted amount required to settle the asset retirement obligations in respect of the Corporation's 151 net producing and non-producing wells, net of estimated salvage recoveries, was $17.4 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 $4.8 million. Over the next three financial years, the Corporation expects to incur $461,000 ($389,000 discounted at 10%) of these expenditures.

In the Connacher GLJ Report, abandonment costs for total proved plus probable plus possible reserves were estimated to be $13.7 million, undiscounted, and $3.0 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.

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 $300 million. Based on anticipated capital spending, which augment the tax pools, the Corporation does not expect to pay current income taxes for the 2006 fiscal year. Depending on production, commodity prices and capital spending levels, the Corporation may begin paying current income taxes in 2007.

Production Estimates

The following table sets forth the volume of working interest production, before royalties, estimated for 2007 which is reflected in the estimate of future net revenue disclosed in the tables of reserve information in respect of total gross proved plus probable reserves:

Light Crude Oil (mbbl)	Natural Gas (mmcf)	Natural Gas Liquids (bbl)	Bitumen (mbbl)
407	4,122	-	767

The following table indicates the volume of working interest production, before royalties, estimated for 2007 from fields considered to be individually important:

	Light Crude Oil (mbbl)	Natural Gas (mmcf)	Natural Gas Liquids (mbbl)	Bitumen (mbbl)
Battrum, Saskatchewan	301	-	-	-
Marten Creek, Alberta	-	3,618	-	-
Great Divide, Alberta	-	-	-	767

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, 2006	Three Months Ended June 30, 2006	Three Months Ended September 30, 2006	Three Months Ended December 31, 2006
Average Daily Production				
Light and Medium Oil (bbl/d)	689	1,026	1,084	1,139
Natural Gas (mcf/d)	2,600	15,172	13,028	11,291
Average Net Prices Received				
Light and Medium Oil ($/bbl)	$40.93	$61.45	$62.53	$46.65
Natural Gas ($/mcf)	$6.34	$5.66	$5.33	$6.57
Royalties				
Light and Medium Oil ($/bbl)	$8.25	$15.31	$15.63	$9.97
Natural Gas ($/mcf)	$1.28	$1.41	$1.32	$1.40
Production Costs				
Light and Medium Oil ($/bbl)	$8.46	$11.20	$11.86	$10.26
Natural Gas ($/mcf)	$1.31	$1.03	$1.01	$1.45
Netback Received				
Light and Medium Oil ($/bbl)	$24.22	$34.94	$35.13	$26.42
Natural Gas ($/mcf)	$3.75	$3.22	$3.00	$3.72

The following table indicates the Corporation's average daily production for the year ended December 31, 2006 from fields considered to be individually important:

	Light Crude Oil (bbls/d)	Natural Gas (mcf/d)	Natural Gas Liquids (bbls/d)
Battrum, Saskatchewan	723	-	-
Marten Creek, Alberta	-	9,869	-

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.

Supplemental Information Regarding the Corporation's Bitumen Reserves

The following is a summary of the bitumen reserves and the value of future net revenue of the Corporation as at December 31, 2006 as evaluated by GLJ in the Connacher GLJ Report. The Connacher 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 included in the notes set forth on page 14 of this Annual Information Form.

BITUMEN RESERVES AND NET PRESENT VALUE OF FUTURE NET REVENUE BASED ON FORECAST PRICES AND COSTS(9)

	Bitumen		Before Deducting Income Taxes Discounted At					After Deducting Income Taxes Discounted At				
	Gross(1) (mbbl)	Net(1) (mbbl)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Total Proved (2)	43,841	39,808	520,514	313,409	190,721	114,067	63,883	404,453	241,216	143,596	81,991	41,249
Total Probable(3)	40,306	34,340	777,149	344,277	185,677	121,873	93,375	551,068	245,573	136,150	93,361	74,828
Proved Plus Probable Undeveloped(2)(3)(7)	84,147	74,148	1,297,663	657,686	376,398	235,940	157,258	955,521	486,789	279,746	175,352	116,077
Total Possible(4)	25,714	21,626	613,264	200,769	87,661	51,283	37,084	435,225	142,513	63,256	38,119	28,440
Proved Plus Probable Plus Possible Undeveloped (2)(3)(4)(7)	109,861	95,774	1,910,927	858,455	464,059	287,223	194,342	1,390,746	629,302	343,002	213,471	144,517

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

	Bitumen		Before Deducting Income Taxes Discounted At					After Deducting Income Taxes Discounted At				
	Gross(1) (mbbl)	Net(1) (mbbl)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Total Proved(2)	43,841	39,607	449,563	272,700	166,285	98,815	54,049	354,251	212,757	126,770	71,688	34,767
Total Probable(3)	40,306	33,958	568,444	266,558	154,039	107,743	86,410	403,378	191,289	114,364	83,767	70,156
Proved Plus Probable Undeveloped(2)(3)(7)	84,147	73,565	1,018,007	539,258	320,324	206,558	140,459	757,629	404,046	241,134	155,455	104,923
Total Possible(4)	25,714	21,425	392,227	139,383	67,678	43,387	33,241	278,509	99,304	49,235	32,557	25,703
Proved Plus Probable Plus Possible Undeveloped (2)(3)(4)(7)	109,861	94,990	1,410,234	678,641	388,002	249,945	173,700	1,036,138	503,350	290,369	188,012	130,626

Supplemental Information Regarding the Corporation's Crude Oil and Natural Gas Reserves

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, 2006 as evaluated by GLJ in the Connacher GLJ Report. The Connacher 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 included in the notes set forth on page 14 of this Annual Information Form.

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

	Light/Medium Crude 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]	2,106	1,742	21,524	17,607	1	1
Proved Developed Non-Producing[2][6]	-	-	3,167	2,615	-	-
Proved Undeveloped[2][7]	315	240	-	-	-	-
Total Proved[2]	2,421	1,983	24,691	20,221	1	1
Total Probable[3]	786	632	8,769	7,158	-	-
Total Proved Plus Probable[2][3]	3,207	2,615	33,460	27,379	2	1

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]	159,543	127,039	105,942	91,289	80,557	150,364	120,756	101,435	87,927	77,968
Proved Developed Non-Producing[2][6]	15,781	12,553	10,236	8,518	7,209	11,169	8,884	7,241	6,021	5,092
Proved Undeveloped[2][7]	7,963	6,541	5,493	4,698	4,077	5,584	4,616	3,890	3,333	2,896
Total Proved[2]	183,286	146,133	121,672	104,504	91,844	167,117	134,255	112,566	97,282	85,956
Total Probable[3]	73,053	45,012	30,739	22,557	17,433	52,547	32,104	21,850	16,022	12,389
Total Proved Plus Probable[2][3]	256,339	191,145	152,411	127,062	109,277	219,665	166,359	134,416	113,303	98,345

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

	Light/Medium Crude 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]	2,125	1,759	21,531	17,611	1	1
Proved Developed Non-Producing[2][6]	-	-	3,167	2,615	-	-
Proved Undeveloped[2][7]	315	240	-	-	-	-
Total Proved[2]	2,440	1,999	24,698	20,226	1	1
Total Probable[3]	794	640	8,769	7,157	-	-
Total Proved Plus Probable[2][3]	3,234	2,639	33,467	27,383	2	1

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]	127,893	103,715	87,603	76,174	67,665	127,532	103,517	87,491	76,109	67,627
Proved Developed Non-Producing[2][6]	10,939	8,770	7,194	6,012	5,104	7,767	6,558	5,610	4,852	4,236
Proved Undeveloped[2][7]	7,963	6,544	5,499	4,706	4,087	5,552	4,651	3,981	3,467	3,060
Total Proved[2]	146,795	119,029	100,296	86,892	76,856	140,850	114,726	97,083	84,428	74,923
Total Probable[3]	52,668	34,316	24,358	18,366	14,473	38,404	24,590	17,296	12,983	10,211
Total Proved Plus Probable[2][3]	199,462	153,345	124,654	105,257	91,329	179,254	139,316	114,379	97,410	85,134

Oil and Gas Resources

The Connacher GLJ Report also provided calculations of Contingent Resources comprised of "Low Estimate Resources (>15 metre Pay) - higher certainty", together with "Best Estimate Resources (13 metre Pay) - likely certainty" and "High Estimate Resources (>10 metre Pay) - lower certainty". Contingent Resources are those quantities of oil and gas estimated on a given date to be potentially recoverable from known accumulations but are not currently economic. 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 five 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 five 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 five pods had insufficient drilling density, seismic mapping or project definition at December 31, 2006 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 Connacher Report also recognized Best Estimate and High Estimate Prospective Resources attributable to undiscovered pods, utilizing average parameters from six identifiable pods, including Pod One. Prospective Resources are those quantities of oil and gas estimated on a given date to be potentially recoverable from undiscovered accumulations. If discovered, they would be technically and economically viable to recover. There is no certainty that the Prospective Resources will be discovered. This year, calculations of the present value of the future cash flow from remaining recoverable reserves, and, remaining recoverable resources (Contingent and Prospective) were included for the total Great Divide lands, not just Pod One.

Marketable Reserves, Resources	Total Company Interest (mbbl)		Net After Royalty (mbbl)		Future Net Revenue		
					Before Tax Present Value at 0% M$	Before Tax Present Value at 5% M$	Before Tax Present Value at 10% M$
	Bitumen	Oil Equivalent	Bitumen	Oil Equivalent			
1P Reserves and Low Estimate Contingent Resources	70,533	70,533	65,144	65,144	766,390	437,718	243,198
2P Reserves and Best Estimate Contingent Resources	187,818	187,818	167,317	167,317	2,884,883	1,216,744	584,014
3P Reserves and High Estimate Contingent Resources	265,723	265,723	235,115	235,115	4,319,122	1,742,767	813,795
1P Reserves and Low Estimate Total Recoverable Resources	110,477	110,477	99,522	99,522	1,392,950	803,222	486,727
2P Reserves and Low Estimate Total Recoverable Resources	260,625	260,625	232,417	232,417	3,872,084	1,661,404	778,093
3P Reserves and Low Estimate Total Recoverable Resources	478,953	478,953	423,708	423,708	8,058,038	2,898,700	1,245,053
Total	1,374,129	1,374,129	1,223,223	1,223,223	21,293,467	8,760,555	4,150,880

The estimated future net revenues contained in the foregoing tables do not necessarily represent the fair market value of the Corporation's reserves and resources.

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. President of Gusella Oil Investments Limited, an inactive private investment corporation.	May 30, 2001
Charles W. Berard(3)(5) Calgary, Alberta Canada	Director	Partner, Macleod Dixon LLP, a law firm.	May 30, 2001
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 natural gas exploration and production company. President of Evans & Co. Inc., a private consulting corporation providing financial and operating advisory services to oil and gas corporations from 1994 to 2004.	April 5, 2004
Stewart D. McGregor(2)(3)(7) Calgary, Alberta Canada	Director	President of Camun Consulting Corporation, a private investment holding company, since 1994.	June 12, 2003
W.C. (Mike) Seth(1)(4)(5) Calgary, Alberta Canada	Director	President, Seth Consultants Ltd. a private consulting firm. Prior thereto Chairman of McDaniel & Associates Consultants Ltd. and prior thereto, President and Managing Director 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.	-
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.	-

Name and Municipality of Residence	Positions Held	Principal Occupation During the Preceding Five Years	Director Since
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 2001.	-
Cameron M. Todd Calgary, Alberta Canada	Vice President, Refining and Marketing	Vice President, Refining and Marketing of Connacher since May 2006. Prior thereto, Vice President, Worldwide Marketing of Pioneer Natural Resources from June 2002 to May 2006.	-
Darren P. Jackson Calgary, Alberta Canada	Vice President, Operations	Vice President, Operations of Connacher since November 2006. Prior thereto, Production Manager of Canetic Resources Trust from April 2003 to November 2006 and prior thereto Production Engineer of Encana Corporation from May 1994 to April 2003.	-
Stephen J. De Maio Calgary, Alberta Canada	Vice President, Project Development	Vice President, Project Development of Connacher since November 2006 and Consultant Engineer of Connacher from March 2006 to November 2006. Prior thereto, Consultant Engineer of Total E&P Canada from August 2005 to August 2006 and of Deer Creek Energy Limited from March 2005 to August 2005. Chief Executive Officer of Efficient Energy Ltd. from December 2000 to March 2005.	-
Grant D. Ukrainetz Calgary, Alberta Canada	Treasurer	Treasurer of Connacher since June 2006. Prior thereto, Supervisor, Treasury of Talisman Energy Inc. and prior thereto Treasury and Risk Management Analyst of Talisman Energy Inc.	-
Jennifer K. Kennedy Calgary, Alberta Canada	Secretary	Partner, Macleod Dixon LLP, a law firm, since January 2000.	-

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 23, 2007, the directors and executive officers of Connacher, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 3,641,787 Common Shares constituting approximately one percent 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. The Board has determined that all of the members of the Audit Committee are "financially literate" as defined in Multilateral Instrument 52-110. An individual is considered financially literate if he has the ability to read and understand a set of financial statements that present a breadth and complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the issuer's financial statements. In addition, D. Hugh Bessell has, based upon his experience and educational background, been determined by the Board to be an "audit committee financial expert". 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 was a member of the Council of the Institute of Chartered Accountants of Alberta and served as its President for a period of time. 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 an engineer 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., a private consulting firm, and prior thereto he served as Chairman of McDaniel & Associates Consultants Ltd., one of the pre-eminent oil and natural gas reserve evaluators in Canada and internationally. Prior to becoming Chairman of McDaniel Mr. Seth was President and Managing Director 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., a private oil and natural gas exploration and production company. From 1994 to 2004 Mr. Evans was the President of Evans & Co. Inc., a private consulting corporation providing financial and operating advisory services to oil and gas corporations.

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 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, 2006 and December 31, 2005:

	2006	2005
Audit fees	$ 136,943	$ 75,000
Review engagement fees	-	20,000[(1)]
Tax fees	-	1,750[(2)]
All other related fees[(3)]	88,301	84,057
TOTAL	$ 225,244	$ 180,807

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, 2006, the Corporation had 39 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, 2006, 197,894,015 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 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, 2006.

		Monthly Price Range	
	Volume (000's)	High ($)	Low ($)
January	58,320,073	6.07	3.47
February	57,514,454	5.84	4.29
March	32,349,746	5.23	4.64
April	31,868,409	5.05	3.52
May	27,584,050	4.70	3.60
June	20,894,660	4.42	3.10
July	14,235,409	4.55	3.68
August	13,548,578	4.33	3.76
September	21,065,089	4.13	3.09
October	20,468,912	4.43	3.17
November	13,414,044	4.21	3.51
December	12,561,871	3.78	3.37

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.

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.

Stage of Development of Connacher

There is a risk that design and construction of the facilities and infrastructure to support the Corporation's Great Divide oil sands 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;
- 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; and
- shortages of or delays in accessing drilling rigs and services.

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 mid-summer 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;
- the cost of natural gas and electricity;
- power outages, particularly in winter when freeze-ups could occur;
- produced sand causing issues of erosion, hot spots and corrosion;
- 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; and
- catastrophic events such as fires, earthquakes, storms or explosions.

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.

Seasonality of Refining Operations and Sales

The Refinery is subject to a number of seasonal factors which may cause product sales revenues to vary throughout the year. The Refinery's primary asphalt market is paving for road construction which is predominantly a summer demand. Consequently, prices and volumes for our asphalt tend to be higher in the summer and lower in the colder seasons and during the winter most of the Refinery's asphalt production is stored in tankage for sale in the subsequent summer. Seasonal factors also affect gasoline (higher demand in summer months) and distillate and diesel (higher winter demand). As a result, inventory levels, sales volumes and prices can be expected to fluctuate on a seasonal basis.

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.

Transportation

It is expected that the Corporation will initially truck bitumen to market. Normal hazards associated with trucking include proximity to a busy highway (Highway 63) and traffic.

Vehicular traffic to and from the Great Divide site will be via Highway 63 for the life of the project. Collisions between vehicles and wildlife remain a significant hazard.

Travel by air into the Fort McMurray area is increasing dramatically as oil sands development continues. This, too, is an emerging issue for all operators.

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 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. 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.

The Corporation has not recorded an asset retirement obligation for the Montana Refinery as it is currently the Corporation's intent to maintain and upgrade the Refinery so that it will be operational for the foreseeable future. Consequently, it is not possible at the present time to estimate a date or range of dates for settlement of any asset retirement obligation related to the Refinery.

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.

Volatility of Refinery Margins

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 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 intends to continue to use its credit facility and term debt to finance its conventional oil sands and refining expenditures. 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 service and/or 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. Connacher has deposited US$14 million of the proceeds of the US$180 million term debt arranged in 2006 to service this term debt until the expected start-up date of Pod One.

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 or Colombia, 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, Peru and Colombia could be substantially affected by factors beyond Petrolifera's control, any of which could have a material adverse effect on the Corporation.

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 Canada and 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 Corporation's oil sands projects and reclamation of the projects' land are conditional upon various environmental and regulatory approvals issued by governmental authorities. There is no assurance approvals will be issued for future oil sands projects, 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 such projects.

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. For example, water usage, water table and potable water issues in the Fort McMurray area are an emerging environmental and regulatory concern. 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. The Corporation has developed a restoration plan that has been approved.

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 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 GLJ with an effective date of December 31, 2006. 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 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$. All of MRC's business is conducted in US$. 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. Additionally, the Corporation maintains term debt denominated in US$. To mitigate these risks, the Corporation has, in the past, fixed the price of a portion of its crude oil sales in CDN$.

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. Connacher continues to consult with, and work with, Aboriginal groups in the Great Divide area.

LEGAL PROCEEDINGS

There are no material legal proceedings against the Corporation.

INTERESTS OF EXPERTS

Each of Sayer and GLJ have prepared a report or valuation described herein. Neither Sayer or 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 Sayer or GLJ is to be elected, appointed or employed by Connacher.

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, 2006, which are contained in the Annual Report of the Corporation for the year ended December 31, 2006.

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*.

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 prepared an evaluation of the Company's reserves data as at December 31, 2006. The reserves data consist of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006, 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, 2006, 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, 2006, 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 7, 2007	Canada	-	$528,809	-	$528,809

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 9, 2007.

(Signed) *"Terry L. Aarsby"*
Terry L. Aarsby, P. Eng.
Vice-President

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, 2006 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, 2006 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 A 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) *D. Hugh Bessell*
D. Hugh Bessell
Director

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

(signed) Stewart *D. McGregor*
Stewart D, McGregor
Director

March 23, 2007

SCHEDULE C
CONNACHER'S 26% INTEREST IN PETROLIFERA'S OIL AND GAS RESERVES AND FUTURE NET REVENUE

The following is a summary of the Corporation's 26% interest in Petrolifera's oil and gas reserves and future net revenue as at December 31, 2006 as evaluated by GLJ in the Petrolifera GLJ 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/Medium Crude Oil		Natural Gas		Oil Equivalent	
	Gross(1) (mbbl)	Net(1) (mbbl)	Gross(1) (mmcf)	Net(1) (mmcf)	Gross(1) (mbbl)	Net(1) (mbbl)
Proved Developed Producing(2)(5)	1,338	1,158	2,467	2,134	1,749	1,513
Proved Developed Non-Producing(2)(6)	37	32	-	-	37	32
Proved Undeveloped(2)(7)	1,361	1,177	1,239	1,072	1,567	1,356
Total Proved(2)	2,736	2,367	3,707	3,206	3,353	2,901
Total Probable(3)	2,343	2,027	3,781	3,271	2,973	2,572
Total Proved Plus Probable(2)(3)	5,079	4,394	7,488	6,477	6,326	5,473

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)	44,450	40,894	38,031	35,657	33,646	32,908	30,096	27,850	26,002	24,447
Proved Developed Non-Producing(2)(6)	988	809	684	593	524	644	522	434	370	322
Proved Undeveloped(2)(7)	36,738	30,337	25,384	21,463	18,301	23,873	19,323	15,828	13,079	10,875
Total Proved(2)	82,176	72,040	64,099	57,713	52,471	57,425	49,940	44,112	39,451	35,644
Total Probable(3)	81,715	64,746	52,691	43,834	37,147	53,126	41,848	33,860	28,011	23,608
Total Proved Plus Probable(2)(3)	163,891	136,786	116,790	101,547	89,618	110,551	91,788	77,973	67,462	59,252

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

	Revenue(1) (M$)	Royalties(1) (M$)	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)	134,800	18,198	23,398	10,720	307	82,177	24,752	57,425
Total Proved Plus Probable(2)(3)	251,817	33,995	41,777	11,786	367	163,891	53,341	110,550

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 and medium crude oil	62,545
	Associated gas and non-associated gas	1,554
Total Proved Plus Probable(2)(3)	Light and medium crude oil	113,174
	Associated gas and non-associated gas	3,616

RESERVES DATA - CONSTANT PRICES AND COSTS

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

	Light/Medium Crude Oil		Natural Gas		Oil Equivalent	
	Gross(1) (mbbl)	Net(1) (mbbl)	Gross(1) (mmcf)	Net(1) (mmcf)	Gross(1) (mbbl)	Net(1) (mbbl)
Proved Developed Producing(2)(5)	1,339	1,159	2,469	2,136	1,751	1,515
Proved Developed Non-Producing(2)(6)	38	33	-	-	38	33
Proved Undeveloped(2)(7)	1,367	1,182	1,243	1,076	1,574	1,361
Total Proved(2)	2,744	2,373	3,713	3,212	3,362	2,908
Total Probable(3)	2,357	2,039	3,791	3,279	2,989	2,585
Total Proved Plus Probable(2)(3)	5,101	4,412	7,504	6,491	6,351	5,494

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)	43,520	40,211	37,481	35,188	33,229	32,222	29,603	27,464	25,679	24,165
Proved Developed Non-Producing(2)(6)	1,072	866	725	624	549	761	591	479	401	345
Proved Undeveloped(2)(7)	38,434	31,819	26,666	22,571	19,264	24,990	20,298	16,670	13,806	11,506
Total Proved(2)	83,026	72,896	64,872	58,384	53,042	57,972	50,492	44,613	39,886	36,015
Total Probable(3)	82,928	65,572	53,286	44,287	37,507	53,916	42,390	34,253	28,310	23,846
Total Proved Plus Probable(2)(3)	165,955	138,467	118,159	102,671	90,549	111,889	92,882	78,866	68,196	59,862

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

	Revenue (M$)	Royalties (M$)	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)	134,264	18,126	22,156	10,699	257	83,026	25,054	57,972
Total Proved Plus Probable(2)(3)	250,526	33,821	38,723	11,739	289	165,954	54,068	111,887

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 and medium crude oil	64,230
	Associated gas and non-associated gas	642
Total Proved Plus Probable(2)(3)	Light and medium crude oil	116,665
	Associated gas and non-associated gas	1,494

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 GLJ Report were as follows: (1) Light sweet crude oil price at Edmonton: $73.16/bbl, (2) Natural gas at Spot Plant Gate: $5.87/mmbtu and (3) Natural gas liquids (Edmonton butane): $54.06/bbl.
(9) The pricing assumptions used in the Petrolifera GLJ Report with respect to the inflation rates used for operating and capital costs and exchange rates are set forth below and are as at December 31, 2006.

	Inflation Rate	Exchange Rate
	%/year	$US/$Cdn
Year Forecast		
2007	2.0	0.870
2008	2.0	0.870
2009	2.0	0.870
2010	2.0	0.870
2011	2.0	0.870
2012	2.0	0.870
2013	2.0	0.870
2014	2.0	0.870
2015	2.0	0.870
2016	2.0	0.870
2017	2.0	0.870
Thereafter	2.0	0.870

The crude oil price received by Petrolifera is based on the following formula: [(WTI - Quality Differential) x Price Factor /0.98 + Price Premium]/Exchange Rate

Where: WTI=WTI price limited by ceiling price of $55.00/bbl
Quality Differential = 0.37
Price Factor = 0.68966
Price Premium (WTI $55 to $80/bbl) = WTI - 55) x 0.305

Forecast prices used in the above formula are as follows:

	WTI
Year Forecast	$US/bbl
2007	62.00
2008	60.00
2009	58.00
2010	57.00
2011	57.00
2012	57.50
2013	58.50
2014	59.75
2015	61.00
2016	62.25
2017	63.50
2018	64.77
2019	66.07
2020	67.39
2021	68.73
2022	70.11
2023	71.51

Gas prices were forecast to be $2.39/mmbtu in 2007 and to escalate at 2 percent per year thereafter. This forecast is based on gas marketing information provided by Petrolifera. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

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, 2006 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**		
-	64,963	1,302,309	1,349,737

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

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;

(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.

Connacher
OIL AND GAS LIMITED

PRESS RELEASE **MARCH 29, 2007**

CONNACHER FILES YEAR END DISCLOSURE DOCUMENTS

Calgary, Alberta – Connacher Oil and Gas Limited (CLL – TSX) today filed its Annual Information Form for the year ended December 31, 2006 which includes Connacher's reserves data and other oil and gas information for the year ended December 31, 2006 together with the report on reserves data by independent qualified reserves evaluator on Form 51-101F2 and the report of the management and directors on oil and gas disclosure on Form 51-101F3 as mandated by National Instrument 51-101 - Standards Disclosure for Oil and Gas Activities of the Canadian Securities Administrators. Connacher today also filed its Audited Consolidated Financial Statements and Management's Discussion and Analysis for the years ended December 31, 2006 and 2005. Copies of Connacher's Annual Information Form, Audited Consolidated Financial Statements and Management's Discussion and Analysis for the year ended December 31, 2006 may be obtained via SEDAR at www.sedar.com.

Connacher is a Calgary-based oil and natural gas exploration and production company. Its principal asset is its 100 percent interest in reserves, resources and lands in the Great Divide regions of Alberta's oil sands. Connacher also has conventional crude oil and natural gas properties in Alberta and Saskatchewan, owns a 9,500 bbl/d refinery in Great Falls, Montana and owns a 26 percent basic and fully-diluted interest in, and assists in the management of, Petrolifera Petroleum Limited. This investment has a current market value in excess of $200 million.

For further information

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Connacher
OIL AND GAS LIMITED

PRESS RELEASE **MARCH 23, 2007**

CONNACHER REPORTS 2006 RESULTS

Calgary, Alberta – Connacher Oil and Gas Limited (CLL – TSX) achieved significant operational and financial progress during 2006. The Company's financial and operating metrics were expansive and positive.

Connacher made big steps in 2006 on our oil sands properties at Great Divide, Alberta. The development of the high quality oil sands reservoir at Great Divide's Pod One project is well advanced. Start up is expected to commence in the summer of 2007. Meanwhile, other pods have been identified for future growth. Connacher also plans to submit an application to regulators (including due consultation with all stakeholders) to proceed with an additional 10,000 bbl/d project (the "Algar Project") at its Pod Two located east of Pod One at Great Divide. Our conventional natural gas production and our oil refinery are supporting our oil sands initiative as planned. Connacher's investment in Petrolifera Petroleum has performed exceptionally well, with significant growth in market value.

Highlights of the 2006 year were as follows:

- Conventional production more than tripled to 2,725 boe/d
- Revenues expanded approximately 25 times to reach $245 million
- Cash flow from operations before working capital adjustments(1) increased 9 fold to $40 million
- Cash flow per share(1) increased 450 percent, despite a 75 percent increase in weighted average outstanding shares issued to finance growth
- Capital spending including acquisitions reached $452 million
- Almost $600 million of debt and equity financing was completed during the year, assuring control of Great Divide
- Great Divide Pod One 10,000 bbl/d SAGD oil sands development project approved, financed and underway, on time and on budget
- Pod Two development application being finalized – subject to regulatory and final approval by Connacher's Board of Directors, another 10,000 bbl/d project to follow completion of Pod One
- Proved conventional and bitumen reserves up 30 times over 2005 level

The following table summarizes the company's financial and operating highlights for the full year, compared to 2005 reported results.

FINANCIAL AND OPERATING HIGHLIGHTS

	2006	2005	% Change
FINANCIAL			
($000 except per share amounts)			
Revenues net of royalties	**$244,684**	$9,795	2400
Cash flow from operations (1)	**40,196**	4,358	822
Basic, per share (1)	**0.22**	0.04	450
Diluted, per share (1)	**0.21**	0.04	425
Net earnings	**6,953**	991	602
Basic and diluted, per share	**0.04**	0.01	300
Capital expenditures and acquisitions	**451,525**	16,807	2,587
Proceeds on disposal of oil and gas properties	**10,000**	-	-
Bank debt	**229,254**	-	-
Working capital	**118,626**	75,427	59
Cash on hand	**142,391**	75,511	89
Shareholders' equity	**385,398**	129,108	196
Total assets	**712,930**	134,813	429
OPERATING			
Production			
Natural gas (mcf/d)	**10,473**	827	1,166
Crude oil (bbl/d)	**980**	729	34
Equivalent (boe/d) (2)	**2,725**	867	214
Pricing			
Crude oil ($/bbl)	**53.85**	42.33	27
Natural gas ($/mcf)	**5.85**	1.37	327
Selected Highlights ($/boe) (2)			
Weighted average sales price	**41.83**	36.91	13
Royalties	**9.87**	8.16	21
Operating and transportation costs	**8.32**	7.73	8
Netback	**24.67**	23.23	6
Reserves (mboe) (3)			
Proved (1P)	**50,381**	1,501	3,256
Probable	**42,555**	70,598	(40)
Total proved plus probable (2P) (4)	**92,936**	72,099	29
COMMON SHARE INFORMATION			
Shares outstanding at end of period (000)	**197,894**	139,940	41
Weighted average shares outstanding			
Basic (000)	**184,469**	106,114	74
Diluted (000)	**188,432**	111,846	68
Volume traded during the year (000)	**323,825**	338,402	(4)
Common share price ($)			
High	**6.07**	4.20	45
Low	**3.09**	0.49	531
Close, end of year	**3.49**	3.84	(9)

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's 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: 1bbl. 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) The reserve estimates for 2006 and 2005 were prepared by an independent professional petroleum engineering firm in accordance with National Instrument 51-101 (NI 51-101). Under NI 51-101, proved reserve assignments are based on a high degree of certainty with a targeted 90 percent probability that total quantities received will equal or exceed proved reserve estimates. Proved plus probable reserves are the most likely case with a targeted 50 percent probability that they will equal or exceed estimates. Proved plus probable plus possible reserves are based on a low degree of certainty with a 10 percent probability that they will equal or exceed estimates.
(4) After production of 1 million boe in 2006.
(5) No dividends have been declared by the company since its incorporation.

Summary fourth quarter 2006 results are contained in the enclosed MD&A.

Connacher Oil and Gas Limited experienced a year of great expansion in 2006. As indicated above, revenues exploded to $245 million; cash flow increased almost ten fold to $40 million; conventional production more than tripled to 2,725 boe/d and our proved reserve base expanded 30 fold to over 50 million boe, following the initial recognition of proved reserves at our Great Divide Pod One oil sands project in northeastern Alberta.

During the year we successfully implemented our integration strategy to enable a smaller producer like Connacher to successfully manage its involvement in a steam assisted gravity drainage ("SAGD") oil sands project. This included:

- purchasing Luke Energy Ltd. for its natural gas reserves, exploratory potential, cash flow and credit capacity to allow us to physically hedge against natural gas costs to be incurred with the steam generating process at Pod One;

- addressing crude oil pricing differential risk by purchasing a small but efficient and profitable refinery (and associated product inventory) located just across the Canada-US border at Great Falls, Montana. Following the purchase, which also provided revenue, cash flow and considerable earnings, we expanded throughput capacity and improved operating efficiency;

- strengthening our balance sheet with successful equity and term debt financings totaling $591 million, thereby assuring Connacher the ability to develop Pod One on its own. Shares were also issued in conjunction with the aforementioned purchases to ensure financial viability and to avoid undue balance sheet leverage. Of particular note was our successful private placement of an attractively priced US$180 million issue of seven year term debt to assist in financing the $256 million Pod One project and to repay the bridge loan incurred to acquire the Montana refinery. As a result, Connacher secured the balance of funding required to complete its initial oil sands project. The company was able to secure the loan solely with its oil sands and refining interests, leaving Connacher with optimum financial flexibility and the debt capacity of its conventional properties and its valuable holdings of Petrolifera Petroleum Limited, which during the year exceeded $300 million; and

- addressing execution risk. In initiating its Pod One plant and site construction and arranging for the drilling of its 15 SAGD well pairs for steam injection and production, Connacher was able to reduce execution and cost escalation risk by careful pre-planning and adopting a modular approach, particularly for its plant construction program. In this manner, Connacher has been able to build most of its long lead essential and expensive components in nearby fabrication shops away from the plant site, which is remote and would have been prone to increasing inflationary cost pressures. Under our approach, components can be skid-mounted and transported by road to Pod One when the timetable is appropriate. By introducing an oil field mentality to the process, Connacher is confident of its general ability to control costs and complete on time.

This strategy translates into a reduction of operating cost risk, construction cost risk, balance sheet risk and downstream crude oil price differential risk. It forms an integral part of Connacher's integrated approach and will set precedents for future developments by the company in the region.

Considerable drilling success was encountered at Marten Creek, Alberta and elsewhere in northern Alberta during the current 2007 winter drilling season. Also, approximately 80 core holes and an extensive 3D seismic program were completed on our Great Divide main lease block during this period.

As a consequence, Connacher will be updating its reserve estimates for both conventional properties and its oil sands properties during the second quarter of 2007 and will communicate the results of this update upon acceptance by our Board of Directors of reports to be prepared by GLJ Petroleum Consultants ("GLJ") of Calgary, Alberta.

Construction at Great Divide Pod One is proceeding favorably with a view to commissioning and startup during the summer 2007. Drilling of the SAGD well pairs has been efficient and yielded favorable results. Readers are referred to our website at www.connacheroil.com for pictorial updates of our progress. Connacher has introduced innovative, cost-saving and environmentally friendly technology to its Pod One plant and remains mindful of sound relationships with regulators and stakeholders, including First Nations people, in its operations in this area of northern Alberta. Transportation alternatives are under late-stage evaluation and a decision on the preferred alternative is pending.

Successful follow up drilling at Pod Two has enabled Connacher to arrive at a decision to proceed with an application to develop another 10,000 bbl/d small scale commercial operation (the "Algar Project") at Great Divide. It is anticipated the application for Algar will to be submitted in May 2007 with a view to commencement of construction sometime in early 2008, subject to final approval by Connacher's Board of Directors and following due consultation with stakeholders and receipt of regulatory approval. Preliminary design and advance equipment ordering would likely occur throughout the second half of 2007. This sequential development will enable Connacher to retain its access to personnel and suppliers while it starts up and commences production at Pod One. It is consistent with Connacher's commitment of sustainability and repeatability of growth opportunities for its shareholders.

Connacher's total capital budget for 2007 has initially been established at $249 million, with the majority of this amount directed to completion of our development project at Great Divide Pod One. When the final decision on transportation and development of Pod Two occurs, additional capital and related budgetary allocations will be required at some point during 2007.

Connacher's outlook remains very buoyant and exciting.

Connacher is a Calgary-based oil and natural gas exploration and production company. Its principal asset is its 100 percent interest in reserves, resources and lands in the Great Divide regions of Alberta's oil sands. Connacher also has conventional crude oil and natural gas properties in Alberta and Saskatchewan, owns a 9,500 bbl/d refinery in Great Falls, Montana and owns a 26 percent basic and fully-diluted interest in, and assists in the management of, Petrolifera Petroleum Limited. This investment has a current market value in excess of $200 million.

FORWARD LOOKING STATEMENTS

This press release contains forward-looking statements, including but not limited to estimated reserves, resources and future net revenues related thereto, future exploration and development plans, anticipated capital expenditures and sources of funding in respect thereof, anticipated start-up of Pod One and current plans with respect to the development for Pod Two, including plans for regulatory application and commencement of construction including final approval by

Connacher's Board of Directors. These statements are based on current expectations that involve a number of risks and uncertainties, which could cause actual results to differ materially from those anticipated. These risks include, but are not limited to risks associated with the oil and gas industry (e.g. operational risks in development, exploration and production delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve and resource estimates; the uncertainty of estimates and projections in relation to production, costs and expenses and health, safety and environmental risks), risks associated with construction and commencement of first production, the risk of commodity price and foreign exchange rate fluctuations, the uncertainty associated with geological interpretations and risks relating to securing required approvals and consents to proceed with future development opportunities. Additional risks and uncertainties are described in the company's Annual Information Form which is filed on SEDAR at www.sedar.com.

The reserves, resources and future net revenue in this press release represent estimates only. The reserves, resources and future net revenue from the company's properties have been independently evaluated by GLJ Petroleum Consultants with an effective date of December 31, 2006. This evaluation includes a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves and resources, timing and amount of capital expenditures, marketability of production, future prices of bitumen, crude oil and natural gas, operating costs, abandonment and salvage values, royalties and other government levies that may be imposed during the producing life of the reserves and resources. These assumptions were based on price forecasts in use at December 31, 2006 and many of these assumptions are subject to change and are beyond the control of the company. Actual production, sales and cash flows derived therefrom will vary from the evaluation and such variations could be material. The present value of estimated future net cash flows referred to herein should not be construed as the current market value of estimated bitumen, crude oil and natural gas reserves attributable to the company's properties.

Forecast capital expenditures are based on Connacher's current budgets and development plans which are subject to change based on commodity prices, market conditions, drilling success and potential timing delays. Additionally, forecast capital expenditures do not include capital required to pursue future acquisitions or for the development of additional oil sands projects, such as Pod Two. Anticipated production has been estimated based on the proposed drilling program with a success rate based upon historical drilling success and an evaluation of the particular wells to be drilled and has been risked.

For further information

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MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is dated as of March 23, 2007 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 2006 and 2005 as contained in the Company's annual report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and are presented in Canadian dollars. This MD&A provides management's view of the financial condition of the company and the results of its operations for the reporting periods.

FORWARD-LOOKING INFORMATION

Information in this report contains forward-looking information based on current expectations, estimates and projections of future production, capital expenditures and available sources of financing and estimates of reserves, resources and future net revenues and exploration and development plans. 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, 2006, which include, without limitation, changes in market conditions, law or governing policy, operating conditions and costs, operating performance, demand for crude oil and natural gas, price and exchange rate fluctuations, 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.

BUSINESS STRATEGY

Strategic Priorities	Progress in 2006
Operate with large focused working interest	Great Divide – 100% working interest retained through the financing of Pod One Battrum Saskatchewan crude oil and Marten Creek natural gas
Apply financial discipline	Great Divide (Pod One) financing arranged with term debt – non-recourse to conventional assets & equity in Petrolifera Successful equity financings in 2005 and 2006 totaling $220 million Cash flow finances conventional and refinery projects; available banking lines of credit
Focus on projects with characteristics of sustainability, repeatability	Develop Great Divide Pod One and use as a template to develop additional pods
Mitigate and manage risks of smaller company in the oil sands -integrated approach	Purchased Luke Energy Ltd. ("Luke") (gas producer) for natural gas required for steaming Pod One at Great Divide Purchase of Montana refinery to mitigate price differential risk and potential for marketing Great Divide bitumen production Initiatives to mitigate environmental concerns -low impact seismic (minimum line width) -SAGD provides smaller surface footprint than mining -produced gas conserved -evaporator/package boiler

FINANCIAL AND OPERATING REVIEW
CONVENTIONAL PRODUCTION, PRICING AND REVENUE

For the years ended December 31	**2006**	2005	2004
Daily production / sales volumes			
Crude oil – bbl/d	**980**	729	785
Natural gas – mcf/d	**10,473**	827	1,620
Combined – boe/d	**2,725**	867	1,055
Product pricing ($)			
Crude oil – per bbl	**53.85**	42.33	31.42
Natural gas – per mcf	**5.85**	1.37	3.62
Boe – per boe	**41.83**	36.91	28.95
Revenue ($000)			
Petroleum and natural gas – gross	**41,607**	11,678	11,180
Royalties	**(9,821)**	(2,583)	(2,139)
Petroleum and natural gas revenue – net	**31,786**	9,095	9,041

In 2006, net petroleum and natural gas revenues were up 256.3 percent to $31.8 million from $9.1 million in 2005. This was primarily attributable to a substantial increase in natural gas production resulting from the Luke acquisition in March 2006. Natural gas sales volumes increased 1,166 percent and crude oil sales volumes increased 34 percent in 2006. As a consequence of increased world oil prices in 2006, the company's average crude oil selling price increased by 27 percent to $53.85 per barrel compared to $42.33 per barrel in 2005. Natural gas sales prices increased 327 percent in 2006, but this was primarily due to the influence of low natural gas prices received in Argentina in 2005 when the results of Petrolifera Petroleum Limited ("Petrolifera") were consolidated with those of Connacher. As a result of the Luke acquisition, the company's product mix is more balanced. Crude oil sales represented 46 percent of the company's total production revenue in 2006 and natural gas sales contributed 54 percent.

ROYALTIES ON CONVENTIONAL PETROLEUM AND NATURAL GAS SALES

	2006		2005	
	Total	**Per boe**	Total	Per boe
Petroleum and natural gas royalties	**$9,821**	**$9.87**	$2,583	$8.16
Percentage of petroleum and natural gas revenue	**23.6%**		22%	

Royalties represent charges against production or revenue by governments and landowners. Royalties in 2006 were $9.8 million ($9.87 per boe, or 23.6 percent of petroleum and natural gas revenue) compared to $2.6 million in 2005 ($8.16 per boe, or 22 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 2005 to 2006 reflects market conditions related to increased product prices and production volumes.

CONVENTIONAL OPERATING EXPENSES AND NETBACKS [(1)]
For the years ended December 31

($000 except per boe)	2006		2005		% Change	
	Total	Per boe	Total	Per boe	Total	Per boe
Average daily production (boe/d)	2,725		867		214	
Petroleum and natural gas revenue	$41,607	$41.83	$11,678	$36.91	256	13
Royalties	(9,821)	(9.87)	(2,583)	(8.16)	280	21
Net revenue	31,786	31.96	9,095	28.75	250	11
Operating costs	(8,270)	(8.32)	(2,445)	(7.73)	238	8
Operating netback	$23,516	$23.64	$6,650	$21.02	254	13

(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 with performance measures and provides shareholders and investors with a measurement of the company's efficiency and its ability to fund future growth through capital expenditures. Operating netbacks are reconciled to net earnings below.

For 2006 operating costs of $8,270 were 238 percent higher than in the prior year, and on a per unit basis, increased by 7.6 percent to $8.32 per boe reflecting the higher cost environment in 2006 and the substantial increases in production volumes during the year. However, higher product prices resulted in higher operating netbacks in 2006.

NETBACK BY PRODUCT TYPE

For the year ended December 31	2006			
($000, except per unit amounts)	Oil (bbl/d)		Gas (mcf/d)	
Average daily production	980		10,473	
Revenue	$19,257	$53.85	$22,350	$5.85
Royalties	(4,534)	(12.68)	(5,287)	(1.38)
Operating costs	(3,829)	(10.71)	(4,441)	(1.16)
Netback	$10,894	$30.46	$12,622	$3.30

Reconciliation of Operating Netback to Net Earnings

For the year ended December 31	2006		2005	
($000, except per unit amounts)	Total	Per boe	Total	Per boe
Operating netback as above	$23,516	$23.64	$6,650	$21.02
Interest income	1,024	1.03	700	2.21
Refining margin – net	29,206	29.36	-	-
General and administrative	(3,886)	(3.91)	(2,660)	(8.40)
Stock-based compensation	(7,816)	(7.86)	(1,192)	(3.77)
Finance charges	(5,086)	(5.11)	(308)	(0.97)
Foreign exchange (loss) gain	(4,287)	(4.31)	30	0.09
Depletion, depreciation and amortization	(32,949)	(33.13)	(5,797)	(18.32)
Income taxes	(3,870)	(3.89)	(870)	(2.75)
Equity interest in Petrolifera earnings and dilution gain	11,101	11.16	4,437	14.02

Net earnings	$6,953	$6.98	$991	$3.13

REFINING REVENUES AND MARGINS

The operating results of the refinery since its acquisition on March 31, 2006 to December 31, 2006 are summarized below.

Refinery Throughput

Crude charged	8,713 bbl/d
Refinery production	9,498 bbl/d
Sales of produced refined products	9,661 bbl/d
Sales of refined products (includes purchased products)	10,053 bbl/d
Refinery utilization (1)	94%

(1) Note in Q4 refinery capacity was increased to 9,900 bbl/d.

Feedstocks

Sour crude oil	92%
Other feedstocks & blend	8%

Revenues and Margins

Refining sales revenue ($000)		211,874
Refining – crude oil and operating costs ($000)		182,668
Refining – margin ($000)		29,206
Refining margin (%)		13.8%

Sales of Produced Refined Products (Volume %)

Gasolines	35.6%
Diesel fuels	17.6%
Jet fuels	3.4%
Asphalt	40.2%
LPG and other	3.2%
Total	100%

Averages Per Barrel of Refined Products Sold

Refining sales revenue	$76.63
Less: Refining – crude oil and operating costs	$66.07
Refining margin	$10.56

On March 31, 2006, Connacher completed the acquisition of an 8,300 bbl/d refinery and related assets, including substantial product inventory, in Great Falls, Montana.

The refinery is a good strategic fit with Connacher's oilsands development, as it is well-located – the closest U.S. refinery to Alberta's oilsands. It processes Canadian heavy crude into a range of higher value products including regular and premium gasoline, jet fuel, diesel, home heating oil and asphalt. The refinery thus provides a physical hedge protecting Connacher's future oil sands revenues against crude oil/bitumen price differentials.

The refinery is a complex operation and includes reforming, isomerization and alkylation processes for formulation of gasoline blends, hydro-treating for sulphur removal and fluid catalytic cracking for conversion of heavy gas oils to gasoline and distillate products. It also is a major supplier of paving grade asphalt, polymer modified grades and asphalt emulsions for road construction. The Montana refinery markets products to retailers in Montana and neighbouring states by truck and rail transport.

Shortly after taking over the refinery, the company undertook a 20 day turnaround to complete normal maintenance and de-bottlenecking activities. As a result, throughput capacity was increased to 9,000 bbl/d. Through the year, subsequent optimizations have increased crude throughput capacity to 9,900 bbl/d. Since the turnaround, the refinery has operated continuously with no downtime and crude throughput has averaged 9,400 bbl/d with an average annual capacity utilization of 94%.

Connacher's refinery operation achieved an outstanding year in 2006 with record levels of throughput, profit and profit margin. This performance was due to improved efficiencies implemented subsequent to the acquisition, increased throughput and sales volumes, and high product prices and differentials for the heavy crude feedstocks used as a result of market conditions.

During the year, the company also made significant environmental improvements to the operation. These included capital projects to remove excess sulphur from boiler fuel and recovery and remediation of an old wastewater aeration pond. Sulphur removal in the boiler fuel has now been improved by over 200 times from the previous operation. Sulphur removal is accomplished by means of a unique process which converts the sulphur to a product now being used commercially for environmental remediation in other parts of the U.S.

Other improvements initiated during the year included the construction of a new 150,000 barrel asphalt tank (commissioned in March 2007) and expanded rail loading facilities, both undertaken to handle the increased throughput achieved during the year.

Connacher employs a well-trained and experienced staff in Great Falls. The company was successful in retaining most of the key personnel associated with the refinery, as well as recruiting a number of other experienced professionals. Key processes and systems have been fully integrated into the company. Connacher's operation includes a strong training and development program as well as rigorous procedures for safety and environmental protection.

In 2007, Connacher plans to continue making environmental and capacity enhancements at the Montana refinery. We are designing new high efficiency boilers, further increasing rail load-out capabilities, improving wastewater treatment facilities, and further enhancing our sulphur treatment process.

As well, Connacher has initiated a major Clean Fuels project targeted to allow the production of ultralow sulphur diesel and gasoline in 2008.

Engineering and marketing studies have also been initiated to assess the possibility of major expansion of the refinery's heavy oil capacity.

INTEREST AND OTHER INCOME

In 2006, the company earned interest of $1 million (2005 - $700,000) on excess funds invested in secure short-term investments.

GENERAL AND ADMINISTRATIVE EXPENSES

In 2006, general and administrative ("G&A") expenses were $3.9 million compared to $2.7 million in 2005, an increase of 46 percent, reflecting increased costs associated with being a public company as well as increased staffing that occurred in 2006 in connection with the acquisition of the Montana refinery and to support the development of Great Divide. G&A of $1.0 million was also capitalized in 2006 (2005 - $205,000).

Non-cash stock-based compensation costs of $11.8 million were recorded in 2006 (2005-$1.6 million). These charges reflect the fair value of all stock options granted and vested in each year. Of this amount, $7.8 million was expensed (2005 - $1.2 million), $3.5 million was capitalized (2005 - $410,000) and $500,000 was charged to refining operating costs in 2006.

FINANCE CHARGES

Financing charges were $5.1 million in 2006 compared to $308,000 reported in 2005. These charges increased significantly from 2005 due to the issuance of debt in 2006, including the US$51 million bridge loan used to fund the acquisition of the Montana refinery and the conventional line of credit. In addition, an unrealized foreign exchange loss of $4.3 million was incurred in 2006 primarily due to the conversion of US$180 million oil sands term loan to Canadian dollars for reporting purposes.

The company's main exposure to foreign currency risk relates to the pricing of its crude oil sales, which are denominated in US dollars, and the translation of the US$180 million oil sands term loan. On an economic basis, the company's crude oil and bitumen reserves hedge the company's exposure to foreign currency fluctuations of its US dollar denominated oil sands term loan.

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 2006 was $32.9 million, a 468 percent increase from last year due to increased production volumes and due to the significant additions made to capital assets in 2006. This equates to $33.13 per boe of production compared to $18.32 per boe last year.

Capital costs of $156.7 million (2005 – $11.3 million) related to the Great Divide oil sands project, which is in the pre-production stage, have been excluded from the depletion calculation. Additionally, undeveloped land acquisition costs of $16.2 million (2005 – $2.5 million) were excluded from the depletion calculation, while future development costs of $3.2 million (2005 - $1.8 million) for proved undeveloped reserves were included in the depletion calculation.

Included in DD&A is a charge of $348,000 (2005 - $165,000) 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 $7.3 million to the estimated total undiscounted liability of $17.4 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 2006 or 2005.

TAXES

The income tax provision of $3.9 million in 2006 includes a current tax provision of $7.4 million, principally related to US refinery operations and a future tax recovery of $3.5 million reflecting the benefit of increased tax pools.

At December 31, 2006 the company had approximately $25.8 million of non-capital losses which do not expire before 2009, $253.5 million of deductible resource pools and $20.7 million of deductible financing costs.

EQUITY INTEREST IN PETROLIFERA PETROLEUM LIMITED

Connacher accounts for its 26 percent equity investment in Petrolifera on the equity method basis of accounting. Until the third quarter of 2005, Petrolifera was consolidated with Connacher. Connacher's equity interest share of Petrolifera's earnings in 2006 was $11.1 million (2005 - $27,000 loss)

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, in late 2005, it was reduced to 33 percent and in 2006 it was further reduced to 26 percent. These reductions resulted in a dilution gain to the company of $23,000 in 2006 and $4.5 million in 2005.

NET EARNINGS (LOSS)

In 2006 the company reported earnings of $7.0 million ($0.04 per basic and diluted share outstanding). This compares to earnings of $991,000 or $0.01 per basic and diluted share for 2005. Earnings per boe produced was $6.98 compared to $3.13 last year.

SHARES OUTSTANDING

For 2006, the weighted average number of common shares outstanding was 184,468,631 (2005 – 106,113,563) and the weighted average number of diluted shares outstanding, as calculated by the treasury stock method, was 188,431,809 (2005 – 111,845,687). The substantial increase in shares outstanding year over year reflects the issuance from treasury of 55,461,382 common shares for cash proceeds of $130 million and in connection with the acquisitions of Luke and the Montana refinery assets.

As at March 23, 2007, the company had the following securities issued and outstanding:
- 198,218,448 common shares; and
- 15,840,057 share purchase options.

Details of the exercise provisions and terms of the outstanding options are noted in the consolidated financial statements.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2006, the company had working capital of $118.6 million, including $123 million of cash dedicated to funding the remaining costs of completing Pod One.

In 2006 the company drew US$51 million on a bridge loan facility to partially fund the acquisition of the Montana refinery assets, which closed on March 31, 2006. This bridge loan was repaid in full on October 20, 2006 from the proceeds of a US$180 million term loan facility that was fully drawn on that date (the "oil sands term loan"). The primary purpose of the oil sands term loan is to fund the development of the company's first oil sands project at Great Divide in northern Alberta ("Pod One"). After also depositing US$14 million into an account to fund the estimated interest costs during the course of completing the Pod One project and after paying US$4 million in costs to complete the transaction, the balance of oil sands term loan proceeds have been designated solely to fund the total estimated remaining costs necessary to complete Pod One.

The oil sands term loan has a seven year term. Its principal is amortized by one percent per year commencing in 2008. Additional repayments will be due if certain cash flow performance thresholds are attained. Principal payments on the oil sands term loan are not expected to be significant in the first six years. The oil sands term loan is a floating-rate facility, bearing interest either at a US Dollar Base Rate plus a margin or a US Eurodollar rate plus a margin. In October 2006, the company entered into an interest rate swap with a financial institution whereby the floating rate on US$90 million of the oil sands term loan was fixed at an all-in rate of 8.516 percent over the term of the loan. All interest on the oil sands term loan is being capitalized until Pod One becomes operational.

On October 20, 2006 the company also secured a US$15 million revolving line of credit ("refining line of credit") to fund the working capital requirements of the refinery in Great Falls, Montana. The refining line of credit has a five year term and bears interest at a US Eurodollar rate plus a margin or at a US Dollar Base Rate plus a margin.

The oil sands term loan and the refining line of credit are secured by debenture and mortgage agreements covering all of the assets of the refinery and all of the company's interest in the Great Divide oil sands assets. These two facilities are non-recourse to the company's conventional petroleum and natural gas assets or to its investment in Petrolifera.

The company also has available a $55 million extendible revolving loan facility (the "conventional line of credit") with no scheduled repayments. At December 31, 2006, $19.5 million was drawn in the form of bankers' acceptances under this facility at an interest rate of 5.62 percent including margin. The facility matures on April 15, 2007 and is extendible upon request by the company, at the lender's option for 364 days. The conventional line of credit is secured by a $50 million fixed and floating charge debenture and a general assignment of book debts over the company's conventional crude oil and natural gas assets, and is non-recourse to the company's Great Divide oil sands, its refining assets or to its investment in Petrolifera.

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 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 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 boe) 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.

In addition to available cash, unused debt facilities and cash flow, additional sources of funding in the form of additional equity issuances or additional debt financing may be utilized to provide sufficient funding for working capital purposes and for the company's anticipated capital program in 2007.

The company's only financial instruments are cash, accounts receivable and payable, bank debt and the interest rate swap. The company maintains no off-balance sheet financial instruments.

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

	Twelve months ended December 31	
($000)	**2006**	2005
Net earnings	**$6,953**	$991
Items not involving cash:		
Depletion, depreciation and accretion	**32,949**	5,797
Stock-based compensation	**8,293**	1,192
Financing charges	**2,237**	150
Future income tax provision (recovery)	**(3,535)**	768
Employee future benefits	**381**	-
Foreign exchange (gain) loss	**4,287**	(30)
Lease inducement amortization	**(268)**	(72)
Dilution gain	**(23)**	(4,465)
Equity interest in Petrolifera loss (earnings)	**(11,078)**	27
Cash flow from operations before working capital changes	**$40,196**	$4,358

For 2006, cash flow was $40.2 million ($0.22 per basic and $0.21 per diluted share), 822 percent higher than the $4.4 million reported ($0.04 per basic and diluted share) in 2005.

Cash flow per boe was $40.41 in 2006 compared to $13.77 in 2005. This represents 97 percent of the average company selling price per boe compared to 37 percent in 2005 and an increase of 193 percent over 2005.

CAPITAL EXPENDITURES AND FINANCING ACTIVITIES

Capital expenditures totaled $452 million in 2006. A breakdown of the expenditures follows:

	Twelve months ended December	
($000)	2006	2005
Acquisition of Luke	$204,658	$-
Acquisition of refinery assets	66,333	-
Minor property acquisitions	6,767	1,700
Oil sands expenditures	144,765	7,224
Conventional oil and gas expenditures	23,152	7,783
Refinery expenditures	5,850	-
	$451,525	$16,807

Additionally, the company disposed of non-core properties for proceeds of $10 million in the fourth quarter of 2006.
Oil sands expenditures include exploratory core hole drilling, seismic, lease acquisition and facility costs. In 2006, 26 exploratory core holes were drilled.

Conventional oil and gas expenditures include costs of drilling, completing, equipping and working over conventional oil and gas wells as well as undeveloped land acquisition and seismic expenditures.

A significant part of the company's capital program is 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 approximate 87 percent working interest in its conventional properties, providing the company with operational and timing controls.

Recent Financings

In February 2006, 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 partially fund the acquisition of Luke. Proceeds of the financing were utilized as follows:

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

In September 2006, the company issued 5,714,300 common shares on a "flow-through" basis at $5.25 per common share for gross proceeds of $30 million to fund exploration activities including the further delineation of the company's oil sands properties through the drilling of additional core holes and shooting 3D seismic. Proceeds of the financing were utilized as follows:

($000)	As stated at the time of financing	As actually applied

Gross proceeds	$30,000	$30,000
Underwriters commission and issue costs	2,075	1,883
Available for exploration activities	$27,925	$28,117

Refer also to the "Liquidity and Capital Resources," above, for a discussion of the US$180 million and US$15 million debt facilities entered into in October 2006.

Great Divide Oil Sands Project, Northern Alberta

The company holds a 100 percent working interest in approximately 90,000 acres of oil sands leases in northern Alberta. To date, the focus has been on an approximate 1,586 acre tract ("Pod One") on which approximately $155 million has been invested to the end of 2006 to acquire the oil sands leases, to delineate the oil bearing reservoir, and for certain facilities related to the project. Capital development costs for Pod One are expected to approximate $256 million. These costs will be incurred in 2007.

Acquisition of Luke Energy Ltd. ("Luke")

In March 2006 the company closed the purchase of Luke for cash consideration of $92.7 million and the issuance of 29.7 million Connacher common shares from treasury.

Luke produced natural gas, largely at Marten Creek in northern Alberta and operated 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 SAGD oil sands project (Pod One) at Great Divide. Based on purchased production volumes and anticipated development programs, the Luke purchase is expected to provide surplus natural gas volumes for sale in the marketplace and meet future Connacher requirements at Great Divide. Luke was amalgamated with Connacher on January 1, 2007

Acquisition of Refining Assets in Montana

In March 2006, the company acquired an 8,300 bbl/d refinery located in Great Falls, Montana, USA, for cash of $61 million and one million Connacher common shares issued from treasury.

This acquisition was considered strategic to provide Connacher with protection against wider and more volatile type of heavy crude oil price differential swings. These have become increasingly frequent in the current higher oil price environment for the type of heavy oil which would be produced at Great Divide. Since its acquisition, the refinery has been a profitable and strong business unit contributing to the company's cash flow.

Connacher completed the purchase of the refining assets and related inventory through a new wholly-owned subsidiary, Montana Refining Company, Inc. ("MRC"). Its continued profitability will depend largely on the spread between market prices for refined petroleum products and the cost of crude oil.

MRC's principal source of revenue is from the sale of high value light end products such as gasoline, diesel and jet fuel in markets in the western United States. Additionally, MRC sells a high grade asphalt into the local market. MRC's principal expenses relate to crude oil purchases and operating expenses.

In April 2006, MRC completed a scheduled plant "turnaround" maintenance program of its refinery facilities. Such turnarounds are normally scheduled every two to five years. Turnaround costs are capitalized and amortized over the period to the next scheduled turnaround.

With minimal additional anticipated capital investment, MRC will be capable of producing low sulfur gasoline and diesel as required in 2008.

The above mentioned regulatory compliance items or other presently existing or future environmental regulations, could cause management to make additional capital investments beyond those described above and/or incur additional operating costs to meet applicable requirements.

In 2004, the American Jobs Creation Act of 2004 was signed into law. Among other things, the Act creates tax incentives for small refiners preparing to produce low sulphur gasoline and diesel. The Act provides an immediate deduction of 75% of certain costs paid or incurred to comply with tthese standards and a tax credit based on production for up to 25% of those costs. Management intends to utilize these incentives when it makes these required expenditures.

RELATED PARTY TRANSACTIONS

In 2006 the company paid professional legal fees of $1.8 million (2005 - $539,000) to a law firm in which an officer and director of the company are partners. 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 estimates and assumptions may have a material impact on the company's financial results and condition. The following discusses such accounting policies and is included herein 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 its estimates and assumptions regularly. The emergence of new information and changed circumstances may result in changes to estimates and assumptions 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 regulatory 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 of 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 company's oil and gas reserve estimates are made by independent reservoir engineers 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

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 is depleted using the unit-of-production method based on estimated proved oil and gas reserves.

Major Development Projects and Unproved Properties

Certain costs related to acquiring and evaluating unproved properties are excluded from net capitalized costs subject to depletion until proved reserves have been determined or their value is impaired. Costs associated with major development projects are not depleted until commencement of commercial production. All capitalized 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.

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 prepared by qualified independent evaluators, 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 costs as estimated by the company's engineers adjusted for inflation and credit risk. These estimates are subject to management uncertainty.

Legal, Environmental 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.

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 income tax asset and liability amounts are enacted tax rates expected to be used in future periods when the timing differences reverse. 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 charge for future income 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 estimates of stock volatility, interest rates and the term of the option. These estimates by their nature are subject to measurement uncertainty.

NEW SIGNIFICANT ACCOUNTING POLICIES

The company has assessed new and revised accounting pronouncements that have been issued but that are not yet effective and has determined that the following may have a significant impact on the company.

Beginning with the year ending December 31, 2007 the company will be required to adopt, if applicable, the Canadian Institute of Chartered Accountants ("CICA") Sections 1530, 3251, 3855 and 3865 on "Comprehensive Income", "Equity", "Financial Instruments – Recognition and Measurement", and "Hedges" respectively, all of which were issued in January 2005. Under the new standards additional financial statement disclosure, namely Consolidated Statement of Other

Comprehensive Income, has been introduced that will identify certain gains and losses, including the foreign currency translation adjustments and other amounts arising from changes in fair value, to be temporarily recorded outside the income statement. In addition, all financial instruments, including derivatives, are to be included in the company's Consolidated Balance Sheet and measured, in most cases, at fair values. Requirements for hedge accounting have been further clarified. Although Connacher is in the process of evaluating the impact of these standards, the company does not expect these standards to have a material impact on its Consolidated Financial Statements.

Over the next five years the CICA will adopt its new strategic plan for the direction of accounting standards in Canada, which was ratified in January 2006. As part of the plan, Canadian GAAP for public companies will converge with International Financial Reporting Stands ("IFRS") over the next five years. The company continues to monitor and assess the impact of the convergence of Canadian GAAP with IFRS.

MRC's financial results are reported in accordance with Canadian GAAP and are consolidated with Connacher's other business units. The preparation of MRC's financial results require certain estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities as of the date of the financial statements. Actual results may differ from those estimates under different assumptions or conditions. Connacher's management considers the following new MRC accounting policies to be the most critical to understanding the judgments that are involved and the uncertainties that could impact on the company's results of operations, financial condition and cash flows.

Inventory Valuation

Crude oil and refined product inventories are stated at the lower of cost or net realizable value. Since acquiring the refining assets in March 2006, management re-evaluated the inventory costing method and has chosen the average cost method in order to conform to impending Canadian GAAP changes. The effect of this change was to decrease inventory by $2.5 million at December 31, 2006 (see Note 4 to the Consolidated Financial Statements). Net realizable value is determined using current estimated selling prices.

Deferred Maintenance Costs

MRC's refinery units require regular major maintenance and repairs which are commonly referred to as "turnarounds". Catalysts used in certain refinery processes also require routine "change-outs". The required frequency of the maintenance varies by unit and by catalyst, but generally is every two to five years. Turnaround costs are capitalized and amortized over the period to the next scheduled turnaround or change-out. In order to minimize downtime during turnarounds, contract labor as well as maintenance personnel are utilized on a continuous 24 hour basis. Whenever possible, turnarounds are scheduled so that some units continue to operate while others are down for maintenance. The costs of turnarounds are recorded as deferred charges and are amortized over the expected periods of benefit.

Employee Future Benefits

As a consequence of the refinery acquisition and related employment of refinery personnel, the company's new US subsidiary, MRC, adopted new employee future benefit plans with effect from March 31, 2006.

A new non-contributory defined benefit retirement plan covers only MRC's employees from March 31, 2006. MRC's policy is to make regular contributions in accordance with the funding requirements of the United States Employee Retirement Income Security Act of 1974. Benefits are to be based on the employee's years of service and compensation. MRC also established new defined contribution (US tax code "401(k)") plans that cover all of its employees from March 31, 2006. The company's contributions are based on employees' compensation and partially match employee contributions.

Long-lived Refining Assets

Depreciation and amortization is calculated based on estimated useful lives and salvage values. When assets are placed into service, estimates are made with respect to their useful lives that are believed to be reasonable. However, factors such as new technologies, competition, regulation or environmental matters could cause changes to estimates, thus impacting the future calculation of depreciation and amortization. Long-lived assets are also evaluated for potential impairment by identifying whether indicators of impairment exist and, if so, assessing whether the long-lived assets are recoverable from estimated future undiscounted cash flows. The actual amount of impairment loss, if any, to be recorded is equal to the amount by which a long-lived asset's carrying value exceeds its fair value. Estimates of future discontinued cash flows and fair values of assets require subjective assumptions with regard to future operating results and actual results could differ from those estimates.

Goodwill

Goodwill arose on the acquisition of Luke in 2006.

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed for impairment annually. Goodwill and all other assets and liabilities have been allocated to the company's segments, referred to as reporting units. To assess impairment, the fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount.

RISK MANAGEMENT - MRC

Certain strategies could be used to reduce some commodity prices and operational risks. No attempt will be made to eliminate all market risk exposures when it is believed the exposure relating to such risk would not be significant to future earnings, financial position, capital resources or liquidity or that the cost of eliminating the exposure would outweigh the benefit. MRC's profitability will depend largely on the spread between market prices for refined products sold and market prices for crude oil purchased. A substantial or prolonged reduction in this spread could have a significant negative effect on earnings, financial condition and cash flows.

Petroleum commodity futures contracts could be utilized to reduce exposure to price fluctuations associated with crude oil and refined products. Such contracts could be used principally to help manage the price risk inherent in purchasing crude oil in advance of the delivery date and as a hedge for fixed-price sales contracts of refined products. Commodity price swaps and collar options could also be utilized to help manage the exposure to price volatility relating to forecasted purchases of natural gas. Contracts could also be utilized to provide for the purchase of crude oil and other feedstocks and for the sales of refined products. Certain of these contracts may meet the definition of a hedge and may be subject to hedge accounting.

The supply and use of heavy crude oil from the company's Great Divide Oil Sands Project, as a feedstock for the refinery, would provide a physical hedge to this exposure, as planned.

MRC's operations are subject to normal hazards of operations, including fire, explosion and weather-related perils. Various insurance coverages, including business interruption insurance, are maintained in accordance with industry practices. However, MRC is not fully insured against certain risks because such risks are not fully insurable, coverage is unavailable, or, in management's judgment, premium costs are prohibitive in relation to the perceived risks.

Additionally, the company has recently issued parental guarantees and indemnifications on behalf of MRC. This is considered to be in the normal course of business. The company has not entered into any off-balance sheet arrangements.

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 foreign 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 will require a significant amount of natural gas in order to generate steam for the SAGD process used at Great Divide. The company is exposed to the risk of changes in the price of natural gas, which could increase operating costs of the Great Divide project. This risk is mitigated to a certain extent by the production and sale of natural gas from the company's gas properties at Marten Creek acquired with the purchase of Luke.

Additionally, the company is exposed to exchange rate fluctuations since oil prices and its long term debt are denominated in US dollars, while the majority of its operating and capital costs are denominated in Canadian dollars. On an economic basis, the company's crude oil and bitumen reserves hedge the company's exposure to foreign currency fluctuations of its US dollar denominated oil sands term loan.

Bitumen is generally less marketable than light or medium crude oil, and prices received for bitumen are generally lower than those for crude oil. The company is therefore exposed to the price differential between crude oil and bitumen; fluctuations in this differential could have a material impact on the company's profitability. The purchase of the Montana Refinery was meant to help mitigate the risk exposure.

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.

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

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

Contractual obligations ($000)	2007	2008-2010	2011-2012	Subsequent to 2012	Total
Term debt and short-term loans	$19,500	$2,360	$4,079	$205,296	$231,235
Asset retirement obligations	166	31	75	7,050	7,322
Operating leases	1,426	6,355	3,323	7,649	18,753
Employee future benefits	488	-	-	-	488
Other long term obligations	638	1,069	-	-	1,707
Total	$22,218	$9,815	$7,477	$219,995	$259,505

The above table excludes ongoing crude oil and refined product purchase commitments of the Montana refinery which are in the normal course of business and are contacted at market prices, where the products are for resale into the market.

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 arrangements.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the company is accumulated, recorded, processed and reported to the company's management as appropriate to allow timely decisions regarding required disclosure. The company's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by this MD&A, that the company's disclosure controls and procedures as of the end of such period are effective to provide reasonable assurance that material information related to the company, including its consolidated subsidiaries, is communicated to them as appropriate to allow timely decisions regarding required disclosure.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of the company is responsible for designing adequate internal controls over the company's financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP.

It should be noted that while the company's Chief Executive Officer and Chief Financial Officer believe that the company's disclosure controls and procedures provide a reasonable level of assurance that they are effective and that the internal controls over financial reporting are adequately designed, they do not expect that the financial disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

FOURTH QUARTER

During the fourth quarter of 2006, the company drew down in full the US$180 million oil sands term loan in order to secure financing for the costs of completing Pod One at the Great Divide project and to repay the bridge loan incurred to purchase the Montana refinery. Spending during the fourth quarter related to Pod One amounted to approximately $65 million.

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. Additional financing may be required for the Great Divide Oil Sands Project, the company's conventional petroleum and natural gas assets and for the Montana refinery.

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

QUARTERLY RESULTS

Fluctuations in results over the previous eight quarters are due principally to variations in oil and gas prices and the acquisitions of Luke and the Montana refinery in 2006, both of which increased revenues substantially. Additionally, operating and general and administrative costs increased due to higher staff levels necessitated by the company's growth. Depletion, depreciation and amortization increased as a result of higher production volumes and additions to capital assets.

	2005				2006			
Three Months Ended	Mar 31	Jun 30	Sept 30 [3]	Dec 31	**Mar 31**	**Jun 30**	**Sept 30**	**Dec 31**
Financial Highlights ($000 except per share amounts) – Unaudited								
Revenue net of royalties	1,488	2,107	3,222	2,978	**3,635**	**61,239**	**103,110**	**76,700**
Cash flow from operations before working capital changes [1]	265	877	1,978	1,238	**1,725**	**9,499**	**14,957**	**14,015**
Basic, per share [1]	-	0.01	0.02	0.01	**0.01**	**0.05**	**0.08**	**0.08**
Diluted, per share [1]	-	0.01	0.02	0.01	**0.01**	**0.05**	**0.08**	**0.07**
Net earnings (loss)	1,673	(230)	(1,034)	582	**(666)**	**(2,419)**	**6,771**	**3,267**
Basic and diluted per share	0.02	-	(0.01)	-	**-**	**(0.01)**	**0.03**	**0.02**
Capital expenditures	6,047	5,649	2,870	2,241	**300,836**	**34,280**	**41,449**	**74,960**
Proceeds on disposal of PNG properties	-	-	-	-	**-**	**-**	**-**	**10,000**
Bank debt	-	250	-	-	**17,600**	**70,365**	**62,380**	**229,254**
Working capital surplus (deficiency)	5,588	854	67,440	75,427	**(11,061)**	**(42,483)**	**(39,942)**	**118,626**
Cash on hand	8,286	2,629	67,708	75,511	**-**	**7,505**	**14,450**	**142,391**
Shareholders' equity	41,079	41,090	113,081	129,108	**337,584**	**340,639**	**378,730**	**385,398**
Operating Highlights								
Production / sales volumes								
Natural gas - mcf/d	1,328	1,416	497	86	**2,600**	**15,172**	**13,028**	**11,291**
Crude oil - bbl/d	629	702	808	775	**689**	**1,026**	**1,084**	**1,139**
Equivalent - boe/d [2]	850	938	891	789	**1,122**	**3,554**	**3,256**	**3,021**
Pricing								
Crude oil - $/bbl	30.02	41.23	53.40	41.54	**40.93**	**61.45**	**62.53**	**46.65**
Natural gas - $/mcf	1.18	0.99	1.88	7.55	**6.34**	**5.66**	**5.33**	**6.57**
Selected Highlights - $/boe [2]								
Weighted average sales price	24.04	32.35	49.48	41.61	**39.83**	**41.88**	**42.16**	**42.15**
Royalties	4.82	8.06	11.73	7.76	**8.02**	**10.43**	**10.72**	**9.00**

Operating costs	7.01	7.42	7.69	8.90	**8.24**	**7.63**	**7.99**	**9.27**
Operating netback [4]	12.21	16.87	30.06	24.95	**23.57**	**23.82**	**23.45**	**23.88**
Common Share Information								
Shares outstanding at end of period (000)	92,753	93,013	134,236	139,940	**191,257**	**191,924**	**197,878**	**197,894**
Weighted average shares outstanding for the period								
Basic (000)	91,189	92,875	103,851	136,071	**154,152**	**191,672**	**193,587**	**193,884**
Diluted (000)	94,197	95,555	106,397	142,507	**160,574**	**198,931**	**200,572**	**204,028**
Volume traded during quarter (000)	40,486	16,821	180,848	100,246	**148,184**	**80,347**	**48,849**	**46,444**
Common share price ($)								
High	1.22	1.05	2.69	4.20	**6.07**	**5.05**	**4.55**	**4.43**
Low	0.49	0.68	0.76	1.09	**3.47**	**3.10**	**3.09**	**3.17**
Close (end of period)	0.93	0.82	2.54	3.84	**4.95**	**4.30**	**3.60**	**3.49**

(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. Boe 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 BALANCE SHEETS

Connacher Oil and Gas Limited
December 31

($000)	**2006**	2005
ASSETS		
CURRENT		
Cash and cash equivalents	**$19,603**	$75,511
Restricted cash (Note 15(c))	**122,788**	-
Accounts receivable	**30,956**	1,605
Refinery inventories (Note 4)	**24,437**	-
Due from Petrolifera (Note 5)	**32**	221
Prepaid expenses	**1,525**	407
	199,341	77,744
Property and equipment (Note 6)	**384,311**	45,242
Goodwill (Note 3)	**103,676**	-
Deferred charges (Note 7)	**4,005**	256
Investment in Petrolifera (Note 5)	**21,597**	10,496
Future income tax asset (Note 8)	**-**	1,075
	$712,930	$134,813

LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities	**$57,571**	$2,184
Income taxes payable	**3,644**	132
Current portion of bank debt (Note 9)	**19,500**	-
	80,715	2,316
Asset retirement obligations (Note 10)	**7,322**	3,108
Deferred credits	**-**	281
Employee future benefits (Note 11)	**388**	-
Bank debt (Note 9)	**209,754**	-
Future income taxes (Note 8)	**29,353**	-
	327,532	5,705
SHAREHOLDERS' EQUITY		
Share capital and contributed surplus (Note 12)	**376,500**	127,033
Cumulative translation adjustment	**(130)**	-
Retained earnings	**9,028**	2,075
	385,398	129,108
	$712,930	$134,813

Commitments, contingencies and guarantees (Note 16)

Approved by the Board

Signed
"D.H. Bessell", Director

Signed
"C.M. Evans", Director

CONSOLIDATED STATEMENTS OF OPERATIONS AND RETAINED EARNINGS
Connacher Oil and Gas Limited
Years Ended December 31

($000, except per share amounts)	2006	2005
REVENUE		
Petroleum and natural gas revenue, net of royalties	$31,786	$9,095
Refining and marketing sales	211,874	-
Interest and other income	1,024	700
	244,684	9,795
EXPENSES		
Petroleum and natural gas operating costs	8,270	2,445
Refining – crude oil purchases and operating costs	182,668	-
General and administrative	3,886	2,660
Stock-based compensation (Note 12)	7,816	1,192
Finance charges	5,086	308
Foreign exchange loss (gain)	4,287	(30)
Depletion, depreciation and accretion	32,949	5,797
	244,962	12,372
Loss before income taxes and other items	(278)	(2,577)
Current income tax provision (Note 8)	7,405	102
Future income tax provision (recovery)	(3,535)	768
	3,870	870
Loss before other items	(4,148)	(3,447)
Equity interest in Petrolifera earnings (loss) (Note 5)	11,078	(27)
Dilution gain (Note 5)	23	4,465
NET EARNINGS	6,953	991
RETAINED EARNINGS, BEGINNING OF YEAR	2,075	1,084
RETAINED EARNINGS, END OF YEAR	$9,028	$2,075
EARNINGS PER SHARE (Note 15(a))		
Basic and diluted	$0.04	$0.01

CONSOLIDATED STATEMENTS OF CASH FLOW
Connacher Oil and Gas Limited
Years Ended December 31

($000)	2006	2005
Cash provided by (used in) the following activities:		
OPERATING		
Net earnings	$6,953	$991
Items not involving cash:		
Depletion, depreciation and accretion	32,949	5,797
Stock-based compensation (Note 12)	8,293	1,192
Financing charges	2,237	150
Employee future benefits	381	-
Future income tax provision (recovery)	(3,535)	768
Foreign exchange loss (gain)	4,287	(30)
Dilution gain	(23)	(4,465)
Lease inducement amortization	(268)	(72)
Equity interest in Petrolifera (earnings) loss	(11,078)	27
Cash flow from operations before working capital changes	40,196	4,358
Changes in non-cash working capital (Note 15 (b))	(9,271)	(485)
	30,925	3,873
FINANCING		
Issue of common shares, net of share issue costs	123,188	86,512
Increase in bank debt	280,078	-
Repayment of bank debt	(57,707)	-
Issue of shares by Petrolifera, net of share issue costs	-	6,228
Deferred financing costs	-	(258)
	345,559	92,482
INVESTING		
Acquisition and development of oil and gas properties	(175,033)	(16,807)
Proceeds on disposal of oil and gas properties	10,000	-
Increase in restricted cash (Note 15(c))	(122,788)	-
Acquisition of Luke Energy Ltd. (Note 3)	(92,692)	-
Acquisition of refining assets (Note 3)	(61,273)	-
Acquisition of other assets	(5,185)	-
Purchase of Petrolifera shares (Note 5)	-	(6,000)
Collection of Petrolifera note (Note 5)	-	750
Change in non-cash working capital (Note 15(b))	14,122	396
	(432,849)	(21,661)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(56,365)	74,694
Impact on cash resulting from de-consolidation of Petrolifera (Note 5)	-	(3,097)
Impact of foreign exchange on foreign currency denominated cash balances	457	-

CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	**75,511**	3,914
CASH AND CASH EQUIVALENTS, END OF YEAR	**$19,603**	$75,511

Supplementary information – Note 15

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
Connacher Oil and Gas Limited
Years Ended December 31. 2006 and 2005

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. Operating in Canada, and in the U.S. through its subsidiary Montana Refining Company, Inc. ("MRC"), the company is in the business of exploring, developing, producing, refining 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 5) it also conducted a conventional petroleum and natural gas business in Argentina.

2. SIGNIFICANT ACCOUNTING POLICIES

Cash and cash equivalents

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

Inventory Valuation

Crude oil and refined product inventories are stated at the lower of cost or net realizable value. Subsequent to the acquisition of the refining assets, the company has adopted the average cost method; net realizable value is determined using current estimated selling prices.

Deferred charges

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

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 before royalites 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 less impairment 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 less impairment 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 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. Costs associated with major development projects are not depleted until commencement of commercial production. All capitalized 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.

To date, all costs, including financing costs, incurred in relation to the oil sands project in Northern Alberta have been capitalized as the project is considered to be in the pre-production stage. Judgment is required in order to determine when commercial operations have commenced. Once commercial operations have been achieved, revenue will be recognized, operating costs will be expensed to earnings and the capitalized costs of the project will be added to the full cost pool and depleted using the unit-of-production method.

Gains or losses on sales of properties are recognized only when crediting the proceeds to the cost pool 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.

Refining Assets

Depreciation and amortization is calculated based on estimated useful lives and salvage values. When assets are placed into service, estimates are made with respect to their useful lives that are believed to be reasonable. However, factors such as competition, regulation or environmental matters could cause changes to estimates, thus impacting the future calculation of depreciation and amortization. Long-lived refining assets are also evaluated for potential impairment by identifying whether indicators of impairment exist and, if so, assessing whether the long-lived assets are recoverable from estimated future undiscounted cash flows. The actual amount of impairment loss, if any, to be recorded is equal to the amount by which a long-lived asset's carrying value exceeds its fair value. Estimates of future discontinued cash flows and fair values of assets require subjective assumptions with regard to future operating results and actual results could differ from those estimates.

Deferred Maintenance Costs

The refining assets require regular major maintenance and repairs which are commonly referred to as "turnarounds". Catalysts used in certain refinery processes also require routine "change-outs". The required frequency of the maintenance varies by asset type and by catalyst, but generally is every two to five years. The costs of turnarounds are recorded as deferred charges and are amortized over the period to the next scheduled turnaround or change-out.

Investment in Petrolifera Petroleum Limited

The investment in Petrolifera Petroleum Limited ("Petrolifera") 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 accumulated income and losses. Any permanent decline in value would be charged to earnings.

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 assets and liabilities 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. An impairment is recognized when management assesses that it's not more likely than not that the asset will be recovered.

Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed for impairment annually. Goodwill and all other assets and liabilities have been allocated to the company's segments, referred to as reporting units. To assess impairment, the fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount.

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 property 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 amount of the capitalized retirement obligation is depleted and depreciated on the same basis as the other capitalized oil and natural gas property costs. Actual restoration expenditures are charged to the accumulated obligation as incurred and costs for properties disposed are removed.

Employee future benefits

The costs of the defined benefit pension plan and other retirement benefits are actuarially determined using the projected benefit method prorated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. For the purpose of calculating the expected return on plan assets, those assets are valued at a market-related value. The cost of the company's portion of the defined contribution plan is expensed as incurred.

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 liability is increased by the tax benefits related to the expenditures at the time they are renounced.

Foreign currency translation

The company has assessed the operations of MRC to be self-sustaining. Assets and liabilities of self-sustaining foreign operations are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date and revenues and expenses are translated at the average monthly rates of exchange during the periods. Gains or losses on translation of self-sustaining foreign operations are included in currency translation adjustment in shareholders' equity.

Financial instruments

Financial instruments include cash and cash equivalents, accounts receivable, amounts due from/to Petrolifera, bank debt and accounts payable. All carrying values of financial instruments approximate fair value unless otherwise noted. The fair value of interest rate swaps and all payments received or made under interest rate swaps are recorded as part of financing costs.

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.

Revenue recognition

Petroleum and natural gas sales and refined product sales are recognized as revenue at the time the respective commodities are delivered to purchasers.

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 expensed or capitalized and credited to contributed surplus over the vesting period. Upon exercise of the options, the exercise proceeds together with amounts credited to contributed surplus, are credited to share capital.

Segment reporting

Management has determined that the company operates in the following segments:

Canada Oil and Gas includes the exploration, development, production and sales in western Canada of conventional and unconventional hydrocarbon reserves.

Canada Administrative includes assets not related directly to any of the company's other business segments, being primarily the company's investment in Petrolifera. Income and expense in this segment are comprised mainly of equity in the earnings of Petrolifera, financing charges, stock-based compensation and general and administrative expenses.

USA Refining includes the refining and marketing of refined petroleum products from the company's refinery in Great Falls, Montana.

Argentina Oil and Gas includes the exploration, development, production and sales of conventional crude oil and natural gas in Argentina, through the company's investment in Petrolifera during the time its results were consolidated.

The above have been defined as the operating segments of the company because they (a) produce products which are sufficiently differentiated from each other so as to be separately identifiable, (b) are those whose operating results are regularly reviewed by the company's chief operating decision maker to make decisions about resources to be allocated to each segment and assess its performance; and (c) are those for which discrete financial information is available.

Segment accounting policies are the same as those described in this summary of significant accounting policies. Transfers of assets between segments are recorded at book amounts.

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. Estimates of the stage of completion of capital projects at the financial statement date affect the calculation of additions to property, plant and equipment and the related accrued liability.

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 future taxes 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.

Credit risk

The majority of the accounts receivable is in respect of refining operations. The company generally extends unsecured credit to customers and therefore, the collection of accounts receivable may be affected by changes in economics or other conditions. Management believes this 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, 2006 there were no such contracts in place. Additionally, the company is exposed to interest rate risk as a portion of the company's bank debt is subject to floating interest rates.
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 plus the amount of stock-based compensation not yet recognized would be used to purchase common shares at the average market price during the period.

3. BUSINESS ACQUISITIONS

During 2006, Connacher completed the following transactions:

(a) Acquisition of Luke Energy Ltd.
The company completed the acquisition of all of the outstanding shares of Luke Energy Ltd. ("Luke") on March 16, 2006. The results of operations of Luke have been included in the financial statements since that date. Net assets acquired and consideration paid were as follows:

($000)	
Net assets acquired:	
Petroleum and natural gas assets	$153,755
Goodwill	103,676
Asset retirement obligations (Note 10)	(2,109)
Working capital deficit	(19,308)
Future income tax liability	(31,356)
Net assets acquired	$204,658
Consideration paid:	
Cash	$92,692
Common shares (Note 13)	111,966
	$204,658

Included in cash consideration paid are transaction costs of $1.2 million. The value of the common share consideration paid was determined by reference to the market value of the company's shares at the time of announcing the acquisition. Effective January 1, 2007, Luke was amalgamated with Connacher.

(b) Acquisition of refining assets

On March 31, 2006 the company acquired all of the assets of a refinery in Great Falls, Montana. The refinery's results of operations have been included in the consolidated financial statements from that date. Net assets acquired and consideration paid were as follows:

($000)	
Net assets acquired:	
Refining assets	$46,337
Inventory	19,996
Net assets acquired	$66,333
Consideration paid:	
Cash	$61,273
Common shares (Note 12)	5,060
	$66,333

Included in cash consideration paid are transaction costs of $1.2 million. The value of the common share consideration paid was determined by reference to the market value of the company's shares at the time of announcing the acquisition.

The purchase agreement commits the vendor to resolve any environmental liabilities arising over the next five years for environmental matters existing at the purchase date.

As a means to facilitate the expeditious transition of the ongoing refinery business, MRC assumed all of the ongoing purchase and sales contracts with suppliers and customers of the refinery. These contracts are all short-term in nature and necessitated some guarantees from Connacher, all considered to be in the normal course of business.

4. REFINERY INVENTORIES

Inventories at December 31 consist of the following:

($000)	**2006**	2005
Crude oil	**$3,520**	$-
Other raw materials and unfinished products (1)	**1,292**	-
Refined products (2)	**17,440**	-
Process chemicals (3)	**909**	-
Repairs and maintenance supplies and other	**1,276**	-
	$24,437	$-

(1) Other raw materials and unfinished products include feedstocks and blendstocks, other than crude oil. The inventory carrying value includes the costs of the raw materials and transportation.

(2) Refined products include gasoline, jet fuels, diesels, asphalts, liquid petroleum gases and residual fuels. The inventory carrying value includes the cost of raw materials including transportation and direct production costs.

(3) Process chemicals include catalysts, additives and other chemicals. The inventory carrying value includes the cost of the purchased chemicals and related freight.

Subsequent to the acquisition of the refinery, management changed the method of inventory cost determination from the last in, first out (LIFO) method to the average cost method. Had the LIFO method been used throughout 2006, inventory at December 31, 2006 would have been increased by $2.5 million, refinery cost of sales would have been decreased by $2.4 million and net income would have been increased by $1.5 million.

5. INVESTMENT IN PETROLIFERA PETROLEUM LIMITED ("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 the reduction in its ownership percentage below 50%. The investment in Petrolifera has since been accounted for following the equity basis of accounting.

The impact of not consolidating Petrolifera had the effect of reducing the company's net assets by $4.1 million as follows:

($000)	
Cash	$(3,097)
Other current assets	(321)
Future income tax asset	(985)
Property and equipment	(4,110)
Current liabilities	381
Asset retirement obligations	442
Non-controlling interests	3,564
Changes in net assets	$(4,126)

Connacher's investment in Petrolifera at the time of de-consolidation	$4,126
Increases (decreases) in investment:	
Equity interest in Petrolifera's loss from the time of deconsolidating to December 31, 2005	(27)
Collection of Promissory Note and reclassification of amounts due from Petrolifera	(1,047)
Purchase of shares in Petrolifera	6,000
Dilution gain on shares issued by Petrolifera to unrelated parties after de-consolidation	1,444
Investment in Petrolifera, December 31, 2005	10,496
Equity in Petrolifera's 2006 earnings	11,078
Dilution gain resulting from issuance of Petrolifera shares in 2006	23
Investment in Petrolifera, December 31, 2006	$21,597

Dilution gains have been recognized whenever changes have occurred in the company's equity interest in Petrolifera, most notably relative to Petrolifera's $7 million private placement financing completed in March 2005 when Connacher's equity interest holding was reduced from 61 percent to 40 percent, resulting in a dilution gain of $3 million. Although Connacher participated in Petrolifera's $21.3 million initial public offering in November 2005 by investing $6 million, Connacher's equity investment interest was reduced to 35 percent and a further dilution gain of $1.5 million was then recognized.

In consideration for the assistance provided to Petrolifera in securing two Peruvian licenses for exploratory lands and for the provision of financial guarantees respecting Petrolifera's annual work commitments in the two licensed blocks in 2005, 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 CWI 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.

Under the terms of a Management Services Agreement with Petrolifera which expires in May 2007, Connacher provides all management, operational, accounting and general and administrative services necessary or appropriate to manage and operate Petrolifera. The fee for this service $15,000 per month. At December 31, 2006, Connacher was owed $32,000 for these services, and for other amounts advanced and other amounts paid on Petrolifera's behalf (2005 - $221,000).

6. PROPERTY AND EQUIPMENT

($000)	Cost	Accumulated Depletion, Depreciation and Amortization	Net Book Value
2006			
Petroleum and natural gas properties and equipment	$377,172	$43,816	$333,356
Refining assets	51,959	2,319	49,640
Furniture, equipment and leaseholds	2,625	1,310	1,315
	$431,756	$47,445	$384,311
2005			
Petroleum and natural gas properties and equipment	$60,291	$15,680	$44,611
Furniture, equipment and leaseholds	1,058	427	631
	$61,349	$16,107	$45,242

In 2006, the company capitalized $4.5 million (2005 - $615,000) of general and administrative expenses, including stock-based compensation of $3.5 million (2005 - $410,000), related to conventional petroleum and natural gas activities and oil sands activities and $7.9 million (2005 – $nil) of interest and financing costs related to major development projects.

Depletion, depreciation and accretion expense includes a charge of $348,000 (2005 – $165,000) to accrete the company's estimated asset retirement obligations (Note 10).

The ceiling test as at December 31, 2006 excludes $16.2 million (2005 – $2.5 million) of undeveloped land and $156.7 million (2005 – $11.2 million) of major development projects, principally related to oil sands assets in the pre-production stage, 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, 2006.

Connacher's oil and natural gas reserves were evaluated by qualified independent evaluators as at December 31, 2006 in a report dated March 9, 2007. The evaluation was conducted in accordance with the Canadian Securities Administrators' National Instrument 51-101, using the following base price assumptions adjusted for the company's product quality and transportation differentials:

	Bitumen Wellhead Current (CDN$/bbl)	WTI @ Cushing ($US/bbl)	Alberta Spot (CDN$/mcf)
2007	31.50	62.00	7.25
2008	32.75	60.00	7.50
2009	33.50	58.00	7.50
2010	33.37	57.00	7.50
2011	34.50	57.00	7.50
		+ approximately 2% after 2012	+ approximately 2% thereafter

7. DEFERRED CHARGES

The balance of $4 million as at December 31, 2006 represents deferred maintenance costs. Deferred charges of $256,000 at December 31, 2005 relate to costs incurred in respect of transactions incomplete at that date and which were subsequently capitalized to property, plant and equipment.

8. INCOME TAXES

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

Years Ended December 31 ($000)	2006	2005
Earnings before income taxes	$10,823	$1,861
Canadian statutory rate	35.4%	39.0%
Expected income taxes (recovery)	3,831	726
Non-deductible Canadian crown payments	1,729	555
Canadian resource allowance	(945)	(371)
Impact of reduction in Canadian tax rates and other	(3,955)	245
Foreign taxes (recovery)	973	(17)
Capital taxes	502	119
Non taxable portion of capital gains	762	-
Equity income and dilution gain	(1,962)	(852)
Non deductible stock-based compensation	2,935	465
Provision for taxes	$3,870	$870

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

As at December 31 ($000)	2006	2005
Book value in excess of tax basis of property, plant and equipment	$(37,628)	$(2,370)
Non-capital losses carried forward	7,754	1,075
Foreign exchange gain on debt	882	-
Partnership deferral	(5,930)	-
Investment in Petrolifera	(1,980)	-
Deferred maintenance costs	(1,547)	-
Share issue costs	6,463	2,370
Asset retirement obligation	2,158	-
Other	475	-
Net future income tax asset (liability)	$(29,353)	$1,075

At December 31, 2006 the company had approximately $25.8 million of non-capital losses which expire at various periods to 2026, $253.5 million of deductible resource pools and $20.7 million of deductible financing costs.

9. BANK DEBT

The company had the following loans outstanding, as at December 31:

($000)	2006	2005
Conventional line of credit	$19,500	$-
Refinery line of credit	-	-
Oil sands term loan	209,754	-
Total	229,254	-
Less current portion	19,500	-
Long-term portion	$209,754	$-

At December 31, 2006, the company had available a $55 million Extendible Revolving Loan Facility (the "Conventional line of credit"). Borrowings are available in the form of prime loans, bankers' acceptances, US dollar base rate loans, LIBOR loans and letters of credit. As at December 31, 2006, $19.5 million in bankers' acceptances were outstanding at a rate of 5.62 percent and $168 thousand in letters of credit were issued. The facility's borrowing base is redetermined semi-annually based on the lending value of the company's conventional crude oil and natural gas reserves, as determined by the company's lenders in accordance with customary practice. The facility matures on April 15, 2007 and is extendible upon request by the company and at the lender's option for 364 days. The Conventional line of credit is secured by a $50 million fixed and floating charge debenture and a general assignment of book debts over the company's conventional crude oil and natural gas reserves and assets, and is non-recourse to the company's Great Divide oil sands, its refining assets and its investment in Petrolifera.

At December 31, 2006 the company also had available a US$15 million revolving line of credit (the "Refinery line of credit") to fund the working capital requirements of the refinery in Great Falls, Montana. Borrowings are available under this facility in the form of US dollar base rate loans, US Eurodollar rate loans and letters of credit. As at December 31, 2006 no amounts were drawn on this facility other than US$1.7 million of letters of credit. This facility matures October 20, 2011 and is secured by debenture and mortgage agreements covering all of the assets of the refinery and all of the company's interest in its Great Divide oil sands assets but is non-recourse to the company's conventional petroleum and natural gas assets and investment in Petrolifera.

In October 2006, the company secured a US$180 million, seven-year term loan (the "Oil sands term loan"). The full amount of the loan was drawn to fund US$51 million of the acquisition cost of the Montana refinery, to fund a US $14 million debt-service reserve account and to fund all of the remaining budgeted costs to complete the development of Pod One, the company's first oil sands project at Great Divide in northern Alberta. The loan is a floating rate facility, bearing interest either at a US dollar base rate plus a margin or a US Eurodollar rate plus a margin. The loan's Eurodollar interest rate as at December 31, 2006 was 8.61 percent. In October 2006 the company entered into an interest rate swap with a financial institution whereby the floating rate on US$90 million of the loan was fixed at an all-in rate of 8.516 percent over the term of the loan. All interest on this loan is being capitalized until Pod One becomes operational. One percent of the principal is required to be repaid annually, commencing in the fourth quarter of 2008. The oil sands term loan is secured by debenture and mortgage agreements covering all of the assets of the refinery and all of the company's interest in its Great Divide oil sands assets, but is non-recourse to the company's conventional petroleum and natural gas assets and to its investment in Petrolifera.

As indicated above, at December 31, 2006, the company had in place an interest rate swap to convert the effective rate on one-half of the oil sands term loan to an all-in fixed interest rate of 8.516 percent. The fair value of this interest rate swap at December 31, 2006 was a liability of $1.4 million.

Principal repayments under the aforementioned loans are due as follows: ($000)

2007	$19,500
2008	524
2009	2,098
2010	2,098
2011	2,098
Thereafter	202,936
	$229,254

10. ASSET RETIREMENT OBLIGATIONS

The following table reconciles the beginning and ending aggregate carrying amount of the obligation associated with the company's retirement of its conventional petroleum and natural gas properties and facilities and its oil sands properties and facilities.

Year ended December 31 ($000)	2006	2005
Asset retirement obligations, beginning of year	**$3,108**	$2,905
Liabilities incurred	**2,384**	301
Liabilities acquired (Note 3(a))	**2,109**	-
Liabilities settled with Petrolifera deconsolidation	-	(442)
Liabilities disposed	**(864)**	(24)
Change in estimated future cash flows	**237**	203
Accretion expense	**348**	165
Asset retirement obligations, end of year	**$7,322**	$3,108

At December 31, 2006 the estimated total undiscounted amount required to settle the asset retirement obligations was $17.4 million (2005 - $5.4 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 an inflation rate of 2.0 percent.

The company has not recorded an asset retirement obligation for the Montana refinery as it is currently the company's intent to maintain and upgrade the refinery so that it will be operational for the foreseeable future. Consequently, it is not possible at the present time to estimate a date or range of dates for settlement of any asset retirement obligation related to the refinery.

11. EMPLOYEE FUTURE BENEFITS

During 2006, the company established the following retirement/savings plans for its employees: a defined benefit pension plan and a defined contribution savings plan for its new US-based employees and a defined contribution savings plan for its Canadian employees.

(a) The defined benefit pension plan

As a consequence of the refinery acquisition and related employment of refinery personnel, the company's new US subsidiary, Montana Refining Company, Inc. ("MRC"), adopted a new non-contributory defined benefit retirement plan (the "Plan") covering MRC's employees on March 31, 2006. MRC's policy is to make regular contributions in accordance with the funding requirements of the United States Employee Retirement Income Security Act of 1974 as determined by regular actuarial valuations. The company's pension obligation is based on the employees' years of service and compensation, effective from, and after, March 31, 2006.

MRC is responsible for administering the plan. MRC has retained the services of an independent and professional investment manager, as fund manager, for the related investment portfolio. Among the factors considered in developing the investment policy are the Plan's primary investment goal, rate of return objective, investment risk, investment time horizon, role of asset classes and asset allocation.

Details of this Plan and the December 31, 2006 actuarial valuation are as follows:

($000)	**Pension benefits**
Components of net benefits cost	
Current service cost	**$365**
Interest cost	**16**
Net benefit cost	**$381**

Change in benefit obligation:

Benefit obligation at acquisition of refinery	$-
Current service cost	365
Interest cost	16
Foreign currency translation	7
Benefit obligation at December 31, 2006	$388

Amount recognized in the consolidated balance sheet consists of:	
Accrued benefits	$(388)

Assumptions used to determine benefit obligations at December 31, 2006	
Discount rate	5.75%
Long-term rate of compensation increase	3.00%

(b) The MRC defined contribution savings plan for United States employees
MRC also established new defined contribution (US tax code "401(k)"), savings plans that cover all of its employees from March 31, 2006. MRC's contributions are based on employees' compensation and partially match employee contributions. In 2006, MRC contributed $201,000 to this plan.

(c) The defined contribution savings plan for Canadian employees
In 2006, the company established a new defined contribution savings plans for its Canadian employees, whereby the company matches employee contributions to a maximum of eight percent of each employee's salary. In 2006, the company contributed $121,500 to this plan.

12. SHARE CAPITAL AND CONTRIBUTED SURPLUS

Authorized
The authorized share capital comprises 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 ($000)
Balance, December 31, 2004	89,626,743	$38,756
Issued for cash in public offerings (a)	45,541,000	90,001
Issued upon exercise of stock options (d)	981,000	666
Issued upon exercise of warrants (e)	3,791,705	1,986
Share issue costs		(5,980)
Tax effect of share issue costs		2,339
Tax effect of expenditures renounced pursuant to the issuance of flow through common shares (f)		(2,697)
Balance, December 31, 2005	139,940,448	125,071
Issued for cash in private placement (b)	19,047,800	100,001
Issued for cash in public offerings (c)	5,714,300	30,000

Issued for Luke acquisition (Note 3)	29,699,282	111,966
Issued for refinery acquisition (Note 3)	1,000,000	5,060
Issued upon exercise of options (d)	998,365	1,017
Issued upon exercise of warrants (e)	1,493,820	881
Share issue costs		(8,390)
Tax effect of share issue costs		2,924
Tax effect of expenditures renounced pursuant to the issuance of flow through common shares (g)		(5,448)
Balance, December 31, 2006	197,894,015	$363,082

Contributed Surplus:	
Balance, December 31, 2004	$535
Fair value of share options granted in 2005(d)	1,588
Assigned value of options exercised in 2005	(161)
Balance, December 31, 2005	1,962
Fair value of options granted in 2006 (d)	11,777
Assigned value of options exercised in 2006	(321)
Balance Contributed Surplus, December 31, 2006	$13,418

Total Share Capital and Contributed Surplus:	
December 31, 2005	$127,033
December 31, 2006	$376,500

(a) Public Offerings – 2005
In September 2005 the company issued from treasury 40,541,000 common shares at $1.85 per share. In December 2005 the company issued 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.

(b) Private Placement – 2006
In February 2006, the company issued 19,047,800 common shares from treasury at $5.25 per share on a private placement basis.

(c) Flow-through Share Issue - 2006
In September 2006, the company issued from treasury 5,714,300 common shares on a flow through basis at $5.25 per share. The company agreed to renounce the related resources expenditures of $30 million to the flow through investors effective December 31, 2006. The company has until December 31, 2007 to incur the eligible resource expenditures. As at December 31, 2006 $6.5 million of these expenditures have been incurred.

(d) Stock Options
A summary of the company's outstanding stock options, as at December 31, 2006 and 2005 and changes during those years is presented below:

	2006			2005
	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price
Outstanding, beginning of year	8,592,600	$1.49	3,988,600	$0.53
Granted	8,739,255	$4.81	5,994,000	$1.94
Exercised	(998,365)	$0.70	(981,000)	$0.51
Expired	(121,000)	$3.68	(409,000)	$1.05
Outstanding, end of year	16,212,490	$3.31	8,592,600	$1.49
Exercisable, end of year	6,563,864	$2.14	3,159,869	$1.03

All stock options have been granted for a period of five years. Options granted under the plan are generally fully exercisable after three years and expire five years after the date granted. The table below summarizes unexercised stock options.

Range of Exercise Prices	Number Outstanding	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Number Outstanding	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
At December 31		2006			2005	
$0.20 - $0.99	3,137,235	$0.69	1.7	4,276,600	$0.67	3.2
$1.00 - $1.99	1,996,000	$1.61	2.4	1,886,000	$1.61	5.0
$2.00 - $3.99	3,679,000	$3.18	3.1	2,430,000	$2.84	4.9
$4.00 - $5.99	7,400,255	$4.99	3.3	-	$-	-
	16,212,490	$3.31		8,592,600	$1.49	

In 2006 a compensatory non-cash expense of $8.3 million (2005 - $1.2 million) was recorded, reflecting the fair value of stock options amortized over the vesting period. Of this amount, $7.8 million (2005 - $1.2 million) was expensed as G&A and $0.5 million was charged to refining operating costs. A further $3.5 million (2005 - $0.4 million) 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:

	2006	2005
Risk free interest rate	4.1%	3.0%
Expected option life (years)	3	3
Expected volatility	50%	50%

The weighted average fair value at the date of grant of all options granted in 2006 was $1.81 per option (2005 - $0.65).

(c) Share purchase warrants
A summary of the company's outstanding share purchase warrants, as at December 31, 2006 and 2005 and changes during the years is presented below:

	2006	2005
Outstanding, beginning of year	1,493,820	5,300,525
Exercised	(1,493,820)	(3,791,705)
Expired	-	(15,000)
Outstanding, end of year	-	1,493,820

(f) Flow-through shares (2004)
The company renounced $7 million 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 $2.7 million and the company incurred the expenditures in 2005 as required.

(g) Flow-through shares (2005)
Effective December 31, 2005, the company renounced $15 million of resource expenditures to flow-through investors. The related tax effect of $5,448,000 on those expenditures was recorded in 2006. The company incurred all of the required expenditures related to these flow-through shares in 2006.

13. RELATED PARTY TRANSACTIONS

In 2006 the company paid professional legal fees of $1.8 million (2005 - $539,000) to a law firm in which officers or directors of the company are partners. 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.

14. SEGMENTED INFORMATION

In Canada, the company is in the business of exploring and producing conventional petroleum and natural gas and has recently commenced exploration and development of bitumen in the oil sands of northern Alberta. In the U.S., the company is in the business of refining and marketing petroleum products. Prior to the de-consolidation of Petrolifera in 2005 (Note 5) it also conducted a conventional petroleum and natural gas business in Argentina. The significant aspects of these operating segments are presented below. Included in Canadian administrative assets is the company's carrying value of its investment in Petrolifera.

Year ended December 31 ($000)	Canada Oil and Gas	Canada Administrative	USA Refining	Argentina Oil and Gas	Total
2006					
Revenues, net of royalties	$31,786	$-	$211,874	$-	$243,660
Equity interest in Petrolifera earnings	-	11,078	-	-	11,078
Dilution gain	-	23	-	-	23
Interest and other income	600	-	424	-	1,024
Crude oil purchase and operating costs	8,270	-	182,668	-	190,938
General and administrative	3,886	-	-	-	3,886
Stock-based compensation	-	7,816	-	-	7,816
Finance charges	4,992	-	94	-	5,086
Foreign exchange loss	4,287	-	-	-	4,287
Depletion, depreciation and accretion	29,366	-	3,583	-	32,949
Taxes (recovery)	(5,165)	-	9,035	-	3,870
Net earnings (loss)	(13,250)	3,285	16,918	-	6,953
Property and equipment, net	333,358	1,314	49,639	-	384,311
Capital expenditures and acquisitions	378,173	1,169	72,183	-	451,525
Total assets	582,325	22,795	107,548	262	712,930
2005 (1)					

Revenues, net of royalties	$8,202	$-	$-	$893	$9,095
Equity interest in Petrolifera loss	-	(27)	-	-	(27)
Dilution Gain	-	4,465	-	-	4,465
Interest and other income	678	-	-	22	700
Operating costs	2,126	-	-	319	2,445
General and administrative	-	2,348	-	312	2,660
Stock-based compensation	-	1,178	-	14	1,192
Finance charges	261	-	-	47	308
Foreign exchange loss (gain)	5	-	-	(35)	(30)
Depletion, depreciation and accretion	5,304	-	-	493	5,797
Taxes (recovery)	893	-	-	(23)	870
Net earnings (loss)	(3,262)	4,465	-	(212)	991
Property and equipment, net	44,611	631	-	-	45,242
Capital expenditures	14,771	269	-	1,767	16,807
Total assets	134,182	631	-	-	134,813

(1) 2005 comparative figures have been restated to conform to the current year's presentation.

15. SUPPLEMENTARY INFORMATION

(a) Per share amounts

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

For the years ended December 31	**2006**	2005
Weighed average common shares outstanding	**184,468,631**	106,113,563
Dilutive effect of stock options and stock purchase warrants	**3,963,178**	5,732,124
Weighed average common shares outstanding – diluted	**188,431,809**	111,845,687

(b) Net change in non-cash working capital

For the years ended December 31 ($000)	**2006**	2005
Accounts receivable	**$(25,284)**	$(277)
Refinery inventories	**(4,441)**	-
Due from Petrolifera	**189**	61
Prepaid expenses	**(692)**	(124)
Accounts payable and accrued liabilities	**31,567**	251
Income taxes payable	**3,512**	-
Total	**$4,851**	$(89)

Summary of working capital changes:

($000)	**2006**	2005
Operations	**$(9,271)**	$(485)
Investing	**14,122**	396
	$4,851	$(89)

(c) Supplementary cash flow information

For the years ended December 31	2006	2005
($000)		
Interest paid	$6,578	$67
Income taxes paid	3,655	3
Stock-based compensation capitalized	3,485	410

At December 31, 2006 cash of $122.8 million is restricted for use in paying expenditures for a designated oil sands project under the terms of the Oil sands term loan (Note 9).

16. 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:

2007 - $1.7 million; 2008 - $2.6 million; 2009 - $2.6 million; 2010 - $2.2 million; 2011 - $1.6 million; total thereafter $9.3 million.

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.

END